

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

| | | |
|--|---|----------------|
| Central Illinois Light Company | : | |
| d/b/a AmerenCILCO, Central | : | |
| Illinois Public Service Company | : | |
| d/b/a AmerenCIPS and Illinois | : | 07-0527 |
| Power Company d/b/a AmerenIP | : | |
| | : | |
| Approval of Initial Procurement | : | |
| Plan. | : | |

ORDER

DATED: December 19, 2007

TABLE OF CONTENTS

| | | |
|------|--|----|
| I. | PROCEDURAL HISTORY/STATUTORY AUTHORITY | 1 |
| II. | AMEREN'S PROCUREMENT PLAN..... | 3 |
| | A. Introduction | 3 |
| | B. Load Forecast..... | 4 |
| | 1. Load Forecast For the Period June 1, 2008 – May 31, 2013 | 4 |
| | 2. Switching Trends and Competitive Retail Market Analysis (II.B.2).. | 7 |
| | 3. Analysis of the Impact of Demand Side and Renewable Energy Programs (II.C)..... | 9 |
| | C. Portfolio Design (Section III) | 11 |
| | 1. Analytical Approach (III.B)..... | 11 |
| | 2. Proposed Procurement Plan to Meet Expected Load Requirements (III.C) | 16 |
| | 3. Renewable Energy Resources Plan (III.E)..... | 24 |
| | D. Procurement Administrator (IV) | 26 |
| III. | OBJECTIONS TO THE PLAN; PARTIES' COMMENTS; AMEREN'S REPLIES | 28 |
| | A. Load Forecast..... | 28 |
| | B. Portfolio Design | 29 |
| | 1. Introduction | 29 |
| | 2. Hedging, Risk Assessment and Related Issues..... | 30 |
| | a. The AG's Position..... | 30 |
| | b. CUB's Position | 36 |
| | c. Staff's Position..... | 36 |
| | d. Ameren's Position | 37 |
| | e. Commission Analysis and Conclusions..... | 44 |

| | | |
|-----|---|----|
| 3. | Contingency Plans | 47 |
| a. | Positions of the Parties..... | 47 |
| b. | Commission Analysis and Conclusions | 48 |
| 4. | Renewable Energy Standard and Related Issues..... | 48 |
| a. | Introduction; Statutory Authority | 48 |
| b. | Statutory Intent Regarding Priorities..... | 49 |
| c. | Use of Energy Credits | 52 |
| d. | RECs -- Timing Related Issues | 53 |
| 5. | Demand Response; Energy Efficiency; Related Issues | 54 |
| a. | Positions of the Position | 54 |
| b. | Commission Analysis and Conclusions | 59 |
| 6. | Supplier Contracts and Related Issues | 61 |
| a. | Positions of the Parties..... | 61 |
| b. | Commission Analysis and Conclusions | 64 |
| 7. | Customer Information; Bidding Process; and Related Issues | 66 |
| a. | Positions of the Parties..... | 66 |
| b. | Commission Analysis and Conclusions | 70 |
| 8. | Use of Short-Term Contracts | 71 |
| a. | Positions of the Parties..... | 71 |
| b. | Commission Analysis and Conclusions | 74 |
| C. | Procurement Administrator | 75 |
| IV. | TARIFF RELATED ISSUES | 75 |
| A. | Introduction | 75 |
| B. | Rider MVA; True-Up Mechanism | 75 |
| 1. | Positions of the Parties | 76 |

| | | |
|----|--|----|
| 2. | Commission Analysis and Conclusions..... | 78 |
| C. | Rider MVA; Rate Mitigation..... | 78 |
| 1. | Positions of the Parties | 78 |
| 2. | Commission Analysis and Conclusions..... | 83 |
| D. | Cost Recovery; Rider PER – Review of Reasonableness/Prudence of Costs..... | 85 |
| 1. | Introduction; Statutory Authority | 85 |
| 2. | Positions of the Parties | 86 |
| 3. | Commission Analysis and Conclusions..... | 91 |
| E. | Riders PER and MVA – General Tariff Language..... | 93 |
| F. | Rider PER – Generating Facility Cost Recovery..... | 94 |
| G. | Rider PER- Adjustments to Purchase Electricity Charges | 94 |
| H. | Rider HSS - Hourly Supply Service | 95 |
| I. | Deferral of Determinations on Tariffs | 96 |
| V. | FINDING AND ORDERING PARAGRAPHS | 97 |

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Central Illinois Light Company :
d/b/a AmerenCILCO, Central :
Illinois Public Service Company :
d/b/a AmerenCIPS and Illinois : **07-0527**
Power Company d/b/a AmerenIP :
: :
Approval of Initial Procurement :
Plan. :

ORDER

By the Commission:

I. PROCEDURAL HISTORY/STATUTORY AUTHORITY

Section 16-111.5(j) of the Public Utilities Act (“PUA” or “Act”), 220 ILCS 5/16-111.5, requires certain electric utilities to file an “initial procurement plan.” That section further provides, “The initial procurement plan shall identify the portfolio of power and energy products to be procured and delivered for the period June 2008 through May 2009, and shall identify the proposed procurement administrator”

The initial procurement plan shall include the components identified in Section 16-111.5(b). They include (1) an hourly load analysis; (2) an analysis of the impact of any demand side and renewable energy initiatives; (3) a plan for meeting the expected load requirements that will not be met through preexisting contracts; and (4) proposed procedures for balancing loads.

Section 16-111.5(c) provides that the “procurement process” shall be administered by a “procurement administrator.” The duties of the procurement administrator (“PA”) are detailed in 16-111.5(c)(1).

Section 16-111.5(k) provides in part, “In order to promote price stability for residential and small commercial customers during the transition to competition in Illinois, and notwithstanding any other provision of this Act, each electric utility subject to this Section shall enter into one or more multi-year financial swap contracts that become effective on the effective date of this amendatory Act.”

Section 16-111.5 (l) provides in part, “An electric utility shall recover its costs of procuring power and energy under this Section. The utility shall file with the initial procurement plan its proposed tariffs through which its costs of procuring power that are incurred pursuant to a Commission-approved procurement plan and those other costs identified in this subsection (l), will be recovered.”

Regarding the **timeline** following the filing of the initial plan, Section 16-111.5(j)(i) provides:

- Within 14 days following filing of the initial procurement plan, any person may file a detailed objection with the Commission contesting the procurement plan submitted by the electric utility. All objections to the electric utility's plan shall be specific, supported by data or other detailed analyses.
- The electric utility may file a response to any objections to its procurement plan within 7 days after the date objections are due to be filed.
- Within 7 days after the date the utility's response is due, the Commission shall determine whether a hearing is necessary. If it determines that a hearing is necessary, it shall require the hearing to be completed and issue an order on the procurement plan within 60 days after the filing of the procurement plan by the electric utility.

Pursuant to 16-111.5(j)(ii), "The order shall approve or modify the procurement plan, approve an independent procurement administrator, and approve or modify the electric utility's tariffs that are proposed with the initial procurement plan." The Commission "shall approve the procurement plan if the Commission determines that it will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."

On October 26, 2007, Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP (jointly, "Ameren," "the Companies," or "the Utilities") filed their plans and related tariffs, which were intended to comply with the statutory requirements.

Petitions for leave to intervene in this proceeding were filed by the People of the State of Illinois through the Attorney General, Lisa Madigan (the "AG"), the Citizens Utility Board ("CUB"), Dynegy Inc. ("Dynegy"), Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. ("Constellation"), the Retail Energy Supply Association ("RESA"), and Invenergy Wind North America LLC ("Invenergy").

On November 9, 2007 objections to Ameren's plan, or comments, were filed by the AG, CUB, Dynegy, Constellation, RESA, Invenergy, and the Staff of the Illinois Commerce Commission ("Staff"). On November 16, 2007, Ameren filed its Reply Comments.

On November 20, 2007, pursuant to Section 16-111.5(j) of the PUA, the Illinois Commerce Commission ("Commission"), in conference, approved the holding of a

hearing. On November 21, 2007, parties were advised by letter of the action of the Commission. Notice of the hearing was served on parties and on Municipalities served by the Ameren Companies.

On November 28, 2007, Supplemental Comments were filed by the AG and CUB; Staff filed Reply Comments as did RESA; Invenergy filed a Response, and Dynegy and Constellation each filed Additional Comments. On November 30, 2007, Ameren filed Supplemental Comments.

Pursuant to Notice, a hearing was held in this in this matter on December 3, 2007 at the Commission's Office in Springfield, Illinois. Appearances were entered by various parties. At the conclusion of that hearing, the record was marked "heard and taken."

A proposed order was served on all parties of record on December 11, 2007. On December 13, 2007, briefs on exceptions to the proposed order ("BOEs") were filed by CUB, Staff, the AG, Ameren, and Constellation. Those BOEs have been duly considered in this final Order.

II. AMEREN'S PROCUREMENT PLAN

A. Introduction

The Illinois Power Agency Act ("IPA Act" or "IPAA") and the PUA provide specific guidelines regarding the procurement process. However, the responsibility for such procurement activities by the Illinois Power Agency ("IPA") does not commence until the planning period beginning June 1, 2009, with the Utilities bearing responsibility to acquire supply resources until such time. 220 ILCS 5/16-111.5(a) of the PUA requires the Utilities procure power and energy for their eligible retail customers in accordance with the applicable provisions set forth in Section 1-75 of the IPA Act and Section 16-111.5 of the PUA.

As the Utilities are affiliated by virtue of a common parent company, they are considered by the PUA to be a single electric utility for the purpose of preparing the procurement plan, and as such are jointly presenting their plan covering their combined needs. They shall procure resources for those combined needs in conjunction with their plan and allocate capacity, and energy, and cost responsibility therefore amongst themselves in proportion to their requirements.

The Ameren Plan is divided into four sections. Section I contains an introduction and overview. Section II addresses the "Load Forecast for Period June 1, 2008 – May 31, 2113." Section III covers Portfolio Design. Section IV concerns the Procurement Administrator. Various tables and appendices are attached to the Plan.

B. Load Forecast

In accordance with Section 16-111.5(b) of the Act, Ameren's Plan 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 renewable energy initiatives, as well as demand response and energy efficiency programs are also addressed.

1. Load Forecast For the Period June 1, 2008 – May 31, 2013

Ameren states that the load forecast provides the basis for subsequent analysis resulting in a projected system supply requirement. In Section II.B of the Plan, "Hourly Load Analysis," Ameren's load forecast process includes a multi-year historical analysis of loads (subsection B.1), analysis of switching trends and competitive retail markets by customer class (B.2), known and projected changes affecting load (B.3), and customer class-specific growth forecasts (B.4). Section II.C contains an impact analysis of statutory programs related to demand response, energy efficiency and renewable energy. The results of Ameren's analysis and modeling include a 5-year summary analysis of the projected system supply requirements.

In Section B(1), "Multi-Year Historical Analysis of Hourly Loads," Ameren states that the models developed for the June 1, 2008 – May 31, 2013 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 identifying historical trends and to projecting 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 the residential and small commercial classes, while traditional econometric models were developed for the industrial, public authority, lighting and wholesale classes. Models were developed using revenue month sales data spanning from January 1995 (data for some models start later than 1995) to June 2006. Economic variables were obtained from Economy.com. Saturation and efficiency data was 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 to obtain the calendar month sales forecast.

The resultant sales were converted to the 2007 delivery service rate structure based on customer classifications within each of the 2007 delivery service rates. As a result, the DS1 class is equivalent to the residential class. The commercial, industrial, and public authority customers were separated into the DS2, DS3a, DS3b, and DS4

classes based on their maximum demand. The DS2 customers have a maximum demand less than 150 kW; DS3a customers have a maximum demand between 150kW and 399kW; DS3b customers have a maximum demand between 400kW and 999kW; and DS4 customers have a maximum demand over 1 MW. DS5 represents the lighting customers.

The peak forecast for the Utilities' eligible customer retail load was performed at the operating company level. For each company, historical hourly data was collected. The data for each company was gathered for the longest period of time that consistently defined load data was available. This ranged by company from about 2 1/2 to 8 1/2 years. From this hourly data, daily peak loads were determined. Ameren says the daily peak loads were the basis for the peak load 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, seasonal, day-type, and growth or 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. Ameren says 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).

Ameren says 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.

Ameren's daily peak model also includes independent binary variables representing each day of the week, each month of the year, and major holidays. Ameren claims 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.

According to Ameren, 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. Ameren says 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.

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

Ameren claims that statistical tests verify that the models fit the data quite well. Ameren says the R-Squared statistic, which indicates the amount of variation in the dependent variable (load) that is explained by the model, ranges from 91.9% to 94.5%. The Mean Absolute Percent Error (MAPE) of the models range from 2.68% to 3.70%, indicating that over all of the years of the analysis, the average day has an absolute error within this range.

The Utilities currently define normal for a weather element as the arithmetic mean of that weather element computed over the 30 year period from 1971-2000. This coincides with the definition that NOAA uses for normal weather. 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 30 year period. Ameren states that averaging temperatures by date (i.e. all 30 January 1st values averaged, then all 30 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, Ameren says a routine known as the “rank and average” method is used. In this method, all 30 years of historical weather data are collected. For each month of each year, the temperature data is sorted from the highest average temperature value to the lowest. Then the sorted data is average across the 30 years, with all of the hottest days in each month averaged with each other. Likewise, all of the coldest days in each month are averaged, while the mild days are averaged together.

After the weather has been averaged by the temperature rank, Ameren indicates that the days are “mapped” back to the actual weather from a calendar year. In this process, a specific reference year is selected. The average temperature from that year is sorted from high to low by month, retaining the original date as a record. The rank and average normal temperatures are associated with the ranked reference year data, and all data is resorted by the reference year dates. In this way, the “normal” temperatures follow a realistic contour that in fact has actually occurred in the past. The normal temperature series is run through the daily peak forecast model to produce a normal peak load forecast.

When each individual operating company has been forecast, Ameren says the final steps are to adjust for transmission losses, combine the three companies into one forecast, and adjust the months of July and August to allow for the annual peak to occur in each one. Once the peak load is determined for each operating company, an

adjustment for transmission losses is made. Ameren says the data used to forecast the peak load is at the generator level. The load will not include energy losses on the transmission system. Therefore, Ameren adjusts the peak down by a loss factor specific to the operating company determined by an engineering study of system losses.

Each operating company's monthly peak is independently forecasted. Ameren states that in reality, these three distinct peak load events can and likely will occur at different times in the month. As a result, Ameren says the Utilities' peak loads should be something slightly less than the sum of its component non-coincident peak loads. In order to make an adjustment for this potential diversity in the timing of the peak, historical peaks for Jan. 2004 through Aug. 2006 were analyzed. A coincidence factor was developed by month to be applied to the sum of the three operating company peaks. The coincidence factor applied ranges between 96.6% and 99.9% for the various months.

Ameren indicates that 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. 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. Ameren says the peaks were allocated to the Delivery Service classes based on an application of the typical load factors for each class at the time of monthly peak as a result of load research analysis of the classes.

2. Switching Trends and Competitive Retail Market Analysis (II.B.2)

Ameren states that the Utilities necessarily must make some assumption of 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 September 2007). 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, Ameren says 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.

As of September 1, 2007, Ameren indicates there were two Alternate Retail Electric Suppliers ("ARES") registered with both the ICC and the Utilities to serve residential customers in the Utilities' territories, as compared to ten so registered to serve non-residential customers in the Utilities territories. However, as of the date Ameren's plan was prepared, no residential customers of the Utilities have exercised

their right to choice and Ameren believes significant switching is not expected in the near term.

Ameren asserts that future retail switching may be dampened in part by the rate credits resulting from the recent legislation. 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, Ameren believes it is reasonable to expect some increase in residential switching.

In Ameren's view, 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. Ameren also states that 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. Ameren estimates that residential switching will be approximately 5% by the end of the five year planning period.

Ameren indicates that the 0-149 kW Non-Residential customer class has seen approximately 13% switching since January 1, 2007. All ten of the ten ARES registered to serve such customers were actually serving customers as of August, 2007. Ameren claims 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, although it is uncertain what effect if any the transition to an RFP procurement model will have on this class. In Ameren's view, 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. Ameren estimates that switching in this class will be approximately 37% by the end of the five year planning period.

According to Ameren, the 150-399 kW Non-Residential customer class has seen approximately 40% switching since January 1, 2007. All ten of the ten ARES registered to serve such customers were actually serving customers as of August, 2007. Again, Ameren asserts that 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, although it is uncertain what effect if any the transition to an RFP procurement model will have on this class. Ameren maintains that it is reasonable to believe 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. Ameren estimates that switching in this class will be approximately 55% by the end of the five year planning period.

Ameren indicates that the 400-999 kW Non-Residential customer class has seen approximately 59% switching since January 1, 2007. Nine of the ten ARES registered to serve such customers were actually serving customers as of August, 2007. Ameren

states that Section 16-113(f) of the PUA declares this class to be competitive as of the effective date of Public Act 95-0461. 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, Ameren says those customers who choose to remain with their applicable utility will 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. Ameren 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%.

The 1,000 kW and Greater Non-Residential customer class is declared competitive and therefore these customers can no longer take the fixed price service after May 31, 2008.

For the residential customer class, Ameren projects a 5-year Compound Annual Growth rate for AmerenCILCO, AmerenCIPS and AmerenIP of 1.57%, 1.30%, and 2.05% respectively. Ameren states that commercial growth rates for the Utilities are projected to be 1.47%, 1.13% and 0.84%, respectively.

3. Analysis of the Impact of Demand Side and Renewable Energy Programs (II.C)

Section 12-103 of PA 95-0481 establishes specific requirements for Demand Response Programs to reduce peak demand of eligible retail customers (those with peak demands up to 400 kW) by 0.1% in the 2008 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:

| | |
|------|---------|
| 2008 | 1.6 MW |
| 2009 | 6.7 MW |
| 2010 | 15.0 MW |
| 2011 | 20.0 MW |
| 2012 | 25.0 MW |

Ameren states that for the planning year June 1, 2008 through May 31, 2009, the demand response requirement is 0.1% of supply peak or 1.6 MW. Ameren says it will review the cost effectiveness of these programs as specified by statute and modify the program design accordingly if needed.

Section 1-75 (c) of the IPA Act establishes a Renewable Portfolio Standard that requires a minimum percentage of the Utilities' supply for eligible retail customers, as defined in Section 16-111.5(a) of the PUA, to be procured from cost-effective renewable energy resources. These standards are:

2% by June 1, 2008
 4% by June 1, 2009
 5% by June 1, 2010
 6% by June 1, 2011
 7% by June 1, 2012
 8% by June 1, 2013
 9% by June 1, 2014
 10% by June 1, 2015

These amounts will increase 1.5% each year thereafter until reaching at least 25% by June 1, 2025. To the extent available, 75% of these resources shall be from wind generation.

Ameren states that for the first year, the Utilities shall comply with these requirements through the acquisition of Renewable Energy Credits ("RECs"). Ameren says the acquisition of such credits will not reduce the amount of energy to be served in the planning year. Should the IPA contract for physical purchases of renewable energy resources in the future, Ameren says an adjustment to the forecasted load should be made at that time.

The amount of renewable purchases shall be limited such that the estimated average net increase due to the cost of renewable resources included in the amounts paid by eligible retail customers in connection with electric service is:

- In 2008, no more than 0.5% of the amount paid per kWh by those customers during the year ending May 31, 2007.
- In 2009, the greater of an additional 0.5% of the amount paid by those customers during the year ending May 31, 2008 or 1% of the amount paid per kWh by those customers during the year ending May 31, 2007.
- In 2010, the greater of an additional 0.5% of the amount paid by those customers during the year ending May 31, 2009 or 1.5% of the amount paid per kWh by those customers during the year ending May 31, 2007.
- In 2011, the greater of an additional 0.5% of the amount paid by those customers during the year ending May 31, 2010 or 2.0% of the amount paid per kWh by those customers during the year ending May 31, 2007.
- In each year thereafter, the greater of a) no more than 2.015% of the amount paid per kWh by those customers during the year ending May 31, 2007, or b) the incremental amount per kWh paid for these resources in 2011.

Ameren has determined that 0.5% of the amount paid per kWh during the year ending May 31, 2007 to equates to 0.04348 ¢/kWh eligible retail customers. These limits were multiplied by the forecast requirements for the June 2008 through May 2009 planning year to arrive at the total cost cap of approximately \$7.7 million dollars.

Section 12-103 (b) of Public Act 95-0481 establishes specific requirements for Energy Efficiency Programs that reduce energy consumption of delivery services customers by 0.2% in the 2008 planning year and increasing 0.2% each year for the remainder of the five year planning period. Ameren states that the effective reduction in the Utilities' supply requirements to be acquired through the RFP process (net of customer switching) is projected to be:

| | |
|------|-------------|
| 2008 | 12,948 MWh |
| 2009 | 77,546 MWh |
| 2010 | 224,483 MWh |
| 2011 | 372,546 MWh |
| 2012 | 556,871 MWh |

Ameren says 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 existing contracts. For the planning year June 1, 2008 through May 31, 2009, Ameren says the energy efficiency requirement is 0.2% of delivered energy or approximately 12,948 MWh. Ameren states that it will review the cost effectiveness of these programs as specified by statute and modify the program design accordingly.

C. Portfolio Design (Section III)

According to Ameren, the objective of the procurement plan supply portfolio, as stated in Section 1-5 of the IPA Act, is to "ensure adequate, reliable, affordable, efficient and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." Ameren plans to use a portfolio of forward contracts and Midwest ISO ("MISO") spot purchases to supply the Utilities' eligible retail customer load.

1. Analytical Approach (III.B)

Ameren believes that when designing a portfolio to serve the Utilities' eligible retail customer load from June 1, 2008 through May 31, 2009, a key concern is how much of the supply should be hedged with forward contracts and how much should be subject to MISO spot market prices. Ameren used a simulation modeling approach to arrive at a supply portfolio of standard market products.

In Ameren's view, it is helpful to consider two of the Utilities' base assumptions prior to a discussion of the details of that analysis. The first assumption is that forward contracts represent an incremental cost to customers. Ameren claims this is due to the fact that sellers of forward contracts are taking on pricing risk by entering into these contracts. Ameren believes that these suppliers expect to extract a premium for taking on this risk although the magnitude of this premium is uncertain. The second assumption is that the risk to customers (measured in standard deviation) is reduced with the addition of fixed priced forward contracts, as compared to the 100% spot

purchase portfolio, until a point where risk is minimized, at which point additional forward contracts then cause risk to increase.

Ameren defines the term “hedge ratio” as the quantity (MWh) of forward energy contracts in a specified time period divided by the total energy (MWh) required to serve the load in that same period. For example, if the Utilities were to supply their eligible retail customer load in a specific time period utilizing only MISO spot market purchases this would equate to a 0.0 hedge ratio. As a second example, if during a specific time period the Utilities procured forward contracts of 1,000 MW in each on-peak hour (a 5x16 contract) that would equate to 336,000 MWhs acquired using forward contracts. If the energy forecast for the July on-peak period was also 336,000 MWhs, this would equate to a 1.0 hedge ratio.

Ameren’s analysis of how much to contract forward for the June 1, 2008 through May 31, 2009 planning year was performed as 24 independent analyses (1 analysis for each of the 12 monthly on-peak periods and 1 analysis for each of the 12 monthly off-peak period), utilizing a simulation model (RT Sim) populated with 250 load and price scenarios.

Ameren states that these 250 load and price scenarios were developed using a Monte Carlo simulation model. Scenarios were based on the relationship of daily power prices and daily peak-hour loads to a series of variables. The variables included weather, calendar day, load growth, volatility, and forward price. The models also took into account the correlation between load and price, and the impact of load that will be served via existing Illinois Auction contracts and by ARES. Load models (based on 2006 actual hourly loads for relevant Illinois customer classes) produced daily peak-hour load estimates, which were “shaped” to hourly load estimates. Price models (using historical price volatility and expected monthly forward price estimates) produced daily price estimates, which were “shaped” to hourly price estimates.

Final output of the 250 load and price scenarios closely converge to the expected monthly forward price estimates and the Utilities peak demand and energy forecast. Despite Ameren’s belief that there is a risk premium associated with forward contracts relative to the spot market prices, such an assumption was not incorporated into the model as there was not sufficient market data available to enable Ameren to reasonably determine the magnitude of this premium. Ameren says it has considered the potential impact of such a premium outside the construct of this model.

Ameren says each of these 24 independent analyses consisted of evaluating multiple contract portfolios against the 250 load and price scenarios. In the initial analysis, the model considered portfolios ranging from no forward contracts (0.0 hedge ratio) to an amount of forward contracts in excess of two times the average load (2.0 hedge ratio) in 100 MW increments. For each portfolio option, RT Sim calculated the expected cost and risk as measured in standard deviation. In the final analysis, each of the 24 analyses was refined to 25 MW increments around the 1.0 hedge ratio to provide more detail.

Ameren indicates that the model results showed no change in the expected cost to serve the load as additional forward contracts were added to the 0.0 hedge ratio portfolio. Ameren expected this relationship due to the modeling assumption that there is no risk premium associated with forward contracts relative to the spot market prices. As stated earlier, Ameren accounted for the potential impact of such a premium outside the construct of the simulation model.

According to Ameren, the model results also showed that, as forward contracts were added to the 0.0 hedge ratio portfolio, the associated price risk decreased until a point very close to a 1.0 hedge ratio. As additional forward contracts were added beyond the 1.0 hedge ratio, price risk increased. Ameren states that while these results were consistent across all 24 analyses, risk in the on-peak periods increased more dramatically as the portfolio began to deviate either positively or negatively from the 1.0 hedge ratio as compared to the off-peak periods.

Ameren asserts that the amount of price risk associated with serving the portfolio is sensitive to changes in the quantity of forward contracts, with the lowest risk being achieved when forward contracts are close to the average load, a 1.0 hedge ratio. In addition, Ameren says the increase in risk associated with a portfolio that deviates from a 1.0 hedge ratio is much more pronounced in the on-peak periods relative to the off-peak periods. Once the above analysis was completed, Ameren then determined the specific products that should be procured via the RFP process, taking into account the belief that a risk premium may be applied to any forward contracts above and beyond what was included in the model analysis.

One alternative reviewed was procuring each of the 24 individual products, monthly on-peak and off-peak, in the exact amounts required to meet the 1.0 hedge ratio. Ameren believes this alternative is unlikely to produce the most efficient result for several reasons. First, the energy markets tend to place a premium on odd-lot contracts; therefore, a more efficient result likely will be obtained by purchasing in blocks such as 25 or 50 megawatts. Secondly, Ameren says including 24 products, one each for each monthly on-peak and off-peak period, may result in insufficient supplier interest in one or more of the products if such products are not liquidly traded in the market. Ameren argues that conversely, consolidating the 24 products into a smaller number of annual and seasonal products that more closely align with the products that are actively traded in the energy markets should increase supplier interest and simplify the process for the Procurement Administrator to develop the price benchmarks required by the law.

Ameren states that because the model did not account for risk premiums that suppliers will likely include in their bids for forward contracts, procuring products in an amount equal to a 1.0 hedge ratio likely results in a higher expected cost than procuring products in an amount to achieve a relatively lower hedge ratio. As described below, multiple consolidated portfolios were analyzed and the impact of each on risk was considered by Ameren.

The “100% Spot Purchase Portfolio” assumes that no additional forward contracts are made and that 100% of the currently unhedged eligible retail customer load is priced only based on the MISO day-ahead and real-time energy market prices that result in the future. The 400 MW annual swap included in this portfolio represents the existing swap contract that was executed between the Utilities and Ameren Energy Marketing Company as part of the new legislation. The model results for this portfolio show a standard deviation of \$34.821 million.

“Portfolio A” represents a level of forward hedging approximately equal to a hedge ratio of 0.8. This portfolio attempts to shape the forward hedges in the on-peak periods to closely match the monthly shape of the average energy requirements while the contracts in the off-peak periods represent a flat annual block. The model results for this portfolio show a standard deviation of \$15.533 million.

“Portfolio B” represents a level of forward hedging approximately equal to a hedge ratio of 0.9. This portfolio attempts to shape the forward hedges in the on-peak periods to closely match the monthly shape of the average energy requirements while the contracts in the off-peak periods represent a flat annual block. The model results for this portfolio show a standard deviation of \$10.663 million.

“Portfolio C” represents a level of forward hedging approximately equal to a hedge ratio of 0.95. This portfolio attempts to shape the forward hedges in the on-peak periods to closely match the monthly shape of the average energy requirements while the contracts in the off-peak periods represent a flat annual block. The model results for this portfolio show a standard deviation of \$9.212 million.

“Portfolio D” represents a level of forward hedging approximately equal to a hedge ratio of 1.0. This portfolio attempts to shape the forward hedges in the on-peak periods to closely match the monthly shape of the average energy requirements while the contracts in the off-peak periods represent a flat annual block. The model results for this portfolio show a standard deviation of \$8.762 million.

“Portfolio E” represents a level of forward hedging approximately equal to a hedge ratio of 1.0. This portfolio attempts to shape the forward hedges in both the on-peak periods and off peak periods to closely match the monthly shape of the average energy requirements. The model results for this portfolio show a standard deviation of \$8.252 million.

What Ameren calls “The Model Solution” represents a portfolio consisting of a level of hedging for each of 24 products analyzed by the model which minimizes customer risk. The model results for this portfolio show a standard deviation of \$7.069 million.

According to Ameren, consolidating the 24 monthly on-peak and off-peak products into a much smaller number of annual and seasonal products that are more

liquidly traded in the energy markets has a relatively small impact on the standard deviation of the expected cost to serve the load. Comparing Portfolio D and the Model Solution shows that the standard deviation increases by just \$1.693 million, which represents 0.50% of the expected cost to serve the load under portfolio D.

Ameren also asserts that there is very little value added by attempting to shape the off-peak hedges to match the shape of the monthly average energy requirements. The difference in the standard deviation between Portfolio D and Portfolio E is only marginally better (\$510,000) in Portfolio E, which attempts to shape the off-peak hedges.

Ameren claims that the standard deviation of expected cost to serve the load increases at an increasing rate as the hedge ratio is decreased from 1.0 to 0.8. This is illustrated by comparing the results for portfolios A, B, C & D. In comparing to the Portfolio D (1.0 hedge ratio) to Portfolio C (0.95 hedge ratio) Ameren says that by decreasing the forward hedge by 5% the standard deviation is increased by \$451,000. For the next 5% decrease in hedging, going from a 0.95 hedge ratio to a 0.9 hedge ratio (comparing Portfolio B to Portfolio C), the standard deviation increases much more dramatically at \$1.450 million. Ameren says the final comparison of Portfolio A and Portfolio B shows this trend continuing with an increase in standard deviation of \$4.870 million for this final 10% decrease in hedging.

Prior to selecting the final hedge ratio, Ameren claims one final factor must be considered, that being the risk premium suppliers in the market add to forward contracts, relative to projected spot market prices, that Ameren believes exists in the market. In an attempt to see how such a risk premium would affect the optimal level of hedging Ameren considered a scenario in which it is hypothesized that this risk premium is 5%. Such a 5% premium applied to the approximately \$340 million of expected energy cost produced by the model equates to a \$17 million premium to contract at a 1.0 hedge ratio as compared to leaving 100% of the energy priced at the spot market prices. Stated otherwise, Ameren says that each 5% increase in the hedge ratio equates to an \$850,000 increase in costs directly associated with the hypothetical 5% risk premium.

Ameren states that applying this hypothetical risk premium to the model results pushes the optimal level of hedging below the 1.0 hedge ratio. The model results showed that going from a 1.0 hedge ratio to a 0.95 hedge ratio increased the standard deviation of the expected cost by \$451,000 and that further decreasing the hedge ratio to 0.9 increased this standard deviation by \$1.450 million. If the hypothetical risk premium is included, each of these decreases in the level of hedging would decrease the expected energy cost by \$850,000. Comparing the increase in standard deviation to the decrease in expected cost as the hedge ratio is decreased from 1.0 to 0.95 to 0.9 illustrates that consideration must be given to the tradeoff between cost and standard deviation. Ameren concludes that the inclusion of the hypothetical 5% premium supports a hedge ratio lower than 1.0.

According to Ameren, however, the hypothetical risk premium does not appear to be sufficient to drive the hedge ratio any lower than 0.9. Ameren says this is because the model results showed that going from a 0.9 hedge ratio to a 0.8 hedge ratio increased the standard deviation of expected cost by \$4.870 million. If the hypothetical risk premium is included, this decrease in the level of hedging would decrease the expected energy cost by \$1.7 million, which is not sufficient to overcome the nearly \$5 million in increased standard deviation. On the basis of the model results, and considering the effect that the inclusion of a risk premium on forward contracts likely has on the level of forward hedging, Ameren has elected a hedge ratio of 0.9 as illustrated in Portfolio B.

2. Proposed Procurement Plan to Meet Expected Load Requirements (III.C)

Ameren states that supply will be procured for those customers in the following customer classes that acquire power and energy from the Utilities under fixed price, bundled service tariffs:

- Residential (BGS-1)
- Non Residential less than 150 kW (BGS-2)
- Non Residential from 150 kW up to 400kW (BGS-3A)
- Non Residential from 400 kW up to 1,000 kW (BGS-3B)
- Lighting Service (BGS-5)

Monthly forecasted system supply requirements for energy are shown in a table in Section III.C.2 of the Plan.

Monthly forecasted system supply requirements for capacity are shown in a table in Section III.C.3 of the Plan. According to Ameren, capacity is required of the Utilities to ensure reliable service of their customers and is mandated by the Southeastern Electric Reliability Council (SERC) and MISO. Ameren says the MISO Open Access Transmission and Energy Markets Tariff ("MISO Tariff") requires that the Utilities demonstrate they have acquired capacity in an amount equal to their expected peak load plus planning reserves.

MISO further specifies that the amount of planning reserves must be the higher of the amount required by the Regional Reliability Organization (SERC in the case of the Utilities) or the State of Illinois, but in no case is the planning reserve requirement to be less than 12%. Ameren states that since the state of Illinois does not specify a required planning reserve requirement and SERC specifies the requirement to be a minimum of 15%, the Utilities are therefore required to acquire capacity equal to their expected peak load plus 15% for planning reserves.

Ameren indicates that its procurement plan forecast for peak demand was developed in similar fashion as the energy forecast and included adjustments for: competitive declarations, customer switching, demand response, and existing auction

contracts. For each month of the period, the hourly peak forecast was developed after adjustment for the above factors. Reserves in the amount of 15% were added to calculate monthly capacity requirements. Monthly peak forecasts are shown on a table on Section III.C.3

Section III.C.4 contains a description and analysis of **preexisting supply contracts**. As part of the 2006 Illinois Auction the Utilities entered into a series of Supplier Forward contracts to serve the BGS-FP load, which encompasses the eligible load. One third of these contracts (BGS-FP17) expire May 31, 2008. Of those contracts that will remain, one half (BGS-FP29) expire May 31, 2009 and the remainder (BGS-FP41) expire May 31, 2010.

The Illinois Auction was designed to procure full requirements service. A product in the Illinois Auction corresponded to a specific category of load for a specific supply period. Three of the four Utilities' products were to procure supply for residential and small business customers for various supply periods, ranging from seventeen to forty-one months. Each product was divided into a number of units called tranches. A tranche is defined as a percent of actual customer load as suppliers at the Auction bid to provide full requirements service for at least one load category and for at least one supply period.

Full requirements service involves providing the capacity, energy and ancillary services needed to serve load and assessing and managing load variability risks. Tranches were defined in this way so that the supply being provided through the Auction is structured similarly to the competitive supply that a customer may buy from an ARES. Thus the functions of assembling a portfolio of power supply, managing supply price risks and managing load variability risks are performed by competitive entities and subject to the discipline of competitive market pricing. A tranche is not defined by MW, but as a percentage of the actual load of the Utilities' customers for the load category.

There were 36 tranches in each of the FP-29 and FP-41 products, with 4 winning suppliers and 3 winning suppliers respectively. These preexisting BGS-FP contracts reduce the amount of supply to be acquired under this procurement plan, and the associated load was excluded from the determination of the Utilities' combined supply requirements.

Ameren states that the following **financial swap agreement** is also a preexisting supply contract:

June 1, 2008 to May 31, 2009: 400 MW for all hours;
June 1, 2009 to May 31, 2010: 800 MW for all hours; and
June 1, 2010 to December 31, 2012: 1,000 MW for all hours.

Under the terms of the swap agreement, the Utilities will pay a fixed price in exchange for a floating price: the MISO real-time LMP at the Ameren Illinois Load Zone. Ameren

states that the preexisting financial swap contracts reduce the amount of supply to be acquired under its procurement plan, which has been accounted for in the determination of the specific products to be acquired to meet these supply requirements. Ameren also indicates that the Utilities are parties to various contracts with qualifying facilities under their applicable QF tariffs.

Section III.D, **Identification of Wholesale Products to be Acquired**, contains five subsections.

In Subsection III.D.1, the Plan describes the proposed mix of standard power and energy products. With regard to energy, according to Ameren, the Utilities will acquire the physical energy necessary to meet their combined load requirements via the MISO day-ahead and real-time energy markets, and will enter into **financial swap contracts** to hedge price exposure. Ameren states that a financial swap is a commercial transaction between two parties involving the exchange (swap) of risk. In this instance, the Utilities desire to pay a fixed price, and will settle all loads with the MISO at LMP. Under a swap transaction the Utilities will pay a fixed price to their supplier in exchange for receiving a floating price (MISO LMPs) from the supplier. As such, the LMP paid by the Utilities to the MISO is offset by the LMP received from the supplier, leaving the Utilities only paying the fixed price. Ameren asserts that financial swaps provide the same level of hedging as physical transactions but with greater ease of administration and are expected to yield a lower total cost.

Ameren claims that within MISO, financial swaps have become a standard, if not preferred, product among market participants including generators, load serving entities and financial participants. Ameren says the existence of the MISO Markets facilitates this, as the historical concept of physical deliveries of energy from source to sink has been replaced with the concept of energy injections and withdrawals. Financial swaps may be offered by traditional generation owners and pure financial market participants. For this reason, Ameren believes it is reasonable to expect a larger number of participants in their competitive RFP process than if the product were restricted to physical deliveries. Ameren also believes it is reasonable to expect that the greater the number of participants in a competitive process, the higher the likelihood of a competitive result.

Ameren contends that financial swaps do not have the same administrative burden as bilateral transactions for physical delivery. Ameren claims such transactions have increased operational requirements with the MISO, and incrementally higher associated costs, including certain MISO administrative fees. Given their lower administrative burden, lower expected total cost, acceptance by the marketplace and ability to effectively deliver the same price hedging characteristics as traditional bilateral transactions for physical delivery, Ameren believes financial swaps are a superior product.

Ameren claims that the use of financial swaps will not adversely affect reliability as the Utilities will contract for sufficient Capacity to meet the load obligations; the

contracts for such Capacity shall obligate the seller to offer such Capacity into the MISO markets. Ameren says this portfolio was reviewed by the Utilities' Procurement Administrator to ensure that that the final portfolio would be viewed favorably by potential suppliers and that the portfolio would have a high likelihood of being procured from the markets successfully at competitive market prices.

Regarding **capacity**, Ameren indicates that the Utilities will use the RFP process administered by the Procurement Administrator to acquire 100% of the monthly capacity requirements for the summer period, June 2008 through September 2008, and 90% of the monthly capacity requirements for all remaining months. Ameren says the remaining capacity needs for the non-summer period will be procured through monthly spot purchases using a process similar to that used to procure non-summer capacity for the RTP-L load. According to Ameren, this process will ensure that the Utilities acquire adequate capacity in advance of the summer period when usage is at its highest and reliability is most critical. In addition, Ameren says it will help protect against the purchase of spot capacity in the summer, when the possibility of scarcity pricing is greatest.

Ameren asserts that by purchasing forward only 90% of the requirement for the non-summer months, the Utilities also protect against a scenario where switching is greater than expected, thus resulting in excess capacity. In the event the Utilities have excess capacity in non-summer months, Ameren says it is highly unlikely they could recover a significant portion of the cost, if any, by selling this excess back to the market, as the market has significantly more capacity in non-summer months when compared to summer months thus resulting in prices that are 5 to 10 times less than the summer months. Because of these factors, Ameren believes it is reasonable to expect that any additional capacity needed in non-summer months and not contracted for in the forward markets can easily be acquired by the Utilities in the spot market with little or no price volatility.

Ameren says the monthly spot purchases will be made directly by the Utilities using a competitive solicitation process. Under this process, the Utilities will identify, prior to each month, the then current capacity shortfall for the month by comparing the current forecast to the quantity of capacity previously acquired. Ameren indicates that an electronic bulletin board, such as the Non-MISO Bilateral Transactions Bulletin Board, will be utilized to notify market participants of the opportunity to sell capacity to the Utilities. The Utilities will then survey those counterparties with current enabling agreements via email, instant messaging service, telephone or other electronic means. Once the deliverability of the capacity is confirmed via a report on the MISO website, Ameren says the Utilities will buy from the entity offering the lowest price. The Utilities will document this solicitation process to include records of market surveys, a list of offers received and the final purchase price, quantity and counterparty.

In addition to the acquisition of power and energy related products, Ameren says the Utilities are obligated by the MISO Tariff to acquire certain **transmission service related products** and services to effectuate delivery of power and energy to the

applicable loads. (III.D.2) These services include Network Transmission Service and Ancillary Service. Further, the Utilities may be allocated certain Financial Transmission/Auction Revenue Rights.

According to Ameren, the Utilities utilize Network Integrated Transmission Service (“NITS”) to reliably deliver capacity and energy from their Network Resources to their Network Loads -- namely their Native Load obligations. The MISO tariff requires each NITS customer to complete an application for service, complete any applicable technical arrangements in conjunction with the Transmission Provider and Transmission Owner and execute both a Service Agreement and a Network Operating Agreement. Ameren says the Utilities will acquire the necessary NITS in accordance with the tariff and the cost for this service will be that established in the applicable MISO tariff schedules.

Ameren indicates that the MISO tariff defines **ancillary services** as “(t)hose services that are necessary to support Capacity and the transmission of Energy from Resources to Loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.” As detailed in Module A, Section II.3 of the MISO tariff, each Transmission Service Customer is required to acquire the following ancillary services (i) Scheduling, System Control and Dispatch, (ii) Reactive Supply and Voltage Control from Generation Resources, (iii) Regulation and Frequency Response, (iv) Operating Reserve-Spinning and (v) Operating Reserve-Non-Spinning -- whether from the Transmission Provider, from the Control Area, from the ITC, from a third party, or by self-supply.

Within MISO, energy imbalance service is provided by the operation of the real time market and is no longer required to be acquired as a separate ancillary service. Ameren says the Utilities will acquire the necessary ancillary services in accordance with the MISO tariff and the cost for this service will be that established in the applicable MISO schedule or as otherwise determined by the operation of the MISO ancillary services market.

Ameren states that **Auction Revenue Rights** (“ARRs”) are not a power and energy resource; however, the nomination and subsequent allocation of such rights to the Utilities generally serves to reduce the cost of congestion borne by the utilities and ultimately by their customers. Ameren says the Utilities are actively participating in the process to identify and register the historic relationship between loads and resources which forms the basis of the ARR entitlements. They will also actively participate in the nomination and allocation phase of this process. They will seek to nominate those ARR's with an expected positive value, recognizing that they may be required by the MISO to accept certain ARR's which do not have an expected positive value and further that though nominated, they ultimately may not be allocated all of the ARR's requested. Ameren says the Utilities will retain the allocated ARR's, except to the extent that should the delivery point for one or more of the energy resources be other than within the AMIL balancing authority; the Utilities may attempt to reallocate the applicable ARR's from

their historical resource points to those which align more closely with the designated energy resource delivery point.

Section III.D.3 describes the **assessment, including sensitivity analysis, of price risk, load uncertainty and other factors.**

In addition to the load uncertainty in terms of weather, known and projected changes and customer switching, Ameren addresses **load uncertainty and price risk** in its analysis of the expected cost of various hedge ratios. Ameren states that estimates of hourly loads and hourly power prices were developed from a series of models. The models were based on the relationships of daily power prices and daily peak hour loads to a series of variables, including weather, calendar, growth, volatility, and forward price. The models also took into account the correlation between loads and prices, and the impact of “tranches” and customer switching.

According to Ameren, **contracts** entered into as a result of the procurement process shall be through either an ISDA agreement (for financial instruments such as fixed/floating rate swaps) or an EEI agreement (for physical products such as capacity). Ameren says individual transactions will be memorialized utilizing standard transaction specification sheets, such that to the extent practical purchasing decisions shall be made on the basis of price, rather than non-price factors. Ameren states that the terms and conditions of these agreements shall determine the relative obligations of the parties and as such, are expected to have an influence on the price of an individual transaction. Given that this represents an allocation of the risk between the parties, Ameren expects overall cost to consumers would not be materially affected. That is, suppliers will be expected to include in their price compensation for those risks that they bear.

For those risks borne directly by the utilities (and thus their customers), the associated costs are directly borne. Whether the risk is borne by suppliers and compensation for assuming such a risk is included in their overall price, or the risk is born directly by the utility and the associated cost included in the determination of rates, Ameren says the end-use customer ultimately bears the cost of managing this risk. As such, Ameren believes the agreements should seek to assign risk to that party best capable of managing that risk.

Ameren says that because the Utilities do not own generation resources, risks related to **fuel costs** are reflected within the prices offered by potential suppliers and have not been separately analyzed.

Ameren states that the assessment and variability of load uncertainty is primarily driven by assumptions of **weather** patterns and that assessment and sensitivity analysis regarding this variable is included in the discussion of price and load uncertainty.

According to Ameren, the Utilities shall bear the cost of **Network Integrated Transmission Service** and the related Ancillary Services. Ameren says the

procurement plan is expected to result in deliveries to a homogeneous delivery point, thus removing transmission costs as a factor in the analysis.

With regard to **market conditions**, the Utilities are members of the MISO, their loads are within the MISO footprint, and are settled via the MISO markets. The anticipated delivery points for the contracts to be acquired through the procurement process are likewise located within the MISO. Ameren says the MISO Independent Market Monitor's most recent State of the Market Report indicates that the MISO energy markets performed competitively in 2006. Total generation resources within the MISO footprint were 127 GW in 2006. Reserve margins within the footprint at the time of the report showed a wide range, depending upon the method of measurement and whether interruptible demand is included.

When permanent de-rates and temperature sensitive capacity not expected to be available at times of system peak are removed from nameplate capacity, Ameren indicates that the MISO reserve margin ranges from 5.5% - 12.7%. The former value does not account for interruptible load. Ameren says the Utilities currently maintain a 15% planning reserve margin; they are currently members of SERC and the MISO planned reserve sharing group, and in future periods will be obligated to hold the reserve margin established by these organizations.

Since the 2006 auction, Ameren says the Utilities have run two RFP processes to acquire capacity and numerous short term solicitations for capacity. In each instance, more supply was offered than required and the Utilities were able to secure their needs. Ameren believes this recent experience supports a belief that the upcoming procurement process is reasonably expected to attract sufficient interest to likewise yield competitive results.

Subsection III.D.4 briefly discusses the identification of alternatives for portfolio measures having significant price risk.

Procedures for **balancing loads** are discussed in Section III.D.5. Given the Utilities' intent to enter into financial swap transactions to hedge the energy price risk, rather than physical transactions, Ameren indicates that 100% of the energy required to supply the load included in this procurement plan will be purchased in the MISO energy markets. Ameren says the Utilities will make a good-faith forecast of their respective load requirements for each delivery day. These forecasts will be utilized to submit a day-ahead demand bid to the MISO market, which will be settled with the MISO at a price equal to the MISO day-ahead LMPs for each hour.

According to Ameren, hourly balancing will be performed through the MISO real time energy market, with deviations from the day-ahead demand bid settling at a price equal to the MISO real-time LMP. MISO charges, including Revenue Neutrality Uplift and Revenue Sufficiency Guarantee payments will also apply.

With regard to portfolio re-balancing in the event of “significant” load shifts, in the event the Utilities’ annual peak demand forecast increases or decreases by 200 MW or more from those values included in the approved Procurement Plan, and such change is identified no later than February 29, 2009, the Utilities shall promptly notify the Procurement Administrator of a need to rebalance the portfolio. Ameren says the Procurement Administrator will subsequently issue a request for proposal in an amount that rebalances the portfolio for the period ending May 31, 2009. In the event that such change results in reduction in the supply requirement, the Procurement Administrator will issue a reverse request for proposal.

Ameren indicates that the amount of portfolio rebalancing will be determined by dividing the change in the annual peak demand forecast contained in the approved Procurement Plan by the annual peak forecast contained in the approved Procurement Plan itself, and then applying the resulting ratio to each product previously contracted for in the remaining months in the planning period. The ratio will be applied to all active contracts, including the 400 MW baseload contract made prior to this plan. Ameren says no consideration of contracts that terminated earlier in the planning year shall be required.

Within five business days of notification by the Utilities of the need to rebalance the portfolio, and the specific product requirements, Ameren indicates that the Procurement Administrator will issue the applicable request for proposal or reverse request for proposal to all parties previously registered to participate in the most recently completed Procurement Process. The deadline for binding responses will be no later than ten business days from the date of issuance, and the selection and notification of winning parties will occur immediately thereafter. Prior to the deadline for binding responses, Ameren says the Procurement Administrator will develop appropriate benchmarks to be used in analyzing the responses. Execution of the applicable agreements will occur within two business days thereafter.

Given the use of standard market products in the portfolio, with tenures of no less than one-month, Ameren claims it will be necessary that the agreements resulting from any such rebalancing will be effective on the first Calendar Day of the month following their execution. In the event that one or more of the products being procured in the rebalancing request for proposal (or reverse request for proposal) are not fully subscribed at the conclusion of the request for proposal process, Ameren says the Utilities will meet with the Staff of the Commission to make a determination if the request for proposal (or reverse request for proposal) should be re-issued.

Ameren notes that the Utilities have jointly submitted a single Procurement Plan under which they will procure resources for their combined needs. To the extent permitted by the applicable legal and regulatory authorities, Ameren says the Utilities will jointly pool such resources for their mutual benefit, and that of their eligible retail customers, and will allocate capacity and energy and cost responsibility among themselves in proportion to their actual requirements. For purposes of determining

such requirements, the Utilities will use either kWh or kW, as appropriate to determine the ratio of the individual Utility's requirement to the total requirement.

3. Renewable Energy Resources Plan (III.E)

Section 1-75, subsection (c) of the IPA Act establishes cost effective renewable energy resource standards for the Utilities. For the June 1, 2008 through May 31, 2009 planning period, at least 2% of the total supply required to serve the load of eligible retail customers as defined in Section 16-111.5 of the PUA must be from such renewable energy resources. In addition, to the extent available, 75% of these resources should come from wind generation. Notwithstanding this requirement, the PUA limits the total amount of renewable energy resources acquired in this initial planning year such that the annual estimated average net increase due to the cost of the renewable energy resources included in the amounts paid by eligible retail customers in connection to electric service does not exceed 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007.

Eligible retail customers are defined by Section 16-111.5 of the PUA as "those retail customers who purchase power and energy from the electric utility under fixed price bundled service tariffs, other than those retail customers whose service is declared or deemed competitive under Section 16-113." For the Utilities this includes those residential customers and non-residential customers with peak demands less than 400 kW who acquire power and energy under fixed priced tariffs.

As provided for in the IPA Act, the actual amount of electricity (megawatt-hours) supplied by the electric utility to eligible retail customers in the planning year ending immediately prior to the procurement period (June 2006 – May 2007) is used as the basis for calculating this requirement. During that period, Ameren says the Utilities supplied 20,719,607 MWhs of electric energy to their eligible retail customers. 2% of this value establishes a planning year renewable energy requirement of 414,392 MWhs.

With regard to **products to be acquired**, the Plan says the Utilities will meet the renewable energy resource portfolio standard for the immediate planning period through the acquisition of qualifying renewable energy credits ("REC's") as defined in Section 1-10 IPA Act. Ameren believes the acquisition of REC's for this period meets the requirements of the IPA Act and provides several benefits over the direct acquisition of energy from qualifying renewable resources. Each REC is equal to 1MWh and as such, the Utilities will acquire 414,392 REC's to satisfy this standard.

Ameren believes that the market for REC's is currently more robust than that for the acquisition of renewable energy resources that include energy, thus providing for a more competitive result. Ameren says such an approach is reasonably expected to reduce the cost of administering the overall portfolio and ensure compliance with the IPA Act. Furthermore, the acquisition of such physical resources would necessarily offset the volumes to be acquired under the balance of the plan. In order to ensure the proper amounts were obtained under both plans, Ameren claims it would be necessary

to hold the Renewable Procurement event prior to the primary procurement event, as the cost effectiveness calculation could reduce the amount of purchases made under the Renewable Procurement. By purchasing REC's, Ameren claims the Utilities and the Procurement Administrator will have greater flexibility in scheduling both the primary and Renewable Procurements.

To the extent that it would be necessary to acquire such resources from facilities located outside of the MISO footprint, Ameren asserts that the acquisition of RECs avoids potential complexities (and additional time and costs) related to possible transmission line upgrades and acquiring transmission service to deliver such energy resources to the Utilities' loads. To prevent the wind supplier from proposing inflated REC quantities, Ameren says an independent third party wind consultant will be utilized to evaluate the suppliers' wind resources. Based on a standard methodology developed by the consultant, an estimate of the expected REC production of each wind farm will be developed. In the event the supplier's quantity of RECs exceeds the consultants estimated quantity, the bid amount will be limited to the consultant's estimate.

Ameren indicates that the Utilities will solicit offers for such credits for a term of one year. Sufficient credits to comply with the quantities established by 1-75 (c) (1) of the IPA Act shall then be acquired on the basis of (1) the requirements established in 1-75 (c) (3) of the IPA Act and (2) price. Ameren states that acquisitions of renewable energy credits shall be memorialized with a Master Renewable Energy Certificate Purchase and Sale Agreement.

Regarding **Compliance Tracking**, Ameren believes the acquisition of renewable energy credits in finite amounts equal to the statutory requirement ensures compliance. To the extent that the load data from the prior twelve month period which forms the basis for the required volume is not available at the time of the initial solicitation, Ameren says the Utilities will use forecasted load data to estimate the requirement. When such data does become available, the Utilities' will make the appropriate adjustment to their portfolio of renewable energy credits, including a reallocation between one or more of the Utilities' if appropriate.

According to Ameren, RECs delivered to the Utilities will be measured by metering equipment installed, maintained, replaced, tested and read pursuant to Attachment R-4, Section 10 (Metering) of the Midwest ISO Open Access Transmission and Energy Markets Tariff ("TEMT") or similar as approved by Utilities. All costs associated with the installation, change, or administration of metering equipment and will be borne by the supplier of the RECs. The seller will be responsible for timely monthly submission of accurate, complete, and verified metering data to the Utilities, which shall have the right to audit such submissions.

Ameren states that each agreement for the acquisition of a REC will have a specified term. All RECs used by the Utilities to comply with the statutory requirements shall be retired in compliance with 1-75 (c) (4). RECs must be generated and retired in the planning year in which they were acquired to satisfy the REC requirement.

Regarding **RFP evaluation criteria** (Ill.E.4), Section 1-75 (c) (3) of the IPA Act requires that cost effective renewable energy resources be procured from facilities in the State of Illinois. If sufficient cost effective resources are not available in the State of Illinois, they shall be procured next from states that adjoin Illinois and finally, if unavailable from such other states, they shall be acquired elsewhere.

According to Ameren, offers for RECs will be received simultaneously from Illinois, adjacent states, and all other areas. First, Illinois REC offers will be ranked by unit price (lowest to highest). A REC portfolio will be built starting from the lowest unit cost until the Illinois REC Requirement can be met, and the aggregate price of those Illinois RECs are within the Budget Limit, if this condition is met the 75% Minimum Wind Test will be applied.

Second, if the aggregate portfolio cost exceeds the Budget Limit, the highest unit cost REC will be eliminated until the Budget Limit is met, provided however that compliance with the 75% Minimum Wind Test is required. Third, if all of Illinois RECs offered do not meet the REC Requirement and the Budget Limit is not met, RECs from adjacent states will be added starting from the lowest cost until the REC Requirement or Budget Limit is met, provided however that compliance with the 75% Minimum Wind Test is required. Fourth, if Illinois and adjacent state RECs offered do not meet the REC Requirement and the Budget Limit is not met, RECs from adjacent states will be added starting from the lowest cost until the REC Requirement or Budget Limit is met, provided however that compliance with the 75% Minimum Wind Test is required.

Ameren asserts that at least 75% of the RECs used to meet the standards shall come from wind generation. If the portfolio is made up of 75% wind, the bid evaluation is completed. If the portfolio is made up of less than 75% wind resources, non-wind RECs shall be replaced with the next available low cost wind resource, starting with those located in Illinois and progressing through final stack as needed to achieve 75% wind portfolio.

D. Procurement Administrator (IV)

Section 16-111.5(c) provides that the “procurement process” shall be administered by a “procurement administrator.”

Section 16-111.5 (c)(1) details the role and specific activities of the Procurement Administrator (“PA”). Specifically, the PA shall (i) design the final competitive procurement process in accordance Section 1-75 of the IPA Act; (ii) develop benchmarks in accordance with 16-111.5 (e)(3) to be used to evaluate bids; (iii) serve as the interface between the Utilities and suppliers; (iv) manage the bidder pre-qualification and registration process; (v) obtain the Utilities' consent to the final form of all supply contracts and credit collateral agreements; (vi) administer the request for proposals process; (vii) have the discretion to negotiate to determine whether bidders are willing to lower the price of bids that meet the benchmarks approved by the

Commission; (viii) maintain confidentiality of supplier and bidding information; (ix) submit a confidential report to the Commission; (x) notify the Utilities of contract counterparties and contract specifics; and (xi) administer related contingency procurement events.

The components of the “procurement process” are identified in Section 16-111(e) and may be summarized as follows: (1) solicitation, pre-qualification, and registration of bidders; (2) standard contract forms and credit terms and instruments; (3) establishment of a market-based price benchmark; (4) request for proposals competitive procurement process; and (5) a plan for implementing contingencies.

For the initial procurement period, of June 1, 2008, through May 31, 2009, the PA shall be engaged by the Utilities themselves, whereas in future periods, the PA shall be engaged by the IPA. In addition to the specific roles detailed above, during this initial procurement process, Ameren sys the PA will work with the Utilities renewable team to design and implement a competitive procurement process to acquire the renewable energy credits as provided in the procurement plan.

Ameren states that the PA shall specifically not be responsible for procurement activities for those portions of the procurement plan related to the power and energy requirements of customers with peak demand requirements of 1 MW or greater, those whose service has been declared competitive and are no longer taking the transitional fixed price utility service, or those taking service under on or more of the Utilities’ tariffs for Real Time Pricing Service. For this initial procurement period, Ameren indicates that the PA shall be provided with a detailed portfolio of specific, standard market products to be acquired prior to their commencement of activities to design and implement the competitive procurement process.

Ameren indicates that the agreement for services with the Procurement Administrator for this initial procurement period shall obligate the PA to comply with the specific requirements of the IPA Act and the PUA related to procurement. The activities of the PA shall be monitored by the Procurement Monitor and the Utilities. Any deviation from the statutory requirements shall be brought to the immediate attention of the PA upon identification.

With regard to compliance with federal regulation standards, including Edgar, the agreement for services with the Procurement Administrator for this initial procurement period shall obligate the PA to comply with the directives provided by the Federal Energy Regulatory Commission including those commonly referred to as the Edgar Standards and the Allegheny Model. The solicitation shall be developed in light of the principles of transparency, precise definition of product, standardized evaluation criteria, and oversight.

With respect to the **selection of the administrator** (IV.C), the Utilities issued a Request for Proposals to twelve potential bidders on August 17, 2007. Responses from five entities were received on or before September 10th and final selection was made

September 21st. Ameren indicates that Levitan and Associates was selected by the Utilities to serve as the Procurement Administrator for the initial procurement process. A description of the scoring/selection process was provided in the Plan.

III. OBJECTIONS TO THE PLAN; PARTIES' COMMENTS; AMEREN'S REPLIES

A. Load Forecast

In accordance with Section 16-111.5(b) of the Act, Ameren's Plan 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 renewable energy initiatives, as well as demand response and energy efficiency programs are also addressed. The forecast is described in some detail in the summary of Ameren's Plan above.

Staff indicates that several different models were utilized by Ameren to forecast the eligible load. When it filed its objections, Staff had "unresolved questions" pertaining to these models. (Objections at 10)

Staff states that Ameren's projections of energy savings due to newly-required energy efficiency programs appear to be significantly below the energy saving goals specified in the Act. For example, Staff says Ameren forecasts needs of 17,778,380 MWh, and a reduction in those needs, due to energy efficiency programs, of 12,948 MWh (approximately 0.073%), even though the Act appears to require a reduction of 35,557 MWh (0.2% of 17,778,380) in the initial year.

Staff adds, however, that even if the Companies are ultimately induced to reduce demand by the entire 35,557 MWh, rather than 12,948 MWh, the difference amounts to a mere 3 MW when averaged over the course of every hour in the year. Thus, given its relatively small magnitude, Staff does not believe this potential source of forecast bias will give rise to an objection or be material enough to effect a determination of whether the proposed plan will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.

Ameren responded to Staff assertions that the projections of energy savings due to newly-required energy efficiency programs appear to be significantly below the energy savings goals specified in the Act. Ameren says this is likely due to a misunderstanding of what the values included in the Plan represent. (Ameren Reply at 5-6) Ameren says it included, in Section II(C)(3) of the Plan, its forecast of the impact of the energy efficiency programs as they effect the load that will be served under the procurement plan purchases. Ameren states that because the energy efficiency programs will reduce customer consumption and the existing BGS-FP auction contracts are for supply for a fixed percentage of the actual load, 67.3% of the energy savings due to these newly-required energy efficiency programs will reduce the supply

obligations of the suppliers holding these BGS-FP contracts, with the remaining 32.7% of the energy savings reducing the supply requirements of the procurement plan purchases.

In its November 28th Reply Comments, **Staff** states that it may have misunderstood the figures presented in Ameren's plan. (Staff Reply Comments at 3) In any event, as noted in Staff's initial comments, Staff believes the mistake or misunderstanding is limited to a relatively small quantity of energy. Staff concludes that its concern has not risen to the level of an objection.

Having reviewed the filings, the Commission notes that no party proposed any modifications to Ameren's forecast. The Commission finds that the forecast appears reasonable and that no modifications are required.

B. Portfolio Design

1. Introduction

The portfolio design components of Ameren's Plan are summarized in some detail above. Major categories include, among others, a description of the analytical approach; identification of wholesale products to be acquired, with a subsection on price risk including sensitivity analyses; and a description of the renewable energy resources plan.

As explained by Staff, the existing SFCs account for a full two-thirds of the demand of included customers. The SFCs are load following contracts ("vertical tranches") and include both energy and capacity requirements, as well as certain transmission and ancillary services.

The new swap contract, on the other hand, is not a load following contract. Rather, it specifies a fixed megawatt quantity for all hours of the year (400 MW for the initial planning year). For those fixed quantities, Staff says it provides a price hedge against energy-only spot market prices. Specifically, the swap settles hourly against the MISO real-time locational marginal prices ("LMPs") for the Ameren Illinois Load Zone. It does not provide any hedge against capacity cost, ancillary cost, or quantity risk.

Furthermore, the swap settles financially (rather than physically), meaning that Ameren will still have to find a means of physically purchasing the energy associated with the swap quantities. Ameren proposes to do this by purchasing energy directly from MISO in both the day-ahead and real-time energy markets. Ameren will also be required to purchase capacity, ancillary services, and transmission services associated with the one-third of load not covered by the existing SFCs from MISO or the wholesale market. For the difference between demand and the existing supplies discussed above, Staff indicates that Ameren's plan relies on standard block forward market contracts for hedging purposes, as well as MISO organized markets.

According to Staff, for a significant portion of the expected level of this difference between demand and the existing supplies discussed above, Ameren’s plan is to use an RFP process to acquire new forward market financial swap contracts for the following fixed blocks of power within 6 different time periods:

| | |
|-----------------------|--------|
| Annual all hours | 200 MW |
| Jan/Feb on-peak hours | 200 MW |
| Jun on-peak hours | 175 MW |
| Sep on-peak hours | 175 MW |
| Jul/Aug on-peak hours | 325 MW |
| Oct-Dec on-peak hours | 75 MW |

According to Ameren, for the one-third portion of total load not already hedged 100% by the existing SFCs, when the above contracts are combined with the existing 400 MW swap with Ameren Energy Marketing, they result in an average hedge of 91% of peak hour demand and 88% for non-peak hour demand. When the existing SFCs, the swap, and the additional forward contracts are considered together, Staff states that Ameren’s portfolio hedges approximately 96-97% of expected annual demand. (Staff Objections at 13)

Staff indicates that this collapse of the 24 time periods examined in Ameren’s analysis into a set of only six time periods for purposes of securing this hedge is in contrast to the ComEd procurement plan, which specifies MW values for 24 different time periods, but notes that bidders will have the opportunity to present bids for combinations of periods, subject to certain rules and restrictions yet to be developed. Staff says that in essence, Ameren’s plan already includes the only permissible combinations. (Objections at 13)

In this proceeding, a number of parties filed objections, comments and proposed modifications to Ameren’s proposed portfolio design, as discussed below.

2. Hedging, Risk Assessment and Related Issues

a. The AG’s Position

The **AG** filed “Objections and Proposed Modifications” supported by the affidavit of Robert McCullough. According to the AG, the Ameren plan exposes customers to unnecessary risk because Ameren fails to hedge the cost of purchasing supply in excess of the forecasted load. (AG Objections at 3-4) The AG asserts that the potential for harm is greatest during critical peak periods when prices are high, conditions that occur frequently on hot summer afternoons. The AG believes that the risk to Ameren customers cannot be ignored and Ameren’s failure to hedge these costs will force consumers to pay higher rates for electricity procured at high prices in the MISO spot market if they need more electricity than predicted in the utility forecast. The AG reiterates this position in its November 28th “Supplemental Comments” also supported by the affidavit of Robert McCullough. (AG Supplemental Comments at 2-3)

The AG claims there is a well-known aphorism that describes utility planners' typical strategy to avoid the problem created by Ameren's failure to adequately hedge supply: "If you're wrong, be long." The AG says this strategy recognizes that the penalties for being long unnecessarily are often preferable to the penalties of failing to be long when in need when prices are likely to be at their highest.

According to the AG, the extent of Ameren's forward position, either physical or financial, should exceed forecasted load during critical peak periods by amounts greater than those proposed by Ameren. The AG argues that the specific monthly and on/off peak distribution of deviation of forward position from forecasted load should be explicitly evaluated based on a realistic estimation of the expected joint distribution of various key variables, especially overall load, the price of natural gas and the market price of electricity. In the AG's view, increasing Ameren's forward position during critical peak periods (e.g., summer afternoons) will avoid exposing Ameren customers to unnecessary costs.

The AG filed **Supplemental Comments** on November 28, 2007, supported by an affidavit from Robert McCullough. The AG argues that the Commission should require the utility to limit spot market purchases to non-summer off-peak periods to reduce costs to consumers. (AG Supp. Comments at 2-3) The AG states that Ameren's proposed procurement plan relies primarily on forward contracts for standard products with the remainder of the portfolio to be purchased in the spot market. The AG maintains that the proposed spot market purchases expose customers to significant price risk.

The AG claims its analysis, which is discussed further below, shows that costs to consumers would be reduced if Ameren were to limit spot market purchases to non-summer off-peak periods. The AG believes that during the rest of the year, hedging is more cost-effective. That is, costs to consumers would be reduced if Ameren were to purchase electricity in the forward markets as insurance for those instances when their forecasts of demand during the summer and on-peak non-summer periods are too low.

The AG requests that the Commission condition approval of the Ameren procurement plan on modifications to the plans that would eliminate spot purchases throughout the summer and during on-peak non-summer periods. The AG also wants the Commission to require Ameren to specify the standard forward products that they propose to procure as a substitute for those spot purchases. The AG claims these modifications will protect Ameren customers from price risk, as required by PA 95-0481.

The AG says its analysis shows that forward prices tend to be higher during on peak months. In Illinois, that means that forward prices are higher in summer and the months of December and January than during the rest of the year. In order to avoid these higher prices, the AG requests that the Commission direct Ameren to conduct the 2008 procurement in March and April.

In its supplemental filing, through the affidavit and analysis of Mr. McCullough, the AG provides an ex-post (after the fact) estimate of the cost of hedging. The affidavit also addresses the use of load forecast point estimates in the calculation of optimal hedge ratios, and it provides estimates of hedging cost and volatility by season and product.

According to the AG, forward markets ultimately depend on the presence of speculators who are willing to risk capital in exchange for a risk premium. In practice, the AG says it is only possible to infer the size of the risk premium by observing price in the market. This is ex-post evidence – the results are evident only after all other impacts on spot prices have taken place. The AG asserts that new forward markets, like the NYMEX market in Northern Illinois, tend to be volatile as different market participants enter the market due to observed profits or leave the market due to observed losses. (Affidavit at 2)

The AG asserts that the level of volatility in returns for speculators offering unhedged forward contracts is quite high: fully 35% of forward on-peak NYMEX contracts were out of the money between February 2005 and November 2007. For contracts related to the time horizon relevant to the current proceeding – those sold four to sixteen months before settlement – the AG says 28.3% of unhedged contracts were in the red.

The AG contends that in a perfect world, it is possible to calculate ex-ante pricing decisions from ex post market data. This generally requires that a substantial time period is available. The AG states that here, however, there is approximately thirty three months of pricing data in a thin and immature market. According to the AG, ex-post data reflects a variety of economic events including many that could not have been foreseen by those making hedging decisions months or years ahead. In pricing forward contracts, the AG claims market participants themselves rely heavily on ex-post data in formulating their pictures of the risks involved. In the AG's view, while the available ex-post data is far from ideal, it does reflect the same dataset that market participants use to price their forward contracts. (Affidavit at 2-3)

To provide an estimate of the cost of hedging, the AG used all of the available data and calculated the average margin between NYMEX forward contracts and the corresponding actual spot prices. In order to avoid idiosyncratic results on such a small dataset, the analysis was performed by the summer (June through September) and non-summer (all other months) periods for both on-peak and off peak hours.

The AG's analysis restricted the NYMEX contracts to a subset ranging from four months before delivery to sixteen months before delivery. The AG also addresses the curve shift phenomena – the tendency for forward markets to put an unduly high weight on spot prices in formulating forward prices. For the purpose of this analysis, the AG accepts the assumption that forward contracts will be purchased in February for hedges from June 2008 through May 2009. (Affidavit at 3)

The AG states that for the period where data is available, the observed costs are:

| | Summer months | Non-summer months |
|----------------|------------------|----------------------|
| On peak hours | \$ 4.88 | \$ 5.71 |
| Off peak hours | \$ 0.37 | \$ (2.01) |

The AG notes that contracts settled from four to sixteen months before delivery during off-peak hours in non-summer months actually lost money over the short period for which data is available. The AG says this is simply an outcome of a limited dataset and a new market. The AG claims that no amount of theory or sophisticated statistical analysis can fully protect sellers of futures contracts from losses when the data available to make their decisions is limited. This is the case for Northern Illinois NYMEX over this short period. The AG asserts that because it would be naïve to believe that sellers of forward contracts would price future deals as poorly as historical results suggest, it used the Summer Months Off-Peak Hours price for both summer and non-summer periods in its analysis. (Affidavit at 3)

The AG notes that Ameren focused its procurement plan on the point estimate of loads for the period June 2008 through May 2009. The AG says that while this is a reasonable approach for traditional utility planning, it may not adequately mitigate risk in the new procurement planning process mandated by Public Act 95-0481.

The AG states that a significant component of risk is the uncertainty of future loads. In the new procurement planning process, the AG claims this is critical since there is a high correlation between market price and loads: periods when loads are high are also periods when prices are high. The AG asserts that whenever loads are high, the impact on the consumer is magnified by the presence of higher than normal prices as well. The AG suggests that the correlation between load and price is significant at the 99% level for both on-peak and off-peak periods.

While calculating a specific, most likely value for future load is common in the industry, the AG believes it is not the best approach when considering risk. The AG claims a better approach is to recognize that the estimate is just that – an estimate – and that the actual loads will lie in a distribution around the estimate. The AG asserts that hedging above the point estimate of load is logical if the cost of loads higher than forecast is greater than the cost experienced when loads underrun forecasts.

To evaluate the impact of load risk as well as price risk on the optimal hedging ratio, the AG's analysis divided the year into four periods: summer on-peak (June through September), summer off-peak, non-summer on-peak (all other months), and non-summer off-peak. The AG calculated costs and a measure of volatility across different hedge ratios as applied to the forecasted mean load. The phrase "hedge ratio" represents the ratio of hedge to the estimate of load. If 50% of the load was hedged, the hedge ratio is 50%. (Affidavit at 6)

The AG states that mathematically, if hedges were free, total cost would not change if the hedge ratio was adjusted. The AG says such a mathematical result is hostage to a number of assumptions seldom observed in the real world. In its analysis, the AG calculated the expected profits or losses on a daily basis for summer on-peak hours, summer off-peak hours, non-summer on-peak hours, and non-summer off-peak hours at a variety of hedge ratios. Given the relatively low cost of hedges observed since the start of the NYMEX Northern Illinois market, the AG claims it is possible to purchase significant reductions in risk at relatively low costs. The AG says if the cost of the hedge is \$4.88/MWh, increasing the hedge ratio 10% costs the consumer only \$0.49/MWh. The AG claims this may be a very low price if it purchases a significant reduction in volatility.

The AG contends that its analysis shows that when loads are above the load forecast, prices are also above expected levels. The AG believes a risk-averse strategy would be to hedge above the load forecast level during summer on-peak hours. According to the AG, the lowest risk occurs at a hedge ratio of 140%. The AG says that costs are higher at higher hedge ratios and that for summer on-peak hours, moving from a 100% hedge ratio to a 140% hedge ratio will cost less than \$2.00/MWh, but reduce volatility to its minimum level – a reduction of 50 %. (Affidavit at 7)

In the AG's view, hedging at levels lower than the very probable levels of load that may occur during summer months is the more dangerous of the two alternatives. The AG insists that the prudent plan is to hedge above the point estimate for loads: that is, to make purchases in the forward markets as insurance against errors in the load forecast during periods of high demand rather than risking purchases in the spot market on hot summer afternoons.

The AG asserts that during off-peak hours reaching the point of minimum volatility is relatively inexpensive. According to the AG, for non summer on-peak hours the minimum volatility is a 125% hedge ratio and moving to this level will only cost \$1.43/MWh. (Affidavit at 8)

The AG states that for non-summer off-peak hours the effect is not noticeable, and the optimal hedge ratio falls to 100%. The AG's analysis for non-summer off-peak hours indicates that the optimal hedging ratio is 100% and raising the hedge ratio for these hours will not reduce risk.

The AG concludes that relatively nominal increases in expected costs can purchase significant reductions in risk during summer months and during on-peak hours during non-summer months. The AG claims that the evidence does not support higher hedge ratios for off-peak periods during non-summer months. (Affidavit at 10)

Regarding "Curve Shift and Optimal RFT Timing," the AG asserts that there is an empirical benefit to making long term purchases during off-peak months. In other words, it is less generally less expensive to purchase electricity in forward markets during off-peak months than in on-peak months. The AG states that while it seems illogical that

traders would allow seasonal issues to affect long term pricing calculations, evidence indicates that this is a widespread phenomenon. The AG says a commonly used phrase for this effect is “curve shift.”

The AG says the so-called “curve shift” phenomena are the subject of continued debate in the industry. As a practical matter, the AG claims surprising influence of spot prices on forward prices is a common feature in commodity markets. The AG asserts that many of Enron’s market manipulation schemes in the Western Market Crisis of 2000-2001 depended on the manipulation of spot prices in order to raise long term markets. (Affidavit at 10-11)

The AG contends that although the phrase “curve shift” has “general currency” among traders, the impact on spot prices on forward markets has been debated extensively at FERC. The AG asserts that well-known econometrician, Robert Pindyck, conducted a very detailed analysis of the phenomena in chapter five of the Final Report on Price Manipulation in Western Markets in 2003 and found that spot prices do, in fact, impact long term prices. The AG says traders use this phrase to reflect a tendency for forward curves to be marked up across the board in response to a change in spot prices.

Based upon its analysis, the AG asserts that for Northern Illinois, a logical period to take advantage of the “curve shift” phenomena would be March or April when loads are significantly lower. (Affidavit at 13)

According to the AG, while data is scarce for the forward markets in Northern Illinois, there is relatively little data for the Ameren Utilities on the costs of forward markets. The AG argues, however, that the logic of the analysis is based on the correlation between prices and loads, a correlation just as true in Central Illinois as it is in the Chicago area.

In conclusion, the AG recommends that Ameren adjust its hedge ratio to offset the additional risk of all on-peak hours as well as summer off-peak hours. (Affidavit at 13)

In its **BOE**, the AG comments on the conclusion in the Proposed Order that would modify the plan to require Ameren to use forward contracts to meet 110% of forecasted load for on-peak hours of July and August, 2008. The AG requests that in addition to requiring Ameren to make those forward purchases, the Commission grant Ameren discretion to purchase additional forward contracts to cover up to 140% of load during summer on-peak hours and 125% of load during summer off-peak and non-summer peak hours. The AG also requests that the prudence of Ameren’s decisions as to whether to purchase in the spot or forward markets should be subject to annual review by the Commission. (AG BOE at 3, 7)

According to the AG, its witness recommended that Ameren purchase forward contracts in amounts that exceed projected requirements during summer on-peak hours

and, to a lesser extent, during summer off-peak and non-summer peak hours, based on price data purportedly showing that over a historical period, a hedge ratio of 1.40 minimizes daily price volatility during summer peak periods and a hedge ratio of 1.25 minimizes daily price volatility during summer off-peak and non-summer peak periods. (AG BOE at 5) The AG also characterizes Mr. McCullough's position as one that would limit spot purchases throughout the summer and during the on-peak non-summer periods, not eliminate them. (AG BOE at 5)

b. CUB's Position

In its objections, **CUB** states that Ameren's initial procurement proposal hedges the energy supply that it procures with financial swap agreements instead of physical energy contracts. CUB asserts that Ameren has not adequately explained this choice. In addition, CUB claims that Ameren has not supported its hypothesis that a 5.0% risk premium on these contracts is appropriate. Consequently, CUB requests that Ameren's initial procurement plan be revised to ensure that these assumptions lead to the lowest total cost over time, as required by the Public Utilities Act. (CUB Objection at 3; CUB Supplemental Comments at 1-2)

CUB also requests that the Ameren's initial procurement plan be revised to include the procurement of all available cost effective demand response and energy efficiency resources. (CUB Supplemental Comments at 2) This issue is discussed below.

c. Staff's Position

According to **Staff**, one problem with Ameren's approach to risk assessment is that the output is expressed in total costs as opposed to cost per unit, making it more difficult to appraise the impact on customers. (Objections at 17) In addition, Staff says it had not been able to appraise the assumptions and detailed methods that were used in the Companies' analysis. However, Staff has identified the following concerns.

First, Staff notes that while Ameren's risk analysis examines changes in the expected level of demand, the changes examined were almost insignificant. (Response at 17) Examination of work papers provided in response to data requests indicate that the standard deviation of annual demand generated in the 250 scenarios is less than $\frac{1}{2}$ of 1 percent of the expected level of annual demand and the 90% percentile and 10th percentiles are only 0.6% above and below the average, respectively. In contrast, the high and low load scenarios in ComEd's procurement plan are 18% above and below the expected (base) level of demand.

One main reason for the small degree of load variability in the Ameren plan is that it does not include any possible deviations in its base projections of customer retention (the percent of customers that do not switch to alternative suppliers). While it is still under review, Staff also suspects that Ameren did not allow for any deviations from normal weather. The problem with such assumptions, Staff asserts, is that the

resulting risk analysis fails to adequately capture as much risk as ratepayers will face under each of the portfolios under consideration.

Staff states that while it appreciates the use of a Monte Carlo analysis, it would have been even more helpful if the Companies had also presented a **sensitivity analysis**, showing more details on the inputs and outputs of a relatively small subset of the 250 scenarios. Staff says on the other hand, while such modifications and enhancements to the risk analysis presentation would be of value to Staff, it is not particularly likely that they would significantly alter Staff's view of the proposed portfolio.

d. Ameren's Position

Ameren disagrees with Staff's opinion that the 250 load scenarios lack variability. (Ameren Reply at 6) According to Ameren, the fact the standard deviation of the total annual demand across the 250 scenarios is less than 1% is attributable to the manner in which the Monte Carlo process generates the 250 load scenarios. Ameren says the Monte Carlo process does not generate distinct scenarios in which the load is high in all hours for some scenarios and the load is low in all hours in other scenarios. Rather, Ameren states that the Monte Carlo process generates scenarios in which the load in any given scenario may be high in some hours and low in others. Based on this, in order to see the variability in the scenarios, Ameren asserts that one needs to assess the specific details rather than consider or view a comparison of the annual total demand.

Ameren claims that an analysis of the 250 load scenarios for the July 2008 on-peak period shows that while the weather normalized peak demand forecast for this period is roughly 1,600 MW, the range of peaks across the 250 scenarios is from just under 1,300 MW (or 81% of the forecast) to above 1,930 MW (or 121% of the forecast). Ameren states that while the energy forecast for the July 2008 on peak period is just over 357,000 MWh, the range of total energy across the 250 scenarios ranges from approximately 341,000 MWh to approximately 377,000 MWh.

As Ameren understands it, the AG is proposing that the Ameren Utilities purchase more than what is proposed in the Plan, by up to 130% of the expected load. Ameren complains that how this recommendation is to be implemented is never explained. Ameren claims the AG does not identify the critical peak periods for which the AG would like the forward position increased. In Ameren's view, this recommendation is incomplete and cannot be commented on in its current form.

In reply to CUB, Ameren says it first determined that the point at which the volatility in total cost is minimized for customers is when hedging is equal to the average load (100% hedge ratio). (Ameren Supplemental Reply at 10) In this analysis, Ameren states that an assumption was made that forward prices equal spot prices in the analysis. Ameren asserts that the analysis recognizes that forward prices may command a risk premium relative to spot prices but no such premium was included due to the inability to calculate such a value. In order to consider the potential effect of such

a premium, Ameren says an additional analysis was run, with a hypothetical 5% premium. According to Ameren, this additional analysis indicated that the existence of a 5% risk premium, between forward prices relative to spot prices, would suggest the hedge ratio could be reduced from 100% to 90%, in an effort to appropriately balance cost and volatility. Ameren acknowledges that while a risk premium exists, it is difficult to quantitatively demonstrate, and further its magnitude is uncertain as well. Ameren believes it is acceptable to establish a hedge ratio between 90% and 100%. (Ameren Supplemental Reply at 10)

Ameren disagrees with **CUB's second objection** that Ameren has not supported critical Plan assumptions including; (1) the use financial **swap** agreements instead of physical energy contracts to hedge energy supply; and (2) its hypothesis that a 5.0% risk premium on these contracts is appropriate. (Ameren Reply at 26; Supplemental Reply at 10)

With regard to using **financial swap agreements**, Ameren states that while CUB acknowledges that there may be differences in the requirements between PJM and MISO, which may lead to the different positions held by Ameren and ComEd, it fails to acknowledge that credit risks are ultimately borne by the customer. In Ameren's view, it is reasonable to expect a supplier who is directly bearing such risks to include compensation for doing so in its price. Ameren asserts that one who does not bear such risks would not be expected to include such compensation in its price. Ameren claims that alone does not necessarily mean that one product results in a lower total cost than the other. (Ameren Supplemental Reply at 10-11)

Ameren believes CUB ignores that Ameren has already provided an explanation which describes why the cost of credit, for Ameren, operating within the MISO market is expected to be lower by utilizing financial swaps than it would be to enter into physical transactions. Ameren claims the mark-to-market exposure of both products is identical but, the accounts payable exposure is not. Ameren asserts that the mechanics of the MISO market, particularly the differences in settlement timelines, and the existence of an unsecured credit line with MISO that is not likely to exist with a physical counterparty, provide the basis for an expected lower total cost. (Ameren Supplemental Reply at 11)

According to Ameren, the mechanics of both financial swaps and physical forwards as it relates to mark-to-market exposure, credit exposure, and accounts receivable are detailed in responses to data requests. In addition, Ameren says the data request responses describe that physical forward contracts are limited to MISO market participants, while financial swaps can include non-MISO entities, thus potentially increasing the pool of competitive suppliers. Financial swaps were chosen, as in the particular instance of Ameren, operating within the MISO footprint, and are expected to provide the equivalent level of price hedging at a lower expected total cost over time when compared to physical forward contracts. (Ameren Supplemental Reply at 11)

In its Supplemental Reply filed November 30, 2007, Ameren indicates that the AG, in its Supplemental Comments, continues to advocate that Ameren hedge the load at levels significantly above what is included in the Procurement Plan. Ameren complains, however, that the AG has left it unclear as to what the exact level of hedging is being proposed.

Ameren asserts that the recommendation included in the AG's Supplemental Comments, which states "...the People respectfully request that the Commission condition approval of the ComEd and Ameren procurement plans on modifications to the plans that would eliminate spot market purchases throughout the summer and during on-peak non-summer periods," is not consistent with the affidavit of Mr. McCullough. (Ameren Supplemental Reply at 12, citing AG Supplemental Comments at 7) The AG claims Mr. McCullough's analysis shows that costs to consumers would be reduced if ComEd and Ameren were to limit spot market purchases to non-summer off-peak periods. Ameren contends that Mr. McCullough's affidavit does not state nor recommend this, and were the Commission to adopt the AG's specific language recommendation in this regard, the unintended consequence to customers could be severe.

Ameren says it will purchase 100% of its customers' needs which are not provided by preexisting Illinois Auction contracts or from QF's in the spot market. Ameren also says it will enter into financial swaps to hedge this hourly price risk. Ameren claims Mr. McCullough does not discuss his analysis in terms of spot market purchases, but rather in terms of levels of hedging. Ameren maintains that it has already entered into a significant amount of financial swaps as directed by the statute. Ameren says it is unclear if the AG is now suggesting the Commission find that the underlying spot market purchases are inappropriate, and that Ameren should be required to duplicate these hedges with a like amount of physical forward purchases. Ameren does not believe that can be its intent. (Ameren Supplemental Reply at 12-13)

Ameren says Mr. McCullough refers to levels of hedging in terms of hedge ratios, just as Ameren has. Hedge ratios are calculated by taking the total amount of energy purchased in a given period and dividing it by the expected load. A 100% hedge ratio therefore means that total forward purchases equal total expected load. A 200% hedge ratio means that total forward purchases are twice the total expected load. Ameren states that since load varies by hour, whereas the hedges do not, this necessarily means there are hours in which the amount of hedge is greater than the load in that hour and there are hours in which the amount of the hedge is less than the load in that hour.

In order to achieve a hedge ratio sufficient such that the Ameren Companies "eliminate spot purchases throughout the summer and during on-peak non-summer periods," Ameren claims it would necessarily have to acquire hedges in a nominal amount equal to the highest potential peak demand in any hour of the given period, regardless of weather or customer switching. (Ameren Supplemental Reply at 13)

Ameren says the July 2008 weather normalized peak forecast value is 1,601 MW, which includes the assumption of a significant amount of customer switching. The expected energy forecast for this same period, again on a weather normalized basis, is 669,299 MWh. In order to ensure that Ameren “eliminate spot purchases” in July 2008, Ameren claims it would be necessary to acquire hedges at a level in excess of 1,601 MW which includes an adjustment to account for the possibility that actual weather may result in loads significantly higher than the weather normalized forecast and an adjustment to account for the highest possible variance in the customer switching assumption for the entire period in which this peak may possibly occur. (Ameren Supp. Reply at 13)

Ameren asserts that a value of 320 MW (20%) for weather and 230 MW for customer switching (current assumption for load leaving) are reasonable to use in this scenario, leaving a total potential peak demand to be covered of 2,151 MW. The resulting hedge ratio for the month of July 2008 would then be 240% or nearly twice the level Mr. McCullough actually recommended in his affidavit. (Ameren Supplemental Reply at 13-14)

While Ameren is not in agreement with Mr. McCullough’s recommendations, should the Commission determine that it is more appropriate to utilize a hedge ratio closer to his recommendation than the hedge ratio proposed by Ameren, Ameren believes it is critical that the Commission does not adopt the language used by the AG in its Supplemental Comments. Ameren asserts that to do so would result in a consequence not even its own expert intended, and which would cost customers \$5/MWh (above his 100% recommendation) or nearly \$3.3 million – for the month of July 2008 alone. Ameren reiterates that Mr. McCullough does not recommend eliminating spot market purchases; rather he recommends a specific hedge ratio for each period. (Ameren Supplemental Reply at 14)

Ameren argues that the Mr. McCullough’s revised analysis is incomplete and continues to ignore available data sources. The data analysis included in his most recent analysis exclusively uses load and price data applicable to ComEd, and the only support for applying the results downstate is the offhand comment “a correlation just as true in Central Illinois as it is in the Chicago area.” Ameren claims that the AG has presented no evidence in support of this statement. There is, Ameren argues, no information or evidence that supports any correlation between the weather (and thus load and prices) in Chicago and the weather (and thus load and prices) in Central Illinois, let alone the weather in Southern and Western Illinois where Ameren also serves load.

Ameren asserts that the AG failed to show any correlation between the NYMEX forward prices for Northern Illinois and forward prices applicable in Ameren Illinois Utilities’ service territories. According to Ameren, the AG failed to show a correlation between the NYMEX forward prices for Northern Illinois and the actual price paid for standard traded forward market products which will actually be utilized by ComEd. Ameren also complains that the AG has not identified the source of the hourly prices

used in its analysis. Ameren says it is impossible for Ameren and the Commission to understand Mr. McCullough's analysis without knowing this elementary point. (Ameren Supplemental Reply at 14-15)

Ameren says the matter is further confused as Mr. McCullough's illustration of 140% for the summer on-peak hours is different than the values he used in his original affidavit in both this docket and the ComEd docket. In those affidavits, he appeared to recommend 130% for the Ameren Illinois Utilities, while for ComEd he appeared to recommend 135% in general, but 160% for the summer peak air conditioning months. Now he is lowering the ratio substantially in ComEd's case – from 160% to 140% for summer periods. His failure to make a specific recommendation as to the level of hedges to put in place for the Ameren Illinois Utilities only adds to the confusion.

Ameren asserts that Mr. McCullough's volatility analysis of Ameren's load and associated market prices is seriously deficient and provides no justification for any modification in the proposed quantities to be procured specified in Ameren's Plan. Adopting the AG's recommendation, Ameren argues, would unnecessarily expose Ameren's customers to unacceptable levels of price volatility. (Ameren Supplemental Reply at 15)

According to Ameren, Mr. McCullough's analysis does not support the AG's conclusions that Ameren's forward position should significantly exceed forecasted load during critical peak periods. Ameren claims this is because his analysis incorrectly seeks to minimize the volatility of the average daily MISO market price which Ameren will pay in serving the load rather than the total cost paid by the customers of Ameren. Ameren asserts that the bills that the customers receive will not reflect the daily price volatility the Mr. McCullough's analysis seeks to minimize. Rather, the customers' bills will reflect the total cost.

In looking at the results of Mr. McCullough's analysis, Ameren says the expected total cost to serve the load is identical at every level of hedging analyzed. Ameren asserts that this is because his analysis only considers a single distribution of average daily prices across each of his hedging levels. In contrast, Ameren says its analysis considered 250 separate scenarios of hourly market price and hourly load – each of which yielded a different expected total cost. Ameren then analyzed the volatility of these expected costs at each hedging level seeking to minimize the volatility of the total expected cost across the 250 market price and load scenarios. Ameren also claims Mr. McCullough's analysis includes several questionable input assumptions that bring the validity of the results in question. (Ameren Supplemental Reply at 15-16)

Ameren argues that the use of PJM NiHub in Mr. McCullough's analysis is better suited to ComEd than to Ameren. Ameren says the more relevant pricing point for the Ameren Illinois Utilities would be MISO Cinergy Hub because it is the most liquidly traded point in MISO and correlates strongly with the locational marginal prices of the Ameren Illinois Utilities' load zones. (Ameren Supplemental Reply at 18)

Ameren says a second flaw is that the analysis is limited to three years of data. While Ameren acknowledges that given the infancy of RTO markets, this is the extent of available RTO data, Ameren says it is not responsible to use a limited data source in order to draw far-reaching conclusions regarding forward prices and the relationship forward prices have to spot prices. Ameren states that Mr. McCullough's uses the historical data as a predictor for the summer of 2008 and therefore argues that excess hedging will have little cost impact to customers while reducing volatility, which Ameren believes is a speculative position. (Ameren Supplemental Reply at 18)

Ameren contends that a third flaw in the analysis is that Mr. McCullough averages the three summers to estimate the cost associated with forward hedging is \$4.88/MWh. What is not discussed, Ameren claims, is that the relationship between forward prices and spot prices varies widely over the three-year period. In Ameren's view, hedging an amount significantly beyond the average load in any given year exposes customers to a "roll of the dice" as to whether such hedging will reduce costs or add costs. (Ameren Supplemental Reply at 18)

The final flaw in the analysis, Ameren claims, relates to Mr. McCullough's minimization of the \$.49/MWh cost he claims will be added for each 10% increase in the hedge ratio. Ameren claims the methodology employed to yield this calculation is flawed. However, for illustrative purposes, Ameren assumes the calculation is valid. To hedge summer on-peak periods at 140% of average load, the expected cost of adding additional forward hedges would be \$1.96/MWh (\$.49/MWh per 10% increase in hedge beyond 100% hedge ratio). Ameren forecasts an average on-peak load in July and August 2008 of 992 MW.

Following the 140% recommendation of the AG, hedges would be put in place for 1,389 MW which result in an excess position of 397 MW per hour. Applying the additional cost of hedging to the 140% hedging level would cost customers approximately \$535,000. Of even greater importance, Ameren claims, is the potential that the \$.49/MWh premium may be far from what actually occurs in 2008. Ameren says that if the forward price of hedges turns out to be \$16/MWh higher than the spot price, as was the case in 2007, for each 10% increase in hedge beyond 100% hedge ratio, the cost would be \$1.60/MWh. In this case, Ameren claims a 140% hedge ratio in the summer on-peak period would be expected to add costs in an amount equal to \$6.40/MWh, or \$1,750,000. (Ameren Supplemental Reply at 19-20)

According to Ameren, minimizing the volatility in hourly pricing does not necessarily translate into minimizing the volatility in total cost. Ameren says that while "over hedging" will protect against a coincidental rise in loads and prices, it fails to protect, and in fact compounds, the negative consequences of a coincidental decrease in loads and price, or for that matter, a simple decrease in price. Ameren argues that adopting the AG's proposal unnecessarily exposes customers to a potential significant increase in cost arising from holding large, excess hedge positions during periods when loads and price decrease. Ameren maintains that its analysis, using 250 distinct scenarios, as the hedge ratio diverges from near 1.0, the range of expected costs

widens significantly. Ameren says the AG's analysis fails to address this issue. (Ameren Supplemental Reply at 20)

Ameren also asserts that excessive "hedging" actually represents an artificial increase in demand for scarce resources at the point in time they are acquired. Ameren says it is a fundamental principle in economics that an increase in demand, with a constant supply, results in a higher price. Given that the RFP process will result in a pay as bid RFP, Ameren claims that all of these additional hedges are acquired at ever increasing prices – thus, the last 40% of the hedge, will be at a higher price than the first 100%. (Ameren Supplemental Reply at 20-21)

Ameren refutes the AG's suggestion that it used a "point estimate of loads" in the Plan. Ameren says in its Procurement Plan, the analysis used to arrive at the portfolio of financial swap contracts included in the Plan considered 250 scenarios of load and market prices. According to Ameren, these 250 scenarios were developed such that the volatility of both load and market prices across the 250 scenarios were consistent with the historical volatility of each. Ameren claims the 250 scenarios were created such that the correlation between these two parameters within the 250 scenarios is consistent with the historical correlation between the two.

According to Ameren, it is Mr. McCullough's analysis that utilizes a single "point estimate" of market prices and loads with that point estimate being the historical loads and MISO market prices for June 16, 2005 through December 31, 2006. Ameren claims Mr. McCullough's analysis utilized this single "point estimate" which drove the results of its analysis to show an identical total expected cost to serve the load across all hedge ratios tested in his analysis, and it is this single "point estimate" that causes its analysis to have no meaning in determining the appropriate level of hedging. (Ameren Supplemental Reply at 21)

Ameren says the Commission should consider the issue of how much to hedge very carefully because the final decision has the potential to have a profound impact on the final price paid by customers. Ameren maintains that hedging the load in the 90% – 100% range of average expected load minimizes the volatility in the total expected cost to serve the load of the customers. (Ameren Supplemental Reply at 21-22)

In the months of July and August, 2008, during the on-peak periods, Ameren claims that adopting a 140% hedge ratio as the AG suggests would result in 96% of the hours being over-hedged. Ameren asserts that for the year, the AG recommendation would have Ameren contracting forward for just under 8,000,000 MWh, while the expected load to be served by these purchases is closer to 6,400,000 MWh. (Ameren Supplemental Reply at 22)

Finally, with regard to the AG's recommendation that unless there is a compelling reason to contract for a hedge in the early months of the year, it is reasonable to wait until **March or April** to make the procurement decision, Ameren says it is willing to accept this recommendation related to acquiring the forward hedges – (i.e. the financial

swaps). Ameren emphasizes that the AG's recommendation was exclusive to contract for hedges – and not for acquiring renewable energy credits or capacity. Ameren says it will acquire RECs and capacity at various times during the planning period. Ameren claims there has been no evidence presented or recommendation made by any party, which suggest that the scheduling of purchases for RECs and/or capacity should be altered from that proposed in the Plan.

Ameren says the Procurement Plan contains rebalancing and contingency provisions which would be triggered in the event of significant shifts in load or supplier default – which could occur at any point during the year. These rebalancing and contingency provisions, Ameren states, have been included to protect customers from undue price volatility. In Ameren's view, it would not be reasonable to delay implementing these procedures until the following March or April, and these provisions in the Plan should not be modified. Ameren also asserts that it would be contrary to the legislative intent to delay this subsequent procurement event. (Ameren Supplemental Reply at 22-23)

e. Commission Analysis and Conclusions

Currently, Ameren acquires all power and energy its bundled customers require through SFCs entered into pursuant to the Illinois Auction. Approximately one-third of the SFCs will expire on May 31, 2008, an additional one-third of the SFCs will expire on May 31, 2009 and the SFCs for the remaining one-third of Ameren's bundled load will expire on May 31, 2010. Thus, for the period in question, existing SFCs will provide approximately two-thirds of the needs of Ameren's bundled customers. Ameren has also entered into a swap contract which provides a financial hedge for 400 MW for all hours during the period June 1, 2008 to May 31, 2009.

To meet the remaining requirements of its bundled customers' requirements, Ameren will acquire the physical energy via the MISO day-ahead and real-time energy market and will enter into financial swap contracts to hedge price exposure. Ameren plans to procure financial swap products for the following contract quantities and terms during the initial planning period of June 1, 2008 through May 31, 2009:

| | | |
|------------------|------|--------|
| Annual | 7x24 | 200 MW |
| January/February | 5x16 | 200 MW |
| June | 5x16 | 175 MW |
| September | 5x16 | 175 MW |
| July/August | 5x16 | 325 MW |
| 4th Quarter (Q4) | 5x16 | 75 MW |

Ameren proposes to use a hedging ratio of 0.9 for the summer and non-summer on-peak and off-peak periods. (Plan at 22)

The AG wants Ameren to acquire additional forward contracts such that, except during non-summer off-peak hours, Ameren would not be required, or allowed, to make

purchases on the spot market. The AG's witness seems to suggest that during summer on-peak hours Ameren should be required to maintain a hedge ratio of 1.40. He also seems to suggest that during off-peak hours, Ameren should be required to maintain a hedge ratio of 1.25. He claims that hedge ratios of 1.40 and 1.25 minimize price volatility.

Among other things, the AG asserts that forward electric prices tend to be higher during on-peak periods. Based in part on this assumption, the AG recommended that the Commission condition approval of Ameren's Plan on modifications to the plan that would eliminate spot purchases throughout the summer and during the on-peak non-summer periods. In its BOE, the AG clarified that the intent is to limit, not eliminate, spot purchases during those periods. The AG's recommendation is also founded in its analyses regarding the cost of hedging which is summarized above. The AG's recommendation in its BOE is further described above.

In its Supplemental Reply, Ameren indicates that it plans to purchase 100% of its customers' needs, which are not provided by preexisting SFCs or from qualifying facilities, in the spot markets. Ameren suggests that the AG's proposal should not be taken literally with regard to spot market purchases but, should only be considered with regard to the hedging ratio that is adopted in this proceeding.

As explained in more detail above, Ameren complains, among other things, that while the AG's analysis may be applicable to ComEd and Northern Illinois, it is not applicable to Ameren and Central Illinois. Additionally, Ameren asserts that the AG's analysis does not support a conclusion that Ameren's forward position should significantly exceed forecasted load during peak periods. While Ameren acknowledges that over-hedging will protect against a coincident rise in loads and prices, it claims the negative consequences from over-hedging will be compounded in the event of coincident decrease in load and price.

Ameren insists that as the hedge ratio diverges from near 1.0 the range of expected costs widens significantly. Ameren emphasizes that while it does not agree with Mr. McCullough's recommendations, should the Commission determine that it is more appropriate to utilize a hedge ratio higher than the one proposed by Ameren, it is critical that the Commission not adopt the language used in the AG's Supplemental Comments.

The Commission has reviewed all of the information provided by the parties regarding this issue, including the data in Appendix A to Ameren's Plan. As an initial matter, the Commission believes the AG's position, at least to the extent it argues that quantities subscribed should exceed projected requirements, warrants some consideration. Ameren performed extensive analyses of various hedging ratios, and the results of some of those analyses support consideration of this notion. The Commission finds, however, that the specific modification to Ameren's Plan, as proposed by the AG, cannot be adopted at this time. The Commission believes that prohibiting purchases from the spot market except during non-summer off-peak hours is simply too extreme.

The Commission is also concerned that requiring Ameren to purchase so much excess supply for so many hours would likely result in additional costs as Ameren suggests. As noted above, in its BOE, the AG clarified that the intent is to limit, not eliminate, spot purchases during those periods.

While Ameren has explained why it chose a hedging ratio of 0.9, the Commission remains somewhat concerned about the possible adverse impact on customers that could result if prices during the summer on-peak hours increase more than anticipated. In fact, Ameren's own analyses seem to suggest that a hedging ratio above 1.0 might be appropriate during summer on-peak hours.

Accordingly, the Commission directs Ameren to modify its Plan to incorporate a hedging ratio of 1.10 for the on-peak hours of July and August 2008. Ameren acknowledges that "over hedging will protect against a coincidental rise in load and prices." (Ameren Supplemental Reply at 20) The Commission believes that the modification to Ameren's Plan is reasonable and will provide adequate price protection when it is most likely to be important.

This modification appears to mitigate many of Ameren's concerns about "significantly" increasing the hedging ratio above 1.0. In its BOE, Ameren indicates that it does not disagree with this modification. (Ameren BOE at 2) Ameren points out that the modification will involve an increase in contract quantities over those originally proposed for the months of July and August, 2008. The AG's position in its BOE is summarized above.

Having reviewed all of the information provided by the parties, the Commission concludes that this modest modification is appropriate given current market conditions. All things considered, the Commission concludes that this modification to Ameren's Plan strikes the proper balance between price protection and other factors.

As discussed above, the AG recommends that the Commission direct Ameren to **conduct the 2008 procurement in March and April**. The AG asserts that by doing so, Ameren can avoid forward prices that are higher in summer and the months of December and January than during the rest of the year.

Ameren says it is willing to accept this recommendation related to acquiring the forward hedges, that is, the financial swaps. Ameren emphasizes that the AG's recommendation was exclusive to contract for hedges, not for acquiring renewable energy credits or capacity. Ameren says it will acquire RECs and capacity at various times during the planning period. Ameren claims there has been no evidence presented, or recommendation made by any party, which suggest that the scheduling of purchases for RECs and/or capacity should be altered from that proposed in the Plan.

It appears to the Commission that there is no longer a dispute regarding the timing of acquiring financial swaps. Ameren has agreed with the AG's proposal, and the Commission finds the agreed-to resolution reasonable.

CUB alleges that Ameren's has not adequately explained its decision to hedge the energy supply that it procures with **financial swap agreements instead of physical energy contracts**.

Among other things, Ameren argues that the cost of credit for operating within the MISO market is expected to be lower by utilizing financial swaps than it would be to enter into physical transactions. Ameren asserts that the mechanics of the MISO market, particularly the differences in settlement timelines, and the existence of an unsecured credit line with MISO that is not likely to exist with a physical counterparty, provide the basis for an expected lower total cost. Ameren maintains that financial swaps were chosen because it operates within the MISO footprint, and financial swaps are expected to provide the equivalent level of price hedging at a lower expected total cost over time when compared to physical forward contracts.

Having reviewed the filings, the Commission declines to modify the Plan based on the argument that Ameren has not adequately explained the basis for its decision to use financial swaps rather than physical forward contracts to hedge its energy supply. That explanation is contained at pages 25 through 27 of Ameren's Plan. There is no specific indication of what, if anything, is lacking from Ameren's explanation. Additionally, there appears to be no real criticism of the rationale underlying Ameren's decision. Finally, the Commission notes that in addition to operating in different regional transmission organizations, Ameren and ComEd plan to use fundamentally different means to meet the energy requirements of their bundled customers. The Commission would expect that this fact, as much as anything else, could lead to different decisions by Ameren and ComEd.

3. Contingency Plans

a. Positions of the Parties

The procurement Plan filed by the Ameren Companies contain contingency plans in the event of significant changes in demand or supply levels.

In its Objections, **Staff** indicates that Ameren's plan does not specifically identify what happens in the presumably unlikely event that Ameren Energy Marketing Company defaults on the 400 MW swap contract. (Objections at 15) Staff states that instead, the "for all other events" provision would apply. Staff asserts that since MISO does not include a forward market for energy, the hedge would be eliminated for the remainder of the planning year. As an alternative, Staff suggests it may be preferable for Ameren to apply a modified version of the contingency plan for SFC defaults. Specifically, Staff recommends "that if Ameren Energy Marketing Company defaults on the swap with at least 92 days remaining in the June 2008-May 2009 planning year, then Ameren would attempt to replace the swap for the remainder of that planning year through an RFP process."

In its Reply, page 6, **Ameren** indicates that Staff correctly points out that, absent this proposed modification, the hedge for this portion of the load would be eliminated for the remaining of the planning year. Ameren agrees with Staff's recommendation and is "willing to modify Rider PER to incorporate this concept."

In its November 28th Reply Comments, **Staff** states that, with respect to the contingency plan in the event that Ameren Energy Marketing Company defaults on the 400 MW swap contract, Ameren has agreed with Staff's recommendation. (Staff Reply Comments at 4, citing Ameren Reply Comments at 6) Thus, Staff believes this objection can be resolved by the uncontested adoption of Staff's recommendation.

b. Commission Analysis and Conclusions

Staff and Ameren now agree that the contingency plan should be modified for the reasons outlined by Staff. The Commission concurs. The swap is intended to provide an important hedge; thus, appropriate contingency measures need to be in place to replace the swap in the event of a default. Therefore, the Commission finds that the procurement plan should be modified in the manner recommended by Staff.

4. Renewable Energy Standard and Related Issues

a. Introduction; Statutory Authority

Section 1-75(c) of the IPAA, "Renewable Energy Standard," requires, in subsection (1), that "the procurement plans shall include cost-effective renewable energy resources." Renewable energy resources are defined in Section 1-10 of the IPAA to include "energy and its associated... renewable energy credits from wind, solar thermal energy" and other resources. 20 ILCS 3855/1-75

Section 1-75(c)(1) provides, "A minimum percentage of each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act, procured for each of the following years shall be generated from cost-effective renewable energy resources: at least 2% by June 1, 2008; at least 4% by June 1, 2009"

Section 1-75(c)(1) further provides:

To the extent that it is available, at least 75% of the renewable energy resources used to meet these standards shall come from wind generation. For purposes of this Section, "cost-effective" means that the costs of procuring renewable energy resources do not cause the limit stated in paragraph (2) of this subsection (c) to be exceeded.

Section 1-75(c)(3) contains "locational requirements." It provides in part:

Through June 1, 2011, renewable energy resources shall be counted for the purpose of meeting the renewable energy standards set forth in paragraph (1) of this subsection (c) only if they are generated from facilities located in the State, provided that cost-effective renewable energy resources are available from those facilities. If those cost-effective resources are not available in Illinois, they shall be procured in states that adjoin Illinois and may be counted towards compliance

b. Statutory Intent Regarding Priorities

With regard to the renewable energy standard, **Staff** says Ameren appears to treat "cost cap" as an absolute constraint, an interpretation of the Act shared by the Staff. Staff asserts, however, that the IPAA is not specific regarding how to prioritize between the locational criteria, the wind resources criterion, and the overall goal of 2% renewable energy resources. (Objections at 19) In Ameren's plan, Staff indicates that the Companies appears to give the greatest priority to meeting the 2% renewable goal, the second greatest priority to the 75% minimum wind criterion, and the lowest priority to meeting the locational criteria.

Staff agrees with Ameren that the greatest priority in the context of an annual purchase of RECs should be to the overall 2% cost-effective renewable goal subject to the cost cap, and that the wind and locational criteria should receive secondary priority. In Staff's view, the language of the Act only gives preference to wind resources and renewable resources within Illinois that are "cost effective," which means that they can be attained within the budget constraint. (Objections at 21) While Staff believes that the Ameren decision rules may have been intended to be consistent with this interpretation, Staff claims they do not clearly accomplish that task.

According to Staff, the Commission's analysis of the Companies renewable energy requirement proposal requires a two-part analysis. First, the Commission needs to determine the priorities that apply in meeting the renewable energy resources goal under PA 95-0481. Second, a set of decisional rules needs to be developed consistent with those priorities.

Staff believes that the highest priority under the IPAA is to meet the renewable energy resource standards with resources that are cost-effective. Section 1-75(c)(1) of the IPAA (20 ILCS 3855/1-75(c)(1)) requires that certain minimum percentages (varying by year) of the load of eligible retail customers shall be generated from cost-effective renewable energy resources. Per Section 1-75(c)(1), "'cost-effective' means that the costs of procuring renewable energy resources do not cause the limit stated in paragraph (2) of this subsection (c) to be exceeded." Staff asserts that the limits in paragraph 2 are annual caps on the cost of renewable energy resources. Section 1-75(c)(a) also provides that "[t]o the extent that it is available, at least 75% of the renewable energy resources used to meet these standards shall come from wind generation."

Staff argues that under this language, the requirement to obtain the specified level of renewable resources within the cost cap is superior to the requirement to use 75% wind. The applicable standard is to obtain a particular level of “cost-effective” renewable energy resources. Cost-effective is defined as not causing the caps in paragraph (2) to be exceeded. Staff says the wind generation goal is conditional – “if available” – and is stated as a sub-requirement of the renewable energy resources standard – “75% of the renewable energy resources used to meet these standards shall come from wind generation.” Thus, if using 75% wind generation results in a level of costs that exceeds the cap and there are other less costly renewable resources that would allow compliance with the percentage renewable resources standard, then Staff claims wind generation is not a cost-effective resource as defined in the statute. (Objections at 22)

According to Staff, the locational requirements of Section 1-75(c)(3) are mandatory – “shall be counted . . . only if” – whereas the wind requirements are permissive – “[t]o the extent that it is available, at least 75% of the renewable energy resources . . . shall come from wind” Staff states that while the IPAA is not exceedingly clear on the priority of the wind and locational requirements, Staff submits that it is consistent with the statutory language and reasonable to read the locational requirements as having a higher priority than the percent wind requirements.

Thus, Staff submits that Ameren’s plan and related decisional rules for RECs should reflect the following priorities: (1) achieving the required level of renewable energy resources within the cost cap; (2) meeting the locational requirements; and (3) meeting the percent wind requirement. Since there are varying levels of locational requirements, the wind requirement should be applied such that wind resources within each locational level are utilized before non-wind resources. Staff submits that Ameren’s decisional rules should be modified to comply with the priorities it describes. Staff’s proposed modifications are shown on pages 23-25 of Staff’s Objections.

In its Reply, **Ameren** responds to Staff’s position that a two-part analysis is required. In the first part, the Commission should clearly define the priorities between meeting the 2% renewable requirement, the wind resource criterion included in the Act, and the locational criterion included in the Act. In the second part, the Commission should develop a set of decision rules consistent with the priorities previously defined. Ameren states that in this respect, it agrees with the Staff recommendation. Ameren says that while it believes the intent of this portion of the Act is to encourage the construction of wind resources within the state of Illinois, to the extent the Commission finds a different interpretation is warranted, it will abide by that direction. (Ameren Reply at 7)

Staff’s second recommendation is a specific set of decision rules that follow from Staff’s interpretation of the Act, that meeting the 2% cost effective renewable energy resource requirement is the top priority.

Ameren maintains its belief that the intent of this section of the Act is to encourage the construction of wind resources within the state of Illinois and, therefore, Ameren does not support the set of decision rules set forth by Staff unless the Commission interprets the law differently. (Ameren Reply at 8)

In its reply comments, **Staff** reiterates its claim that PA 95-0481 established that the highest priority must be given to the 2% cost effective renewable resources requirement, followed by locational criterion and then the wind resource criterion. (Staff Reply Comments at 4-5) Staff says Ameren's only response is to state that its belief that the intent of this portion of the Act is to encourage the construction of wind generation within the state of Illinois, and thus does not support the decision rules proposed by Staff. Since Ameren does not explain the basis for its different priority determination, Staff says it cannot respond further.

Having said that, Staff acknowledges that it would be possible to interpret the Act to give the wind resource criterion priority over the locational criterion (although Staff believes the opposite is a better construction for the reasons indicated in Staff's Response), but Staff does not believe it would be reasonable to give the wind resource criterion or the locational criterion priority over the 2% cost effective renewable resources requirement for the reasons stated in Staff's Response. (Staff Reply Comments at 4-5)

The only party to file a BOE on the issue of priorities was Constellation, which had not previously addressed the issue in its previous filings. (BOE at 1-4)

The **Commission** has reviewed the positions of the parties; as the parties have observed in this case and the ComEd docket, in 07-0528, Section 1-75(c) of the IPAA is susceptible to multiple interpretations in terms of ranking, and reconciling, the competing priorities of cost-effectiveness, wind preference and locational requirements.

Having reviewed the statute and the arguments, the Commission agrees with Staff that the highest priority under the IPAA is to meet the renewable energy resource standards with resources that are cost-effective. Absent a clear indication in the statute that an option which is not cost-effective is to be favored over resources which are cost-effective, the Commission believes it should err on the side of the cost-effective resources.

Next, whether the wind preference should take priority over the locational requirement, or vice versa, is a difficult call. Of all the available renewable energy resources, only wind generation is singled out in Section 1-75(c) as a resource of preference. Therefore, to the extent the Commission needs to make a determination at this time, it appears that wind generation should receive priority over the locational requirement.

With regard to the resource selection rules, the Commission notes that the Staff modifications provide a good starting point, subject to the findings above. The

Commission believes the final details can best be addressed by the Procurement Administrator, subject to Staff review.

c. Use of Energy Credits

Invenergy, a developer of wind-powered generation, believes that one of the key goals of Illinois' new renewable portfolio standard ("RPS") is to encourage the construction of new renewable generation in Illinois. Invenergy says that meeting RPS goals solely through renewable energy credit purchases is a concern, as the only providers of this product will be existing renewable providers in the region. Similarly, Invenergy asserts that short-term, year-to-year utility procurement plans will not provide the necessary certainty needed for the establishment of new renewable generation in Illinois that is contemplated by the RPS. If the Commission does approve Ameren's Procurement Plan, Invenergy is of the belief that, following the one-year period between June 2008 and May 2009, a utility procurement plan that is short-term and/or "REC-only" is not a suitable way to proceed and is contrary to the long-term goals of the RPS. (Comments at 2; Response of Invenergy at 1)

If the Commission approves the Plan, Invenergy strongly urges the Commission to clarify that (i) given the circumstances, the Plan will not be considered to have set precedent for approval of future procurement plans and (ii) a core purpose of Section 16-111.5 – the construction of new renewable generation in Illinois – would be circumvented by the use of RECs as the exclusive or primary long-term method of compliance with the renewable portfolio standard. (Response of Invenergy at 2)

In response, **Ameren** claims nothing meaningful is offered by Invenergy. Ameren states that Invenergy fails to explain how an entity that is not an existing renewable provider in the region would be able to provide the necessary resources for the subject delivery period. Ameren claims that nowhere in its filing does Invenergy state that its projects, currently under development, will be operational in time to provide renewable resources for the subject delivery period. (Reply at 32)

According to Ameren, the better and more informed approach would be to comment on the Plan itself, rather than what is not in the Plan, or what should or should not be in future procurement plans. Ameren states that Section 16-111.5(j)(i) is clear in that specific, detailed objections, supported by data or other detailed analyses, be directed at the "procurement plan submitted by the electric utility." In Ameren's view, Invenergy has failed in both respects: offering nothing that resembles detailed objections supported by data and analyses, and no meaningful commentary as it relates to the Plan for the June 2008 through May 2009 planning period. (Supplemental Reply at 28)

As indicated above, Section 1-10 of the IPAA defines renewable energy resources to include associated renewable energy credits. The IPAA, in Section 1-75(c), also contains provisions prioritizing the use of wind generation. Invenergy does not appear to be arguing that Ameren's plan is out of compliance with the IPAA in that

regard. Further, the **Commission** observes that its role in reviewing Ameren's proposed procurement plan and tariffs is to approve or modify that plan and tariffs. It does not appear that Invenergy is proposing any modifications to that plan.

The Commission's approval of the plan, as modified, is not intended to create any presumptions regarding the use of energy credits in the future procurement plans. Beyond that, while the Commission appreciates Invenergy's comments and suggestions, the Commission does not believe the instant docket is the place for the Commission to make any determinations on Invenergy's policy concerns.

d. RECs -- Timing Related Issues

Constellation also comments on the "Renewable Portfolio Standard Procurement Plan." (Comments at 4) Ameren indicates that it intends to satisfy the requirement that 2% of its portfolio be made up of renewable energy, through the purchase of Renewal Energy Credits ("RECs"). Constellation claims that other markets will likely need or want some of the same renewable resources as would Ameren, and that holders of RECs may participate in these other markets. Constellation argues that dates relating to RECs should be set promptly, such as identifying when offers will be out for bid, and when final decisions regarding RECs will be made. Additionally, Constellation says the Plan should be clarified to state that the RECs used to satisfy the renewable standard must match the delivery period, and historical RECs should not qualify as compliant with the standard.

In response to what it describes as Ameren's confusion with regard to the notion of historical RECs, Constellation states that RECs may be used in a time commensurate with their creation (such RECs 'match' the delivery period), or held for use in future years not commensurate with their creation (such RECs are 'historical' with respect to the future year in which they are used). Constellation recommends that RECs being used to satisfy the RPS for a particular calendar/planning year come from renewable energy generated in that same delivery period (calendar/planning year). It is Constellation's position that RECs associated with energy generated in a prior calendar/planning year – historical RECs – should not be considered in evaluating compliance with the RPS. According to Constellation, matching the RECs to the delivery period best reflects Ameren's energy load for the current year, encourages new renewable energy sources, and discourages the "banking" of RECs by prospective sellers in the hopes that market prices will rise. (Constellation Supplemental Comments at 4-5)

Ameren indicates that Constellation's third concern relates to the renewable portfolio standards procurement. Constellation asks that the timeline related to RECs should be set promptly. Ameren argues that the Plan is not the proper place to include such timelines, as it is the procurement administrator's responsibility to manage the procurement process.

Further, Constellation asks the Plan be clarified such that the RECs used to satisfy the renewable standard match the delivery period, and historical RECs should not qualify as compliant with the standard. Ameren asserts that Constellation's proposal is unclear at best. Ameren suggests that it does know what the terms "historic Renewable Energy Credits" and "historic RECs" mean. Also Ameren claims, Constellation's statement that "RECs...must match the delivery period," needs to be clarified.

In terms of matching the RECs with the delivery period, the **Commission** finds that the timing of the procurement of RECs should be undertaken in a manner that takes into account the lags that can result between procurement and availability.

Beyond that, the Commission observes that the specific timeline for the REC bidding process appears, generally speaking, to be part of the "procurement process" administered by the Procurement Administrator under Section 16-111.5(c). As such, the Commission does not believe the record supports a finding that more specific direction to the Procurement Administrator is necessary with respect to this issue.

5. Demand Response; Energy Efficiency; Related Issues

a. Positions of the Position

CUB's objections were supported by the testimony of Mr. Christopher Thomas. According to CUB, Ameren has not shown that its proposed plan will result in the lowest total cost electricity for customers because it has not evaluated all available supply options, including cost effective demand response and energy efficiency, in constructing its plan. (CUB Objection at 2; CUB Supplemental Comments at 1; BOE at 1-6) Consequently, CUB requests that the Ameren's initial procurement plan be revised to include the procurement of all available cost-effective demand response and energy efficiency resources. CUB maintains this position in each of its filings up to and including its BOE. (CUB Supplemental Comments at 5, BOE at 1-6)

CUB says that in the interest of time and brevity, it framed its Objections in terms of the "lowest total cost" criteria, but the omitted portion of the standard, which continues "taking into account any benefits of price stability," does not change the analysis in any way. CUB claims that Ameren's analysis has not taken the benefits of price stability into account. According to CUB, Ameren has not evaluated the effect of demand response and energy efficiency on either total cost or price stability. In addition, CUB asserts that Ameren has not justified its chosen hedge ratio or its choice to hedge via financial swap contracts, as opposed to physical supply contracts, in terms of either total cost or price stability. CUB asserts that the two criteria are related, and Ameren's failure to fully analyze its supply and hedging options fails to satisfy either criteria. (CUB Supplemental Comments at 2-3)

In its Supplemental Comments, CUB says that it does not recommend that Ameren procure specific products, but instead requests that Ameren take a market-

based approach to determine which cost-effective energy efficiency and demand response programs are available from the marketplace. That is, CUB asserts that Ameren must expand the proposed RFP process to procure verifiable demand side resources from energy efficiency and demand response providers that can be used to offset Ameren's supply and capacity obligations, prior to the procurement of electricity supply. CUB argues that prescribing specific products in a restrictive RFP or utility planning process could unnecessarily disqualify innovative products from participating in the RFP. In CUB's view, relying on competitive market forces to determine the exact products that provide these resources will prevent this problem. (CUB Supplemental Comments at 3-4)

CUB claims that contrary to Ameren's argument, the Act's energy efficiency and demand response provisions do not limit Ameren's ability to procure these resources through its procurement plan. (CUB Supplemental Comments at 4) CUB says the Act requires Ameren's plan to procure all energy efficiency and demand response resources that result in the lowest total cost over time, taking into account any benefits of price stability. While the Act requires Ameren to institute energy efficiency and demand response measures that include a rate cap, CUB contends it does not prohibit Ameren from purchasing additional energy efficiency and demand response resources from the marketplace, so long as they comply with the Act's procurement plan standard. In addition CUB claims that if Ameren procures these resources where they are less expensive than supply, they would never hit the rate cap, even if it did apply. According to CUB, Ameren must evaluate the use of these resources to provide electricity at the lowest total cost.

The **AG** argues that "Ameren fails to use demand-response measures effectively to reduce load uncertainty and price risk." (Objections at 4-5) The AG claims Ameren's proposed plan indicates that Ameren intends to implement only enough demand response to comply with the minimum demand response standards that were enacted earlier this year in Public Act 95-0481. According to the AG, the new law requires Ameren to reduce eligible retail customers' peak demand by 0.1 percent, or 1.6 MW, during the planning year from June 1, 2008 through May 31, 2009.

The AG states that Ameren's proposed plan relies primarily on forward contracts for standard products with the remainder of the portfolio to be purchased in the MISO spot market. The AG maintains that Ameren's proposal exposes customers to significant price risk associated with the potential for purchases in the MISO spot market during critical peak when customer demand spikes and prices are at their highest. PA 95-0481 requires Ameren to identify alternatives for those portfolio measures that are identified as having significant price risk. The AG says demand-response is one such alternative. The AG asserts that considerable potential exists in Illinois to tap unrealized potential demand-response, and numerous reports have pointed out differences among various regions of the U.S. in the effectiveness of implemented measures. (Objections at 4)

The AG complains that Ameren has not assessed the effectiveness of demand response as an alternative to spot purchases during summer peaks. In the AG's view, Ameren's failure to consider this alternative is contrary to the express statutory mandate in 220 ILCS 5/16-11.5(b)(3)(v).

According to the AG, Ameren's portfolio should be modified to include additional demand response measures to reduce load uncertainty and price risk. Increased use of direct load controls on central air conditioning systems, along with smart meters and appliances could be dispatched on an economic basis to shave peak demand by Ameren's bundled customers and reduce the need for purchases of expensive on-peak electricity to serve these customers. The AG says the plan should be modified to specify that demand response measures will be implemented in lieu of purchases of electricity where the cost of a demand response measure is less than the cost of procuring electricity in the spot or forward markets. The AG asserts that demand response is an essential least cost strategy to avoid purchases in the spot market during critical peak periods. (Objections at 5)

In addition to the specific objections set forth above, the AG complains that the data and analysis in the proposed plan lack detail. (Objections at 5-6) According to the AG, the data and analysis included in Ameren's filing is not sufficient to support a finding that the plan, as filed, meets the applicable legal standard. The AG contends that Ameren has failed to present sufficient evidence and analysis to support a finding that the plan will ensure adequate, reliable, affordable, efficient and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.

The AG also argues that the Commission should defer assessment of the justness and reasonableness of the proposed tariff until the final mix of products, commodities and services to be included in the procurement plan has been established. The AG claims the Commission has discretion to defer this assessment because the review of tariffs is governed by Article IX of the Public Utilities Act, rather than the expedited procedures specified for procurement plan review in 220 ILCS 5/16-111.5(j)(i). (Objections at 7)

Ameren disagrees with CUB's objection that the Plan does not provide for least-cost energy, and finds CUB's analysis to be incomplete. (Reply at 24-25; Supplemental Reply at 8) According to Ameren, in its objection CUB references only a portion of the standard; it does not state the complete requirement which continues on after "lowest total cost over time," to include "taking into account any benefits of price stability." Ameren argues that to the extent CUB's analysis rests upon its faulty interpretation of the standard, its analysis must also be faulty.

According to Ameren, CUB continues by stating the Plan has not evaluated all available supply options, including cost effective demand response and energy efficiency. CUB requests that the Ameren Plan be revised to include the procurement of all available cost effective demand response and energy efficiency resources.

Ameren asserts that CUB's request is incomplete and does not provide specific details as to what standard cost effective demand response and energy efficiency products should be included in the Plan. (Ameren Reply at 25) Ameren claims the request is lacking an analysis to determine the optimal quantity required. Ameren says the law requires the utility to procure standard market products for a one year term and thus the Ameren Plan was developed to include all of the requirements stated in Section 16-111.5(j)(ii), including the benefits of price stability. According to Ameren, CUB does not refute the fact Ameren has recommended standard products in this time frame.

In addition, Ameren says Section 16-111.5(b)(3)(iii) requires that the Plan shall include the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year. Ameren claims that CUB does not explain how to convert this requirement into a specific modification to the Plan. Ameren believes it is unclear and never explained how demand response and energy efficiency measures would be considered "standard wholesale products." (Ameren Supplemental Reply at 8)

Ameren states that Section 16-111.5(e)(2-4) requires that the procurement process, managed by the procurement administrator, include each of the following components: standard contract forms and credit terms and instruments; establishment of a market-based price benchmark; and request for proposals competitive procurement process. Ameren says the request for proposals shall set forth a procedure for sealed, binding commitment bidding with pay-as-bid settlement, and provision for selection of bids on the basis of price. The statute, Ameren claims, obligates the procurement administrator to execute the Plan as approved by the Commission and manage the process described herein. Ameren says it does not convey upon the procurement administrator the authority to change or adjust the approved Plan, as would be required if CUB's proposal were to be adopted. (Ameren Supplemental Reply at 8-9)

According to Ameren, Section 16-111.5(j) also provides, "The initial procurement plan shall identify the portfolio of power and energy products to be procured and delivered for the period June 2008 through May 2009." Ameren contends that CUB has provided no explanation as to what demand response measures should be considered that would comply with the one-year requirement. Ameren claims that typically, such programs have lives or measures that extend over a number of years.

In Ameren's view, the Commission need not concern itself with energy efficiency and demand response programs as part of the Plan. Ameren says the General Assembly has already provided clear direction in 220 ILCS 5/12-103 (b) and (c). (Ameren Supplemental Reply at 9)

With regard to energy efficiency measures, Ameren says its Plan meets the requirements of the law: "Electric utilities shall implement cost-effective energy efficiency measures to meet the following incremental annual energy savings goals: (1) 0.2% of energy delivered in the year commencing June 1, 2008..." Ameren asserts that

the Plan also includes demand response measures in accordance with the statute: “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 Act. This requirement commences June 1, 2008 and continues for 10 years.” 220 ILCS 5/12-103(c) According to Ameren, its Plan does incorporate these measures and further details regarding the energy efficiency and demand-response measures have been provided in a filing to the Commission on November 15, 2007.

According to Ameren, it is clear on the face of the statute that when the Commission approves the Procurement Plan at the end of the 60 day statutory period, the Commission is also expected to approve the subject tariffs. (Reply at 26-27) Ameren says there is nothing in the law that defers the Commission’s obligation to approve these tariffs until such time as the Commission determines what products are to be included in the Plan.

Ameren asserts that the AG offers no valid reason why there is a need to wait until the procurement process is underway for the Commission to make any determinations about its proposed tariffs. Ameren claims there is nothing about the products, commodities, or services to be procured that will change or affect the tariffs. These are simply cost recovery mechanisms. Finally, Ameren asserts having these tariffs in place earlier, rather than later, is helpful to all stakeholders. Ameren states that as in the auction procurement dockets, the Commission approved the Ameren Illinois Utilities’ Rider MV and other related tariffs in January 2006, even though these tariffs would not go into effect until January 2, 2007. In Ameren’s view, it is important for the Commission, Staff, stakeholders, including ARES, and other market participants, to know well enough in advance the manner and method by which those tariffs operate.

Ameren also disagrees with the AG assertion that the data and analysis included in the Ameren filing do not meet the legal standard as required under the Act, that is, the Plan will not ensure adequate, reliable, affordable, efficient and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits or price stability. (Reply at 27-28) Ameren argues that the AG failed to comply with the requirements of the Act in terms of filing a meaningful response to the Plan. Ameren says Section 16-111.5(j)(i) requires any person that files an objection contesting the Procurement Plan, to provide “detailed” objections that are specific, supported by data or other detailed analysis. According to Ameren, the AG proposes modifications that lack sufficient detail or analysis by which to ascertain what proposal is being made.

Ameren also objects to the AG’s second proposed modification that the portfolio should be modified to include additional demand response measures to reduce load uncertainty and price risk. (Reply at 28-29) Ameren claims that how this recommendation is to be implemented is never explained. Ameren says there are no specific demand response measures being proposed and there is no explanation as to how the additional measures affect the Plan load forecast. Ameren wonders if

additional demand response measures are successful in providing a meaningful reduction in the peak load, whether the AG still believe that a 130% hedge is appropriate.

Ameren complains that the AG's proposed modification is incomplete and cannot be commented on in its current form other than to note that Section 16-111.5(b)(3)(iii) states the Plan shall include the proposed mix of standard products for which contracts will be executed. Ameren says it is unclear and never explained how demand response measures would be considered standard products. Section 16-111.5(j) requires, "The initial procurement plan shall identify the portfolio of power and energy products to be procured and delivered for the period June 2008 through May 2009." Again, Ameren says no explanation is provided as to what demand response measures should be considered that would fit this one-year requirement. Finally, Section 12-103(c) requires that "Electric utilities shall implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers." Ameren indicates that it would expect an analysis to show that additional programs would not cause the spending cap to be exceeded; however, Ameren complains that the AG does not provide this needed analysis.

b. Commission Analysis and Conclusions

According to CUB and the AG, Ameren's portfolio should be modified to include additional demand response measures to reduce load uncertainty and price risk. Increased use of direct load controls on central air conditioning systems, along with smart meters and appliances, could be dispatched on an economic basis to shave peak demand by Ameren's bundled customers and reduce the need for purchases of expensive on-peak electricity to serve these customers. The AG says the plan should be modified to specify that demand response measures will be implemented in lieu of purchases of electricity where the cost of a demand response measure is less than the cost of procuring electricity in the spot or forward markets. The AG asserts that demand response is an essential least cost strategy to avoid purchases in the spot market during critical peak periods.

CUB claims Ameren has not shown that its proposed plan will result in the lowest total cost electricity for customers because it has not evaluated all available supply options, including cost effective demand response and energy efficiency, in constructing its plan. CUB requests that Ameren's initial procurement plan be revised to include the procurement of all available cost-effective demand response and energy efficiency resources. CUB says it does not recommend that Ameren procure specific products, but instead requests that Ameren take a market-based approach to determine which cost-effective energy efficiency and demand response programs are available from the marketplace.

Ameren says the law requires the utility to procure standard market products for a one-year term and that its Plan was developed to include all of the requirements stated in Section 16-111.5(j)(ii), including the benefits of price stability. Ameren asserts

that its Plan includes demand response measures in accordance with the 220 ILCS 5/12-103(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 Act. This requirement commences June 1, 2008 and continues for 10 years.” According to Ameren, its Plan does incorporate these measures and further details regarding the energy efficiency and demand-response measures have been provided in a filing to the Commission in Docket 07-0539.

The Commission has reviewed the arguments of the parties. As an initial matter, the Commission wishes to emphasize that it encourages the implementation of demand response and energy efficiency in the State of Illinois. Additionally, the Commission observes that the statutory framework within which it must evaluate Ameren’s proposed Plan is complex, and the time for this evaluation is short.

In any event, the Commission believes that Ameren’s Plan regarding demand response and energy efficiency complies with the statute. Section 16-111.5(b) requires that a compliant plan include an hourly load analysis that includes an evaluation of both demand response programs and energy efficiency programs. Ameren’s plan at pages 12 and 14 to 15 contains the required analyses.

Section 12-103 of the Act governs utilities’ obligations with regard to energy efficiency and demand response measures. Ameren’s obligations under Section 12-103 are being litigated in Docket No. 07-0539.

The Commission does not mean to suggest that demand response and energy efficiency are irrelevant to the instant proceeding; they are not. However, given the very general nature of the recommendations in the filings of CUB and the AG – that Ameren’s plan “be revised to include the procurement of all available cost effective demand response and energy efficiency resources” – the Commission believes adoption of those recommendations would serve as little more than a vague direction to Ameren, leaving too many questions unresolved to serve as an appropriate modification to the plan as discussed below.

The Commission does not believe the record in this case shows whether or how it would be feasible to include additional cost-effective demand resources in an RFP process in Ameren’s Plan. What DR products that would entail, and which resources it would replace, if that is the intent, is unclear. Thus, while DR resources may be available, there is no showing they include products that are suitable replacements – in terms of type, cost or availability – for the resources they would replace in Ameren’s plan. This is particularly relevant in the instant case, where only a small fraction of Ameren’s requirements are being procured through the plan, inasmuch as two-thirds of Ameren’s requirements in the plan year will be met by existing supplier contracts, and another 400 MW will be provided via statutorily mandated swaps.

Similarly, there are unresolved issues as to whether CUB's recommendation is consistent with the statutory scheme in Section 16-111.5(b) and other provisions of the law. For example, Section 16-111.5(b)(2) requires the utility to describe in its Plan the impact that these energy efficiency and demand-response measures will have on its load forecasts. Then, the utility is to propose the mix of standard wholesale products that are needed to supply the resulting expected load. (16-111.5(b)(3)) Finally, the utility is to propose a procedure for the hourly balancing of loads. (16-111.5(b)(4)) The record in this brief docket does not support a finding that ordering the utility to consider "all available supply options, including cost effective demand-response and energy efficiency" would be compatible with the statutory structure.

Thus, the Commission will not adopt the proposals of the AG and CUB with regard to demand response and energy efficiency. This conclusion creates no presumptions regarding the role of DR in the planning process in other dockets, including those involving future procurement plans where there will be more time to evaluate these issues.

6. Supplier Contracts and Related Issues

a. Positions of the Parties

Dynegy is a wholesale supplier with over 4000 MW of generation. First, Dynegy complains that Ameren's plan did not include draft standard contracts. (Objections at 2-4) Dynegy says that without such draft standard contracts, the Commission cannot know how Ameren believes the contractual risks should be apportioned. Dynegy suggests that in the absence of draft standard contracts, Ameren could develop contracts that favor its affiliates and drive up the price to consumers.

Dynegy states that language in Ameren's plan seems to suggest it is permissible for bids to differ by price and contractual terms. Dynegy says if differing contracts are permitted, the Plan does not specify how anyone will be able to determine how the winners of the procurement will be determined. Dynegy suggests that the process outlined by Ameren may not result in electric service at the lowest total cost over time, nor is it in the best interests of retail customers.

Second, Dynegy complains that Ameren's plan fails to describe the credit terms and conditions that Ameren proposes. (Objections at 4) Dynegy says it is impossible to evaluate a Plan that fails to include important factors such as whether the credit provisions will be bilateral.

Finally, Dynegy observes that Ameren is now proposing a procurement process whereby it, not suppliers, will bear substantial risk relating to variation in supply, load, price, and the like. (Objections at 4-5) Dynegy says that in prior proceedings, Ameren argued such risks were better managed by suppliers. Dynegy wants Ameren to explain how its new portfolio will result in lower cost to customers than the previous full requirements portfolio. (Dynegy Additional Comments at 5-6)

Dynergy states that absent the information it has identified, the Commission should reject Ameren's Plan.

In its Additional Comments filed on November 28th, Dynergy asserts that Ameren's response fails to address meaningfully the points made in Dynergy's Objections. Dynergy also claims that Ameren failed to provide the information Dynergy believes is essential for it to provide before the Commission can make the findings required under Section 16-111.5(j) of the Act. Dynergy reiterates its position that Ameren has an obligation to submit the necessary information and thereafter provide parties with a meaningful opportunity to comment on it before making a decision. (Dynergy Additional Comments at 1)

In response to Ameren's assertion that there is no legal basis for rejecting the Plan, Dynergy says the Commission cannot approve the Plan if it does not meet the statutory requirements. Dynergy claims the statute is very specific: "The Commission shall approve the procurement plan if the Commission determines" Dynergy maintains that Ameren has not supplied sufficient information for the Commission to make the requisite determinations. Thus, Dynergy argues that the Commission cannot approve the Plan in its current state. Dynergy also believes it is unlikely that a modification to the Plan can cure the defects it raises because the defects go to what is missing and not merely to correcting that which is already present. (Dynergy Additional Comments at 2-3)

According to Dynergy, Ameren claims that it is not its place to supply draft contracts or credit information because that role is for the procurement administrator. Dynergy says it agrees that the subsection quoted by Ameren provides for a further part of the process during which form contracts are to be finalized. But the fact that a subsequent process will finalize the contracts, Dynergy argues, in no way precludes Ameren from submitting at this time its conception of the contracts or from explaining how it believes various contractual provisions can be used to meet the statutory requirement of total lowest cost.

Dynergy claims there is nothing that bars the inclusion of such drafts as a part of filing the Plan and implicitly, supplying them is required because they directly impact on the statutory determination this Commission must make. Dynergy says Ameren does not deny that contractual terms can and do make a difference on price or deny that credit terms in particular can and do make a difference on price. Dynergy adds that Ameren does not deny that contractual terms, particularly credit terms, can be used to advantage some parties and not others. (Dynergy Additional Comments at 3-4)

Dynergy finds it disconcerting that Ameren has chosen not to answer some of the questions it posed in its Objections, which Dynergy believes can be answered without the submission of draft contracts and without the presence of a procurement administrator, because the answers represent Ameren's views. Dynergy contends that, regardless, Ameren has an obligation to answer them as a means of demonstrating to

the Commission that its plan does indeed meet the statutory requirements. (Dynergy Additional Comments at 4)

According to **Ameren**, Dynergy fails to provide the statutorily required data or detailed analysis to support its objections. Further, Ameren asserts that Dynergy provides no basis for requesting a rejection of the Plan. Ameren also says that Section 16-111.5(j)(ii) of the Act requires that the Commission approve or modify the procurement plan, but does not contain a provision for rejection of the Plan. (Reply at 29; Supplemental Reply at 24)

With regard to Dynergy's first objection, that Ameren's plan did not include draft standard contracts, Ameren says that Section 16-111.5(e)(2) of the Act, provides that the procurement administrator, not the utilities, "...shall develop and provide standard contract forms for the supplier contracts." Ameren notes that it is not the procurement administrator. Dynergy goes on to express several concerns regarding potential affiliate abuse, in its discussion of the lack of draft contracts. Ameren asserts that the Act addresses this issue stating that such contracts are developed, "...in consultation with the utilities, the Commission, and other interested parties and subject to Commission oversight" 220 ILCS 5/16-111.5(e)(2)

Dynergy asserts that the contracts could be provided now as part of the Plan. Ameren says that in theory, Dynergy is correct but as matter of law, its interpretation is wrong. Ameren claims Section 16-111(e)(2) is there for a purpose -- it explains the role of the procurement administrator and part of that role is facilitating the form of the contracts to be used and their terms. Had the General Assembly wanted the utilities to float form contracts and terms, Ameren says it would have made that requirement to the Plan filing. (Supplemental Reply at 24)

According to Ameren, Section 16-111.5(c)(1)(i) requires that the final procurement process is to be designed by the procurement administrator following the Commission's approval of the procurement plan. Ameren says this statute spells out the obligations of the procurement administrator which include developing benchmarks, serving as the interface between the utilities and the suppliers — Dynergy among others, obtaining the utilities agreement to the final form of the supply contracts and credit collateral agreements, to name a few. Ameren claims that under the statute, Dynergy, as well as other suppliers, will have the opportunity to provide written comments with regard to the contract forms, credit terms, or other like instruments. (Supplemental Reply at 24-25)

Dynergy's second concern regards the lack of detail about credit terms and conditions. Ameren notes that the Act provides that "(s)tandard credit terms and instruments that meet generally accepted industry practices shall be similarly developed" are the responsibility of the yet to be approved procurement administrator. 220 ILCS 5/16-111.5(e)(2) (Ameren Reply at 30-31)

Finally, Dynegy objects that Ameren did not explain how the proposed portfolio is superior to the prior full requirements portfolio. According to Ameren, the Act states utilities are to propose a mix and selection of standard wholesale products for which contracts will be executed. Ameren believes that such full requirements, utility-specific, customized agreements are not standard wholesale products, and thus may not be included in the Plan. In Ameren's view, the analysis suggested by Dynegy is meaningless, as it asks the utility to analyze making a decision it believes is futile. (Reply at 31)

Dynegy also observes that Ameren is now proposing a procurement process whereby it, not suppliers, will bear substantial risk relating to variation in supply, load, price, and the like. (Objections at 4-5) Dynegy says that in prior proceedings, Ameren argued such risks were better managed by suppliers. Dynegy wants Ameren to explain how its new portfolio will result in lower cost to customers than the previous full requirements portfolio. (Dynegy Additional Comments at 5-6)

According to **Ameren**, the Act states utilities are to propose a mix and selection of standard wholesale products for which contracts will be executed. Ameren believes that such full requirements, utility-specific, customized agreements are not standard wholesale products, and thus may not be included in the Plan. In Ameren's view, the analysis suggested by Dynegy is meaningless, as it asks the utility to analyze making a decision it believes is futile. (Reply at 31)

Ameren responds to Dynegy's argument that Ameren previously indicated or implied the Auction Product was an "industry standard," and now does not, without explaining a fundamental change in the wholesale market to support such a change in view. Ameren says Dynegy relies upon two single lines from testimony, without placing these lines into context. Ameren contends that neither statement indicated or implied that these contracts were "industry standards." (Supplemental Reply at 24)

Ameren maintains that the company-specific, full requirements products acquired in the auction do not meet the statutory requirement of a standard wholesale product. Ameren claims this position is supported by the requirement in Section 16-111.5(e)(3) that a market-based price benchmark shall be established "for evaluating the final prices in the contracts for each of the products that will be procured through the procurement process. Ameren says the benchmarks shall be based upon price data for similar products for the same delivery period and same delivery hub, or other delivery hubs after adjusting for that difference." Given the unique, company-specific nature of the full requirements auction product, and the lack of available price data for "similar products," if any, Ameren asserts that the ability to produce such statutorily required benchmarks is seemingly precluded. (Supplemental Reply at 26)

b. Commission Analysis and Conclusions

The Commission appreciates Dynegy's concerns regarding the contracts, credit terms and related issues. As Ameren points out, however, Dynegy's attempt to litigate

these issues in the instant docket appears to be inconsistent with the process outlined in the statute.

Section 16-111.5(c)(1) provides that the procurement process shall be administered by the procurement administrator and monitored by a procurement monitor. The procurement administrator has numerous duties and responsibilities. Section 16-111.5(e)(2), "Standard contract forms and credit terms and instruments," provides, in part:

The procurement administrator, in consultation with the utilities, the Commission, and other interested parties and subject to Commission oversight, shall develop and provide standard **contract forms** for the supplier contracts that meet generally accepted industry practices. **Standard credit terms** and instruments that meet generally accepted industry practices shall be similarly developed. (emphasis added)

It further states:

The procurement administrator shall make available to the Commission all written comments it receives on the contract forms, credit terms, or instruments. If the procurement administrator cannot reach agreement with the applicable electric utility as to the contract terms and conditions, the procurement administrator must notify the Commission of any disputed terms and the Commission shall resolve the dispute. The terms of the contracts shall not be subject to negotiation by winning bidders, and the bidders must agree to the terms of the contract in advance so that winning bids are selected solely on the basis of price.

Thus, the development of standard contract forms and credit terms is the responsibility of the procurement administrator, subject to Commission oversight. Furthermore, the process to be followed in that regard is spelled out in some detail in the statute. Interested parties do have a role in the process; however, contrary to Dynegy's contention, that role is the one defined in 16-111.5(e)(2). In the Commission's opinion, requiring parties to litigate those same issues in this proceeding would be inconsistent with the structured statutory process set forth in the IPAA.

Regarding Dynegy's comment about load-following supply risk, the Commission notes that in Docket Nos. 05-0160/0161/0162, Ameren proposed and the Commission approved the Illinois Auction process which included load-following supply through the approved SFCs. Under the Act as it now exists, such a procurement process does not appear possible. In any case, with regard to this point, Dynegy has not raised an issue that requires Commission action.

7. Customer Information; Bidding Process; and Related Issues

a. Positions of the Parties

Constellation says care should be taken to ensure that customers are informed of the risks they bear. (Comments at 2-3) In accordance with the procurement plan structure as set forth under Section 16-111.5 of the Act, Ameren has estimated its load for the June 2008 – May 2009 procurement cycle, a portion of which Ameren will acquire through the day-ahead market. Constellation states that under the Plan, for this portion of Ameren’s load, retail customers bear all weather- and migration-related risks associated with Ameren’s supply of electric power and energy.

According to Constellation, Ameren’s response focuses only on that portion of the supply portfolio obtained via Supplier Forward Contracts which, as Ameren notes, accounts for two-thirds of its forecasted load. Constellation alleges that Ameren ignores the remaining one-third of the portfolio for which customers, and not suppliers, will bear the risk. (Constellation Additional Comments at 2)

Constellation says Ameren contends that the Plan has provisions for the rebalancing of the portfolio in the event of significant load shifts. Constellation states that Ameren’s portfolio rebalancing assumes that any changes are identified no later than February 29, 2009, and that the Procurement Administrator has sufficient time to issue a Request-For-Proposal or reverse-RFP to account for such shift. In Constellation’s view, Ameren’s proposed portfolio rebalancing does not alleviate potentially significant customer risks. For instance, Constellation says load shifts detected after February 29, 2009 would go unchecked. Constellation also says that for the entire period, portfolio rebalancing cannot adjust for the potentially volatile changes in weather that occur monthly, weekly and daily. (Constellation Additional Comments at 2-3)

Constellation believes Ameren is correct that customers will benefit from these risks being fixed for a portion of customers’ consumption through the current SFCs, and that the costs of these risks will be diluted by these existing SFCs. However, Constellation claims Ameren fails to recognize that one-third of these risks will nevertheless be borne by customers as a result of this procurement plan – risks which have the potential to be significant. Constellation says it is in this way that customers will bear all of the risks related to weather and migration for this portion of Ameren’s load. (Constellation Additional Comments at 3)

Constellation asserts that the AG’s recommendation that Ameren be required to hedge 130% of its anticipated load likewise places risk on customers. Constellation says the AG is correct in the basic premise that there is an economic risk for additional purchases in the spot market, should Ameren’s forecasted load be lower than its actual needs. Constellation asserts, however that procuring in excess of the forecasted load (in the AG’s case, significantly higher than the forecasted load) bears another economic risk – that Ameren will have over-procured, and be forced to sell excess energy when

prices are low, for a loss; the burden for such loss will be placed squarely on the backs of Ameren's consumers. (Constellation Supplemental Comments at 4)

Constellation believes that for these reasons, customers should be informed that their energy supply cost will vary from month to month, potentially significantly, no matter what hedging strategy is employed. Constellation says common means of educating electric customers regarding reasonably foreseeable changes to their electric costs, and therefore their potential usage, have included a notation on the utility bill itself or through a bill insert, in addition to education from consumer advocates.

According to Constellation, Ameren's forecast for its projected load, and the corresponding energy prices, are merely estimates; the actual volumes and prices will differ, potentially dramatically, based on variables such as weather, market changes, and world events. Constellation asserts that it is virtually guaranteed that Ameren's forecast will be different than actual consumption. This may result in Ameren procuring more energy than is needed, after which it will then be forced to sell the excess supply in a potentially low market. Conversely, Ameren's supply needs may exceed its forecast and force it to procure additional energy at a time during which market prices are high. Constellation complains that Ameren's Plan fails to address this reality or set forth a proposal by which to inform customers of this potential volatility. Constellation recommends that customers be sufficiently informed of the risks for which they will ultimately bear responsibility under this new procurement plan.

Constellation next argues that "minimizing regulatory delay and uncertainty benefits customers." (Comments at 3-4) In accordance with Section 16-111.5, under the Plan, a time lag of up to seven business days exists between the time that sealed bids are submitted and the time that the contracts with the winning bidders are ultimately executed, after several rounds of review. Constellation states that the longer bids must remain open, and the greater the possibility that bids will be renegotiated or rejected during the review process, the greater the likelihood that consumers will ultimately be economically harmed.

While bids are held open during the review process, bidders retain the risk that market prices will change suddenly or unexpectedly, and that procurement administrators or regulators will treat the extensive review period as a "call" period, accepting bids only in a market which rises over the course of the seven business day period, and renegotiating or rejecting bids in a market which falls over that period. Constellation says such "option" products typically carry with them an extra cost. Constellation states that similarly, potential bidders will treat broad review criteria as creating broad options for procurement administrators or regulators to accept or reject otherwise competitively procured bids. (Comments at 3)

Constellation states that potential suppliers have to incorporate such risks in their bids to account for this time lag as well as the possibility that the Procurement Administrator will attempt to further negotiate the price. According to Constellation, absent greater clarity regarding the review process, potential suppliers will have to

address the risks associated with the multi-layered review by the Procurement Administrator and the Commission, and may forego the process altogether and sell their products elsewhere. In Constellation's view, the possibility that otherwise winning bids may be rejected only exacerbates the issue. (Comments at 3)

Constellation claims that a potential solution to the above concerns can be addressed with three changes to the procurement plan. First, Constellation suggests that winning and losing bidders should be notified, subject to ICC approval, within hours of submission. Given that the products are standardized, Constellation says the review of bids should be relatively straightforward, and should not require additional time.

Second, Constellation suggests that there should be a shorter time period between the submission of bids and ultimate approval by the Commission, as well as final execution of contracts by Ameren. Constellation says bids should be approved as soon as possible, and contracts should be executed within one business day following Commission approval. Third, Constellation asserts that the possible grounds for recommending rejection of a bid, and the Commission authority to reject bids, must be clear, well-defined and focused on whether the procurement abided by the approved process, rather than on prices or other extraneous criteria. Constellation believes the causes for rejection should be limited to objective criteria made publicly available well in advance of bid submissions, in order to minimize the regulatory risk to the greatest extent possible.

Finally, Constellation comments that "details provided well in advance will improve the procurement process." (Comments at 5) According to Constellation, the sooner that the specific details of the proposed procurement are provided to potential bidders, the greater likelihood that participation will be vibrant, and that the most attractive bids will be received. In addition to the concerns identified above, Constellation asserts certain important details have not been provided, which should be finalized and made available to market participants as soon as possible. Constellation says these details include:

- Standard contract forms and credit terms and instruments to be utilized;
- Date for bid submissions;
- The time at which bidders will be notified of the Procurement Administrator's recommendation; and
- The time at which bidders will be notified of the Commission approval of bids.

According to **Ameren**, Constellation "does not appear so much to be providing comments upon the procurement plan itself as they are the overall procurement process." (Reply at 32-34) Ameren says Constellation enumerates four separate issues. The first is a comment that customers should be informed of the risks they bear. Ameren says Constellation supports this position with several statements, many of which ignore the reality of the entire portfolio to serve these customers.

Ameren claims the first of these, a statement that under the Plan, for this portion of Ameren's load, retail customers bear all weather and migration-related risks associated with Ameren's supply of electric power and energy, is false. Ameren says two-thirds of the supply to serve these customers is obtained via pre-existing, full requirements SFCs, for which the supplier, not the utility or its customers, bears all weather and migration related risks. Ameren also refutes Constellation's assertion that the Plan fails to address the reality of potential over or undersupply. Ameren asserts that its Plan has explicit provisions for the rebalancing of the portfolio in the event of significant load shifts.

Constellation calls for the Plan to include a specific communication plan to inform customers of the risks for which they will ultimately bear. Ameren asserts that the risks to which Constellation alludes have not been documented. Ameren also complains that no detail as to what should be presented to customers is offered. In Ameren's view, Constellation's comments appear more as a scare tactic than anything else.

Constellation's second concern relates to various time lags related to the RFP process. Ameren believes these comments are misplaced. Ameren says the procurement process is detailed in the Act, not the Plan. Ameren indicates that it is not seeking approval of the procurement process in this docket; rather it is seeking approval of the Plan and the associated tariffs, in accordance with the Act. Ameren maintains that the procurement administrator, not the utility, designs the procurement process in accordance with the law.

According to Ameren, Constellation makes three recommendations for change to the Plan; however, Ameren says they fail to explain what part of the Plan should be modified. In Ameren's view, this is understandable, as the Plan does not, nor should it, contain the procurement process itself.

Constellation notes the Plan does not include certain details, such as:

- Standard contract forms and credit terms and instruments to be utilized;
- Date for bid submissions;
- The time at which bidders will be notified of the Procurement Administrator's recommendation; and
- The time at which bidders will be notified of the Commission approval of bids.

Ameren argues that the Plan is not the appropriate place for such details. Ameren maintains that these details are part of the procurement process and whose design is the responsibility of the procurement administrator. (Ameren reply at 34)

In its Supplemental Reply, Ameren states that Constellation continues to advocate the retail customers be informed that their energy supply costs will vary from month to month. According to Ameren, Constellation paints this as a means of educating electric customers regarding possible changes to their electric bills. (Ameren Supplemental Reply at 28, citing Constellation Additional Comments at 4)

Ameren claims that Constellation incorrectly asserts that at issue in this Plan is approximately one third of the Ameren load, which Ameren argues is incorrect. Ameren indicates that it entered into a 400 MW financial swap contract as a result of the new legislation. This financial swap contract was for base load power. Ameren asserts that the 400 MW financial swap contract was taken into account in the context of this Plan and the resultant analyses. Ameren claims that under the procurement plan proposed for June 2008 through May 30, 2009, only about 15% of the load is at issue, and of that 15%, hedges shall be in place. According to Ameren, it is only amounts above or below this hedge in a given period which is subject to such price volatility. Ameren contends that this fraction of the 15% is not the one third that Constellation would have the Commission believe. (Ameren Supplemental Reply at 28-29)

Next, Ameren says Constellation does not cite, nor can it, to any provision in Section 16-111.5 that calls for customer education programs as part of a procurement plan. Ameren states that it is in the Commission's prerogative to consider same in other venues, and utilities do so regularly, but it is important that all parties remain faithful to this new legislation. Ameren suggests that if parties are permitted to insert or delete what they think is appropriate with regard to the procurement plan, notwithstanding the law, then over time the intentions of the legislature become ignored. (Ameren Supplemental Reply at 29)

b. Commission Analysis and Conclusions

Constellation recommends that care be taken to inform customers of the risks they will ultimately bear under this new procurement plan. Constellation believes that customers should be informed that their energy supply cost will vary from month to month, potentially significantly, no matter what hedging strategy is employed. Constellation says common means of educating electric customers regarding reasonably foreseeable changes to their electric costs, and therefore their potential usage, have included a notation on the utility bill itself or through a bill insert, in addition to education from consumer advocates.

Ameren responds that the risks to which Constellation alludes have not been documented. Ameren also complains that no detail as to what should be presented to customers is offered. In Ameren's view, Constellation's comments appear more as a scare tactic than anything else.

The Commission is mindful of comments complaining that January 2007 provides a recent example of difficulties on Ameren's part in communicating with its customers regarding upcoming rate changes, and that this incident led to many of the recent changes to the Act, including the provision under which this proceeding is being conducted. Obviously, the Commission has no desire to see a recreation of the January 2007 situation when Ameren's rates change in 2008, and the Commission agrees with Constellation as to the importance of effective communications with customers. In the instant case, however, the scope of the Commission's charge under

Section 16-111.5 is basically to approve or modify the procurement plan and related tariffs. In that regard, given the lack of more specific recommendations from Constellation and the absence of a citation to any statutory authority by which its recommendations fall within the scope of this proceeding, the Commission will decline to take formal action on those recommendations.

Constellation also expresses concern relating to various time lags in the RFP process. Constellation suggests that winning and losing bidders should be notified, subject to Commission approval, within hours of submission. Second, Constellation suggests that there should be a shorter time period between the submission of bids and ultimate approval by the Commission, as well as final execution of contracts by Ameren. Third, Constellation asserts that the possible grounds for recommending rejection of a bid, and the Commission authority to reject bids, must be clear, well-defined and focused on whether the procurement abided by the approved process, rather than on prices or other extraneous criteria.

With regard to Constellation's three recommendations for changes to the Plan, Ameren says Constellation fails to explain what part of the Plan should be modified. Ameren argues that the Plan does not, nor should it, contain the procurement process itself. Ameren maintains that the procurement administrator, not the utility, designs the procurement process.

Based on its review of the arguments, the Commission will not adopt Constellation's proposals regarding RFP-related procedures and timelines. The Commission believes that many aspects of the procurement process simply will not be decided in this proceeding. Instead, the Act provides that other processes, some of which includes the Procurement Administrator, will determine the type of issues Constellation wants decided here. Section 16-111.5(c)(1) provides that the procurement process shall be administered by the procurement administrator and monitored by a procurement monitor. The procurement administrator has numerous duties and responsibilities, some of which relate specifically to the RFP process. There is not a sufficient basis in the record in the instant case to support a finding that Constellation's recommendations should be imposed, in this order, on the procurement administrator.

8. Use of Short-Term Contracts

a. Positions of the Parties

The Retail Energy Supply Association ("**RESA**") filed an "Objection." RESA's members include Commerce Energy, Inc; Consolidated Edison Solutions, Inc; Direct Energy Services, LLC; Gexa Energy; Hess Corporation; Integrys Energy Services, Inc.; Liberty Power Corp.; Reliant Energy Retail Services, LLC; Sempra Energy Solutions; Strategic Energy, LLC; SUEZ Energy Resources NA, Inc. and US Energy Savings Corp.

In "Issue 1," RESA addresses the "use of short-term contracts." RESA submits that continued progress toward a competitive electric market is the best way to help all

consumers cope with rising energy prices. RESA states that successful retail competition should produce downward pressure on price, increase conservation incentives, enhance customer service, improve environmental management and hasten the introduction of new, innovative products. Retail energy competition requires that default service pricing be properly structured; customers must see a default price that reflects the market, otherwise consumers cannot make informed and thoughtful decisions.

According to RESA, Illinois' residential and small and medium sized businesses need a default service rate providing better price signals to spur more thoughtful efficiency investments and wise energy usage. RESA says the market is always the relevant measure for energy prices, so it makes sense to acquire energy using mechanisms that reflect market prices, and to then price energy accordingly. Without more market reflective price signals, consumers become less concerned about managing their energy usage. Thus, in order to promote conservation effectively, RESA believes that consumers need better price signals.

In the event that the company's procurement costs are higher than those available in the wholesale market, then, RESA claims, customers are harmed by having to pay higher prices. If wholesale market prices rise above the locked in utility costs, then, RESA says, competition will not develop. According to RESA, long-term procurement contracts will recreate one of the unintended consequences of the rate freeze that Illinois has experienced over the past several years: competition cannot develop in the face of artificially lowered prices.

RESA suggests that Ameren take this opportunity to use the short-term contracts in its plan to allow the full default price to adjust on a periodic basis (e.g. quarterly). RESA suggests that the Commission take this opportunity to set the stage for implementation of the new Illinois Power Agency Act by encouraging a greater mix of market-reflective procurement opportunities that would properly reflect the changes in supply costs. (RESA Objection at 2-4)

In "Issue 2," RESA addresses "Riders and Surcharges." It is RESA's understanding that costs associated with supply administration (i.e. legal and consultant costs, cost of utility personnel who manage the process, and other costs associated with managing default service procurement) may be recovered from customers in an adjustment charge. Due to the shortened time frame, RESA has not been able to determine the appropriateness of assigning any of those charges to customers and whether they are being properly allocated. If the Commission decides to open hearings to investigate the procurement plan, RESA suggests that it, and other parties, should have a better opportunity to question these charges.

In its November 28th "Reply Comments," RESA indicates that "these comments" are intended to provide the data Ameren believes is necessary to consider RESA's proposal. (RESA Reply Comments at 1-2) First, RESA asserts that the goal of price stability does not trump all other concerns. If that were the case, then RESA says

Ameren should be entering into the longest contracts possible ignoring the fact that market prices vary over time with customers potentially paying vastly more than the market price. In RESA's view, the Act should be read to require a balancing of price stability against the goal of providing customers with proper economic signals that will lead to better decisions on power consumption levels and timing, investments in equipment and choice of supplier. According to RESA, the issue is whether one-year contracts or quarterly contracts provide the better balance.

Along with its Reply Comments, RESA provides a study that it says provides information relating to historical forward prices and quarterly pricing. RESA asserts that its analysis shows that forward quarterly prices averaged from 2004 through current have been similar to forward prices for one and two year terms. According to RESA, this data demonstrates that, while the quarterly forward prices over time have been similar to the forward prices for one and two year contracts, quarterly pricing provides customers with more frequent price signals. RESA argues that market responsive pricing remains the better path to foster the development of retail competition for the benefit of Illinois ratepayers. RESA asserts that customers in a competitive market could choose an electricity product that varies in term, composition, etc. In RESA's view, price signals empower customers to make choices based on their individual energy usage, needs and desires. (Reply Comments at 2)

Ameren contends that RESA does not present any specific, detailed objections to the Plan as required by Section 16-111.5(j)(i). (Reply at 31-32) Rather, it provides comments on "general issues that should underlie any procurement plan for an Illinois public utility" and they wish to "encourage the company and the Commission to evaluate any procurement methodology through the lens of the competitive marketplace." Ameren says that RESA fails to support their suggestions with data or other detailed analysis as required by the Act. Ameren says that RESA failed to provide the Commission with anything meaningful in terms of possible modifications to the Plan.

RESA urges the inclusion of market reflective price signals, which Ameren infers to refer to shorter term contracts than those proposed in the Plan, and allowing the full default price to adjust on a periodic basis (e.g. quarterly). Ameren says it is not clear if RESA intends for these to be hourly, weekly or monthly contracts, as it fails to provide any detail. Beyond the lack of statutorily required supporting data and analysis, Ameren claims RESA's proposal should not be adopted, as it fails to acknowledge the Act's requirement that the portfolio take into account the benefits of price stability. Ameren believes that adopting such an approach within the portfolio absent any analysis may lead to an unacceptable level of volatility in customer prices.

Finally, Ameren discusses RESA's statement that it has been unable to determine the appropriateness of certain riders and surcharges, and that if the matter is set for hearing they will have a better opportunity to question these charges. Ameren states that RESA failed to submit a single data request in the two weeks following Ameren's filing. Ameren complains that it is difficult to understand how parties, who

now claim they do not have enough information to form an opinion, did not bother to request information to aid in understanding the issue.

In its Supplemental Reply, page 27, Ameren argues that the Commission should completely disregard the Reply Comments of RESA. First, Ameren complains that RESA did not file objections to the Plan that were supported by data or other detailed analyses. Second, Ameren argues that RESA's inclusion of Attachment 1, which contains information relating to historical forward prices, specifically, quarterly pricing, is in direct contravention to the Administrative Law Judge's procedural ruling dated November 20, 2007, which required that the filings made on November 28, 2007 would be limited to those objections that were raised in the November 9, 2007 filings. Ameren says this was not a loophole by which a party that was obligated to provide detailed, specific analyses in the first instance, to use the ruling as a means to introduce such analyses at this late stage. (Supplemental Reply at 27)

RESA asserts that forward quarterly prices averaged from 2004 through the present have been similar to forward prices for one and two year terms. RESA suggests that quarterly pricing provides better price signals, and better price signals translate into customers being able to better manage the retail electricity market. On the surface, the paucity of the data offered makes any conclusions questionable, according to Ameren.

RESA used historical on-peak pricing from NYNEX PJM West Hub in its "analysis." Ameren argues that because pricing associated with the PJM West Hub historically has a specifically low correlation to the load of the Ameren Illinois Utilities, the analysis provides no meaningful insight and, thus, no meaningful conclusions can be made as it relates to the hedging plan offered by the Ameren Illinois Utilities in their Plan. (Supplemental Reply at 27-28)

b. Commission Analysis and Conclusions

RESA argues that Ameren should be directed to include, in its procurement plan, the use of quarterly contracts. RESA contends that such contracts will provide better price signals. RESA also claims the study attached to its Reply Comments shows that forward quarterly prices averaged from 2004 through current have been similar to forward prices for one and two year terms.

The Commission notes that RESA's study appears to consist of two one-page power-point slides using historic pricing data from the NYMEX PJM West hub. While the Commission believes the issue raised in RESA's comments is relevant to this proceeding, its analysis lacks the detail necessary to determine whether or to what extent it supports RESA's conclusions. Accordingly, RESA's proposed modifications to Ameren's plan will not be adopted.

C. Procurement Administrator

Staff states that although it does not necessarily agree with some of the scores assigned to certain applicants, Staff has no basis for opposing Levitan and Associates. (Objections and Comments at 25)

Section 16-111.5(j) provides that the Commission shall approve an independent procurement administrator. It appears that no party has objected to Ameren's proposal to utilize the firm of Levitan and Associates. The Commission finds that Ameren's proposal to utilize Levitan and Associates as its Procurement Administrator is reasonable, and it shall be approved.

IV. TARIFF RELATED ISSUES

A. Introduction

Section 16-111.5 (l) provides in part, "An electric utility shall recover its costs of procuring power and energy under this Section. The utility shall file with the initial procurement plan its proposed tariffs through which its costs of procuring power that are incurred pursuant to a Commission-approved procurement plan and those other costs identified in this subsection (l), will be recovered."

In its petition in 07-0527, Ameren seeks approval of its "proposed cost recovery tariffs and other related tariff proposals."

B. Rider MVA; True-Up Mechanism

Rider MVA contains true-up mechanisms for over or under collections from fixed-price customers. In Ameren's existing Rider MV, a distinction is made that residential and small commercial and industrial ("C&I") customers less than 1,000 kW are currently supplied electricity through supplier forward contracts ("SFCs") entered into pursuant to the blended, fixed rate auction product, while customers 1,000 kW and greater are currently supplied electricity through SFCs entered into pursuant to the annual, fixed rate auction product. (Objections at 27)

From these two sets of distinct SFCs, Ameren developed, and has been charging, a separate MVA to (1) the residential and small C&I customers less than 1,000 kW and (2) all customers 1,000 kW and greater. Thus, the costs of the SFCs for the residential and small C&I customers, along with the related MVA for these customers, were charged only to the residential and small C&I customers. Similarly, the costs of the SFCs for the 1,000 kW and greater customers, along with the related MVA for these customers, were charged only to those larger customers.

In this proceeding, Ameren proposes to group the monthly true-up of costs for those BGS-LFP customers at or above 1,000 kW with the remaining fixed price customers (generally, those under 400 kW demand and those between 400 kW and

1,000 kW still served on fixed price service) after May 2008. Thus any over or under collections for 1,000 kW and greater customers would be allocated to the remaining fixed-price customers.

1. Positions of the Parties

While **Staff** is in agreement that Ameren's new proposed Rider MVA is necessary, Staff has concerns about Ameren's proposal and believes that the Commission should be fully informed about how Ameren's proposed Rider MVA works. Staff states that proposed Rider MVA will ensure that Ameren recovers its full cost of providing electric supply for the 1,000 kW and greater customer segment. However, to ensure full cost recovery, residential and small C&I customers will be assigned the credit or debit balance of the LFP-MVA as caused by the 1,000 kW and greater customers.

To the extent that the 1,000 kW and greater customers cause an underpayment balance for additional months after May 2008, Ameren proposes that the residential and small C&I customers would be required to pay for, and subsidize, that underpayment balance that resulted from the purchase of electric supply for the 1,000 kW and greater customers. Conversely, to the extent that the 1,000 kW and greater customers cause an overpayment balance for additional months after May 2008, Ameren proposes that the residential and small C&I customers would receive the overpayment amount and be subsidized by the 1,000 kW and greater customers.

While Staff is not objecting to the Companies' proposed LFP-MVA assignment method, Staff is expressing its concern and providing its comments to the Commission so that the Commission is more fully informed about Ameren's proposal. Staff has concerns about the Rider MVA proposal because of the subsidization issue. (Staff Objections at 30)

Also, it appears to Staff that there may be at least two alternatives, other than Ameren's proposal, for the disposition of the credit or debit balance, which will occur at the end of the May 2008 billing period.

Staff's first possible alternative would be that any underpayment or overpayment from the 1,000 kW and greater customers not be assigned to the residential and small non-residential customers and, instead, that the final credit or debit amount would be assigned to the Companies. Staff says Ameren will be concerned with the possibility of not being able to fully recover costs. Further, Staff in no way questions the prudence of these costs. However, as between the Companies and the residential and small C&I customer group, the Companies have more input and responsibility than the residential and small C&I customers for any over- or under-recovery of supply costs related to the 1,000 kW and greater customer group.

Staff's second possible alternative would be that the Companies are allowed to assign the over- or under-payment to the customers who were the likely causers of the

final LFP-MVA amount. (Objections at 31) Staff says the customers who are served under this rider over the final three months of March through May, 2008, would likely be the customers who caused the final LFP-MVA amounts that were determined during the settlement process for those three months. The amount to be charged or refunded could be prorated on a usage basis for those three months of use.

If the Commission finds that Ameren's proposed LFP-MVA assignment method is not appropriate, Staff recommends that the Commission order the Companies to modify their proposed tariffs so that residential and small non-residential customers are not responsible for the underpayment, or overpayment, of electricity supply incurred by customers served under BGS-L.

With regard to Rider MVA, **Ameren** addresses the two alternatives described by Staff. The first alternative proposes that the over or under calculations for BGS-LFP customers simply end after May 2008, and that the Ameren Illinois Utilities shoulder the resulting impact – either positive or negative. The second alternative suggests that the over or under calculations continue to follow BGS-LFP customers after May 2008.

The mechanism proposed by Ameren is intended to ensure that Ameren does not accrue a benefit or loss for any over or under collection of costs. Ameren states that presently, the total pool of BGS-LFP customers is less than 30 customers. Ameren says including any over or under collection of costs within the cost recovery pool of customers with demands less than 1,000 kW is expected to result in a small adjustment (either positive or negative), if any. Nevertheless, Ameren says it recognizes that Staff's concern does not appear to be with the potential magnitude of the cost recovery proposal, but instead Staff is concerned about the potential for a subsidy or subsidization.

In its first alternative, the Staff proposes that the BGS-LFP over or under calculation end after May 2008, and Ameren absorb the resulting impact. Ameren states that this proposal is unacceptable to Ameren and unlawful. (Ameren Reply at 9) Ameren claims the basic principles the Commission has established, and that the legislation does not alter, are that the delivery companies should not profit from the procurement function, and all prudently incurred costs should be recovered. Ameren believes Staff's first suggestion violates these principles. Ameren also asserts that Staff's suggestion fails to address its primary concern – elimination of a subsidy or subsidization. In this case, Ameren says BGS-LFP customers will still pay too much or too little, and Ameren will experience a benefit or loss.

Staff's second alternative adequately addresses the subsidy issue since any over or under amounts would continue to follow BGS-LFP customers after May 2008. (Reply at 9) This ensures these customers receive any credits or charges that may have accrued in providing them service. In Ameren's view, implementing this provision is not without concern. Ameren says present customers on BGS-LFP may have an expectation that after May 2008, no provisions of BGS-LFP service are applicable.

Ameren suggests that while customers may not question a possible credit, they may question a possible charge (in the event of a subsequent under recovery).

Should the Commission share Staff's concern, Ameren says it would not object to changing Rider MVA to continue a separate over or under true-up mechanism for BGS-LFP customers beyond May 2008, until just after the settlement of May 2008 costs are determined and charged (the month of September). After September, Ameren proposes that any subsequent true-up costs (due to billing corrections, or further MISO market settlements occurring after 55 days) fall within the reconciliation bucket for smaller fixed price customers.

In its reply comments, **Staff** found Ameren's modifications to Staff's second alternative, including the true-up language, to be acceptable. (Staff Reply Comments at 5-6)

In supplemental comments filed November 28, 2007, the **AG** agrees with Staff's "second alternative" recommendation that costs incurred on behalf of large customers should follow the customer after they leave the system. The AG does not agree with Ameren's modifications to the Staff proposal. (AG Supp. Comments at 3-4)

2. Commission Analysis and Conclusions

As explained above, Rider MVA contains true-up mechanisms for over- or under-collections from fixed-price customers; the true-up mechanism is necessary because the amounts are not immediately quantifiable due to the settlement process and other factors. The issue raised in this case is what to do about over- or under-payment balances associated with fixed-price service to 1000 kW and greater customers, who will no longer receive fixed-price service after May 2008, since those balances will not be known until some months later.

Staff's second alternative, as modified by Ameren, would continue to use a separate true-up mechanism for these customers through September. That is, the true-up costs or credits would follow the customers until then. After that, such amounts would be assigned to remaining fixed-price customers. The Commission believes this approach is appropriate under the circumstances, inasmuch as it assigns the costs or credits to those who gave rise to them, for a reasonable period of time. Thus, it shall be approved.

C. Rider MVA; Rate Mitigation

1. Positions of the Parties

Ameren and Staff appear to agree that rate mitigation, in the context of mitigating bill impacts, is an important element of the design of retail rates. Rate mitigation measures were approved by the Commission in the Procurement dockets in 05-0160, 05-0161 and 05-0162, Consolidated, and in the recent rate design Docket, 07-0165.

Ameren and Staff are in disagreement over the appropriate rate mitigation plan to be adopted in this proceeding.

Ameren's mitigation proposal would address bill impacts for Residential BGS-1 and Small General Service BGS-2 customers only. Ameren's plan would limit increases for the variable portion of ratepayer bills (excluding customer charges) to the greater of 10% or 125% of the average increase for BGS-1 and BGS-2 combined.

Ameren's mitigation plan would apply to increases in charges for individual usage blocks. For example, AmerenCILCO residential customers are billed for electricity usage in three rate blocks: (1) a flat rate that applies to all summer usage, (2) a rate for non-summer usage between 0 and 800 kWhs, and (3) a tail block rate for all non-summer usage of 800 kWhs and above. Ameren's proposed mitigation maximums would apply to the increase for each usage block. AmerenCILCO BGS-2 customers are billed for electricity usage in three blocks: (1) a single summer block, (2) a non-summer first block of 0-2,000 kWhs, and (3) a non-summer tail block of 2,000 kWhs and above. Staff says the increases in the variable component of bills in each of these usage blocks would be subject to the proposed mitigation maximums of 10% or 125% of the average increase for BGS-1 and BGS-2 combined. Under the Companies' proposal, Staff says the mitigation maximums would similarly apply to the corresponding usage blocks for AmerenCIPS and AmerenIP BGS-1 and BGS-2 customers.

Staff's position is set forth in Section IV.C of its Objections. (Objections at 32-38) Staff states that the Commission declined to adopt Staff's equal percentage increase proposal in Docket No. 07-0165 because the Commission had terminated the auction process and no substitute procurement plan had been tendered at that time. However, a new procurement plan has now been proposed and Staff says the Commission must decide how any cost changes resulting from the new procurement process are to be allocated among bundled ratepayers. Thus, the supply rate mitigation issue should be revisited because this docket provides the final opportunity to address associated bill impacts before the new procurement costs become effective on June 1, 2008.

Staff says Ameren recognized the need to address bill impacts in this case. Ameren's proposed Rider PER tariff presents both a method for allocating the costs to be incurred for supply commencing June 1, 2008, as well as a proposal to mitigate the results of the allocation process to limit the differential impacts for ratepayers. Staff states that Ameren's proposed allocation methodology for these procurement costs would determine applicable unit supply costs for four time periods: summer peak; summer off-peak; non-summer peak and non-summer off-peak. (Original Sheet No. 31.004) Then, each of these prices would be allocated to customers according to their share of usage in the applicable time period. (Staff Objections at 34)

In Staff's view, the challenge from a bill impacts standpoint is that the future unit prices, and the resulting allocations under the proposed Rider PER, are currently unknown. Therefore, it is not yet evident how supply rates for bundled customers will

change on June 1, 2008 when the next round of procurement costs are incorporated into rates. Staff asserts that this lack of transparency is a concern given the disturbance for Ameren customers caused by supply cost changes on January 1, 2007.

Staff complains that Ameren's mitigation proposal would address bill impacts for Residential BGS-1 and Small General Service BGS-2 customers only. Staff says Ameren's proposed mitigation plan would limit increases for the variable portion of ratepayer bills (excluding customer charges) to the greater of 10% or 125% of the average increase for BGS-1 and BGS-2 combined.

Staff contends that the problem left unresolved is that the Companies' mitigation plan would allow some realignment of supply costs and overall bills for bundled ratepayers. Staff believes it would be undesirable to adopt a proposal to realign costs for bundled customers on June 1, 2008, only five months after the rates redesigned in Docket No. 07-0165 become effective on January 1, 2008.

The better alternative, according to Staff, would allocate any increase or decrease **in supply charges** resulting from the procurement of power on an **across-the-board** basis among all bundled customers. That across-the-board approach would include bundled customers in BGS-1, BGS-2 and non-competitive BGS-3 customers with demands of less than 400 kW. (Staff Objections at 37)

Staff argues that the across-the-board approach would maintain consistency with the Commission's recently concluded rate redesign process. Staff also asserts that it would ensure that no customer group, or groups, receives an inordinate supply cost increase when supply costs change on June 1, 2008. Given the current lack of information about what these changes will be, Staff believes the across-the-board approach will best ensure that no group of customers receives an inordinate increase over the current supply charges.

Under Staff's proposal, if supply costs rise by 10%, each rate class' supply charge prior to June 1, 2008 would be raised by the same 10%. Similarly, if overall supply costs decline by 10%, the proposal would reduce all existing rate classes' supply charges by that same 10%. (Objections at 37-38)

Staff also says the Companies' proposal is inconsistent with their proposals in their current delivery services case where they are proposing an across-the-board increase on existing rates. (Staff Objections at 37)

In response to Staff, **Ameren** states that Staff's first concern -- not knowing future power supply prices -- are what led Ameren to propose a mitigation adjustment methodology that ensures the increase to the variable components of a BGS-1 or BGS-2 customer's bill will not exceed the greatest of 10% or 125% of the overall BGS-1 or BGS-2 average increase. (Ameren reply at 11-15) In the event that prices decrease, Ameren says application of an across-the-board price change would further reduce already deeply discounted prices for residential space-heat customers at AmerenCIPS

and AmerenIP, and all high winter use customers at AmerenCIPS-ME and AmerenCILCO. Ameren contends that application of its mitigation adjustment begins the process of gradually removing the subsidies embedded in the prices approved in Docket No. 07-0165.

Ameren says Staff's second concern is that it is undesirable to adopt a proposal to realign costs for bundled customers on June 1, 2008, only five months after the rates redesigned in Docket No. 07-0165 become effective on January 1, 2008, and that any resulting realignment could undermine the principles on which the rate redesign of Docket No. 07-0165 was based. In response, Ameren states the purpose of the rate redesign of Docket No. 07-0165 was to establish rates that were more just and more reasonable than those previously in effect. Ameren believes the Commission has a preference for cost-based rates, and considers subsidies as a part of rate design when addressing rate shock. Ameren further believe it is appropriate to begin the gradual removal of these subsidies over a multi-year period. Ameren says it appreciate Staff's concern; however, the proposed mitigation adjustment ensures that disproportionate rate impacts will be adequately mitigated and can be deemed just and reasonable.

Ameren also notes while there are six months between June 1, 2008 and December 1, 2007, customers have received rate relief through Rider RMC credits beginning in September. Ameren says customers have experienced bill impact relief in effect back to January 2, 2007, and so Staff's commentary about changes after five months is moot.

If the Commission shares Staff's concern, that it is too soon to implement a greatest of 10% or 125% of the overall average for BGS-1 and BGS-2, Ameren suggests an even more gradual transition could be implemented for the first year, say the greatest of 5% or 110% of the overall average for BGS-1 and BGS-2 combined. Ameren further suggests that in subsequent years, Ameren's original proposed values of 10% or 125% of the overall average could be implemented. Ameren states that using an across-the-board increase ensures that subsidies remain. Ameren also asserts that subsidies to a class can thwart retail choice competition and efforts to implement energy efficiency and/or demand response measures. Ameren says its mitigation adjustment attempts to balance gradual bill impacts against the backdrop of the general distaste for subsidies, and the resulting market inefficiencies. (Ameren Reply at 16-17)

The third Staff objection, that Ameren previously expressed support for an equal percentage, across-the-board change in BGS-1 and BGS-2 supply charges to incorporate the 2008 supply auction results, but now support a mitigation adjustment approach, can be explained away, according to Ameren. (Ameren Reply at 17) Ameren states that during the rate redesign proceeding, no party had a better proposal or methodology. In other words, the proposed mitigation adjustment methodology was developed after the conclusion of Docket No. 07-0165, and well after the record was marked "heard and taken." Ameren claims that what it has proposed in the proceeding is a superior methodology to simply adjusting prices on an across-the-board basis.

Fourth, Ameren says Staff notes Ameren's revenue allocation proposal in the recently filed delivery services case is to use an across-the-board increase on existing rates, which appears to be inconsistent with the mitigation adjustment proposed within Rider PER. In Ameren's view, there are significant differences that render such comparison invalid. (Ameren Reply at 18)

Ameren states that the Rate DS-1 and Rate DS-2 changes adopted in Docket No. 07-0165 were revenue neutral to each Ameren Illinois Utility, and to each class. Thus, there are no inherent inter-company or interclass subsidies embedded in current delivery service rates. Second, Ameren says DS-1 and DS-2 rates approved in Docket No. 07-0165 are the same for all customers of a particular Ameren Illinois Utility. There is no special space-heat, non-space heat, or discounted block price. Thus, Ameren claims no intra-class subsidy was embedded within existing delivery service rates as was done for BGS-1 and BGS-2. Third, the rate redesign proceeding began with cost-based revenue allocations, without subsidies, from the Ameren Illinois Utilities' last delivery service cases. According to Ameren, applying an across-the-board increase to previously established cost-based delivery service rates should produce a result that is reasonably close to a proposed cost-based delivery service rate, assuming cost of service results do not change significantly over time. Conversely, Ameren claims that applying an across-the-board increase to previously established prices with known subsidies is likely to produce a result that continues subsidies.

In summary, Ameren says the issue of subsidies should not be buried indefinitely as proposed by Staff. Instead, Ameren urges the Commission to approve the proposed mitigation adjustment, which adequately balances bill impacts against implementing cost-based prices. If the Commission prefers an even more cautious approach in the first year, Ameren suggests a constraint of the greatest of 5% or 110% of the overall average for BGS-1 and BGS-2 customers could be used. (Ameren Reply at 18)

In its reply comments filed November 28, 2007, **Staff** stands by its proposal for "an across-the-board equal percentage application of any change to supply charges resulting from the new procurement prices that will become effective June 1, 2008." (Reply Comments at 6-7) Staff believes its proposal, although not cost-based, is justified due to the "extraordinary situation" faced by Ameren customers. Staff also finds Ameren's alternative mitigation proposal to be problematic; according to Staff, the problem of uneven bill impact in the first years would still exist.

In its Supplemental Reply Comments filed November 30, 2007, page 4, **Ameren** asserts that moving away from cost causation may "share the burden" more "evenly," in an arithmetic sense, but in no sense does it share it more fairly; the Ameren Illinois Utilities' proposal attempts to balance evenness with fairness, while Staff's does not. In its BOE, Ameren continues to argue that its proposals are superior to Staff's. (Ameren BOE at 3-6)

2. Commission Analysis and Conclusions

Pursuant to the Ameren Procurement Order in Docket Nos. 05-0160, 05-0161 and 05-0162 (Consolidated), the results of the blended segments of the 2006 auction were entered into series of formulae, sometimes known as the “prism” or “rate prism.” The prism is designed to allocate fixed price generation supply or BGS-FP costs to each participating customer class and translate those charges into retail supply rates for customers.

In addition, the Procurement Order approved a Staff-proposed rate mitigation mechanism. Generally speaking, that plan limited increases for individual customer classes in the first BGS-FP auction to a maximum of 20%; however, if the overall increase in the BGS-FP auction were greater than 13.33%, the maximum increase for an individual class would be 150% of the BGS-FP auction group’s average increase. The rate mitigation plan was applicable on a total bill basis, and was intended to mitigate large increases in the bills of customers in any given rate class to which the results of the blended auction segment is applied, and the plan is still in effect.

Additionally, the Commission recently issued an Order, in October, 2007, approving redesigned electric rates for the Ameren Utilities electric rates in Docket No. 07-0165. The rates approved in that docket were designed to provide rate relief to those customers who have faced the largest increases, particularly electric space-heating customers, while ensuring that other customer groups are not unduly impacted by these rate mitigation measures.

In the instant proceeding, Ameren proposed a mitigation adjustment methodology intended to ensure that the increase to the variable components of a BGS-1 or BGS-2 customer’s bill will not exceed the greatest of 10% or 125% of the overall BGS-1 or BGS-2 average increase. Ameren contends that application of its mitigation adjustment would begin the process of gradually removing the subsidies embedded in the prices approved in Docket No. 07-0165. In the event that the Commission shares Staff’s concern that it is too soon to implement a greater of 10% or 125% of the overall average for BGS-1 and BGS-2, Ameren suggests an even more gradual transition could be implemented for the first year, say the greatest of 5% or 110% of the overall average for BGS-1 and BGS-2 combined. Ameren further suggests that in subsequent years, Ameren’s original proposed values of 10% or 125% of the overall average could be implemented.

Staff, on the other hand, proposes to allocate any increase or decrease in supply charges resulting from the procurement of power on an across-the-board basis among all bundled customers. That across-the-board approach would include bundled customers in BGS-1, BGS-2 and non-competitive BGS-3 customers with demands of less than 400 kW. Staff’s primary concern seems to be that no customer group, or groups, receives an inordinate supply cost increase when supply costs change on June 1, 2008.

The example provided in Ameren's Reply Comments was helpful to understanding how its mitigation proposal would work. As the Commission understands it, rather than starting with the objective underlying the rates approved in 07-0165, Ameren's recommendation appears to be premised upon the assumption that any rate mitigation approved in this proceeding should move toward supply rates that are set at cost. That is, Ameren's proposal seems to assume that the electric rate redesign relief recently adopted in Docket No. 07-0165, as it applies to supply rates, should essentially be scaled back beginning in June of 2008.

While the Commission is not under the illusion that the rates resulting from Docket No. 07-0165 were perfect, they were at least the result of a collaborative effort on the part of Ameren and Staff, as well as months of proceedings involving only rate mitigation issues. In contrast, the instant proceeding is being conducted on a much more expedited basis. It also involves numerous issues going well beyond rate mitigation, and the record on rate mitigation is far less developed than in Docket No. 07-0165.

As a general proposition, the Commission does not favor increasing or decreasing rates on an across-the-board basis. Such an approach, by definition, ignores the underlying cost of service. All else equal, the Commission generally prefers cost-based rates. In this case, however, applying the increase on an across-the-board basis would offer one benefit in comparison to Ameren's proposal. Staff's across-the-board proposal appears to begin with the objectives underlying the rates that were recently established in Docket No. 07-0165, and then adjusts those rates; thus it would maintain the protections built into those rates in response to strong concerns expressed by customers and others about inordinate increases to some customers, particularly space-heating customers.

The Commission further observes that the question of how Ameren's supply rates should be designed over the medium or long term simply cannot reasonably be determined in this proceeding. In the Commission's view, the issue is too complicated, and there is not an adequate basis for making an informed decision on it. Ameren's supply rate caps are a function of total variable costs and it is expected that Ameren's delivery rates will change in 2008. Also, it is not clear to the Commission what impact, if any, the expected changes to Ameren's delivery service rates in 2008 would or should have on Ameren's rate mitigation proposal. Ameren also seems to suggest that if the Commission adopts its rate mitigation proposal in this proceeding, it will remain in effect when supply rates change in subsequent years. As noted above, the limited record in the instant docket simply does not support the adoption of a long-term approach to redesigning electric rates. Rather, the Commission believes that, at best, it will be able to make a short-term, interim decision on how Ameren's supply rates should be designed in this proceeding.

All things considered, the Commission reluctantly concludes that for purposes of this proceeding, it will adopt Staff's proposal to allocate any increase or decrease in supply charges resulting from the procurement of power, after June, 1, 2008, on an

across-the-board basis among all bundled customers. That is, it would apply to bundled customers in BGS-1, BGS-2 and non-competitive BGS-3 customers with demands of less than 1 megawatt.

The Commission expects the question of how Ameren's electric rates will be designed will be addressed in Ameren's recently opened delivery rate cases, where rate mitigation on a total bill basis, including supply charges, could also be addressed. Additionally, there are other avenues available to redesign rates on a revenue neutral basis, should any party believe such a change is necessary. Especially given the uncertainty concerning costs and rates in the future, the Commission does not intend its decision to approve an across-the-board rate design in this order to limit future consideration of any rate design proposal.

D. Cost Recovery; Rider PER – Review of Reasonableness/Prudence of Costs

1. Introduction; Statutory Authority

Section 16-111.5(k) provides in part, "In order to promote price stability for residential and small commercial customers during the transition to competition in Illinois, and notwithstanding any other provision of this Act, each electric utility subject to this Section shall enter into one or more multi-year financial swap contracts that become effective on the effective date of this amendatory Act."

16-111.5(k) later provides, in part, "Costs incurred pursuant to a contract authorized by this subsection (k) shall be deemed prudently incurred and reasonable in amount and the electric utility shall be entitled to full cost recovery pursuant to the tariffs filed with the Commission."

Section 16-111.5(l) provides in part, "An electric utility shall recover its costs of procuring power and energy under this Section. The utility shall file with the initial procurement plan its proposed tariffs through which its costs of procuring power that are incurred pursuant to a Commission-approved procurement plan and those other costs identified in this subsection (l), will be recovered." It further provides:

The tariffs shall include a formula rate or charge designed to pass through both the costs incurred by the utility in procuring a supply of electric power and energy for the applicable customer classes with no mark-up or return on the price paid by the utility for that supply, plus any just and reasonable costs that the utility incurs in arranging and providing for the supply of electric power and energy. The formula rate or charge shall also contain provisions that ensure that its application does not result in over or under recovery due to changes in customer usage and demand patterns, and that provide for the correction, on at least an annual basis, of any accounting errors that may occur.

It further provides:

A utility shall recover through the tariff all reasonable costs incurred to implement or comply with any procurement plan that is developed and put into effect pursuant to Section 1-75 of the Illinois Power Agency Act and this Section, including any fees assessed by the Illinois Power Agency, costs associated with load balancing, and contingency plan costs. The electric utility shall also recover its full costs of procuring electric supply for which it contracted before the effective date of this Section in conjunction with the provision of full requirements service under fixed-price bundled service tariffs subsequent to December 31, 2006.

That section continues, “All such costs shall be deemed to have been prudently incurred.”

In Ameren’s proposed Rider PER, Original Sheet No. 31.004, under Purchased Electricity Price, the tariff describes or summarizes costs that are included in determining Purchased Electricity Prices (“PEPs”) under Rider PER. As presented and used in Rider PER, the statement that “All such costs are deemed to have been prudently incurred” appears to apply to all three cost categories described in the prior sentence, namely: “(a) all costs the Company incurs in meeting its obligations in accordance with the Procurement Obligations section of this Rider; (b) all just and reasonable costs the Company incurs in arranging and providing for the supply of electric power and energy; and (c) all reasonable costs the Company incurs in implementing or complying with any procurement plan that is developed and put into effect pursuant to Section 1-75 of the IPA Act and Section 16-111.5 of the Act, including any fees assessed by the IPA.”

2. Positions of the Parties

While the legislature did provide that certain costs shall be deemed to have been prudently incurred, **Staff** disagrees with Ameren’s proposed language because it is contrary to the provisions of Section 16-111.5(l) to the extent it indicates or implies that all three cost categories are to be deemed prudently incurred. (Staff Objections at 42)

Staff says that while new Section 16-111.5(l) contains a sentence stating “All such costs are deemed to have been prudently incurred,” the context in which that statement is made indicates that it applies only to the costs of procuring power under supply contracts entered into before the effective date of Section 16-111.5 for the provision of full requirements service to bundled customers. Ameren’s proposed language would also render similar language regarding the prudence of certain costs in Section 16-111.5(k) meaningless, contrary to the rule that a statute must be construed so that no term is rendered superfluous or meaningless.

Staff believes that because Ameren is interpreting Section 16-111.5(l) rather than quoting it, and because the proposed language presents an interpretation that is contrary to law and would improperly limit the Commission and other parties, the tariff should either delete the statement that “All such costs shall be deemed to have been prudently incurred” or replace the costs summary and deemed prudent language with a simple reference to Section 16-111.5(l). Staff says such changes are necessary to prevent the tariff from limiting the Commission’s review and approval of such costs to the extent provided for under the law. (Objections at 45-46)

Staff also takes issue with language in Ameren’s proposed Rider PER - Purchased Electricity Recovery (“Rider PER”), Original **Sheet No. 31.015, Miscellaneous General Provisions**. Staff says the language gives the impression that none of the costs which a utility is allowed to recover pursuant to Section 16-111.5 need to be found reasonable by the Commission on an annual basis.

Staff states that while Section 16-111.5(l) does address the need to address accounting errors which may occur, Section 16-111.5(l) also provides that an electric utility’s tariff among other costs set forth in that section can only recover for “just and reasonable costs that the utility incurs in arranging and providing for the supply of electric power and energy” and “all reasonable costs incurred to implement or comply with any procurement plan that is developed and put into effect pursuant to Section 1-75 of the Illinois Power Agency Act and this section, including any fees assessed by the Illinois Power Agency, costs associated with load balancing, and contingency plan costs.” (Staff Objections at 50-51)

Given that Section 16-111.5(l) puts a qualifier of reasonableness on certain cost recoveries by the utilities, “Staff recommends that the Companies’ tariff language be revised so that the tariff is clear to all interested parties and consistent with the law that the reconciliation to take place beginning in 2009 shall also involve a determination that the cost incurred in arranging and providing the supply of power and energy are reasonable and that the costs incurred to implement or comply with any procurement plan developed and put into effect pursuant to the Illinois Power Agency Act, including fees assessed by the Agency, costs associated with load balancing and contingency plan costs are reasonable as well.” (Objections at 51) Staff provides specific proposed language for the tariffs in question.

In its Reply, **Ameren** takes issue with Staff’s recommended changes to Rider PER as described above. (Ameren Reply at 21-24) Ameren claims that Staff’s statutory interpretation to require qualifiers to the utility’s ability to recover its power supply and other related costs are contrary to the plain reading of the statute. Ameren argues that once the Commission has approved the power procurement plan as well as the power procurement process, the electric utility shall recover its costs of procuring power and energy and related costs.

Ameren argues that the “pass through” language is not qualified by some preliminary or post prudence reviews by the Commission as to the propriety of those

costs. Ameren contends that contrary to Staff's interpretation, the General Assembly was clear that these costs are to be recovered without question. Staff asserts the sentence in Section 16-111.5(l), "All such costs are deemed to have been prudently incurred" only applies to the preceding statement. Ameren says in the preceding statement, the statute refers to the utility being able to recover the costs associated with previously entered into supplier forward contracts.

Ameren claims Staff's argument fails on at least two counts. First, the preceding sentence permits the utility to recover the costs associated with the supplier forward contracts. It states "(t)he electric utility shall also recover its full cost of procuring electric supply..." According to Ameren, this means the General Assembly has already declared that these costs are to be recovered and Staff's interpretation is nothing more than a redundancy, that is, in effect both sentences mean according to Staff the subject costs can be recovered. Second, Ameren believes it makes no sense for Staff to be able to selectively pull from the entirety of the statute one sentence and pick and choose where that sentence applies and does not apply. Ameren argues that by reading the statute in its entirety, it is clear the General Assembly is concluding the statute by stating all the costs described throughout the statute are prudently incurred, and if they are prudently incurred, they are to be recovered.

Ameren says Staff relies upon Section 16-111.5(k) in support of its arguments. Subsection (k) refers to the financial swap contracts for which the utilities were obligated to enter into for the reasons described in the statute. According to Ameren, the General Assembly is stating, first, that the costs associated with these financial swap contracts have legislatively been deemed prudently incurred, and that the utilities are permitted to recover those costs through the tariffs filed with the Commission. Ameren states that subsection (l) is complimentary of subsection (k) insofar as the costs associated with these financial swap contracts are to be recovered, not just in this first initial procurement plan, but over the next several years. Ameren asserts that subsection (l) permits the utilities to recover costs associated with the procurement plans, again, not for just this first year but for years to come through the "formula rate" described in subsection (l).

Ameren contends that Staff's interpretation is at odds with a later portion of subsection (l) where the General Assembly has mandated that the utility is to recover ". . . its full costs of procuring electric supply for which it contracted before the effective date of this Section" Ameren asserts that the General Assembly treats these costs and their recovery the same as it does with prospective power supply costs.

According to Ameren, the Commission approves the procurement plan, the procurement process and the procurement administrator. After this initial procurement plan, Ameren says the utilities will not be the entity responsible for preparing the procurement plan and that responsibility falls on the Illinois Power Agency, a separate state agency. Ameren states that beginning in 2009, the Commission will approve this state agency's power procurement plan. According to Ameren, the utilities role has and will be substantially diminished. Ameren claims that Staff has failed to identify any

discretionary activity on the part of the utilities that would justify or warrant a prudence review. Ameren asserts that the prudence review, as it were, is taking place now.

Staff says the plain language of Section 16-111.5(l) specifically requires a finding of reasonableness with regard to implementation and compliance of the procurement plan. That section states, “A utility shall recover through the tariff all reasonable costs incurred to implement or comply with any procurement plan that is developed and put into effect pursuant to Section 1-75 of the Illinois Power Agency Act and this Section, including any fees assessed by the Illinois Power Agency, costs associated with load balancing, and contingency plan costs.”

Staff therefore submits that only supply costs not involving utility discretionary action incurred specifically pursuant to and in strict adherence with a Commission-approved procurement plan are immune from a subsequent review for reasonableness. (Reply Comments at 9-10)

Staff’s believes its revisions are necessary to make it clear that costs incurred for implementation and compliance, such as, load balancing, contingency plans, and Illinois Power Agency fees charged to the Ameren Companies will require a subsequent determination of their just and reasonableness.

Another concern is “collateral requirements or other forms of security requirements.” It is Staff’s position that collateral costs should not be recovered from ratepayers absent more specificity on the part of the Ameren Companies. Staff’s major concern is that the Ameren Companies may attempt to recover in Rider PER collateral costs which have nothing to do with power procurement. (Supp. Reply at 10-12)

In support for this position, Staff says that currently, Ameren’s most likely source of collateral, its February 9, 2007, credit agreement would have two types of fees: a facility fee and letter of credit fees. The facility fee is assessed on the credit facility commitment amount. The letter of credit fee is payable on the undrawn amount of all facility letters of credit (“LC”). Of these two fees, only the latter is traceable to a particular activity, e.g., the issuance of a letter of credit. The facility fee depends on aggregate use of the credit facility which could also be used for purposes other than power procurement, i.e. general corporate purposes. Therefore, whether a portion of the facility fee is a cost of procuring power and energy will be subject to debate.

Fees in a credit agreement are usually based on a utility’s senior unsecured long-term credit ratings. Since credit ratings are a function of a utility’s management decisions, it is objectionable that the entire LC fee should be recovered through Rider PER as power procurement activity costs.

Staff adds that the fee structure of credit agreements might change over time. In the future, a credit agreement might include a whole new set of fees that the Commission may have never seen or contemplated before.

Given the lack of specificity in the Ameren Companies' tariff and plan, Staff argues, the Ameren Companies should not be permitted to recover collateral costs that are unrelated to power procurement.

In its supplemental reply comments, **Ameren** says it "accepts" Staff's position that only supply costs not involving utility discretionary action incurred specifically pursuant to and in strict adherence with a Commission-approved procurement plan are immune from a subsequent review for reasonableness; however, in Ameren's opinion, its tariff language already "supports this notion." (Ameren Supp. Reply at 4-5) In its BOE, Ameren recommends language changes based on its "modifications to Staff's edits to Rider PER." (Ameren BOE at 7-8)

With respect to whether load balancing costs, contingency plan costs and Illinois Power Agency fees charged to the Ameren Companies will require a subsequent determination of their just and reasonableness, Ameren apparently does not object to a review of load balancing and contingency plan costs, subject to Ameren tariff language revisions. Ameren does object to a review of IPA fees as beyond the control of Ameren. (Supp. Reply at 6-8)

Regarding collateral costs, Ameren proposes a modification to Rider PER intended to provide sufficient specificity. (Supp. Reply at 5-6)

In its BOE, **Staff** indicates that it agrees with language proposed by Ameren in its supplemental reply comments at page 6 on the issue of collateral costs. This language provides, "At the earliest reasonable date after the ICC approves a procurement plan, with such date occurring prior to the procurement event associated with such procurement plan, credit activities intended to meet collateral requirements or other forms of security requirements incurred by the Companies, if any, solely as a result of its procurement activities pursuant to the procurement plan approved by the ICC must be reviewed by the Companies' representatives with personnel from the Finance Department of the ICC Staff." (Staff BOE at 4)

The **AG** says the Commission has authority to conduct a prudence review of the 2008 procurement. (AG Supp. Comments at 3-4) A full prudence review of the 2008 procurement is necessary and proper, the AG asserts, because under PA 95-0481 the utilities, rather than the Illinois Power Agency, will be conducting the initial procurement. The utilities tariffs should be modified, as proposed by Staff, to remove any language which suggests that the Commission is precluded from reviewing the reasonableness of costs incurred during the 2008 procurement process.

In the AG's view, the utilities are wrong when they assert that they will not be exercising discretion during the initial procurement; the utilities will exercise a great deal of discretion over a multitude of decisions during the initial procurement.

According to the AG, the Illinois Supreme Court has noted that under the Pike County exception, States retain the authority to review the prudence of a distributor's

actions in incurring FERC-approved supply charges when the distributor had a choice whether to incur the charge. *General Motors*, 143 Ill. 2d at 421-22, 574 N.E.2d at 658, citing *MP&L*, 487 U.S. 354, 373-74, 108 S.Ct. 2428, 2440; *Nantahala*, 476 U.S. 953, 972, 106 S.Ct. 2349, 2359-60.

In *Pike County, Pike County Light and Power Co. v. Pennsylvania Public Utility Comm'n*, 77 Pa. Commw. 268, 273-74, 465 A.2d 735, 737-38 (1983), the court found that FERC approval of the [electric supplier's] tariffs means only that, as a matter of law, it is reasonable for [the electric supplier] to charge such rates; FERC approval does not mean that it is reasonable for [a utility] to incur such costs. 77 Pa. Commw. at 278, 465 A.2d at 739. Hence, the court concluded that a state commission can compare the cost of wholesale electricity purchased by a regulated utility at FERC-approved rates with alternative costs of purchased power. *Id.* at 275, 465 A.2d at 738.

Noting that state retail ratemaking authority and federal wholesale ratemaking authority do not overlap, the court also held that there is nothing in the federal legislation which preempts the [state commission's] authority to determine the reasonableness of a utility company's claimed expenses. In fact . . . the Federal Power Act . . . expressly preserve[s] that important state authority. *Id.* (footnote omitted).

In response, while **Ameren** does not dispute that the Commission can review the reasonableness of discretionary actions, Ameren says the AG has not identified one arguably discretionary act among the so-called "multitude." Ameren's position as to what is properly reviewable has been laid out in the section addressing the Staff.

Finally, and most troubling to Ameren, the AG would seemingly suggest all procurement costs are subject to a prudence review. Why and how non-discretionary costs should ever be subject to a post-hoc prudence review is never justified. As such, Ameren argues, the AG's position must be discarded. (Ameren Supp. Reply at 23)

3. Commission Analysis and Conclusions

As indicated above, Staff, Ameren and the AG have addressed the issue of whether or to what extent costs incurred for procurement of supply, and related activities and transactions, should be subject to a post-incurrence review for reasonableness or prudence. Staff and Ameren also address the question of whether the tariffs should specify which types of costs are immune from a prudence review.

To some extent, provisions in Sections 16-111.5(k) and (l), as quoted above, address the prudence issue. These sections contain language that certain costs shall be "deemed prudently incurred."

To the extent that Section 16-111.5 does specifically exempt certain pass-through expenditures from a post-incurrence prudence review, then further debate would be irrelevant. No prudence review by the ICC would be permissible with respect to those expenditures, regardless of what may otherwise have been either (1) required

under Article IX of the PUA or (2) allowed under the *Pike County* exception and Illinois cases that cite it. Not surprisingly, however, there is some disagreement over the scope or types of expenditures to be “deemed prudently incurred” within the meaning of 16-111.5.

In this case, Staff has taken the position that “only supply costs not involving utility discretionary action incurred specifically pursuant to and in strict adherence with a Commission-approved procurement plan are immune from a subsequent review for reasonableness.” (Reply Comments at 9)

Staff believes its proposed tariff revisions are necessary to make it clear that costs incurred for implementation and compliance, such as, load balancing, contingency plans, and Illinois Power Agency fees charged to the Ameren Companies, will require a subsequent determination of their just and reasonableness.

Ameren appears to generally accept the Staff position enunciated in the quoted language above, although Ameren proposes some modifications. (BOE at 7-8) Ameren also apparently does not object to a review of load balancing and contingency plan costs, subject to Ameren tariff language revisions. Ameren does object to a review of IPA fees as beyond the control of Ameren.

Other types of expenditures, such as collateral costs, were also a subject of concern and some disagreement in this regard, although Staff and Ameren have now reached agreement on the issue of collateral costs. (Staff BOE at 3-4) The language in Staff’s BOE on that issue is hereby found appropriate.

In any event, upon consideration of the parties’ comments, the Commission believes the Staff language quoted above represents a reasonable effort to interpret the statute.

Beyond that, the Commission does not believe it is necessary to approve specific tariff language containing prudency pronouncements for each type of cost, except in those instances where Staff and Ameren, who are the parties who actually offered tariff language on this issue, have agreed to such language.

That is, while there is still some debate over exactly which costs should be subject to a prudency review, the Commission does not believe that issue needs to be further resolved in this docket. There appear to be no objections to a prudency review, at least for some types of costs, inasmuch as no party is arguing that every type of cost involved in the process is insulated from a prudency review. Further, it appears that Ameren will be collecting these various types of costs on a pass-through basis through its tariffs, regardless of whether or not the tariffs contain specific prudency pronouncements for each such cost. To the extent there is ultimate disagreement over which costs actually incurred by Ameren should be immune from the prudency review, that issue can be taken up in as part of the above-referenced review process.

Finally, the Commission will next consider whether the quoted Staff language and related findings above are consistent with caselaw regarding prudency reviews of wholesale purchases of power, assuming such cases are relevant in the instant docket. The Commission observes that these cases address whether state commissions like the ICC are allowed to conduct such prudency reviews, not whether they are required to do so.

As a general rule, wholesale power purchases have been deemed by federal courts to be subject to federal, not state, jurisdiction. (e.g. see *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 964 (1986)) However, there is caselaw holding that states have authority to review the prudency of utility purchases under the under the *Pike County* exception, in situations where the utility had a choice, or discretion, over whether to incur the charge or from whom. (See *General Motors*, 143 Ill. 2d at 421-22: “For example, a State regulatory agency could find that purchase of a particular quantity of power from a particular source was unreasonable if lower cost power was available elsewhere, even if the cost of the purchased power had been approved by FERC and therefore deemed reasonable.”)

As indicated above, the quoted Staff language focuses on whether there is “discretionary action” by the utility. As such, Staff’s proposal would appear, generally speaking, to be in keeping with the distinctions in the caselaw involving jurisdiction over wholesale power purchases and the authority of the states to conduct reviews thereof.

E. Riders PER and MVA – General Tariff Language

Staff also has concerns with certain general tariff language contained in the Companies’ proposed Riders PER and MVA. The language states, in part, that certain costs are “deemed to have been prudently incurred.” (Staff Objections at 38-40) Staff recommends that language in those riders be removed from the proposed tariffs on the grounds that such language is simply inappropriate and unnecessary for inclusion in the tariffs. Staff submits that statements in a tariff paraphrasing statutory language addressing whether certain costs are to be deemed prudent or allowed by the Commission do not belong in a tariff establishing the rates to be charged to bundled customers.

According to Staff, this language is unnecessary. Additionally, Staff states that since the language is more than a mere quotation of the statute, it involves or presents an interpretation of these statutory requirements, limitations and prohibitions that may conflict with the actual intent and meaning of the statute. Staff believes that all language pertaining to the standards for recovery of procurement costs should be removed from the tariffs.

In its Reply, **Ameren** states that it does not object to these certain suggested tariff changes, and will remove the subject language from Rider PER and Rider MVA. Ameren provides language that it suggests will conform to Staff suggestions. (Ameren Reply at 19)

The **Commission finds** that removal of the language, as urged by Staff, would be appropriate; the proposed tariff should be modified accordingly.

F. Rider PER – Generating Facility Cost Recovery

In Ameren’s proposed Rider PER - Purchased Electricity Recovery (“Rider PER”), Original Sheet No. 31.003 (Ameren Exs. 3.1-CILCO, 3.1-CIPS, 3.1-IP), under “Pre-existing Contracts – Generating Facility Cost Recovery,” the tariffs state that the “Company may recover the costs associated with the construction of new generation to meet customer procurement needs in accordance with provisions of Section 16-111.5(p) of the Act.” **Staff** recommends that this language be modified. Under Section 16-111.5(p), supply from an electric generating facility, which a utility proposes to invest in, lease, own, or operate as part of its procurement plan, will be considered a pre-existing contract under Section 16-111.5(b) provided certain requirements are met, including that the generation facility be the least-cost option to provide electric service to eligible retail customers.

Staff claims that Ameren’s proposed tariff language is vague and could be interpreted to imply that regardless of whether the requirements under Section 16-111.5(p) are met, Ameren is entitled to cost recovery for such facilities. (Staff Objections at 41) Second, Staff states that Section 16-111.5(p) does not specifically refer to “the construction of new generation,” but rather refers to “investing in, leasing, owning, or operating such generation facility.” Staff recommends the following revision to the Companies’ tariff language at Original Sheet No. 31.003 of Rider PER:

Provided the requirements set forth in Section 16-111.5(p) are met, the Company may recover costs associated with the construction of new generation facilities it invests in, leases, owns or operates as part of its procurement plan to meet customer procurement needs in accordance with the provisions of Section 16-111.5(p) of the Act.

In its reply comments, **Ameren** accepted the Staff revisions. (Ameren Reply at 19)

The **Commission** finds that that Staff’s revisions, as accepted by Ameren, are appropriate and shall be approved.

G. Rider PER- Adjustments to Purchase Electricity Charges

Staff states that Rider PER contains three sub-parts, the first entitled Procurement Adjustment. Staff says the tariff provides for a broad range of procurement costs to be recovered. According to Staff, given the possibility for costs to be recovered more than once in rates (i.e., the possibility that costs recovered through the rider are also included in base rates), the Commission should order the Companies to put in place accounting controls to prevent the double recovery of these costs. Staff

says the Companies should be further ordered to perform internal audits of those controls and to provide copies of the audits to the Commission Staff on an annual basis.

For all three sub-part adjustments, Procurement, Working Capital, and Uncollectibles, the tariff states that the adjustments will be established by the Commission in a Delivery Services rate case. Staff finds the reference to “Delivery Services rate case” to be vague. Staff proposes specific language to address its concerns about the alleged vague language. (Staff Objections at 46-47)

Ameren says it does not object to adding Staff’s suggested language to Rider PER, Original Sheet Nos. 31.013 and 31.014, pertaining to the Procurement Adjustment, Working Capital Adjustment, and Uncollectibles Adjustment. Ameren also says the proposed changes to Miscellaneous General Provisions are acceptable in principle; however, Ameren proposes different changes to Staff’s proposed addition to more closely match anticipated audit activity. (Ameren Reply at 20)

In reply comments filed November 28, 2007, page 8, Staff finds **Ameren’s** modifications acceptable.

The **Commission finds** that Staff’s language revisions, as modified in Ameren’s Reply, are appropriate and shall be approved to the extent such modifications were accepted by Staff.

H. Rider HSS - Hourly Supply Service

Staff indicates that Ameren’s proposed Rider HSS - Hourly Supply Service (“Rider HSS), Sheet 29.004, Supply Cost Adjustment Charges tariff contains three sub-parts, the first entitled Supply Cost Adjustment – Procurement. The tariff provides for recovery of a broad range of procurement costs. Staff asserts that the breadth of the tariff creates the possibility for costs to be recovered more than once in rates (i.e., the possibility that costs recovered through the rider are also included in base rates). Therefore, Staff recommends that the Commission order the Companies to put in place accounting controls to prevent the double recovery of these costs. Moreover, to ensure the Commission that the accounting controls are properly implemented, Staff wants the Companies further ordered to perform internal audits of those controls and to provide copies of the audits to the Commission Staff on an annual basis.

For all three Supply Cost Adjustment Charges, Procurement, Working Capital, and Uncollectibles, the tariff states that the Commission in a Delivery Services rate case will establish the adjustments. Staff finds the reference to “Delivery Services rate case” to be vague. Staff again proposes specific language to address its concerns about the alleged vague language. (Staff Objections at 48-49)

In its Reply Comments, **Ameren** says it does not object to adding Staff’s suggested language to Rider HSS, Original Sheet No. 29.004, pertaining to the Procurement Adjustment, Working Capital Adjustment, and Uncollectibles Adjustment.

Ameren indicates that Staff's proposed changes to General Supply Provisions in Rider HSS, Original Sheet No. 29.008, are acceptable in principle; however, Ameren proposes changes to the Staff's proposed addition to more closely match anticipated audit activity. (Reply at 20-21)

According to Ameren, it appears Staff's proposed language related to General Supply Provisions is new language in its entirety. Ameren believes the new language would best fit within proposed Rider HSS in the 5th paragraph as the first sentence. With Ameren's suggested modifications, Ameren says the audit language in Rider HSS will be more comparable to similar provisions in Rider PER.

In its reply comments field November 28, 2007, page 8, Staff finds Ameren's modifications acceptable.

The **Commission finds** that Staff's proposed revisions to Rider HSS, as modified in Ameren's Reply, are appropriate and shall be approved.

I. Deferral of Determinations on Tariffs

The **AG** argues that the Commission should defer assessment of the justness and reasonableness of the proposed tariffs until the final mix of products, commodities and services to be included in the procurement plan has been established. The AG claims the Commission has discretion to defer this assessment because the review of tariffs is governed by Article IX of the Public Utilities Act, rather than the expedited procedures specified for procurement plan review in 220 ILCS 5/16-111.5(j)(i). (Objections at 7)

Ameren disagrees with the AG's position. According to Ameren, it is clear on the face of the statute that when the Commission approves the Procurement Plan at the end of the 60 day statutory period, the Commission is also expected to approve the subject tariffs. (Reply at 26-27) Ameren says there is nothing in the law that defers the Commission's obligation to approve these tariffs until such time as the Commission determines what products are to be included in the Plan.

Ameren asserts that the AG offers no valid reason why there is a need to wait until the procurement process is underway for the Commission to make any determinations about its proposed tariffs. Ameren claims there is nothing about the products, commodities, or services to be procured that will change or affect the tariffs. These are simply cost recovery mechanisms. Finally, Ameren asserts having these tariffs in place earlier, rather than later, is helpful to all stakeholders. Ameren states that as in the auction procurement dockets, the Commission approved the Ameren Illinois Utilities' Rider MV and other related tariffs in January 2006, even though these tariffs would not go into effect until January 2, 2007. In Ameren's view, it is important for the Commission, Staff, stakeholders, including ARES, and other market participants, to know well enough in advance the manner and method by which those tariffs operate.

Having reviewed the positions of the parties, the **Commission** finds that determinations on tariff proposals should be made at this time, except as otherwise noted. It appears that such action is contemplated by Section 16-111.5(j). After requiring that an order be entered within 60 days, Section 16-111.5(j) further provides, in part, "The order shall . . . approve or modify the tariffs"

V. FINDING AND ORDERING PARAGRAPHS

The Commission, having considered the entire record, is of the opinion and finds that:

- (1) Central Illinois Light Company, Central Illinois Public Service Company and Illinois Power Company are Illinois corporations engaged in the retail sale and delivery of electricity to the public in Illinois, and each is a "public utility" as defined in Section 3-105 of the Public Utilities Act and an "electric utility" as defined in Section 16-102 of the Public Utilities Act;
- (2) the Commission has jurisdiction over the parties and subject matter of this proceeding;
- (3) the facts recited and conclusions reached in the prefatory portion of this Order are supported by the record and are hereby adopted as findings of fact and/or conclusions of law;
- (4) subject to the modifications explicitly adopted in the prefatory portion of this order, the Plan filed by the Ameren Companies pursuant to Section 16-111.5 of the Act should be approved; as modified, the Plan will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability;
- (5) subject to the determinations made and conditions imposed herein, the tariffs proposed by the Ameren Companies in their initial filing, as modified to reflect the findings herein, are just and reasonable; the Ameren Companies should be authorized to file and place into effect such tariff sheets, as modified;
- (6) the new tariff sheets for Rider PER, Rider MVA, and Rider HSS authorized to be filed by this Order should reflect an effective date not less than 30 days after the date of filing, with the tariff sheets to be corrected, if necessary, within that time period, and should reflect an operational date of no earlier than June 1, 2008; revised Customer Terms and Conditions, cancelled tariff sheets for Rider MV, Rider BGS-L, and Rider RTP-L, and other modifications required to other existing tariffs for the purpose of removing references to Rider MV and replacing with appropriate references to Rider PER, Rider MVA, or Rider HSS, as applicable, should

be submitted with a compliance filing by May 9, 2008, with an effective date of June 1, 2008;

- (7) the Ameren Companies should be subject to the annual reconciliation proceedings, including notice and hearing, related to its power purchases as described and approved in the prefatory portion of this Order.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the proposed Procurement Tariff Sheets filed with its Petition by the Ameren Companies on October 26, 2007 are approved for filing as revised and modified in this Order and the Ameren Companies are authorized and directed to file new tariff sheets in accordance with the Findings of this Order.

IT IS FURTHER ORDERED that the Ameren Companies shall be subject to the annual reconciliation proceedings related to its power purchases as described and approved in the prefatory portion and in the findings of this Order and in the tariffs approved for filing by this Order.

IT IS FURTHER ORDERED that all petitions for leave to intervene, to the extent not heretofore ruled upon, are granted.

IT IS FURTHER ORDERED that Ameren's proposal to utilize Levitan and Associates as its Procurement Administrator for its Initial Plan is hereby approved.

IT IS FURTHER ORDERED that any motions, objections, or other matters in this proceeding that remain unresolved are hereby deemed disposed in a manner consistent with the conclusions contained herein.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 19th day of December, 2007.

(SIGNED) CHARLES E. BOX

Chairman