ATTACHMENT A: Ameren Illinois Utilities Load Forecast for Fiver Year Planning Period, June 2009 – May 2014

Ameren Illinois Utilities
Load Forecast for the period June 1, 2009 – May 31, 2014

A. 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.

B. Load Forecast Methodology

(1) Energy Forecast

The models developed for the June 1, 2009 – May 31, 2014 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 and AmerenIP commercial 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. After the initial forecast was complete, estimated energy efficiency reductions were taken out of the forecast. 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:

[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.

$$HeatIndex_y = \sum_{Type} Weight^{Type} x \frac{\left(Sat_y^{Type} \big/ Efficiency_y^{Type} \right)}{\left(Sat_{01}^{Type} \big/ Efficiency_{01}^{Type} \right)} \quad (4)$$

In the above expression, 2001 is used as a base year for normalizing the index. The ratio is equal to 1 in 2001. In other years, it will be greater than 1 if equipment saturation levels are above their 2001 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$\text{Weight}^{\text{Type}} = \text{Energy}_{01}^{\text{Type}} \times \text{HeatShare}_{01}^{\text{Type}} \quad (5)$$

$\text{Energy}_{01}^{\text{Type}}$ is the unit energy consumption of each end-use in 2001 according to EIA data adjusted for each service territory. $\text{HeatShare}_{01}^{\text{Type}}$ is the saturation levels for each heating end-use in 2001 multiplied by a structural index with base year 2001, which is a function of surface area and building shell efficiency.

$$\text{HeatShare}_{98}^{\text{Type}} = \text{Saturation}_{98}^{\text{Type}} \text{ x Structural Index}_{98} \quad (6)$$

where

$$\text{Structural Index}_{01} = (\text{Building Shell Efficiency}_y \text{ x Surface Area}_y) / (\text{Building Shell Efficiency}_{01} \text{ x Surface Area}_{01}) \quad (7)$$

where

$$\text{Surface Area} = 892 + 1.44 \text{ x House Size} \quad (8)$$

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:

$$HeatUse_{y,m} = \left(\frac{Price_{y,m}}{Price_{01}} \right)^{-0.10} x \left(\frac{HHIncome_{y,m}}{HHIncome_{01}} \right)^{0.20} x \left(\frac{HHSize_{y,m}}{HHSize_{01}} \right)^{0.20} x \left(\frac{HDD_{y,m}}{HDD_{01}} \right) \quad (9)$$

where $\text{Price}_{y,m}$ is the average residential real price of electricity in year (y) and month (m), Price_{01} is the average residential real price of electricity in 2001, $\text{HHIncome}_{y,m}$ is the

average real income per household in a year (y) and month (m), $HHIncome_{01}$ is the average real income per household in 2001, $HHSize_{y,m}$ is the average household size in a year (y) and month (m), $HHSize_{01}$ is the average household size in 2001, $HDD_{y,m}$ is the revenue month heating degree days in year (y) and month (m), and HDD_{01} is the annual heating degree days for 2001.

The HDD term in the HeatUse variable serves to allocate annual values to months of the year. Different values for HeatUse for each year will reflect changes in the economic driver changes, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .99 (computed as 1.10 to the -0.10 power).

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:

$$XOther_{y,m} = OtherIndex_{y} \times OtherUse_{y,m} \qquad (10)$$

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.

(2) 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. HDD and CDD's based on 50, 55, 65, 70, and 80 degrees are then created from the average daily temperature variable to allow load to respond to temperature in a non-linear fashion. These degree day variables are also interacted with seasonal and weekend variables to allow the weather 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).

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. 15-day moving average sales were used to capture growth trend in energy. 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. 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.

In addition, 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. A moving-average GDP variable was also used for AmerenCILCO.

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 91.3% to 93.6%. The Mean Absolute Percent Error (MAPE) of the models range from 2.83% to 3.83%, indicating that over all of the years of the analysis, the average day has an absolute error within this range.

Some adjustments were made after the model was complete. AmerenIP and AmerenCIPS models were consistently underpredicting the peak day loads by 1.3% and 4%, respectively; the model results were adjusted upwards by these percentages. In addition, looking at the historical monthly peaks for June, September and February, some adjustments were made to avoid a significant shortage of capacity.

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 1997-2006. 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

When peak load for each individual operating company has been forecast, the final steps are to adjust the months of July and August to allow for the annual peak to occur in each one and to allocate the total peak load within the various delivery service rates.

A review of historical peak loads indicates that the annual peak may occur anywhere from the latter part of June to the beginning of September. Looking across the companies over the period that data was available; the annual peak fell in months according to the following distribution:

June	July	August	September
3%	62%	33%	2%

To mitigate against a shortage of capacity during the critical summer period the highest monthly peak forecast value is applied to both July and August.

The total peak load forecasts were then divided into the delivery service components by using a load factor approach. From the most recent load research data that was available, the contributions of each delivery service class to the monthly peaks and the associated load factors were estimated. Then, using these load factors and the energy forecast, total peak load forecast was allocated between the various delivery service classes.

(2) 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 May 2008). 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 period 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, 2008, there were two Alternate Retail Electric Suppliers registered with both the ICC and the Utilities to serve residential customers in the Utilities' territories, as compared to eleven 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 choice and significant switching is not expected in the near term.

Future retail switching may be dampened in part by the rate credits resulting from Public Act 095-481. These credits will 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.

Residential switching could be positively influenced by an increase in the number of Alternate Retail Electric Suppliers (ARES) willing to serve residential customers, aggressive marketing campaigns or the development of value added products and services. 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 approximately 0.2% of available customers.

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

0-149 kW Non-Residential

This customer class has seen approximately 17% switching since January 1, 2007. Future switching patterns are difficult to predict due to limited historical data. The transition from frozen rates to the prices arising from the Illinois Auction did result in increased switching among this class.

It is reasonable to believe that ARES will focus their attention on larger industrial and commercial customers first, and as switching in those classes reaches saturation, such

focus will switch to smaller customer classes. In addition, customers in this class have the option of real time pricing.

The Utilities estimate that switching in this class will be approximately 36.4% by the end of the five year planning period.

150-399 kW Non-Residential

This customer class has seen approximately 45% switching since January 1, 2007. Future switching patterns are difficult to predict due to limited historical data. The transition from frozen rates to the prices arising from the Illinois Auction did result in increased switching among this class.

It is reasonable to believe that ARES will focus their attention on larger industrial and commercial customers first, and as switching in those classes reaches saturation, such focus will switch to smaller customer classes.

The Utilities estimate that switching in this class will be approximately 65% by the end of the five year planning period. In addition, customers in this class have the option of real time pricing.

400-999 kW Non-Residential

This customer class has seen approximately 65% switching since January 1, 2007. Section 16-113 (f) of the PUA declares this class to be competitive as of the effective date of Public Act 095-0461. The effect of this declaration is that those customers taking service from an ARES, or who subsequently switch to an ARES, shall no longer be eligible to take fixed price service under tariffs offered by the Utilities. Further, those customers who choose to remain with their applicable utility shall be defaulted to the host utilities' Real Time Price tariff if they do not choose to take service from an ARES by June 1, 2010.

Accordingly, the Utilities have assumed a continuation of the trend until December, 2009, when switching is expected to be approximately 70%. At that time, the switching rate is expected to accelerate in the months immediately preceding May 31, 2010 (the last date upon which a customer in this class is eligible to take service under fixed price tariffs.). After that date, the switching assumption is 100%.

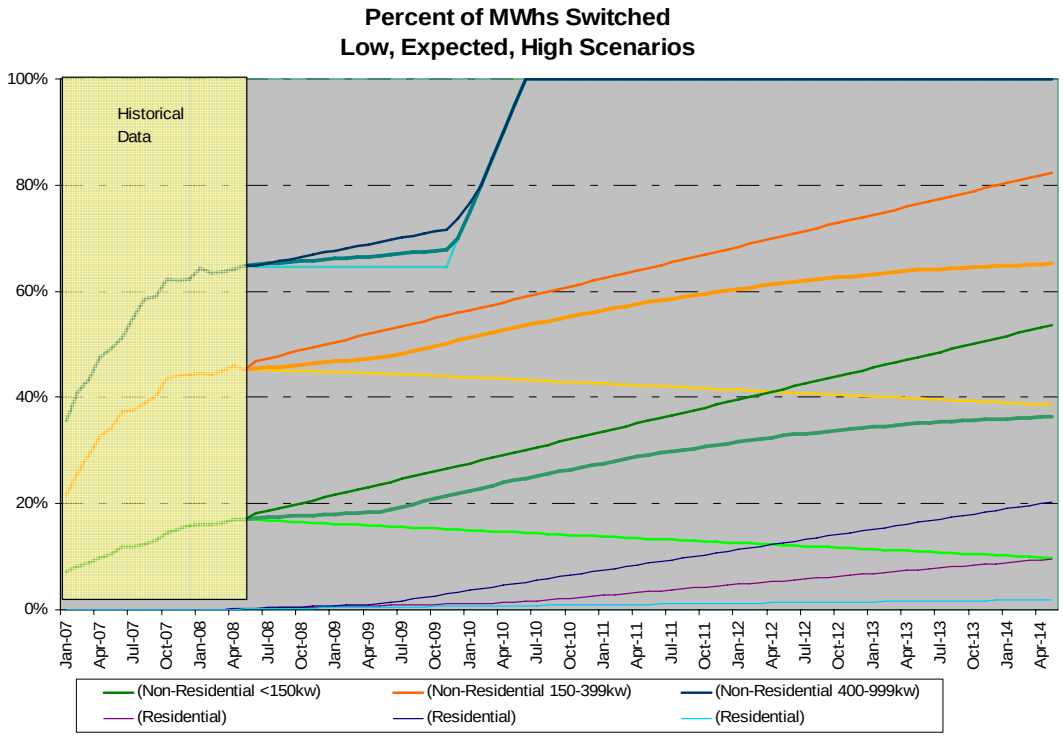
1,000 kW and Greater Non-Residential

This customer class is declared competitive and therefore these customers can no longer take the fixed price service after May 31, 2008.

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 begin to focus on smaller customer classes, market prices change or switching rules are modified. However, switching will 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, 2014 are included in the graph below:



(3) 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)

(1) Growth Forecasts By Customer Class

For the residential customer class, the Utilities currently project a 5-year Compound Annual Growth rate for AmerenCILCO, AmerenCIPS and AmerenIP of 0.44%, -0.08%, and 0.75% respectively. Commercial growth rates for the Utilities are projected to be 0.67%, 0.81% and -0.61%, respectively.

C. Analysis of the Impact Of Any Demand Side And Renewable Energy Initiatives

(1) 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 (those with peak demands up to 400 kW) by 0.2% in the 2009 planning year and increasing 0.1% each year for the remainder of the five year planning period. The effective reduction in the Utilities' aggregate supply requirements to be acquired through the RFP process (net of customer switching) is projected to be:

2009	7 MW
2010	14 MW
2011	18 MW
2012	23 MW
2013	27 MW

For the first planning year (June 1, 2009 through May 31, 2010), the demand response requirement is 0.2% of supply peak or 7 MW.

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

(2) Supply Side Needs Projected to be Offset by Renewable Energy Programs, if any.

RENEWABLE ENERGY PROGRAMS

THIS SECTION WILL BE UPDATED IN THE NEAR FUTURE.

(3) 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 by 0.2% in 2008 planning year and increasing 0.2% each year for the remainder of the five year planning period. The effective reduction in the Utilities' supply requirements to be acquired through the RFP process (net of customer switching) is projected to be

2009	47,075 MWh
2010	100,521 MWh
2011	130,405 MWh
2012	159,312 MWh
2013	217,844 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 and existing auction contracts.)

For the planning year June 1, 2009 through May 31, 2010, the energy efficiency requirement is 0.4% of delivered energy or approximately 47,075 MWh.