Ameren Exhibit 2.1

Procurement Plan

For the Period
June 2008 – May 2009

Proposed on Behalf of
The Ameren Illinois Utilities

AmerenCILCO
AmerenCIPS
AmerenIP

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Procurement Plan of the Ameren Illinois Utilities

I. Introduction and Overview

On August 28, 2007, Governor Rod Blagojevich, signed into law Public Act 095-0481 which includes the Illinois Power Agency Act ("IPA Act") and certain modifications to the Public Utility Act ("PUA"). This legislation fundamentally modified the method of procurement for the power and energy requirements of the Ameren Illinois Utilities ("Utilities"). The IPA Act creates a new unit of State Government responsible for the development of an annual procurement plan and the subsequent administration of the process to acquire the resources identified in the plan.

The IPA Act 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 this plan covering their combined needs. They shall procure resources for those combined needs in conjunction with this plan and allocate capacity, and energy, and cost responsibility therefore amongst themselves in proportion to their requirements.

These provisions prescribe specific activities including hourly load analysis, an analysis of the impact of legislatively mandated demand-side and renewable energy initiatives, the development of a plan for meeting the expected load requirements not met through pre-existing contracts and proposed procedures for balancing loads.

Further, the legislation requires the Utilities to file this initial procurement plan within sixty days of the effective date of the legislation.

Accordingly, this document presents the analysis of the Utilities' combined projected system supply requirements for the period of June 2008 – May 2013, sets forth a proposed portfolio of standard market products to be acquired to meet the supply requirements for the period June 2008 – May 2009, details the means by which they will meet their renewable energy standards, and outlines the process utilized to secure the services of an independent procurement administrator. Each of these components of the plan is prescribed by the aforementioned legislation, and this plan adheres to these requirements.

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

A. Purpose and Summary

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

B. Hourly Load Analysis

(1) Multi-Year Historical Analysis of Hourly Loads

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 are 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.

Residential SAE Model[1]

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

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

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

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

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

Constructing XHeat- Electric

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

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

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

The HeatIndex is defined as a weighted average across equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights,

[1] Commercial indices are constructed using similar approaches; however, different economic drivers were used instead of households and personal income variables in estimating the indices.

the index will change over time with changes in equipment saturations (Sat) and operating efficiencies (Eff). Formally, the equipment index is defined as:

$$HeatIndex_y = \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{98}^{Type} \big/ Eff_{98}^{Type} \right)} \quad (4)$$

In the above expression, 1998 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 1998. In other years, it will be greater than 1 if equipment saturation levels are above their 1998 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{98}^{Type}}{HH_{98}} \times HeatShare_{98}^{Type} \quad (5)$$

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

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices and billing days. Since the heating degree days used in these models are in revenue month cycle, billing degree days is not used as a variable. Using the REEPS default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{Price_{y,m}}{Price_{98}} \right)^{-0.20} \times \left(\frac{Income_{y,m}}{Income_{98}} \right)^{0.25} \times \left(\frac{HHSize_{y,m}}{HHSize_{98}} \right)^{0.25} \times \left(\frac{HDD_{y,m}}{HDD_{98}} \right) (6)$$

where $Price_{y,m}$ is the average residential real price of electricity in year (y) and month (m), Price98 is the average residential real price of electricity in 1998, $Income_{y,m}$ is the average real income per household in a year (y) and month (m), Income98 is the average real income per household in 1998, $HHSize_{y,m}$ is the average household size in a year (y) and month (m), HHSize98 is the average household size in 1998, $HDD_{y,m}$ is the revenue month heating degree days in year (y) and month (m), and HDD98 is the annual heating degree days for 1998.

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year (1998). The HDD term serves to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in the economic driver changes, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.20 power).

Constructing XCool - Electric

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

Constructing XOther - Electric

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

$$\text{XOther}_{y,m} = \text{OtherIndex}_{y} \times \text{OtherUse}_{y,m}$$

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

Illinois Peak Forecast Methodology

The peak forecast for the Utilities' eligible customer retail load was performed at the operating company level. For each company (AmerenIP, AmerenCIPS, and AmerenCILCO), historical hourly data was collected. The data for each company was gathered for the longest period of time 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. The daily peak loads were the basis for the peak load model.

The Daily Peak Model

Daily peak loads were modeled using regression within the MetrixND software package. Daily peak load was the dependent variable, and the independent variables included temperature based variables, seasonal variables, day-type variables, and 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. Temperature splines are then created from the average daily temperature variable to allow load to respond to temperature in a non-linear fashion. These temperature splines are also interacted with seasonal and weekend variables to allow the temperature response of load to change with respect to these variables (i.e. Load will respond more to an 80 degree day in July than in October, and more on a weekday than a weekend).

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

The daily peak model also includes independent binary variables representing each day of the week, each month of the year, and major holidays. This captures the change in load that is not due to weather variation, such as load reductions due to industrial customers and businesses that may not operate on weekends.

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

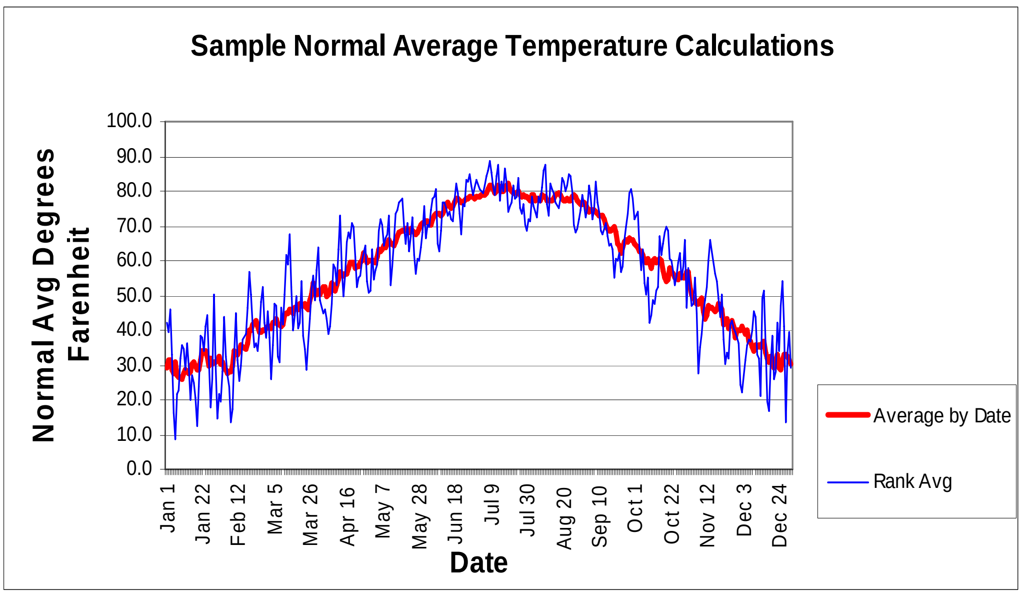
In the absence of sufficient history of weather normalized sales, a trend variable is used that, in essence, attributes peak load growth to the passage of time. Under positive economic conditions with normal load growth, this is a reasonable approach to capture the normal increases that are known to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

Statistical tests verify that the models fit the data quite well. The R-Squared statistic, which indicates the amount of variation in the dependent variable (load) that is explained by the model, ranges from 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.

Forecasting Normal Weather Conditions for the Daily Peak Model

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. Unfortunately, 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, 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, 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. A sample of the comparison of the rank and average normal calculation compared with averaging temperature by date can be seen below:



Final Forecast Steps

When each individual operating company has been forecast, 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. 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 the peak is adjusted 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. In reality, these three distinct peak load events can and likely will occur at different times in the month. So 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.

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

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

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

The 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 (a result of load research analysis of the classes).

(2) Switching Trends and Competitive Retail Market Analysis.

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

Residential

As of September 1, 2007, there were two Alternate Retail Electric Suppliers registered with both the ICC and the Utilities to serve residential customers in the Utilities' territories, as compared to ten so registered to serve non-residential customers in the Utilities territories. However, as of the date this plan was prepared, no residential customers of the Utilities have exercised their right to choice and significant switching is not expected in the near term.

Future retail switching may be dampened in part by the rate credits resulting from 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), it is reasonable to expect some increase in residential switching.

Residential switching could be positively influenced by an increase in the number of Alternate Retail Electric Suppliers (ARES) willing to serve residential customers, aggressive marketing campaigns or the development of value added products and services. More so, significant reductions in market prices or changes in the regulations regarding switching rules (i.e. "wet" signature requirements) would reasonably be expected to have an impact upon residential switching rates.

The Utilities estimate that residential switching will be approximately 5% by the end of the five year planning period.

0-149 kW Non-Residential

This 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. 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.

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

The Utilities estimate that switching in this class will be approximately 37% by the end of the five year planning period.

<u>150-399 kW Non-Residential</u>

This 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. 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.

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

The Utilities estimate that switching in this class will be approximately 55% by the end of the five year planning period.

<u>400-999 kW Non-Residential</u>

This 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

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

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

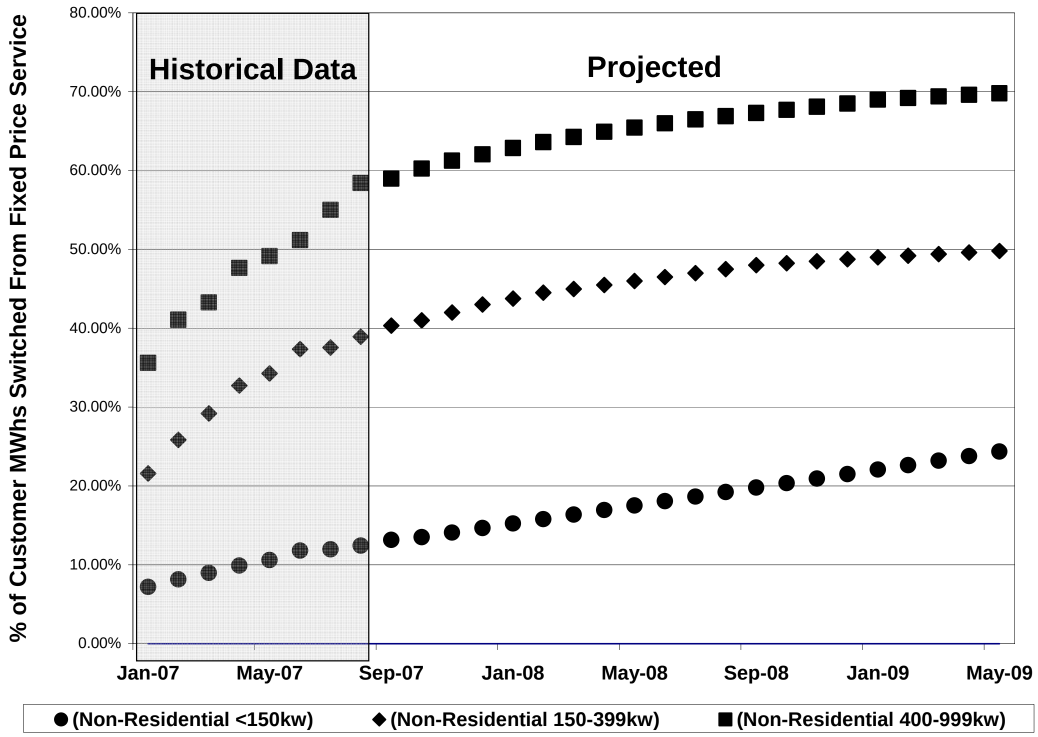
<u>1,000 kW and Greater Non-Residential</u>

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

<u>Switching Patterns</u>

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

The current assumption within the Plan is that switching will continue, although a decreasing rate over time. Expected values for the period June 1, 2008 through May 31, 2009 are included in the graph below:



(3) Known Or Projected Changes To Future Loads.

Known or projected changes to future loads include:

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

(4) Growth Forecasts By Customer Class.

For the residential customer class, the Utilities currently project a 5-year Compound Annual Growth rate for AmerenCILCO, AmerenCIPS and AmerenIP of 1.57%, 1.30%, and 2.05% respectively.

Commercial growth rates for the Utilities are projected to be 1.47%, 1.13% and 0.84%, respectively.

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

(1) Demand Response Programs

Section 12-103 of Public Act 095-0481 establishes specific requirements for Demand Response Programs to reduce peak demand of eligible retail customers (those with peak demands up to 400 kW) by 0.1% 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

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.

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

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

Renewable Energy Programs

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.

For the first year, the Utilities shall comply with these requirements through the acquisition of Renewable Energy Credits (RECs). 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, an adjustment to the forecasted load should be made at that time.

Impact of Cost Limits Applicable to Renewable Energy

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.

The Utilities have 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, as shown below.

Revenue Limit Based Estimated Portfolio Requirements
and Historical Average Rates

	Forecast KWh Needs	¢/KWh Limit Based on 5/31/07	Revenue Limit
(Eligible Retail Customers)			
Residential	12,194,440,732		
Non-residential	5,583,938,861		
Total, Eligible Retail Customers	**17,778,379,593**	**0.04348**	**$ 7,730,039**

Forecast needs per procurement plan, adjusted for energy losses to meter level.

To determine the revenue limit for subsequent years, three data points are necessary. First, forecast KWh for the planning year is needed. The next two data points are the ¢/KWh limits – one based on the average rates for the twelve months ending May 31, 2007, and one based on the average rates for the twelve months ending May 31 of the planning year immediately prior to procurement. The Utilities do not know what the average rates will be for any year beyond 2007 and have used the average rates for the twelve months ending 5/31/2007 to calculate an estimate of the average ¢/KWh limits to be applied to subsequent years. These limits are as follows:

Year	% Limit	5/31/07 ¢/KWh Limit
2008	0.5%	0.04348
2009	1.0%	0.08696
2010	1.5%	0.13045
2011	2.0%	0.17393
2012	2.015%	0.17523

(3) Energy Efficiency Programs

Section 12-103 (b) of Public Act 095-0481 establishes specific requirements for Energy Efficiency Programs that reduce energy consumption of delivery services customers by 0.2% in 2008 planning year and increasing 0.2% each year for the remainder of the five year planning period. The effective reduction in the Utilities' supply requirements to be acquired through the RFP process (net of customer switching) is projected to be:

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

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

For the planning year June 1, 2008 through May 31, 2009, the energy efficiency requirement is 0.2% of delivered energy or approximately 12,948 MWh.

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

III. Portfolio Design

A. Purpose and Summary

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". This section discusses the portfolio of forward contracts and Midwest ISO ("MISO") spot purchases that the Utilities will use to supply their eligible retail customer load in a manner consistent with the above stated objective.

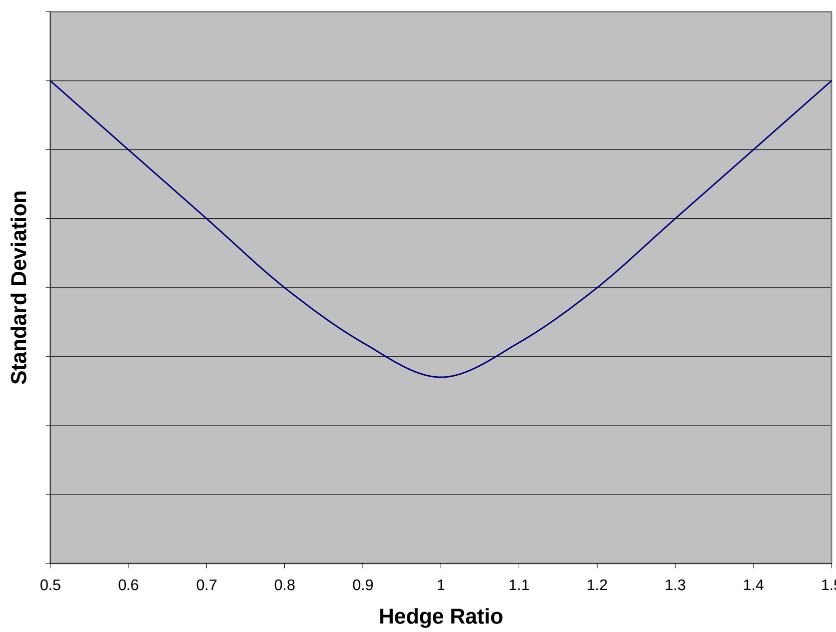
B. Description of the Analytical Approach

When designing a portfolio to serve the Utilities eligible retail customer load from June 1, 2008 through May 31, 2009, a key question is: How much of the supply should be hedged with forward contracts and how much should be subject to MISO spot market prices?

The Utilities used a simulation modeling approach to arrive at a supply portfolio of standard market products. It is helpful to note 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. This is due to the fact that sellers of forward contracts are taking on pricing risk by entering into these contracts. It is the Utilities belief 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. The following graph depicts this relationship.



As utilized in the graph above and throughout this section, the term "hedge ratio" shall mean 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.

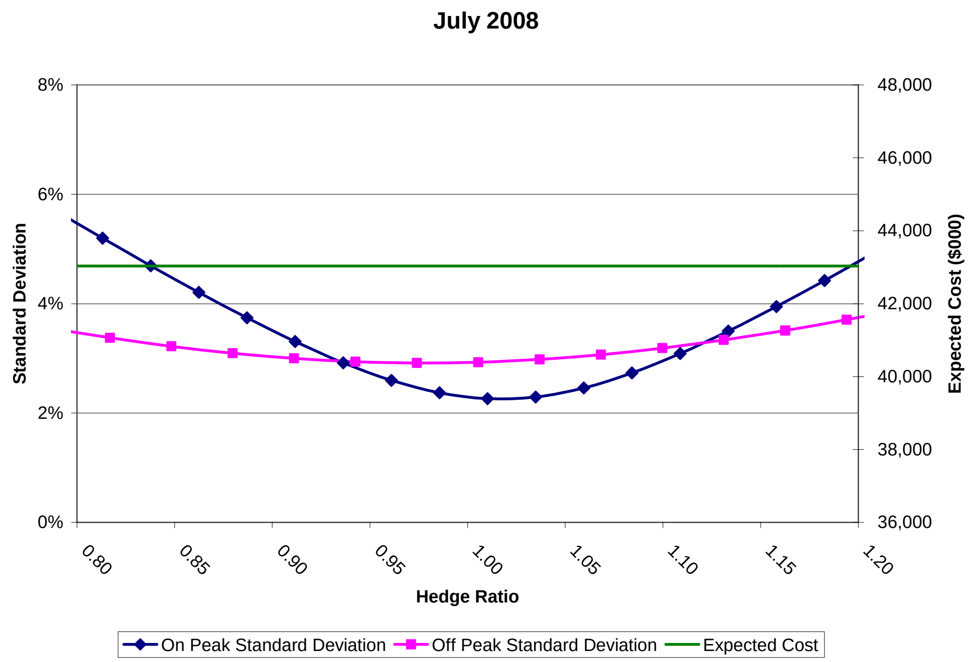
The Utilities' analysis of how much to contract forward for the June 1, 2008 through May 31, 2009 planning year was performed as 24 independent analyses (1 analysis for each of the 12 monthly on-peak periods and 1 analysis for each of the 12 monthly off-peak period), utilizing a simulation model (RT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

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. It should be noted that despite the Utilities 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 the Utilities to reasonably determine the magnitude of this premium. As described later in the plan, the Utilities have considered the potential impact of such a premium outside the construct of this model.

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.

As expected, 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. This relationship was expected due to the modeling assumption that there is no risk premium associated with forward contracts relative to the spot market prices. As stated earlier, the potential impact of such a premium will be accounted for outside the construct of the simulation model. .

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. The following graph shows the results for month of July 2008. A complete set of graphs for all months in the planning period can be found in Appendix A



While these results were consistent across all 24 analyses, it should be noted that 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, as illustrated in the July 2008 graph above.

To summarize, 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, 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. The monthly on-peak and off-peak hedge ratios associated with minimizing customer risk are illustrated in the table below:

	Minimize On-Peak Standard Deviation			Minimize Off-Peak Standard Deviation		
	Hedge Ratio	Cost	Std Dev	Hedge Ratio	Cost	Std Dev
June-08	1.01	$19,957,400	$437,719	0.96	$7,892,931	$256,444
July-08	1.01	$30,296,360	$685,311	0.97	$12,737,700	$371,320
August-08	1.03	$27,450,837	$725,876	0.99	$13,139,339	$435,145
September-08	1.01	$17,141,432	$471,087	0.99	$7,405,665	$241,559
October-08	1.00	$14,350,027	$193,601	0.96	$6,564,079	$97,261
November-08	1.02	$13,131,332	$176,176	0.95	$7,956,610	$110,215
December-08	1.04	$17,045,779	$262,316	0.99	$8,558,982	$132,349
January-09	1.02	$21,381,824	$354,933	0.97	$14,560,540	$290,884
February-09	1.01	$18,962,271	$334,215	0.96	$11,795,440	$217,055
March-09	1.02	$16,571,665	$200,275	0.99	$8,704,780	$125,268
April-09	1.00	$14,974,696	$288,343	0.94	$7,173,889	$150,764
May-09	1.00	$13,045,825	$343,185	0.98	$6,592,708	$167,472

Once the above analysis (which indicates a supply portfolio close to the 1.0 hedge ratio portfolio produces a result that minimizes customer risk) was completed, the Utilities 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. 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, 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.

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.

Finally, it should be noted that as 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.

Multiple consolidated portfolios were analyzed and the impact of each on risk was considered. The following table shows the portfolios that were considered in addition to the optimal portfolio produced by the model (the "Model Solution")

	100% Spot Purchases	Portfolio A	Portfolio B	Portfolio C	Portfolio D	Portfolio E
Swap Annual Base (7x24)	400	400	400	400	400	400
Other Annual Base (7x24)	0	150	200	225	250	150
Annual On Peak (5x16)	0	0	0	0	0	100
Jan/Feb Base (7x24)	0	0	0	0	0	200
Jan/Feb On Peak (5x16)	0	150	200	225	250	50
Mar/Apr Base (7x24)	0	0	0	0	0	0
Mar/Apr On Peak (5x16)	0	0	0	0	0	0
May Base (7x24)	0	0	0	0	0	0
May On Peak (5x16)	0	0	0	0	0	0
Jun/Sep Base (7x24)	0	0	0	0	0	125
Jun/Sep On Peak (5x16)	0	125	175	200	225	100
Jul/Aug Base (7x24)	0	0	0	0	0	225
Jul/Aug On Peak (5x16)	0	275	325	350	375	150
Q4 Base (7x24)	0	0	0	0	0	50
Q4 On Peak (5x16)	0	50	75	75	100	50

The following is a brief summary of each of these scenarios:

The **100% Spot Purchase Portfolio** assumes that no additional forward contracts are made and that 100% of the currently un-hedged 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.

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.

The following table summarizes the model results for each of the portfolios considered.

	100% Spot Purchases	Portfolio A	Portfolio B	Portfolio C	Portfolio D	Portfolio E	Model Solution
On-Peak Hedge Ratio	0.50	0.81	0.91	0.96	1.02	1.02	1.02
Off-Peak Hedge Ratio	0.59	0.81	0.88	0.92	0.96	0.96	0.97
Standard Deviation (000)	$34,821	$15,533	$10,663	$9,212	$8,762	$8,252	$7,069
Standard Deviation	10.32%	4.60%	3.16%	2.73%	2.60%	2.45%	2.10%

These results show the following:

1) 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. This is illustrated by comparing the Portfolio D result to that of the Model Solution results. Comparing these two portfolios 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.

2) There is very little value added by attempting to shape the off-peak hedges to match the shape of the monthly average energy requirements. This is illustrated by comparing Portfolio D with Portfolio E. The difference in the standard deviation between these two portfolios is only marginally better ($510,000) in Portfolio E which attempts to shape the off-peak hedges.

3) 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) it can be seen 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. 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 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 the Utilities believe exists in the market. In an attempt to see how such a risk premium would affect the optimal level of hedging the Utilities 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, each 5% increase in the hedge ratio equates to an $850,000 increase in costs directly associated with the hypothetical 5% risk premium

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. The Utilities' conclusion is that the inclusion of the hypothetical 5% premium supports a hedge ratio lower than 1.0.

However, the hypothetical risk premium does not appear to be sufficient to drive the hedge ratio any lower than 0.9. 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, the Utilities elected a hedge ratio of 0.9 as illustrated in Portfolio B above.

C. Proposed Procurement Plan to Meet Expected Load Requirements

(1) Definition of the Different Retail Customer Classes for Which Supply Is Being Acquired.

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)

(2) Monthly Forecasted System Supply Requirements (Energy)

The table below includes the forecasted monthly supply requirements (in MWh) for the period June 1, 2008 through May 31, 2009. This forecast includes the impact of the expiration of auction contracts and estimates the impact of customer switching.

	(Residential) DS1	**(<150kw)** DS2	**(150-399kw)** DS3A	**(400-999kw)** DS3B	**(Lighting)** DS5	**Energy Efficiency**	**Total**
Jun-08	361,726	127,000	37,396	23,929	10,422	(1,121)	559,352
Jul-08	458,591	136,343	39,955	25,383	10,368	(1,341)	669,299
Aug-08	445,334	130,078	38,096	24,134	10,392	(1,296)	646,737
Sep-08	344,956	122,921	35,942	22,684	10,575	(1,074)	536,004
Oct-08	284,580	116,068	33,997	21,283	10,666	(933)	465,660
Nov-08	309,077	113,120	33,172	20,599	10,861	(974)	485,855
Dec-08	382,537	118,284	34,682	21,407	11,136	(1,136)	566,911
Jan-09	437,369	123,566	36,320	22,173	11,209	(1,261)	629,376
Feb-09	359,782	112,246	33,231	20,265	10,928	(1,073)	535,379
Mar-09	330,024	105,750	31,478	19,127	10,696	(994)	496,081
Apr-09	276,955	99,695	29,932	18,121	10,594	(871)	434,426
May-09	274,491	102,527	30,877	18,650	10,432	(874)	436,102
Total	4,265,420	1,407,598	415,079	257,755	128,279	(12,948)	6,461,182

Average, minimum and maximum projected peak load values are included as Table 1.

A five year table of the monthly forecasted system supply requirement is included as Table 2.

(3) Monthly Forecasted System Supply Requirements (Capacity)

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. 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%. 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.

The 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
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.

	Peak Forecast	Demand Response	Net After Demand Resp	15% Reserves	Capacity Requirement
Jun-08	1,363	0	1,363	205	1,568
Jul-08	1,601	1.6	1,599	240	1,839
Aug-08	1,598	1.6	1,596	239	1,835
Sep-08	1,229	0	1,229	184	1,413
Oct-08	1,001	0	1,001	150	1,151
Nov-08	978	0	978	147	1,124
Dec-08	1,091	0	1,091	164	1,255
Jan-09	1,092	0	1,092	164	1,256
Feb-09	1,121	0	1,121	168	1,289
Mar-09	973	0	973	146	1,119
Apr-09	849	0	849	127	976
May-09	1,064	0	1,064	160	1,223

A five year table of this forecast is included as Table 3

(4) 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. As previously described, 1/3 of these contracts (BGS-FP17) expire May 31, 2008. Of those contracts that will remain, ½ (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 provided in Section III.C.(2) and III.C.(3) above.

The following financial swap agreement is 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
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.

The preexisting financial swap contracts reduce the amount of supply to be acquired under this procurement plan, however this reduction is not reflected in the tables of the Utilities' combined supply requirements provided in Section III.C.(2) and III.C.(3) above. They have been properly accounted for in the determination of the specific products to be acquired to meet these supply requirements.

Additionally, the Ameren Illinois Utilities are parties to various contracts with qualifying facilities under their applicable QF tariffs.

D. Identification of wholesale products to be acquired

(1) Proposed Mix of Standard Power and Energy Products

Energy:

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.

The Utilities will 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
Jan/Feb 5x16	200 MW
Jun 5x16	175 MW
Sep 5x16	175 MW
Jul/Aug 5x16	325 MW
4^{th} Quarter (Q4) 5x16	75 MW

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. 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.

Within MISO, financial swaps have become a standard, if not preferred, product among market participants including generators, load serving entities and financial participants. 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, the Utilities believe it is reasonable to expect a larger number of participants in their competitive RFP process than if the product were restricted to physical deliveries. The Utilities also believe it is reasonable to expect that the greater the number of participants in a competitive process, the higher the likelihood of a competitive result.

Additionally, financial swaps do not have the same administrative burden as bilateral transactions for physical delivery. 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, financial swaps were selected as a superior product.

Their use will not adversely affect reliability as the Utilities will contract for sufficient Capacity to meet the load obligations, and such the contracts for such Capacity shall obligate the seller to offer such Capacity into the MISO markets.

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.

Capacity:

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 (non-summer period). 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.

The forecasted capacity requirements by month and subsequent purchase plan are illustrated as follows:

	Capacity Requirement	Procurement Plan Purchases	Monthly Spot Purchases
	MW	MW	MW
Jun-08	1568	1570	0
Jul-08	1839	1840	0
Aug-08	1835	1840	0
Sep-08	1413	1420	0
Oct-08	1151	1040	111
Nov-08	1124	1020	104
Dec-08	1255	1130	125
Jan-09	1256	1140	116
Feb-09	1289	1170	119
Mar-09	1119	1010	109
Apr-09	976	880	96
May-09	1223	1110	113

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, it will help protect against the purchase of spot capacity in the summer, when the possibility of scarcity pricing is greatest.

Conversely, 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, 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, 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.

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. 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, 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.

(2) Identification of Transmission Service Related Products and Services Associated with the Supply to Serve Load.

In addition to the acquisition of power and energy related products as detailed above, 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. These services include Network Transmission Service and Ancillary Service. Further, the Utilities may be allocated certain Financial Transmission/Auction Revenue Rights.

Network Integrated Transmission Service (NITS)

Network Integrated Transmission Service is described in Section III of Module B to the MISO Tariff. The Utilities utilize such 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.

The Utilities shall acquire the necessary NITS in accordance with the tariff. The cost for this service shall be that established in the applicable MISO tariff schedules.

Ancillary Services

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.

The Utilities shall acquire the necessary ancillary services in accordance with the MISO tariff. The cost for this service shall be that established in the applicable MISO schedule or as otherwise determined by the operation of the MISO ancillary services market.

Auction Revenue Rights

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 thus ultimately by their customers.)

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 shall also actively participate in the nomination and allocation phase of this process. They shall seek to nominate those ARRs 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. The Utilities shall retain the allocated ARRs, 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 ARRs from their historical resource points to those which align more closely with the designated energy resource delivery point.

(3) Assessment (Including Sensitivity Analysis) Of:

Price Risk and Load Uncertainty

In addition to the load uncertainty discussed above in terms of weather, known and projected changes and customer switching, the Utilities addressed load uncertainty and price risk in their analysis of the expected cost of various hedge ratios.

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.

The specific methodology for utilizing these models is discussed in detail in Section III.B.

Contract Terms

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). Individual transactions shall 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.

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, however, that this represents an allocation of the risk between the parties, the expected 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 likewise 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, the end-use customer ultimately bears the cost of managing this risk. As such, the agreements should seek to assign risk to that party best capable of managing that risk.

Fuel Cost

As the Utilities do not own generation resources of their own, risks related to fuel costs are reflected within the prices offered by potential suppliers and have not been separately analyzed

Weather Patterns

The assessment and variability of load uncertainty is primarily driven by assumptions of weather patterns. As such, the requested assessment and sensitivity analysis regarding this variable is included in the discussion of price and load uncertainty above.

Transmission Costs

The Utilities shall bear the cost of Network Integrated Transmission Service and the related Ancillary Services. Further, the procurement plan is expected to result in deliveries to a homogeneous delivery point, thus removing transmission costs as a factor in the analysis.

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.

The MISO Independent Market Monitor's most recent State of the Market Report indicates that the MISO energy markets performed competitively in 2006. (Executive Summary, page 4) Total generation resources within the MISO footprint were 127 GW in 2006 (ibid. 19). 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, the MISO reserve margin ranges from 5.5% - 12.7%. The former value does not account for interruptible load. (ibid. 19).

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.

Last fall's Illinois Auction to provide the Utilities with their supply requirements attracted more than twenty suppliers total and resulted in contracts being awarded to sixteen distinct suppliers. (Of those sixteen, nine were awarded contracts with the Utilities). In the Post Auction Public Report of the

Staff, Staff states "in the view of Staff and the Auction Monitor, the auction was competitive. Further, "(n)either Staff nor the Auction Monitor found evidence of collusive behavior or other anticompetitive actions by bidders." (page iii of v of the report)

Since the auction, 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.

The Utilities believe this recent experience supports a belief that the upcoming procurement process is reasonably expected to attract sufficient interest to likewise yield competitive results.

A variety of reports are publicly available which address issues affecting these markets. These reports include:

1) MISO's annual State of Market Report prepared by the MISO's independent market monitor.

2006 MISO State of the Market Report
http://www.midwestiso.org/publish/Document/4aea7c_113d8e80654_-7ea40a48324a?rev=1

2) Energy Market Assessment reports developed by the FERC Commission oversight staff
http://www.ferc.gov/market-oversight/st-mkt-ovr/st-mkt-ovr.asp

3) NERC Assessment reports
http://www.nerc.com/~filez/rasreports.html

4) U.S. Department of Energy, Energy Information Administration Annual Energy Outlook

http://www.eia.doe.gov/oiaf/aeo/index.html

Governmental / Regulatory Environment

The operation of the Utilities, including procurement activities are subject to regulation and/or oversight by the Illinois Commerce Commission, FERC, NERC, SERC and the SEC.

The recently enacted legislation establishing this procurement process provides participants in the process with significant guidance and certainty. This is reasonably expected to reduce potential counterparties' perception of regulatory risk within the process and therefore reduce expected cost. The roles of the various parties, including the Utilities and the ICC are delineated, the process itself is well described and cost recovery is adequately addressed.

Market rules within the FERC's and SEC's respective jurisdictions are well known to market participants and applied equitably, thereby not providing an unwarranted advantage to any participant in the process.

NERC and SERC provide guidance as to the nature and quantity of supply resources required of the Utilities.

(4) Identification of Alternatives for those Portfolio Measures That Have Been Identified as Having Significant Price Risk.

As discussed in greater detail in Section III.B, a variety of scenarios were analyzed in establishing the proposed portfolio. The scenarios identified varying percentages of the portfolio exposed to spot market pricing and different combinations of products to be procured. Included in these were scenarios that ranged from a 100% spot market portfolio to a scenario of forward contracts in excess of two times the expected average load.

(5) Proposed Procedures For Balancing Loads.

Hourly Balancing of Supply And Demand

Given the Utilities' intent to enter into financial swap transactions to hedge the energy price risk, rather than physical transactions, 100% of the energy required to supply the load included in this procurement plan will be purchased in the MISO energy markets. 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.

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.

Portfolio Re-Balancing in the Event of Significant Shifts in Load

In the event that 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. The Procurement Administrator shall 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 shall issue a reverse request for proposal.)

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. 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, the Procurement Administrator shall 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 shall 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, the Procurement Administrator shall 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 tenors of no less than one-month, it shall be necessary that the agreements resulting from any such rebalancing shall 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, the Utilities shall meet with the Staff of the Illinois Commerce Commission to make a determination if the request for proposal (or reverse request for proposal) should be re-issued.

Intercompany Portfolio Rebalancing of Cost and Sharing of Resources

As noted in section I, the Utilities have jointly submitted this single Procurement Plan, under which they shall procure resources for their combined needs. To the extent permitted by the applicable legal and regulatory authorities, the Utilities shall jointly pool such resources for their mutual benefit, and that of their eligible retail customers. They shall further allocate capacity and energy and cost responsibility therefore among themselves in proportion to their actual requirements.

For purposes of determining such requirements, the Utilities shall use either KWh or KW, as appropriate to determine the ratio of the individual Utility's requirement to the total requirement.

E. Renewable Energy Resources Plan

(1) Description of June 2008-May 2009 Standards.

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 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.

(2) Products to be Acquired to Satisfy the Standard.

The Utilities shall 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. 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 shall acquire 414,392 REC's to satisfy this standard.

The Utilities believe 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. 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, 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, the Utilities and the Procurement Administrator shall 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, 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 possibility of wind supplier from proposing inflated REC quantities, an independent 3rd 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 consultants estimate.

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.

Such acquisitions of renewable energy credits shall be memorialized with a Master Renewable Energy Certificate Purchase and Sale Agreement.

(3) Compliance Tracking

As noted above, 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 12 month period which forms the basis for the required volume is not available at the time of the initial solicitation, the Utilities will use forecasted load data to estimate the requirement. When such data does become available, the Utilities' shall make the appropriate adjustment to their portfolio of renewable energy credits, including a reallocation between one or more of the Utilities' if appropriate.

RECs delivered to the Utilities shall 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 shall be borne by the supplier of the RECs. The seller shall 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.

Each agreement for the acquisition of a REC shall 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.

(4) RFP Evaluation Criteria

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. Based on this requirement, the RFP evaluation will be completed as follow:

Determination of REC Requirement
As provided for in the IPA Act at least 2% of the actual amount of electricity (megawatt-hours) supplied by the electric utility to eligible retail customers as determined in the planning year ending immediately prior to the procurement period (June 2006 – May 2007) is used as the basis for calculating the REC requirement.

Determination of Cost Effectiveness (Budget Limit)
A portfolio of RECs shall be deemed to be cost effective if the portfolio's cost is equal to or less than 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007, multiplied by the kwh consumption of those same eligible retail customers.

REC Evaluation
Offers for RECs will be received simultaneously from Illinois, adjacent states, and all other areas.

Step 1 - 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 (defined below) will be applied, if the condition is not met go to Step 2.

Step 2 – 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.

Step 3 - 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..

Step 4 - 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..

75% Minimum Wind Test and Adjustment
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.

IV. Procurement Administrator

A. Role of the Administrator

Public Act 095-0481, 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 AIU's 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.

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, 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.

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, the PA shall be provided with a detailed portfolio of specific, standard market products, as detailed in III.C.1 above, to be acquired, prior to their commencement of activities to design and implement the competitive procurement process.

B. Independent Party to Design and Administer the Procurement Process

(1) Compliant with Legislation

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.

(2) Compliant 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 (55 FERC 61,382 (1991)) and the Allegheny Model (108 FERC 61,082 (2004)). FERC provides additional guidance in FERC Docket Nos. EC03-53-000 and EC03-53-001 applicable to the referenced procurement process as follows:

A fundamental objective of the solicitation guidelines is to ensure a competitive result, with no party – in particular an affiliate of the Utilities – having an undue advantage over the other parties, in the solicitation process. Adhering to the guidelines will ensure that wholesale customers receive the benefit of the marketplace, including an unbiased assessment of the full range of choices, whether the soliciting utility provides service at cost - or market-based rates.

The solicitation shall be developed in light of these guiding principles:

a. Transparency: the competitive solicitation process should be open and fair.

b. Definition: the product or products sought through the competitive solicitation should be precisely defined.

c. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders.

d. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the Utilities' selection.

(3) Develops Those Elements of the Process Not Proscribed by Legislation

C. Selection of the Administrator

(1) Issuance of RFP for Services

The Utilities issued a Request For Proposals (Attachment B to 12 potential bidders on August 17th, 2007. Responses from five entities were received on or before September10th and final selection was made September 21st.

Levitan and Associates was selected by the Utilities to serve as the Procurement Administrator for the initial procurement process. Following is a description of Levitan and Associates' qualifications, presented in a manner consistent with the outline of the standards established by Section 1-75 of the IPA Act. (A copy of Levitan and Associates' proposal in response to the Utilities RFP is contained in Attachment C. Confidential pricing data has been redacted.)

1. Description of required qualifications and Levitan and Associates' qualifications:
   a. Direct previous experience administering a large scale competitive procurement process;
      - Connecticut Department of Public Utility Control – Oversaw The Connecticut Light & Power Company's, and The United Illuminating Company's procurement of full requirements electric supply.
      - Long Island Power Authority (LIPA) – Assisted LIPA with competitive procurements to meet the utility's long-term energy and capacity requirements.
      - Other clients include; Allegheny Power, Taunton Municipal Lighting Plant, Florida Power and Light Energy, Consolidated Edison Energy, Calpine, and others.

   b. Advanced degree(s) in economics, mathematics, engineering, or a related area of study;
      - Degrees of the Levitan and Associates consulting team:
        - M.S. Engineering
        - Masters with specialization in Energy Economics
        - Ph.D., Geological Sciences
        - MBA in Finance
        - Ph.D., Economics
        - M.S. Engineering

   c. 10 years of experience in the electricity sector, including risk management experience;
      - Members of the Levitan and Associates team each have over 20 years of relevant experience.

d. Expertise in the wholesale electricity market rules, including those established by the FERC and the Midwest ISO;
- Levitan and Associates Represented various other utilities' at FERC
- Experience in NYISO, ISO-NE, PJM
- Global Energy Advisors will be subcontracted for MISO energy market analysis.

e. Expertise in credit and contract protocols;
- Levitan and Associates relevant project experience includes guarantees, letter of credits, bid bonds, and default and dispute guidance.

f. Adequate resources to perform and fulfill the required functions and responsibilities;
- Yes. Levitan and Associates has assigned 16 consultants with varying roles and time commitments to this project.

g. Absence of a conflict of interest and inappropriate bias for or against potential bidders or one or more of the Utilities.
- Levitan and Associates states that they do not have any conflict, interest or bias that will impair their ability to perform as the Procurement Administrator on this project.

2. Timeline of selection process
- RFP issued on August 17^{th}, 2007
- Responses received by September 10^{th}, 2007
- Selected winning bid September 21^{st}, 2007

(2) General Summary Description of Responses
Five consultants submitted bids to the RFP. The relevant experience and qualifications of each of the bidders was varied. Three of the bids were placed on the short list for further evaluation.

(3) Description of the Scoring/Selection Process
Submitted bids were reviewed for qualification and experience to ensure compliance with the applicable statute. Interviews with two of the bidders were conducted to provide clarification of the bids and to resolve any open questions. The Utilities determined it was not necessary to interview the third candidate due to extensive prior relationships with this entity.

Bidder responses were evaluated on the basis of the following matrix.. Prior to evaluation, the Utilities determined that no entity had a conflict of interest, which would have been a disqualifying event. Using a scale of 1 to 10 for each category in the matrix and applying the appropriate weighting factor, resulted in two bids scoring above 8, two in the low 6 range, and one below 5. Levitan and Associates scored the highest among all five bids.

Basis for Contract Award

Factor	**Weight**
Previous experience administering a large-scale competitive procurement process	30%
Educational qualifications of assigned staff	10%
Experience in the electricity sector, including risk management experience	10%
Expertise in wholesale electricity market rules, including FERC and MISO	10%
Expertise in credit and contract protocols	10%
Resources available to perform and fulfill the required functions and responsibilities	10%
Regulatory Risk	10%
Hourly Rates for proposed staff	10%

TABLE 1. Monthly Average, Maximum and Minimum MW

	Peak Demand	Min Demand	Average Energy
June-08	1,363	374	777
July-08	1,601	382	900
August-08	1,598	440	869
September-08	1,229	393	744
October-08	1,001	313	626
November-08	978	404	675
December-08	1,091	411	762
January-09	1,092	519	846
February-09	1,121	513	797
March-09	973	415	667
April-09	849	313	603
May-09	1,064	305	586
June-09	2,735	744	1,549
July-09	3,222	761	1,798
August-09	3,217	881	1,738
September-09	2,466	786	1,486
October-09	2,000	626	1,248
November-09	1,967	812	1,350
December-09	2,198	826	1,529
January-10	2,192	1,041	1,690
February-10	2,244	1,020	1,582
March-10	1,937	821	1,316
April-10	1,669	614	1,179
May-10	2,079	591	1,135
June-10	3,965	1,053	2,212
July-10	4,699	1,075	2,578
August-10	4,689	1,258	2,492
September-10	3,568	1,122	2,117
October-10	2,875	886	1,773
November-10	2,844	1,157	1,923
December-10	3,179	1,173	2,188
January-11	3,191	1,504	2,436
February-11	3,289	1,478	2,286
March-11	2,848	1,200	1,915
April-11	2,459	904	1,726
May-11	3,080	876	1,674
June-11	3,937	1,043	2,177
July-11	4,665	1,064	2,537
August-11	4,657	1,247	2,454
September-11	3,548	1,114	2,085
October-11	2,852	882	1,750
November-11	2,828	1,153	1,901
December-11	3,163	1,167	2,163

	Peak Demand	Min Demand	Average Energy
January-12	3,176	1,499	2,407
February-12	3,282	1,481	2,272
March-12	2,838	1,197	1,896
April-12	2,448	904	1,710
May-12	3,064	876	1,659
June-12	3,928	1,039	2,148
July-12	4,648	1,058	2,501
August-12	4,641	1,242	2,419
September-12	3,542	1,111	2,059
October-12	2,842	881	1,730
November-12	2,820	1,152	1,881
December-12	3,154	1,166	2,140
January-13	3,168	1,497	2,380
February-13	3,262	1,472	2,236
March-13	2,835	1,198	1,878
April-13	2,443	905	1,695
May-13	3,056	877	1,645

TABLE 2: Monthly Forecasted System Supply Requirements (Energy MWh)

	Residential DS1	<150kw DS2	150-399kw DS3A	400-999kw DS3B	Lighting DS5	Energy Efficiency	Total
Jun-08	361,726	127,000	37,396	23,929	10,422	(1,121)	559,352
Jul-08	458,591	136,343	39,955	25,383	10,368	(1,341)	669,299
Aug-08	445,334	130,078	38,096	24,134	10,392	(1,296)	646,737
Sep-08	344,956	122,921	35,942	22,684	10,575	(1,074)	536,004
Oct-08	284,580	116,068	33,997	21,283	10,666	(933)	465,660
Nov-08	309,077	113,120	33,172	20,599	10,861	(974)	485,855
Dec-08	382,537	118,284	34,682	21,407	11,136	(1,136)	566,911
Jan-09	437,369	123,566	36,320	22,173	11,209	(1,261)	629,376
Feb-09	359,782	112,246	33,231	20,265	10,928	(1,073)	535,379
Mar-09	330,024	105,750	31,478	19,127	10,696	(994)	496,081
Apr-09	276,955	99,695	29,932	18,121	10,594	(871)	434,426
May-09	274,491	102,527	30,877	18,650	10,432	(874)	436,102
Jun-09	746,813	238,947	71,810	43,373	21,190	(6,733)	1,115,400
Jul-09	944,898	256,038	77,190	46,451	21,080	(8,074)	1,337,583
Aug-09	917,352	244,037	74,079	44,475	21,128	(7,806)	1,293,264
Sep-09	711,893	230,342	70,308	42,073	21,499	(6,457)	1,069,659
Oct-09	589,093	217,314	66,582	39,733	21,684	(5,606)	928,799
Nov-09	640,020	211,723	65,114	38,788	22,079	(5,866)	971,857
Dec-09	791,506	221,282	68,190	40,634	22,639	(6,866)	1,137,386
Jan-10	902,919	231,267	71,531	36,574	22,786	(7,590)	1,257,486
Feb-10	742,410	210,715	65,648	28,293	22,217	(6,416)	1,062,867
Mar-10	681,027	199,051	62,356	20,495	21,746	(5,908)	978,768
Apr-10	571,354	188,230	59,475	13,452	21,538	(5,124)	848,925
May-10	565,663	193,917	61,469	7,602	21,209	(5,099)	844,761
Jun-10	1,137,713	336,096	106,239	-	32,006	(19,345)	1,592,710
Jul-10	1,434,576	360,701	114,197	-	31,840	(23,296)	1,918,018
Aug-10	1,390,481	344,733	109,741	-	31,912	(22,522)	1,854,345
Sep-10	1,079,603	326,239	104,313	-	32,471	(18,512)	1,524,115
Oct-10	894,892	308,329	98,899	-	32,748	(16,018)	1,318,850
Nov-10	971,181	300,491	96,659	-	33,343	(16,820)	1,384,854
Dec-10	1,198,367	313,758	101,092	-	34,185	(19,769)	1,627,633
Jan-11	1,365,240	328,612	105,990	-	34,406	(22,011)	1,812,238
Feb-11	1,123,367	300,572	97,380	-	33,548	(18,658)	1,536,209
Mar-11	1,031,801	284,945	92,569	-	32,837	(17,306)	1,424,846
Apr-11	866,539	270,506	88,382	-	32,523	(15,095)	1,242,854
May-11	858,102	279,427	91,340	-	32,027	(15,131)	1,245,766
Jun-11	1,141,026	321,715	104,598	-	32,070	(31,988)	1,567,421
Jul-11	1,435,687	345,895	112,335	-	31,903	(38,516)	1,887,304
Aug-11	1,391,119	331,633	107,985	-	31,975	(37,254)	1,825,458
Sep-11	1,082,066	314,899	102,688	-	32,534	(30,644)	1,501,543
Oct-11	899,565	298,509	97,370	-	32,811	(26,565)	1,301,690
Nov-11	976,325	291,578	95,112	-	33,406	(27,928)	1,368,493
Dec-11	1,203,503	304,935	99,354	-	34,248	(32,841)	1,609,200

	Residential DS1	<150kw DS2	150-399kw DS3A	400-999kw DS3B	Lighting DS5	Energy Efficiency	Total
Jan-12	1,368,908	319,652	104,108	-	34,469	(36,543)	1,790,593
Feb-12	1,137,040	291,811	95,371	-	33,610	(31,157)	1,526,676
Mar-12	1,036,758	278,560	91,090	-	32,900	(28,786)	1,410,521
Apr-12	871,653	265,148	87,058	-	32,586	(25,129)	1,231,316
May-12	863,357	274,309	89,972	-	32,090	(25,195)	1,234,533
Jun-12	1,143,809	315,809	102,891	-	32,133	(47,839)	1,546,802
Jul-12	1,436,125	339,750	110,412	-	31,965	(57,548)	1,860,706
Aug-12	1,391,146	326,343	106,163	-	32,037	(55,671)	1,800,018
Sep-12	1,084,082	310,495	100,986	-	32,595	(45,845)	1,482,313
Oct-12	903,847	294,809	95,755	-	32,871	(39,818)	1,287,464
Nov-12	980,931	288,217	93,478	-	33,466	(41,883)	1,354,208
Dec-12	1,207,849	301,498	97,530	-	34,307	(49,236)	1,591,949
Jan-13	1,372,780	315,833	102,126	-	34,527	(54,758)	1,770,508
Feb-13	1,131,425	289,946	94,014	-	33,668	(46,472)	1,502,581
Mar-13	1,042,071	275,738	89,499	-	32,957	(43,208)	1,397,057
Apr-13	877,247	262,747	85,616	-	32,642	(37,748)	1,220,504
May-13	869,112	271,820	88,478	-	32,145	(37,847)	1,223,709

TABLE 3: Monthly Forecasted System Supply Requirements (Capacity MW)

Date	Procurement Plan	Response	Net Demand Response	15% Reserves	Capacity Requirement
Jun-08	1,363	0.0	1,363	205	1,568
Jul-08	1,601	1.6	1,599	240	1,839
Aug-08	1,598	1.6	1,596	239	1,835
Sep-08	1,229	0.0	1,229	184	1,413
Oct-08	1,001	0.0	1,001	150	1,151
Nov-08	978	0.0	978	147	1,124
Dec-08	1,091	0.0	1,091	164	1,255
Jan-09	1,092	0.0	1,092	164	1,256
Feb-09	1,121	0.0	1,121	168	1,289
Mar-09	973	0.0	973	146	1,119
Apr-09	849	0.0	849	127	976
May-09	1,064	0.0	1,064	160	1,223
Jun-09	2,735	0.0	2,735	410	3,146
Jul-09	3,222	6.7	3,215	482	3,698
Aug-09	3,217	6.7	3,210	482	3,692
Sep-09	2,466	0.0	2,466	370	2,836
Oct-09	2,000	0.0	2,000	300	2,300
Nov-09	1,967	0.0	1,967	295	2,262
Dec-09	2,198	0.0	2,198	330	2,527
Jan-10	2,192	0.0	2,192	329	2,521
Feb-10	2,244	0.0	2,244	337	2,581
Mar-10	1,937	0.0	1,937	290	2,227
Apr-10	1,669	0.0	1,669	250	1,920
May-10	2,079	0.0	2,079	312	2,391
Jun-10	3,965	0.0	3,965	595	4,560
Jul-10	4,699	15.0	4,684	703	5,386
Aug-10	4,689	15.0	4,674	701	5,375
Sep-10	3,568	0.0	3,568	535	4,103
Oct-10	2,875	0.0	2,875	431	3,306
Nov-10	2,844	0.0	2,844	427	3,271
Dec-10	3,179	0.0	3,179	477	3,656
Jan-11	3,191	0.0	3,191	479	3,670
Feb-11	3,289	0.0	3,289	493	3,782
Mar-11	2,848	0.0	2,848	427	3,275
Apr-11	2,459	0.0	2,459	369	2,827
May-11	3,080	0.0	3,080	462	3,542
Jun-11	3,937	0.0	3,937	591	4,528
Jul-11	4,665	20.0	4,645	697	5,342
Aug-11	4,657	20.0	4,637	696	5,333
Sep-11	3,548	0.0	3,548	532	4,080
Oct-11	2,852	0.0	2,852	428	3,280
Nov-11	2,828	0.0	2,828	424	3,252
Dec-11	3,163	0.0	3,163	474	3,637

Date	Procurement Plan	Response	Net Demand Response	15% Reserves	Capacity Requirement
Jan-12	3,176	0.0	3,176	476	3,652
Feb-12	3,282	0.0	3,282	492	3,774
Mar-12	2,838	0.0	2,838	426	3,264
Apr-12	2,448	0.0	2,448	367	2,815
May-12	3,064	0.0	3,064	460	3,524
Jun-12	3,928	0.0	3,928	589	4,517
Jul-12	4,648	25.0	4,623	693	5,316
Aug-12	4,641	25.0	4,616	692	5,309
Sep-12	3,542	0.0	3,542	531	4,074
Oct-12	2,842	0.0	2,842	426	3,268
Nov-12	2,820	0.0	2,820	423	3,243
Dec-12	3,154	0.0	3,154	473	3,627
Jan-13	3,168	0.0	3,168	475	3,644
Feb-13	3,262	0.0	3,262	489	3,752
Mar-13	2,835	0.0	2,835	425	3,260
Apr-13	2,443	0.0	2,443	366	2,809
May-13	3,056	0.0	3,056	458	3,515

JUNE 2008							
On Peak				**Off Peak**			
Quantity (MW)	**Hedge Ratio**	**Expected Cost**	**Standard Deviation**	**Quantity (MW)**	**Hedge Ratio**	**Expected Cost**	**Standard Deviation**
0	0.00	$ 19,957,349	$ 4,654,933	0	0.00	$ 7,892,947	$ 928,774
100	0.12	$ 19,957,356	$ 4,127,299	100	0.14	$ 7,892,943	$ 802,931
200	0.23	$ 19,957,362	$ 3,600,445	200	0.28	$ 7,892,941	$ 679,348
300	0.35	$ 19,957,369	$ 3,074,769	300	0.43	$ 7,892,942	$ 559,524
400	0.46	$ 19,957,373	$ 2,551,000	325	0.46	$ 7,892,940	$ 530,455
500	0.58	$ 19,957,379	$ 2,030,619	350	0.50	$ 7,892,939	$ 501,866
525	0.61	$ 19,957,381	$ 1,901,379	375	0.53	$ 7,892,940	$ 473,843
550	0.64	$ 19,957,383	$ 1,772,630	400	0.57	$ 7,892,938	$ 446,492
575	0.67	$ 19,957,383	$ 1,644,490	425	0.61	$ 7,892,939	$ 419,947
600	0.70	$ 19,957,385	$ 1,517,110	450	0.64	$ 7,892,938	$ 394,369
625	0.72	$ 19,957,388	$ 1,390,703	475	0.68	$ 7,892,939	$ 369,958
650	0.75	$ 19,957,389	$ 1,265,556	500	0.71	$ 7,892,936	$ 346,962
675	0.78	$ 19,957,389	$ 1,142,085	525	0.75	$ 7,892,935	$ 325,677
700	0.81	$ 19,957,391	$ 1,020,901	550	0.78	$ 7,892,936	$ 306,466
725	0.84	$ 19,957,393	$ 902,922	575	0.82	$ 7,892,933	$ 289,737
750	0.87	$ 19,957,395	$ 789,587	600	0.85	$ 7,892,935	$ 275,945
775	0.90	$ 19,957,397	$ 683,211	625	0.89	$ 7,892,935	$ 265,545
800	0.93	$ 19,957,396	$ 587,586	650	0.93	$ 7,892,933	$ 258,947
825	0.96	$ 19,957,397	$ 508,809	675	0.96	$ 7,892,931	$ 256,444
850	0.99	$ 19,957,400	$ 455,705	700	1.00	$ 7,892,929	$ 258,157
875	1.01	$ 19,957,400	$ 437,719	725	1.03	$ 7,892,933	$ 264,006
900	1.04	$ 19,957,403	$ 458,997	750	1.07	$ 7,892,931	$ 273,720
925	1.07	$ 19,957,404	$ 514,694	775	1.10	$ 7,892,931	$ 286,910
950	1.10	$ 19,957,408	$ 595,222	800	1.14	$ 7,892,930	$ 303,123
975	1.13	$ 19,957,408	$ 691,970	825	1.18	$ 7,892,933	$ 321,901
1000	1.16	$ 19,957,409	$ 799,064	850	1.21	$ 7,892,932	$ 342,825
1025	1.19	$ 19,957,412	$ 912,872	875	1.25	$ 7,892,929	$ 365,524
1050	1.22	$ 19,957,410	$ 1,031,172	900	1.28	$ 7,892,930	$ 389,692
1075	1.25	$ 19,957,413	$ 1,152,583	925	1.32	$ 7,892,928	$ 415,066
1100	1.28	$ 19,957,415	$ 1,276,217	950	1.35	$ 7,892,929	$ 441,445
1125	1.30	$ 19,957,413	$ 1,401,487	975	1.39	$ 7,892,927	$ 468,655
1150	1.33	$ 19,957,417	$ 1,527,988	1000	1.42	$ 7,892,926	$ 496,559
1175	1.36	$ 19,957,419	$ 1,655,439	1100	1.57	$ 7,892,924	$ 613,204
1200	1.39	$ 19,957,419	$ 1,783,637	1200	1.71	$ 7,892,925	$ 734,988
1225	1.42	$ 19,957,422	$ 1,912,432	1300	1.85	$ 7,892,924	$ 859,727
1250	1.45	$ 19,957,424	$ 2,041,710	1400	1.99	$ 7,892,918	$ 986,300
1275	1.48	$ 19,957,425	$ 2,171,385	1500	2.14	$ 7,892,916	$ 1,114,087
1300	1.51	$ 19,957,427	$ 2,301,390	1600	2.28	$ 7,892,915	$ 1,242,708
1400	1.62	$ 19,957,433	$ 2,823,798	1700	2.42	$ 7,892,913	$ 1,371,931
1500	1.74	$ 19,957,439	$ 3,348,684	1800	2.56	$ 7,892,913	$ 1,501,600
1600	1.86	$ 19,957,444	$ 3,875,039	1900	2.71	$ 7,892,910	$ 1,631,608
1700	1.97	$ 19,957,449	$ 4,402,337	2000	2.85	$ 7,892,904	$ 1,761,882
1800	2.09	$ 19,957,455	$ 4,930,276	2100	2.99	$ 7,892,906	$ 1,892,367
1900	2.20	$ 19,957,463	$ 5,458,670	2200	3.13	$ 7,892,907	$ 2,023,021
2000	2.32	$ 19,957,470	$ 5,987,397				
2100	2.43	$ 19,957,472	$ 6,516,379				
2200	2.55	$ 19,957,479	$ 7,045,556				

JULY 2008							
On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 30,296,290	$ 7,107,261	0	0.00	$ 12,737,669	$ 1,369,622
100	0.10	$ 30,296,296	$ 6,425,193	100	0.13	$ 12,737,672	$ 1,207,400
200	0.20	$ 30,296,301	$ 5,743,965	200	0.25	$ 12,737,675	$ 1,047,467
300	0.30	$ 30,296,309	$ 5,063,912	300	0.38	$ 12,737,679	$ 891,051
400	0.39	$ 30,296,315	$ 4,385,582	325	0.41	$ 12,737,681	$ 852,726
500	0.49	$ 30,296,323	$ 3,709,919	350	0.44	$ 12,737,680	$ 814,801
525	0.52	$ 30,296,323	$ 3,541,599	375	0.47	$ 12,737,682	$ 777,333
550	0.54	$ 30,296,328	$ 3,373,590	400	0.50	$ 12,737,684	$ 740,394
575	0.57	$ 30,296,327	$ 3,205,938	425	0.53	$ 12,737,683	$ 704,066
600	0.59	$ 30,296,328	$ 3,038,705	450	0.57	$ 12,737,685	$ 668,447
625	0.62	$ 30,296,332	$ 2,871,961	475	0.60	$ 12,737,688	$ 633,658
650	0.64	$ 30,296,333	$ 2,705,801	500	0.63	$ 12,737,686	$ 599,844
675	0.67	$ 30,296,336	$ 2,540,335	525	0.66	$ 12,737,688	$ 567,183
700	0.69	$ 30,296,335	$ 2,375,711	550	0.69	$ 12,737,693	$ 535,874
725	0.71	$ 30,296,337	$ 2,212,116	575	0.72	$ 12,737,693	$ 506,185
750	0.74	$ 30,296,340	$ 2,049,795	600	0.75	$ 12,737,694	$ 478,400
775	0.76	$ 30,296,342	$ 1,889,080	625	0.79	$ 12,737,691	$ 452,883
800	0.79	$ 30,296,341	$ 1,730,415	650	0.82	$ 12,737,694	$ 430,031
825	0.81	$ 30,296,345	$ 1,574,422	675	0.85	$ 12,737,696	$ 410,290
850	0.84	$ 30,296,346	$ 1,421,978	700	0.88	$ 12,737,699	$ 394,136
875	0.86	$ 30,296,350	$ 1,274,360	725	0.91	$ 12,737,696	$ 382,009
900	0.89	$ 30,296,349	$ 1,133,456	750	0.94	$ 12,737,701	$ 374,314
925	0.91	$ 30,296,350	$ 1,002,097	775	0.97	$ 12,737,700	$ 371,320
950	0.94	$ 30,296,354	$ 884,551	800	1.01	$ 12,737,698	$ 373,142
975	0.96	$ 30,296,356	$ 787,031	825	1.04	$ 12,737,700	$ 379,710
1000	0.99	$ 30,296,356	$ 717,745	850	1.07	$ 12,737,702	$ 390,787
1025	1.01	$ 30,296,360	$ 685,311	875	1.10	$ 12,737,704	$ 406,002
1050	1.03	$ 30,296,357	$ 694,908	900	1.13	$ 12,737,704	$ 424,910
1075	1.06	$ 30,296,361	$ 744,913	925	1.16	$ 12,737,706	$ 447,044
1100	1.08	$ 30,296,362	$ 828,039	950	1.19	$ 12,737,707	$ 471,950
1125	1.11	$ 30,296,364	$ 935,497	975	1.23	$ 12,737,708	$ 499,215
1150	1.13	$ 30,296,367	$ 1,059,911	1000	1.26	$ 12,737,708	$ 528,472
1175	1.16	$ 30,296,368	$ 1,196,004	1100	1.38	$ 12,737,716	$ 659,877
1200	1.18	$ 30,296,367	$ 1,340,220	1200	1.51	$ 12,737,720	$ 805,615
1225	1.21	$ 30,296,371	$ 1,490,205	1300	1.63	$ 12,737,724	$ 959,172
1250	1.23	$ 30,296,373	$ 1,644,379	1400	1.76	$ 12,737,726	$ 1,117,330
1275	1.26	$ 30,296,376	$ 1,801,667	1500	1.89	$ 12,737,732	$ 1,278,388
1300	1.28	$ 30,296,377	$ 1,961,323	1600	2.01	$ 12,737,732	$ 1,441,364
1400	1.38	$ 30,296,380	$ 2,614,848	1700	2.14	$ 12,737,739	$ 1,605,679
1500	1.48	$ 30,296,389	$ 3,281,483	1800	2.26	$ 12,737,743	$ 1,770,964
1600	1.58	$ 30,296,394	$ 3,954,604	1900	2.39	$ 12,737,746	$ 1,936,964
1700	1.68	$ 30,296,401	$ 4,631,380	2000	2.51	$ 12,737,749	$ 2,103,514
1800	1.77	$ 30,296,408	$ 5,310,419	2100	2.64	$ 12,737,754	$ 2,270,494
1900	1.87	$ 30,296,416	$ 5,990,948	2200	2.77	$ 12,737,761	$ 2,437,809
2000	1.97	$ 30,296,423	$ 6,672,513				
2100	2.07	$ 30,296,425	$ 7,354,824				
2200	2.17	$ 30,296,432	$ 8,037,695				

AUGUST 2008							
On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 27,450,862	$ 6,580,305	0	0.00	$ 13,139,290	$ 1,381,385
100	0.10	$ 27,450,857	$ 5,928,860	100	0.13	$ 13,139,293	$ 1,220,672
200	0.21	$ 27,450,855	$ 5,278,515	200	0.25	$ 13,139,303	$ 1,063,037
300	0.31	$ 27,450,854	$ 4,629,734	300	0.38	$ 13,139,306	$ 910,080
400	0.41	$ 27,450,849	$ 3,983,280	325	0.41	$ 13,139,309	$ 872,860
500	0.52	$ 27,450,851	$ 3,340,508	350	0.44	$ 13,139,313	$ 836,162
525	0.54	$ 27,450,849	$ 3,180,650	375	0.48	$ 13,139,312	$ 800,051
550	0.57	$ 27,450,846	$ 3,021,234	400	0.51	$ 13,139,314	$ 764,614
575	0.59	$ 27,450,847	$ 2,862,333	425	0.54	$ 13,139,314	$ 729,948
600	0.62	$ 27,450,847	$ 2,704,039	450	0.57	$ 13,139,318	$ 696,167
625	0.64	$ 27,450,849	$ 2,546,462	475	0.60	$ 13,139,315	$ 663,409
650	0.67	$ 27,450,845	$ 2,389,745	500	0.64	$ 13,139,318	$ 631,833
675	0.70	$ 27,450,845	$ 2,234,070	525	0.67	$ 13,139,322	$ 601,624
700	0.72	$ 27,450,845	$ 2,079,672	550	0.70	$ 13,139,325	$ 572,998
725	0.75	$ 27,450,844	$ 1,926,855	575	0.73	$ 13,139,325	$ 546,201
750	0.77	$ 27,450,843	$ 1,776,028	600	0.76	$ 13,139,330	$ 521,518
775	0.80	$ 27,450,843	$ 1,627,746	625	0.79	$ 13,139,329	$ 499,267
800	0.83	$ 27,450,843	$ 1,482,773	650	0.83	$ 13,139,333	$ 479,780
825	0.85	$ 27,450,840	$ 1,342,178	675	0.86	$ 13,139,334	$ 463,410
850	0.88	$ 27,450,844	$ 1,207,496	700	0.89	$ 13,139,335	$ 450,493
875	0.90	$ 27,450,841	$ 1,080,935	725	0.92	$ 13,139,336	$ 441,332
900	0.93	$ 27,450,842	$ 965,696	750	0.95	$ 13,139,340	$ 436,171
925	0.95	$ 27,450,839	$ 866,309	775	0.99	$ 13,139,339	$ 435,145
950	0.98	$ 27,450,839	$ 788,788	800	1.02	$ 13,139,339	$ 438,286
975	1.01	$ 27,450,840	$ 740,038	825	1.05	$ 13,139,344	$ 445,507
1000	1.03	$ 27,450,837	$ 725,876	850	1.08	$ 13,139,341	$ 456,613
1025	1.06	$ 27,450,836	$ 748,274	875	1.11	$ 13,139,345	$ 471,324
1050	1.08	$ 27,450,837	$ 804,177	900	1.14	$ 13,139,345	$ 489,323
1075	1.11	$ 27,450,837	$ 887,279	925	1.18	$ 13,139,349	$ 510,259
1100	1.14	$ 27,450,836	$ 990,756	950	1.21	$ 13,139,348	$ 533,788
1125	1.16	$ 27,450,835	$ 1,108,921	975	1.24	$ 13,139,350	$ 559,580
1150	1.19	$ 27,450,835	$ 1,237,574	1000	1.27	$ 13,139,353	$ 587,339
1175	1.21	$ 27,450,831	$ 1,373,770	1100	1.40	$ 13,139,358	$ 713,229
1200	1.24	$ 27,450,831	$ 1,515,478	1200	1.53	$ 13,139,364	$ 854,756
1225	1.26	$ 27,450,833	$ 1,661,287	1300	1.65	$ 13,139,373	$ 1,005,341
1250	1.29	$ 27,450,835	$ 1,810,208	1400	1.78	$ 13,139,378	$ 1,161,467
1275	1.32	$ 27,450,832	$ 1,961,529	1500	1.91	$ 13,139,387	$ 1,321,172
1300	1.34	$ 27,450,832	$ 2,114,739	1600	2.03	$ 13,139,386	$ 1,483,298
1400	1.44	$ 27,450,829	$ 2,740,063	1700	2.16	$ 13,139,396	$ 1,647,131
1500	1.55	$ 27,450,826	$ 3,377,002	1800	2.29	$ 13,139,399	$ 1,812,207
1600	1.65	$ 27,450,826	$ 4,020,038	1900	2.42	$ 13,139,409	$ 1,978,219
1700	1.75	$ 27,450,826	$ 4,666,653	2000	2.54	$ 13,139,415	$ 2,144,947
1800	1.86	$ 27,450,824	$ 5,315,540	2100	2.67	$ 13,139,420	$ 2,312,230
1900	1.96	$ 27,450,817	$ 5,965,958	2200	2.80	$ 13,139,425	$ 2,479,967
2000	2.06	$ 27,450,811	$ 6,617,455				
2100	2.17	$ 27,450,816	$ 7,269,743				
2200	2.27	$ 27,450,810	$ 7,922,623				

SEPTEMBER 2008							
On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 17,141,445	$ 4,046,376	0	0.00	$ 7,405,609	$ 934,467
100	0.12	$ 17,141,442	$ 3,558,557	100	0.15	$ 7,405,616	$ 804,033
200	0.24	$ 17,141,440	$ 3,071,944	200	0.29	$ 7,405,623	$ 675,714
300	0.37	$ 17,141,440	$ 2,587,217	300	0.44	$ 7,405,633	$ 550,995
400	0.49	$ 17,141,439	$ 2,105,677	325	0.48	$ 7,405,635	$ 520,681
500	0.61	$ 17,141,437	$ 1,630,154	350	0.52	$ 7,405,636	$ 490,845
525	0.64	$ 17,141,437	$ 1,512,879	375	0.55	$ 7,405,639	$ 461,576
550	0.67	$ 17,141,436	$ 1,396,574	400	0.59	$ 7,405,641	$ 432,993
575	0.70	$ 17,141,438	$ 1,281,498	425	0.63	$ 7,405,642	$ 405,238
600	0.73	$ 17,141,435	$ 1,168,018	450	0.66	$ 7,405,644	$ 378,494
625	0.76	$ 17,141,435	$ 1,056,648	475	0.70	$ 7,405,647	$ 352,991
650	0.79	$ 17,141,435	$ 948,131	500	0.74	$ 7,405,647	$ 329,018
675	0.82	$ 17,141,438	$ 843,568	525	0.77	$ 7,405,650	$ 306,934
700	0.86	$ 17,141,434	$ 744,628	550	0.81	$ 7,405,652	$ 287,175
725	0.89	$ 17,141,433	$ 653,869	575	0.85	$ 7,405,651	$ 270,251
750	0.92	$ 17,141,434	$ 575,175	600	0.88	$ 7,405,659	$ 256,723
775	0.95	$ 17,141,434	$ 514,117	625	0.92	$ 7,405,660	$ 247,149
800	0.98	$ 17,141,434	$ 477,509	650	0.96	$ 7,405,660	$ 241,999
825	1.01	$ 17,141,432	$ 471,087	675	0.99	$ 7,405,665	$ 241,559
850	1.04	$ 17,141,433	$ 496,024	700	1.03	$ 7,405,667	$ 245,850
875	1.07	$ 17,141,432	$ 548,056	725	1.07	$ 7,405,668	$ 254,634
900	1.10	$ 17,141,430	$ 620,402	750	1.10	$ 7,405,668	$ 267,472
925	1.13	$ 17,141,431	$ 706,854	775	1.14	$ 7,405,671	$ 283,811
950	1.16	$ 17,141,430	$ 802,866	800	1.18	$ 7,405,670	$ 303,085
975	1.19	$ 17,141,432	$ 905,403	825	1.21	$ 7,405,674	$ 324,774
1000	1.22	$ 17,141,429	$ 1,012,483	850	1.25	$ 7,405,676	$ 348,427
1025	1.25	$ 17,141,430	$ 1,122,809	875	1.29	$ 7,405,682	$ 373,671
1050	1.28	$ 17,141,430	$ 1,235,511	900	1.32	$ 7,405,682	$ 400,203
1075	1.31	$ 17,141,429	$ 1,349,993	925	1.36	$ 7,405,684	$ 427,785
1100	1.34	$ 17,141,426	$ 1,465,839	950	1.40	$ 7,405,686	$ 456,228
1125	1.37	$ 17,141,427	$ 1,582,749	975	1.44	$ 7,405,687	$ 485,381
1150	1.41	$ 17,141,429	$ 1,700,505	1000	1.47	$ 7,405,689	$ 515,118
1175	1.44	$ 17,141,427	$ 1,818,941	1100	1.62	$ 7,405,694	$ 638,289
1200	1.47	$ 17,141,427	$ 1,937,933	1200	1.77	$ 7,405,706	$ 765,744
1225	1.50	$ 17,141,428	$ 2,057,385	1300	1.91	$ 7,405,715	$ 895,653
1250	1.53	$ 17,141,425	$ 2,177,220	1400	2.06	$ 7,405,721	$ 1,027,089
1275	1.56	$ 17,141,424	$ 2,297,380	1500	2.21	$ 7,405,730	$ 1,159,531
1300	1.59	$ 17,141,425	$ 2,417,815	1600	2.36	$ 7,405,736	$ 1,292,669
1400	1.71	$ 17,141,422	$ 2,901,621	1700	2.50	$ 7,405,744	$ 1,426,309
1500	1.83	$ 17,141,420	$ 3,387,673	1800	2.65	$ 7,405,755	$ 1,560,322
1600	1.96	$ 17,141,421	$ 3,875,123	1900	2.80	$ 7,405,762	$ 1,694,619
1700	2.08	$ 17,141,420	$ 4,363,505	2000	2.94	$ 7,405,767	$ 1,829,136
1800	2.20	$ 17,141,417	$ 4,852,537	2100	3.09	$ 7,405,778	$ 1,963,833
1900	2.32	$ 17,141,416	$ 5,342,041	2200	3.24	$ 7,405,784	$ 2,098,670
2000	2.44	$ 17,141,416	$ 5,831,896				
2100	2.57	$ 17,141,414	$ 6,322,022				
2200	2.69	$ 17,141,408	$ 6,812,361				

OCTOBER 2008							
On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 14,350,018	$ 3,316,948	0	0.00	$ 6,564,091	$ 937,391
100	0.15	$ 14,350,019	$ 2,823,674	100	0.17	$ 6,564,090	$ 770,899
200	0.30	$ 14,350,019	$ 2,330,813	200	0.35	$ 6,564,088	$ 605,008
300	0.44	$ 14,350,022	$ 1,838,696	300	0.52	$ 6,564,083	$ 440,397
400	0.59	$ 14,350,023	$ 1,348,139	325	0.56	$ 6,564,084	$ 399,629
500	0.74	$ 14,350,023	$ 861,810	350	0.61	$ 6,564,081	$ 359,122
525	0.78	$ 14,350,024	$ 741,865	375	0.65	$ 6,564,082	$ 318,972
550	0.81	$ 14,350,024	$ 623,334	400	0.69	$ 6,564,082	$ 279,337
575	0.85	$ 14,350,024	$ 507,210	425	0.74	$ 6,564,080	$ 240,468
600	0.89	$ 14,350,028	$ 395,620	450	0.78	$ 6,564,080	$ 202,809
625	0.92	$ 14,350,025	$ 293,772	475	0.83	$ 6,564,080	$ 167,176
650	0.96	$ 14,350,024	$ 215,926	500	0.87	$ 6,564,080	$ 135,185
675	1.00	$ 14,350,027	$ 193,601	525	0.91	$ 6,564,074	$ 110,054
700	1.03	$ 14,350,027	$ 242,638	550	0.96	$ 6,564,079	$ 97,261
725	1.07	$ 14,350,027	$ 332,868	575	1.00	$ 6,564,078	$ 101,577
750	1.11	$ 14,350,026	$ 439,617	600	1.04	$ 6,564,077	$ 121,187
775	1.15	$ 14,350,027	$ 553,408	625	1.09	$ 6,564,077	$ 150,217
800	1.18	$ 14,350,028	$ 670,666	650	1.13	$ 6,564,077	$ 184,266
825	1.22	$ 14,350,026	$ 789,848	675	1.17	$ 6,564,074	$ 221,028
850	1.26	$ 14,350,028	$ 910,200	700	1.22	$ 6,564,073	$ 259,352
875	1.29	$ 14,350,028	$ 1,031,310	725	1.26	$ 6,564,075	$ 298,637
900	1.33	$ 14,350,030	$ 1,152,941	750	1.30	$ 6,564,074	$ 338,548
925	1.37	$ 14,350,031	$ 1,274,944	775	1.35	$ 6,564,071	$ 378,887
950	1.40	$ 14,350,030	$ 1,397,220	800	1.39	$ 6,564,071	$ 419,531
975	1.44	$ 14,350,031	$ 1,519,705	825	1.43	$ 6,564,072	$ 460,401
1000	1.48	$ 14,350,031	$ 1,642,351	850	1.48	$ 6,564,071	$ 501,437
1025	1.51	$ 14,350,030	$ 1,765,124	875	1.52	$ 6,564,067	$ 542,607
1050	1.55	$ 14,350,031	$ 1,888,000	900	1.56	$ 6,564,070	$ 583,878
1075	1.59	$ 14,350,031	$ 2,010,961	925	1.61	$ 6,564,068	$ 625,235
1100	1.63	$ 14,350,032	$ 2,133,991	950	1.65	$ 6,564,067	$ 666,657
1125	1.66	$ 14,350,031	$ 2,257,079	975	1.69	$ 6,564,069	$ 708,134
1150	1.70	$ 14,350,030	$ 2,380,216	1000	1.74	$ 6,564,068	$ 749,660
1175	1.74	$ 14,350,032	$ 2,503,395	1100	1.91	$ 6,564,064	$ 916,094
1200	1.77	$ 14,350,035	$ 2,626,610	1200	2.08	$ 6,564,062	$ 1,082,883
1225	1.81	$ 14,350,033	$ 2,749,856	1300	2.26	$ 6,564,061	$ 1,249,883
1250	1.85	$ 14,350,034	$ 2,873,129	1400	2.43	$ 6,564,056	$ 1,417,019
1275	1.88	$ 14,350,035	$ 2,996,426	1500	2.61	$ 6,564,055	$ 1,584,249
1300	1.92	$ 14,350,032	$ 3,119,744	1600	2.78	$ 6,564,053	$ 1,751,548
1400	2.07	$ 14,350,034	$ 3,613,183	1700	2.95	$ 6,564,049	$ 1,918,893
1500	2.22	$ 14,350,037	$ 4,106,816	1800	3.13	$ 6,564,048	$ 2,086,277
1600	2.36	$ 14,350,038	$ 4,600,581	1900	3.30	$ 6,564,045	$ 2,253,690
1700	2.51	$ 14,350,040	$ 5,094,440	2000	3.47	$ 6,564,042	$ 2,421,125
1800	2.66	$ 14,350,040	$ 5,588,368	2100	3.65	$ 6,564,037	$ 2,588,578
1900	2.81	$ 14,350,041	$ 6,082,347	2200	3.82	$ 6,564,037	$ 2,756,049
2000	2.96	$ 14,350,043	$ 6,576,367				
2100	3.10	$ 14,350,046	$ 7,070,418				
2200	3.25	$ 14,350,047	$ 7,564,494				

NOVEMBER 2008							
On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 13,131,289	$ 3,101,620	0	0.00	$ 7,956,626	$ 1,107,814
100	0.14	$ 13,131,294	$ 2,686,814	100	0.16	$ 7,956,624	$ 928,673
200	0.27	$ 13,131,299	$ 2,272,286	200	0.32	$ 7,956,621	$ 750,023
300	0.41	$ 13,131,306	$ 1,858,225	300	0.48	$ 7,956,618	$ 572,327
400	0.54	$ 13,131,311	$ 1,445,031	325	0.52	$ 7,956,618	$ 528,164
500	0.68	$ 13,131,318	$ 1,033,746	350	0.56	$ 7,956,616	$ 484,164
525	0.71	$ 13,131,319	$ 931,519	375	0.60	$ 7,956,617	$ 440,374
550	0.75	$ 13,131,320	$ 829,706	400	0.64	$ 7,956,618	$ 396,864
575	0.78	$ 13,131,321	$ 728,481	425	0.68	$ 7,956,614	$ 353,737
600	0.82	$ 13,131,323	$ 628,128	450	0.71	$ 7,956,616	$ 311,154
625	0.85	$ 13,131,323	$ 529,142	475	0.75	$ 7,956,614	$ 269,373
650	0.88	$ 13,131,325	$ 432,465	500	0.79	$ 7,956,612	$ 228,832
675	0.92	$ 13,131,326	$ 340,070	525	0.83	$ 7,956,611	$ 190,325
700	0.95	$ 13,131,329	$ 256,626	550	0.87	$ 7,956,614	$ 155,372
725	0.99	$ 13,131,327	$ 194,046	575	0.91	$ 7,956,613	$ 126,945
750	1.02	$ 13,131,332	$ 176,176	600	0.95	$ 7,956,610	$ 110,215
775	1.05	$ 13,131,331	$ 214,499	625	0.99	$ 7,956,608	$ 110,621
800	1.09	$ 13,131,334	$ 287,348	650	1.03	$ 7,956,609	$ 128,000
825	1.12	$ 13,131,335	$ 375,120	675	1.07	$ 7,956,604	$ 156,809
850	1.15	$ 13,131,336	$ 469,520	700	1.11	$ 7,956,606	$ 191,966
875	1.19	$ 13,131,337	$ 567,248	725	1.15	$ 7,956,609	$ 230,588
900	1.22	$ 13,131,339	$ 666,843	750	1.19	$ 7,956,604	$ 271,197
925	1.26	$ 13,131,339	$ 767,578	775	1.23	$ 7,956,606	$ 313,023
950	1.29	$ 13,131,340	$ 869,056	800	1.27	$ 7,956,603	$ 355,634
975	1.32	$ 13,131,341	$ 971,045	825	1.31	$ 7,956,603	$ 398,780
1000	1.36	$ 13,131,344	$ 1,073,401	850	1.35	$ 7,956,602	$ 442,303
1025	1.39	$ 13,131,346	$ 1,176,025	875	1.39	$ 7,956,602	$ 486,104
1050	1.43	$ 13,131,347	$ 1,278,854	900	1.43	$ 7,956,602	$ 530,114
1075	1.46	$ 13,131,348	$ 1,381,842	925	1.47	$ 7,956,601	$ 574,283
1100	1.49	$ 13,131,349	$ 1,484,957	950	1.51	$ 7,956,599	$ 618,576
1125	1.53	$ 13,131,352	$ 1,588,173	975	1.55	$ 7,956,599	$ 662,973
1150	1.56	$ 13,131,352	$ 1,691,471	1000	1.59	$ 7,956,598	$ 707,451
1175	1.60	$ 13,131,352	$ 1,794,839	1100	1.75	$ 7,956,597	$ 885,929
1200	1.63	$ 13,131,355	$ 1,898,263	1200	1.91	$ 7,956,592	$ 1,064,978
1225	1.66	$ 13,131,356	$ 2,001,736	1300	2.06	$ 7,956,591	$ 1,244,350
1250	1.70	$ 13,131,358	$ 2,105,251	1400	2.22	$ 7,956,586	$ 1,423,921
1275	1.73	$ 13,131,359	$ 2,208,801	1500	2.38	$ 7,956,583	$ 1,603,627
1300	1.77	$ 13,131,361	$ 2,312,381	1600	2.54	$ 7,956,581	$ 1,783,425
1400	1.90	$ 13,131,366	$ 2,726,942	1700	2.70	$ 7,956,578	$ 1,963,291
1500	2.04	$ 13,131,373	$ 3,141,770	1800	2.86	$ 7,956,578	$ 2,143,209
1600	2.17	$ 13,131,378	$ 3,556,771	1900	3.02	$ 7,956,574	$ 2,323,164
1700	2.31	$ 13,131,382	$ 3,971,892	2000	3.18	$ 7,956,572	$ 2,503,151
1800	2.45	$ 13,131,388	$ 4,387,097	2100	3.34	$ 7,956,569	$ 2,683,162
1900	2.58	$ 13,131,393	$ 4,802,366	2200	3.49	$ 7,956,564	$ 2,863,192
2000	2.72	$ 13,131,398	$ 5,217,683				
2100	2.85	$ 13,131,402	$ 5,633,037				
2200	2.99	$ 13,131,406	$ 6,048,421				

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DECEMBER 2008							
On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 17,045,777	$ 4,057,027	0	0.00	$ 8,558,988	$ 1,249,060
100	0.12	$ 17,045,777	$ 3,575,530	100	0.14	$ 8,558,988	$ 1,074,753
200	0.24	$ 17,045,777	$ 3,094,373	200	0.28	$ 8,558,988	$ 900,883
300	0.37	$ 17,045,779	$ 2,613,750	300	0.42	$ 8,558,990	$ 727,773
400	0.49	$ 17,045,777	$ 2,134,016	325	0.46	$ 8,558,987	$ 684,681
500	0.61	$ 17,045,778	$ 1,655,948	350	0.49	$ 8,558,990	$ 641,695
525	0.64	$ 17,045,778	$ 1,536,873	375	0.53	$ 8,558,987	$ 598,833
550	0.67	$ 17,045,778	$ 1,418,064	400	0.56	$ 8,558,985	$ 556,128
575	0.70	$ 17,045,778	$ 1,299,595	425	0.60	$ 8,558,985	$ 513,617
600	0.73	$ 17,045,781	$ 1,181,566	450	0.63	$ 8,558,987	$ 471,356
625	0.76	$ 17,045,779	$ 1,064,126	475	0.67	$ 8,558,990	$ 429,414
650	0.79	$ 17,045,779	$ 947,492	500	0.70	$ 8,558,987	$ 387,896
675	0.82	$ 17,045,780	$ 832,004	525	0.74	$ 8,558,985	$ 346,958
700	0.85	$ 17,045,781	$ 718,216	550	0.78	$ 8,558,984	$ 306,825
725	0.88	$ 17,045,779	$ 607,082	575	0.81	$ 8,558,984	$ 267,864
750	0.91	$ 17,045,778	$ 500,376	600	0.85	$ 8,558,988	$ 230,672
775	0.95	$ 17,045,781	$ 401,642	625	0.88	$ 8,558,988	$ 196,252
800	0.98	$ 17,045,779	$ 318,383	650	0.92	$ 8,558,988	$ 166,337
825	1.01	$ 17,045,778	$ 265,580	675	0.95	$ 8,558,986	$ 143,765
850	1.04	$ 17,045,779	$ 262,316	700	0.99	$ 8,558,982	$ 132,349
875	1.07	$ 17,045,779	$ 310,160	725	1.02	$ 8,558,980	$ 134,951
900	1.10	$ 17,045,782	$ 390,771	750	1.06	$ 8,558,986	$ 150,846
925	1.13	$ 17,045,783	$ 488,176	775	1.09	$ 8,558,984	$ 176,481
950	1.16	$ 17,045,781	$ 594,174	800	1.13	$ 8,558,984	$ 208,287
975	1.19	$ 17,045,781	$ 704,899	825	1.16	$ 8,558,985	$ 243,864
1000	1.22	$ 17,045,780	$ 818,434	850	1.20	$ 8,558,984	$ 281,785
1025	1.25	$ 17,045,781	$ 933,755	875	1.23	$ 8,558,980	$ 321,223
1050	1.28	$ 17,045,780	$ 1,050,273	900	1.27	$ 8,558,984	$ 361,680
1075	1.31	$ 17,045,780	$ 1,167,632	925	1.30	$ 8,558,985	$ 402,850
1100	1.34	$ 17,045,781	$ 1,285,599	950	1.34	$ 8,558,985	$ 444,536
1125	1.37	$ 17,045,781	$ 1,404,023	975	1.37	$ 8,558,983	$ 486,605
1150	1.40	$ 17,045,778	$ 1,522,796	1000	1.41	$ 8,558,984	$ 528,963
1175	1.43	$ 17,045,781	$ 1,641,843	1100	1.55	$ 8,558,981	$ 700,251
1200	1.46	$ 17,045,783	$ 1,761,107	1200	1.69	$ 8,558,986	$ 873,192
1225	1.49	$ 17,045,784	$ 1,880,548	1300	1.83	$ 8,558,984	$ 1,046,965
1250	1.52	$ 17,045,782	$ 2,000,134	1400	1.97	$ 8,558,983	$ 1,221,216
1275	1.56	$ 17,045,781	$ 2,119,841	1500	2.11	$ 8,558,984	$ 1,395,767
1300	1.59	$ 17,045,783	$ 2,239,649	1600	2.26	$ 8,558,980	$ 1,570,515
1400	1.71	$ 17,045,783	$ 2,719,625	1700	2.40	$ 8,558,981	$ 1,745,404
1500	1.83	$ 17,045,781	$ 3,200,388	1800	2.54	$ 8,558,983	$ 1,920,395
1600	1.95	$ 17,045,782	$ 3,681,632	1900	2.68	$ 8,558,981	$ 2,095,462
1700	2.07	$ 17,045,781	$ 4,163,188	2000	2.82	$ 8,558,979	$ 2,270,585
1800	2.20	$ 17,045,786	$ 4,644,961	2100	2.96	$ 8,558,980	$ 2,445,754
1900	2.32	$ 17,045,785	$ 5,126,888	2200	3.10	$ 8,558,978	$ 2,620,958
2000	2.44	$ 17,045,786	$ 5,608,932				
2100	2.56	$ 17,045,788	$ 6,091,061				
2200	2.68	$ 17,045,788	$ 6,573,260				

JANUARY 2009							
On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 21,379,028	$ 5,550,788	0	0.00	$ 14,562,883	$ 1,930,371
100	0.11	$ 21,379,020	$ 4,946,517	100	0.13	$ 14,562,885	$ 1,686,500
200	0.22	$ 21,379,012	$ 4,342,625	200	0.25	$ 14,562,885	$ 1,443,725
300	0.33	$ 21,379,005	$ 3,739,292	300	0.38	$ 14,562,887	$ 1,202,722
400	0.44	$ 21,378,997	$ 3,136,844	325	0.41	$ 14,562,887	$ 1,142,877
500	0.55	$ 21,378,989	$ 2,535,911	350	0.44	$ 14,562,887	$ 1,083,247
525	0.58	$ 21,378,988	$ 2,386,049	375	0.47	$ 14,562,885	$ 1,023,874
550	0.61	$ 21,378,986	$ 2,236,395	400	0.50	$ 14,562,886	$ 964,802
575	0.64	$ 21,378,985	$ 2,086,994	425	0.53	$ 14,562,887	$ 906,090
600	0.66	$ 21,378,982	$ 1,937,904	450	0.56	$ 14,562,887	$ 847,814
625	0.69	$ 21,378,979	$ 1,789,204	475	0.60	$ 14,562,886	$ 790,070
650	0.72	$ 21,378,978	$ 1,640,997	500	0.63	$ 14,562,889	$ 732,985
675	0.75	$ 21,378,976	$ 1,493,434	525	0.66	$ 14,562,863	$ 676,729
700	0.77	$ 21,378,979	$ 1,346,725	550	0.69	$ 14,562,826	$ 621,531
725	0.80	$ 21,378,994	$ 1,201,194	575	0.72	$ 14,562,809	$ 567,698
750	0.83	$ 21,378,992	$ 1,057,351	600	0.75	$ 14,562,750	$ 515,658
775	0.86	$ 21,379,027	$ 915,990	625	0.78	$ 14,562,568	$ 466,030
800	0.89	$ 21,379,139	$ 778,454	650	0.81	$ 14,562,389	$ 419,622
825	0.91	$ 21,379,400	$ 647,121	675	0.85	$ 14,562,127	$ 377,662
850	0.94	$ 21,379,880	$ 526,576	700	0.88	$ 14,561,683	$ 341,710
875	0.97	$ 21,380,629	$ 425,876	725	0.91	$ 14,561,280	$ 313,804
900	1.00	$ 21,381,283	$ 361,872	750	0.94	$ 14,560,908	$ 296,231
925	1.02	$ 21,381,824	$ 354,933	775	0.97	$ 14,560,540	$ 290,884
950	1.05	$ 21,382,416	$ 408,052	800	1.00	$ 14,560,286	$ 298,406
975	1.08	$ 21,383,134	$ 502,543	825	1.03	$ 14,560,006	$ 317,895
1000	1.11	$ 21,383,887	$ 619,753	850	1.07	$ 14,559,845	$ 347,368
1025	1.13	$ 21,384,619	$ 749,195	875	1.10	$ 14,559,716	$ 384,571
1050	1.16	$ 21,385,122	$ 885,701	900	1.13	$ 14,559,684	$ 427,473
1075	1.19	$ 21,385,351	$ 1,026,434	925	1.16	$ 14,559,622	$ 474,550
1100	1.22	$ 21,385,451	$ 1,169,861	950	1.19	$ 14,559,686	$ 524,673
1125	1.24	$ 21,385,481	$ 1,315,085	975	1.22	$ 14,559,787	$ 577,062
1150	1.27	$ 21,385,495	$ 1,461,567	1000	1.25	$ 14,559,956	$ 631,154
1175	1.30	$ 21,385,494	$ 1,608,963	1100	1.38	$ 14,560,267	$ 858,063
1200	1.33	$ 21,385,499	$ 1,757,045	1200	1.50	$ 14,560,293	$ 1,093,753
1225	1.36	$ 21,385,503	$ 1,905,645	1300	1.63	$ 14,560,297	$ 1,333,582
1250	1.38	$ 21,385,498	$ 2,054,660	1400	1.75	$ 14,560,299	$ 1,575,658
1275	1.41	$ 21,385,496	$ 2,203,999	1500	1.88	$ 14,560,297	$ 1,819,088
1300	1.44	$ 21,385,495	$ 2,353,603	1600	2.01	$ 14,560,296	$ 2,063,389
1400	1.55	$ 21,385,489	$ 2,953,856	1700	2.13	$ 14,560,298	$ 2,308,287
1500	1.66	$ 21,385,482	$ 3,555,931	1800	2.26	$ 14,560,299	$ 2,553,611
1600	1.77	$ 21,385,473	$ 4,159,039	1900	2.38	$ 14,560,300	$ 2,799,245
1700	1.88	$ 21,385,466	$ 4,762,785	2000	2.51	$ 14,560,302	$ 3,045,120
1800	1.99	$ 21,385,459	$ 5,366,955	2100	2.63	$ 14,560,302	$ 3,291,175
1900	2.10	$ 21,385,450	$ 5,971,421	2200	2.76	$ 14,560,301	$ 3,537,378
2000	2.21	$ 21,385,441	$ 6,576,101				
2100	2.32	$ 21,385,437	$ 7,180,940				
2200	2.43	$ 21,385,428	$ 7,785,902				

FEBRUARY 2009							
On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 18,959,855	$ 4,898,937	0	0.00	$ 11,797,072	$ 1,718,886
100	0.12	$ 18,959,858	$ 4,326,231	100	0.13	$ 11,797,078	$ 1,488,991
200	0.24	$ 18,959,859	$ 3,753,989	200	0.26	$ 11,797,086	$ 1,259,874
300	0.36	$ 18,959,862	$ 3,182,460	300	0.40	$ 11,797,093	$ 1,032,048
400	0.48	$ 18,959,864	$ 2,612,114	325	0.43	$ 11,797,095	$ 975,401
500	0.60	$ 18,959,866	$ 2,043,943	350	0.46	$ 11,797,096	$ 918,922
525	0.63	$ 18,959,868	$ 1,902,468	375	0.49	$ 11,797,098	$ 862,645
550	0.66	$ 18,959,867	$ 1,761,330	400	0.53	$ 11,797,099	$ 806,613
575	0.69	$ 18,959,868	$ 1,620,616	425	0.56	$ 11,797,101	$ 750,881
600	0.72	$ 18,959,868	$ 1,480,448	450	0.59	$ 11,797,102	$ 695,520
625	0.75	$ 18,959,869	$ 1,340,998	475	0.63	$ 11,797,104	$ 640,626
650	0.78	$ 18,959,872	$ 1,202,514	500	0.66	$ 11,797,106	$ 586,332
675	0.80	$ 18,959,857	$ 1,065,431	525	0.69	$ 11,797,107	$ 532,821
700	0.83	$ 18,959,837	$ 930,378	550	0.73	$ 11,797,045	$ 480,376
725	0.86	$ 18,959,867	$ 798,320	575	0.76	$ 11,797,020	$ 429,384
750	0.89	$ 18,960,038	$ 670,926	600	0.79	$ 11,796,882	$ 380,390
775	0.92	$ 18,960,526	$ 551,458	625	0.82	$ 11,796,821	$ 334,293
800	0.95	$ 18,961,184	$ 446,195	650	0.86	$ 11,796,638	$ 292,474
825	0.98	$ 18,961,597	$ 367,380	675	0.89	$ 11,796,494	$ 256,980
850	1.01	$ 18,962,271	$ 334,215	700	0.92	$ 11,796,046	$ 230,749
875	1.04	$ 18,962,960	$ 359,643	725	0.96	$ 11,795,440	$ 217,055
900	1.07	$ 18,963,747	$ 433,524	750	0.99	$ 11,795,225	$ 218,248
925	1.10	$ 18,964,524	$ 536,180	775	1.02	$ 11,794,956	$ 234,125
950	1.13	$ 18,965,118	$ 654,309	800	1.06	$ 11,794,878	$ 262,081
975	1.16	$ 18,965,631	$ 781,015	825	1.09	$ 11,794,638	$ 298,760
1000	1.19	$ 18,966,006	$ 912,717	850	1.12	$ 11,794,692	$ 341,401
1025	1.22	$ 18,966,206	$ 1,047,541	875	1.15	$ 11,794,656	$ 388,013
1050	1.25	$ 18,966,366	$ 1,184,427	900	1.19	$ 11,794,692	$ 437,379
1075	1.28	$ 18,966,515	$ 1,322,735	925	1.22	$ 11,794,830	$ 488,644
1100	1.31	$ 18,966,611	$ 1,462,055	950	1.25	$ 11,794,865	$ 541,278
1125	1.34	$ 18,966,680	$ 1,602,131	975	1.29	$ 11,794,955	$ 594,936
1150	1.37	$ 18,966,708	$ 1,742,767	1000	1.32	$ 11,794,977	$ 649,331
1175	1.40	$ 18,966,706	$ 1,883,848	1100	1.45	$ 11,795,032	$ 871,600
1200	1.43	$ 18,966,705	$ 2,025,279	1200	1.58	$ 11,795,035	$ 1,097,902
1225	1.46	$ 18,966,705	$ 2,166,990	1300	1.71	$ 11,795,045	$ 1,326,180
1250	1.49	$ 18,966,704	$ 2,308,931	1400	1.85	$ 11,795,053	$ 1,555,562
1275	1.52	$ 18,966,706	$ 2,451,060	1500	1.98	$ 11,795,057	$ 1,785,625
1300	1.55	$ 18,966,708	$ 2,593,348	1600	2.11	$ 11,795,064	$ 2,016,133
1400	1.67	$ 18,966,708	$ 3,163,643	1700	2.24	$ 11,795,071	$ 2,246,953
1500	1.79	$ 18,966,711	$ 3,735,142	1800	2.37	$ 11,795,078	$ 2,477,995
1600	1.91	$ 18,966,714	$ 4,307,366	1900	2.51	$ 11,795,085	$ 2,709,200
1700	2.03	$ 18,966,716	$ 4,880,060	2000	2.64	$ 11,795,092	$ 2,940,534
1800	2.15	$ 18,966,717	$ 5,453,075	2100	2.77	$ 11,795,098	$ 3,171,966
1900	2.27	$ 18,966,720	$ 6,026,321	2200	2.90	$ 11,795,106	$ 3,403,480
2000	2.39	$ 18,966,721	$ 6,599,737				
2100	2.50	$ 18,966,726	$ 7,173,282				
2200	2.62	$ 18,966,727	$ 7,746,928				

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MARCH 2009

On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 16,569,066	$ 4,300,871	0	0.00	$ 8,708,434	$ 1,341,899
100	0.14	$ 16,569,061	$ 3,705,160	100	0.16	$ 8,708,448	$ 1,128,999
200	0.28	$ 16,569,056	$ 3,109,732	200	0.32	$ 8,708,462	$ 916,613
300	0.42	$ 16,569,050	$ 2,514,792	300	0.48	$ 8,708,476	$ 705,211
400	0.56	$ 16,569,045	$ 1,920,789	325	0.52	$ 8,708,479	$ 652,626
500	0.71	$ 16,569,040	$ 1,328,987	350	0.56	$ 8,708,482	$ 600,204
525	0.74	$ 16,569,041	$ 1,181,768	375	0.60	$ 8,708,486	$ 547,989
550	0.78	$ 16,569,055	$ 1,035,105	400	0.64	$ 8,708,456	$ 496,061
575	0.81	$ 16,569,091	$ 889,304	425	0.68	$ 8,708,372	$ 444,513
600	0.85	$ 16,569,210	$ 744,913	450	0.72	$ 8,708,220	$ 393,507
625	0.88	$ 16,569,475	$ 603,001	475	0.76	$ 8,708,056	$ 343,257
650	0.92	$ 16,569,934	$ 465,319	500	0.79	$ 8,707,825	$ 294,160
675	0.95	$ 16,570,459	$ 337,127	525	0.83	$ 8,707,528	$ 246,860
700	0.99	$ 16,571,049	$ 234,139	550	0.87	$ 8,706,970	$ 202,726
725	1.02	$ 16,571,665	$ 200,275	575	0.91	$ 8,706,251	$ 164,109
750	1.06	$ 16,572,379	$ 263,583	600	0.95	$ 8,705,648	$ 135,929
775	1.09	$ 16,572,974	$ 378,140	625	0.99	$ 8,704,780	$ 125,268
800	1.13	$ 16,573,503	$ 510,608	650	1.03	$ 8,704,131	$ 136,195
825	1.16	$ 16,573,967	$ 650,264	675	1.07	$ 8,703,573	$ 164,577
850	1.20	$ 16,574,114	$ 793,362	700	1.11	$ 8,703,136	$ 203,249
875	1.24	$ 16,574,238	$ 938,332	725	1.15	$ 8,702,789	$ 247,498
900	1.27	$ 16,574,371	$ 1,084,437	750	1.19	$ 8,702,632	$ 294,820
925	1.31	$ 16,574,469	$ 1,231,264	775	1.23	$ 8,702,617	$ 343,975
950	1.34	$ 16,574,527	$ 1,378,595	800	1.27	$ 8,702,611	$ 394,260
975	1.38	$ 16,574,540	$ 1,526,280	825	1.31	$ 8,702,552	$ 445,308
1000	1.41	$ 16,574,545	$ 1,674,221	850	1.35	$ 8,702,470	$ 496,858
1025	1.45	$ 16,574,561	$ 1,822,360	875	1.39	$ 8,702,438	$ 548,781
1050	1.48	$ 16,574,566	$ 1,970,643	900	1.43	$ 8,702,471	$ 600,989
1075	1.52	$ 16,574,569	$ 2,119,048	925	1.47	$ 8,702,523	$ 653,409
1100	1.55	$ 16,574,566	$ 2,267,546	950	1.51	$ 8,702,498	$ 705,984
1125	1.59	$ 16,574,567	$ 2,416,120	975	1.55	$ 8,702,495	$ 758,697
1150	1.62	$ 16,574,562	$ 2,564,755	1000	1.59	$ 8,702,504	$ 811,512
1175	1.66	$ 16,574,562	$ 2,713,444	1100	1.75	$ 8,702,523	$ 1,023,496
1200	1.69	$ 16,574,561	$ 2,862,178	1200	1.91	$ 8,702,537	$ 1,236,179
1225	1.73	$ 16,574,561	$ 3,010,947	1300	2.07	$ 8,702,550	$ 1,449,251
1250	1.77	$ 16,574,558	$ 3,159,751	1400	2.23	$ 8,702,562	$ 1,662,565
1275	1.80	$ 16,574,558	$ 3,308,581	1500	2.38	$ 8,702,578	$ 1,876,038
1300	1.84	$ 16,574,556	$ 3,457,436	1600	2.54	$ 8,702,592	$ 2,089,619
1400	1.98	$ 16,574,549	$ 4,053,046	1700	2.70	$ 8,702,606	$ 2,303,281
1500	2.12	$ 16,574,545	$ 4,648,873	1800	2.86	$ 8,702,619	$ 2,517,000
1600	2.26	$ 16,574,539	$ 5,244,842	1900	3.02	$ 8,702,630	$ 2,730,767
1700	2.40	$ 16,574,536	$ 5,840,911	2000	3.18	$ 8,702,648	$ 2,944,568
1800	2.54	$ 16,574,531	$ 6,437,050	2100	3.34	$ 8,702,660	$ 3,158,397
1900	2.68	$ 16,574,526	$ 7,033,242	2200	3.50	$ 8,702,673	$ 3,372,249
2000	2.82	$ 16,574,519	$ 7,629,475				
2100	2.97	$ 16,574,513	$ 8,225,740				
2200	3.11	$ 16,574,509	$ 8,822,032				

APRIL 2009							
On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 14,970,656	$ 3,840,026	0	0.00	$ 7,176,834	$ 1,036,643
100	0.15	$ 14,970,654	$ 3,247,718	100	0.18	$ 7,176,841	$ 840,600
200	0.31	$ 14,970,652	$ 2,656,290	200	0.36	$ 7,176,848	$ 646,133
300	0.46	$ 14,970,649	$ 2,066,498	300	0.54	$ 7,176,855	$ 455,264
400	0.61	$ 14,970,647	$ 1,480,298	325	0.58	$ 7,176,858	$ 408,704
500	0.77	$ 14,970,666	$ 904,715	350	0.63	$ 7,176,858	$ 362,966
525	0.81	$ 14,970,731	$ 765,322	375	0.67	$ 7,176,859	$ 318,402
550	0.84	$ 14,970,856	$ 630,173	400	0.72	$ 7,176,830	$ 275,610
575	0.88	$ 14,971,249	$ 502,673	425	0.76	$ 7,176,317	$ 235,670
600	0.92	$ 14,972,192	$ 390,399	450	0.81	$ 7,175,691	$ 200,053
625	0.96	$ 14,973,482	$ 309,903	475	0.85	$ 7,174,909	$ 171,427
650	1.00	$ 14,974,696	$ 288,343	500	0.90	$ 7,174,229	$ 153,689
675	1.04	$ 14,975,250	$ 337,554	525	0.94	$ 7,173,889	$ 150,764
700	1.07	$ 14,975,719	$ 434,288	550	0.99	$ 7,173,443	$ 163,541
725	1.11	$ 14,975,877	$ 554,236	575	1.03	$ 7,173,227	$ 188,872
750	1.15	$ 14,976,025	$ 685,426	600	1.08	$ 7,172,978	$ 222,576
775	1.19	$ 14,976,033	$ 822,502	625	1.12	$ 7,172,588	$ 261,359
800	1.23	$ 14,976,039	$ 963,002	650	1.17	$ 7,172,162	$ 303,271
825	1.27	$ 14,976,055	$ 1,105,640	675	1.21	$ 7,171,841	$ 347,191
850	1.30	$ 14,976,064	$ 1,249,665	700	1.26	$ 7,171,716	$ 392,482
875	1.34	$ 14,976,077	$ 1,394,656	725	1.30	$ 7,171,518	$ 438,763
900	1.38	$ 14,976,078	$ 1,540,336	750	1.35	$ 7,171,478	$ 485,682
925	1.42	$ 14,976,077	$ 1,686,519	775	1.39	$ 7,171,358	$ 533,097
950	1.46	$ 14,976,078	$ 1,833,092	800	1.44	$ 7,171,340	$ 580,893
975	1.50	$ 14,976,077	$ 1,979,960	825	1.48	$ 7,171,301	$ 628,982
1000	1.53	$ 14,976,075	$ 2,127,066	850	1.53	$ 7,171,289	$ 677,299
1025	1.57	$ 14,976,074	$ 2,274,362	875	1.57	$ 7,171,284	$ 725,801
1050	1.61	$ 14,976,075	$ 2,421,814	900	1.62	$ 7,171,285	$ 774,451
1075	1.65	$ 14,976,073	$ 2,569,395	925	1.66	$ 7,171,285	$ 823,222
1100	1.69	$ 14,976,073	$ 2,717,083	950	1.71	$ 7,171,286	$ 872,093
1125	1.73	$ 14,976,072	$ 2,864,863	975	1.75	$ 7,171,292	$ 921,050
1150	1.76	$ 14,976,072	$ 3,012,720	1000	1.80	$ 7,171,291	$ 970,076
1175	1.80	$ 14,976,073	$ 3,160,644	1100	1.98	$ 7,171,295	$ 1,166,717
1200	1.84	$ 14,976,071	$ 3,308,626	1200	2.16	$ 7,171,304	$ 1,363,929
1225	1.88	$ 14,976,071	$ 3,456,658	1300	2.34	$ 7,171,314	$ 1,561,500
1250	1.92	$ 14,976,070	$ 3,604,735	1400	2.52	$ 7,171,321	$ 1,759,306
1275	1.96	$ 14,976,068	$ 3,752,850	1500	2.70	$ 7,171,329	$ 1,957,279
1300	1.99	$ 14,976,070	$ 3,901,001	1600	2.88	$ 7,171,334	$ 2,155,370
1400	2.15	$ 14,976,067	$ 4,493,879	1700	3.06	$ 7,171,343	$ 2,353,551
1500	2.30	$ 14,976,064	$ 5,087,083	1800	3.24	$ 7,171,349	$ 2,551,799
1600	2.45	$ 14,976,061	$ 5,680,511	1900	3.42	$ 7,171,358	$ 2,750,102
1700	2.61	$ 14,976,058	$ 6,274,102	2000	3.60	$ 7,171,365	$ 2,948,446
1800	2.76	$ 14,976,057	$ 6,867,811	2100	3.78	$ 7,171,372	$ 3,146,827
1900	2.91	$ 14,976,055	$ 7,461,611	2200	3.96	$ 7,171,379	$ 3,345,233
2000	3.07	$ 14,976,052	$ 8,055,481				
2100	3.22	$ 14,976,052	$ 8,649,408				
2200	3.37	$ 14,976,047	$ 9,243,381				

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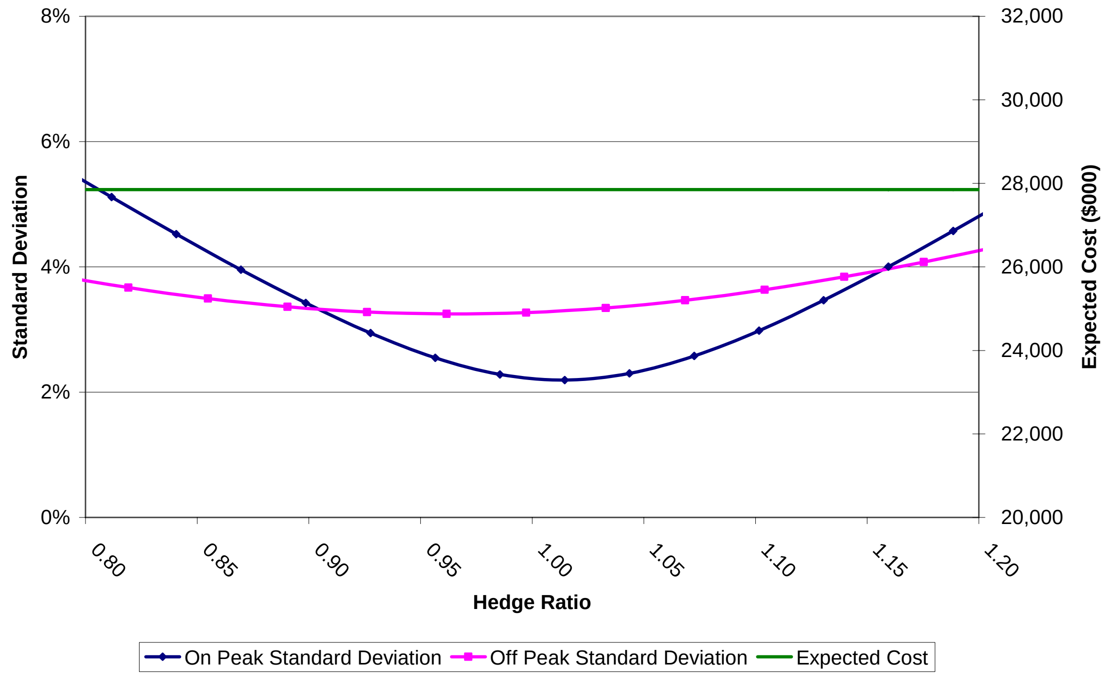
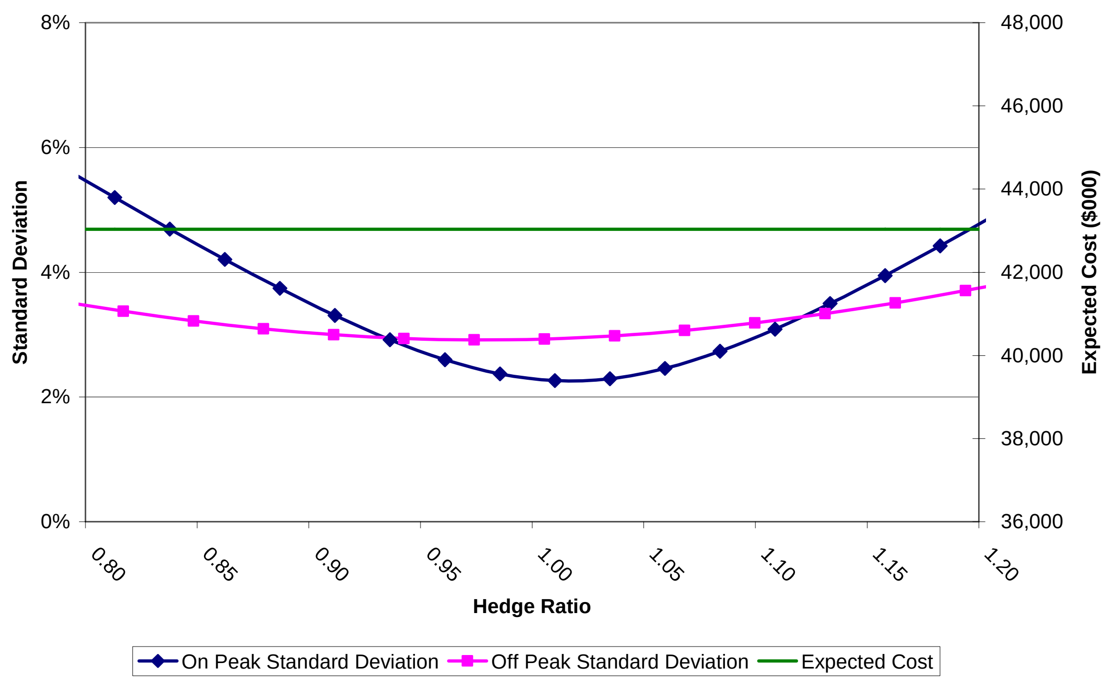
MAY 2009

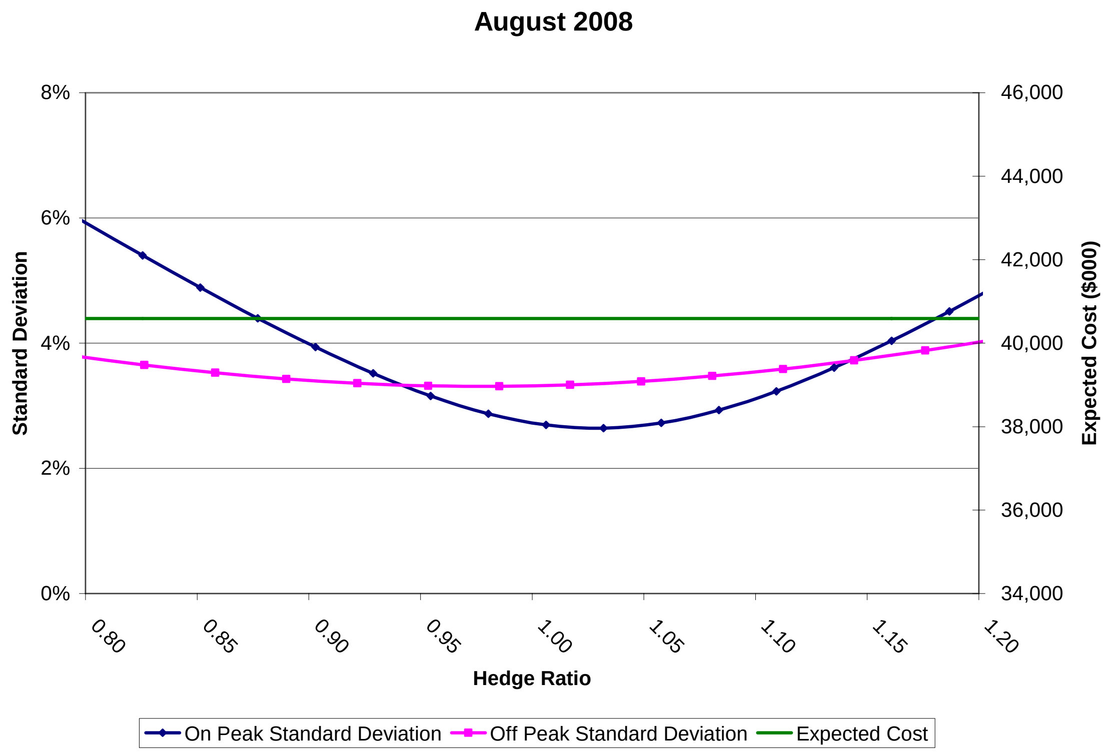
On Peak				Off Peak			
Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation	Quantity (MW)	Hedge Ratio	Expected Cost	Standard Deviation
0	0.00	$ 13,042,751	$ 3,329,723	0	0.00	$ 6,597,967	$ 958,754
100	0.15	$ 13,042,754	$ 2,815,050	100	0.19	$ 6,597,959	$ 779,592
200	0.31	$ 13,042,758	$ 2,301,812	200	0.37	$ 6,597,952	$ 602,492
300	0.46	$ 13,042,761	$ 1,791,243	300	0.56	$ 6,597,941	$ 430,010
400	0.62	$ 13,042,764	$ 1,286,523	325	0.60	$ 6,597,938	$ 388,337
500	0.77	$ 13,042,951	$ 798,984	350	0.65	$ 6,597,897	$ 347,690
525	0.81	$ 13,043,589	$ 684,479	375	0.70	$ 6,597,611	$ 308,515
550	0.85	$ 13,044,272	$ 576,114	400	0.74	$ 6,596,610	$ 271,488
575	0.89	$ 13,044,800	$ 477,974	425	0.79	$ 6,595,564	$ 237,346
600	0.92	$ 13,045,249	$ 397,852	450	0.84	$ 6,594,726	$ 207,502
625	0.96	$ 13,045,551	$ 348,403	475	0.88	$ 6,593,987	$ 184,153
650	1.00	$ 13,045,825	$ 343,185	500	0.93	$ 6,593,408	$ 170,024
675	1.04	$ 13,046,035	$ 384,069	525	0.98	$ 6,592,708	$ 167,472
700	1.08	$ 13,046,211	$ 459,005	550	1.02	$ 6,592,205	$ 177,024
725	1.12	$ 13,046,324	$ 554,324	575	1.07	$ 6,591,549	$ 196,902
750	1.16	$ 13,046,463	$ 661,279	600	1.11	$ 6,591,082	$ 224,361
775	1.19	$ 13,046,572	$ 775,108	625	1.16	$ 6,590,683	$ 257,037
800	1.23	$ 13,046,672	$ 893,171	650	1.21	$ 6,590,423	$ 293,188
825	1.27	$ 13,046,676	$ 1,014,015	675	1.25	$ 6,590,152	$ 331,683
850	1.31	$ 13,046,765	$ 1,136,754	700	1.30	$ 6,589,939	$ 371,804
875	1.35	$ 13,046,803	$ 1,260,832	725	1.35	$ 6,589,745	$ 413,065
900	1.39	$ 13,046,880	$ 1,385,891	750	1.39	$ 6,589,614	$ 455,168
925	1.43	$ 13,046,860	$ 1,511,687	775	1.44	$ 6,589,483	$ 497,888
950	1.46	$ 13,046,947	$ 1,638,049	800	1.49	$ 6,589,362	$ 541,094
975	1.50	$ 13,046,978	$ 1,764,858	825	1.53	$ 6,589,280	$ 584,677
1000	1.54	$ 13,047,036	$ 1,892,036	850	1.58	$ 6,589,228	$ 628,552
1025	1.58	$ 13,047,019	$ 2,019,504	875	1.63	$ 6,589,159	$ 672,665
1050	1.62	$ 13,047,034	$ 2,147,221	900	1.67	$ 6,589,108	$ 716,968
1075	1.66	$ 13,047,072	$ 2,275,133	925	1.72	$ 6,589,077	$ 761,431
1100	1.70	$ 13,047,084	$ 2,403,218	950	1.76	$ 6,589,045	$ 806,027
1125	1.73	$ 13,047,079	$ 2,531,445	975	1.81	$ 6,589,002	$ 850,732
1150	1.77	$ 13,047,076	$ 2,659,795	1000	1.86	$ 6,588,982	$ 895,536
1175	1.81	$ 13,047,079	$ 2,788,251	1100	2.04	$ 6,588,965	$ 1,075,468
1200	1.85	$ 13,047,080	$ 2,916,797	1200	2.23	$ 6,588,957	$ 1,256,169
1225	1.89	$ 13,047,081	$ 3,045,420	1300	2.42	$ 6,588,948	$ 1,437,347
1250	1.93	$ 13,047,082	$ 3,174,113	1400	2.60	$ 6,588,939	$ 1,618,843
1275	1.96	$ 13,047,083	$ 3,302,866	1500	2.79	$ 6,588,932	$ 1,800,561
1300	2.00	$ 13,047,083	$ 3,431,673	1600	2.97	$ 6,588,923	$ 1,982,438
1400	2.16	$ 13,047,087	$ 3,947,333	1700	3.16	$ 6,588,919	$ 2,164,436
1500	2.31	$ 13,047,090	$ 4,463,504	1800	3.34	$ 6,588,910	$ 2,346,525
1600	2.47	$ 13,047,095	$ 4,980,028	1900	3.53	$ 6,588,903	$ 2,528,687
1700	2.62	$ 13,047,096	$ 5,496,806	2000	3.72	$ 6,588,893	$ 2,710,905
1800	2.77	$ 13,047,099	$ 6,013,771	2100	3.90	$ 6,588,886	$ 2,893,172
1900	2.93	$ 13,047,103	$ 6,530,879	2200	4.09	$ 6,588,878	$ 3,075,474
2000	3.08	$ 13,047,105	$ 7,048,100				
2100	3.24	$ 13,047,108	$ 7,565,410				
2200	3.39	$ 13,047,114	$ 8,082,792				

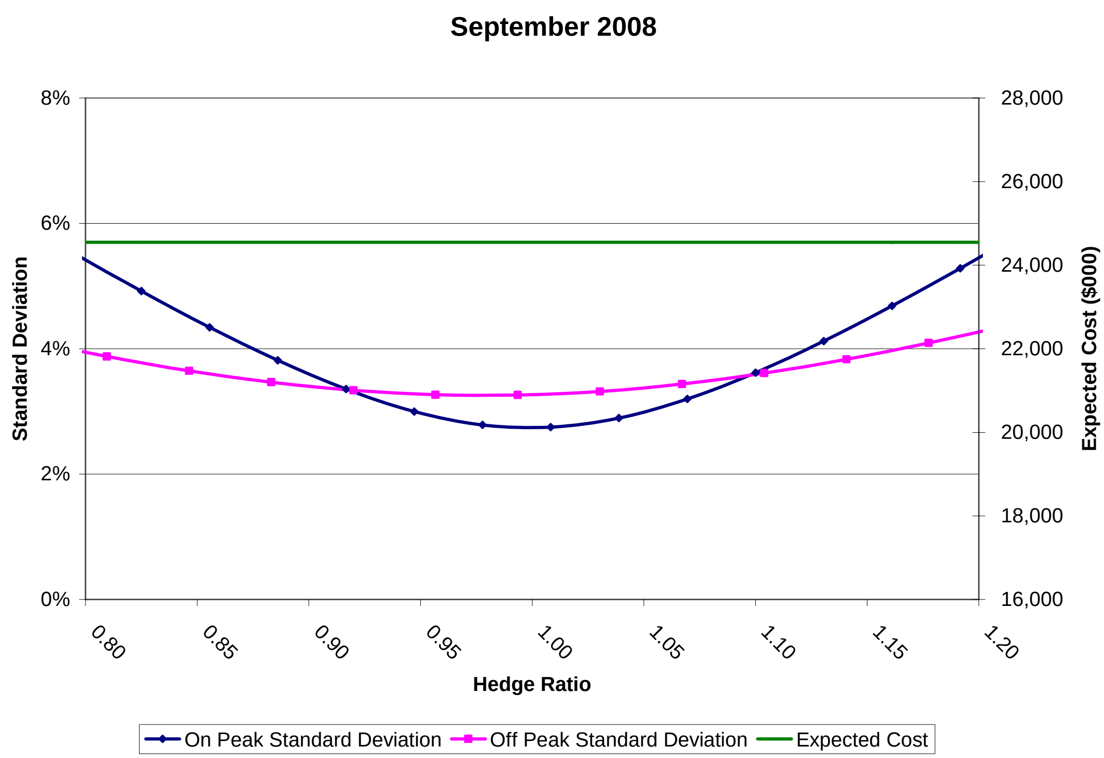
June 2008



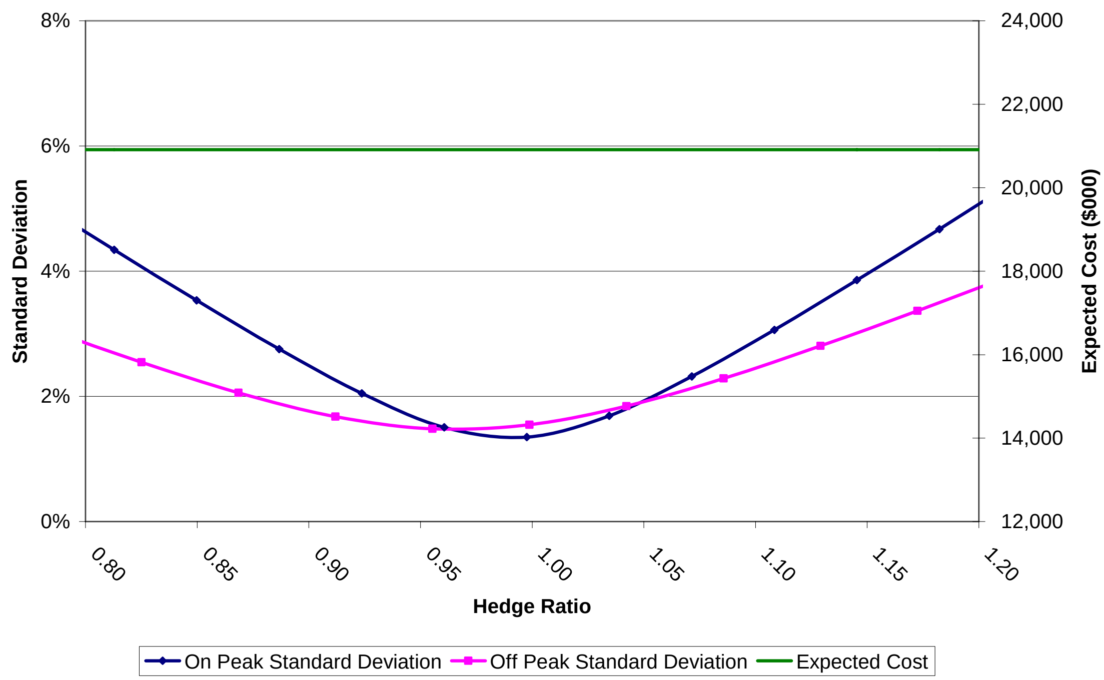
July 2008



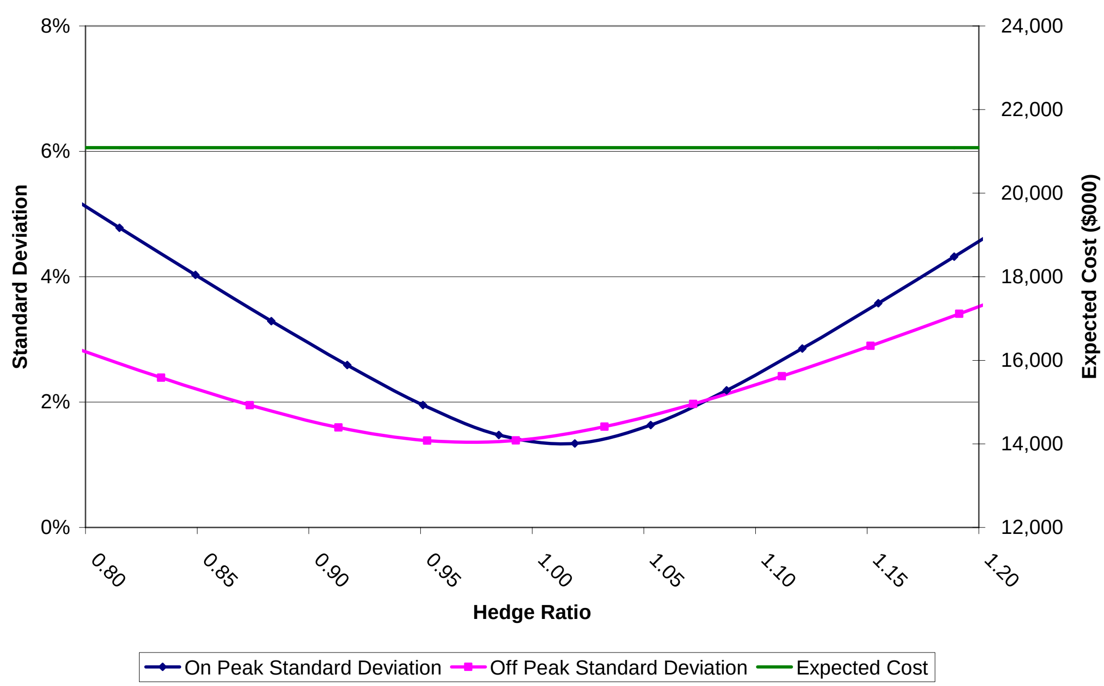

August 2008
Standard Deviation
8%
6%
4%
2%
0%
Expected Cost ($000)
46,000
44,000
42,000
40,000
38,000
36,000
34,000
0.80
0.85
0.90
0.95
1.00
1.05
1.10
1.15
1.20
Hedge Ratio
On Peak Standard Deviation
Off Peak Standard Deviation
Expected Cost

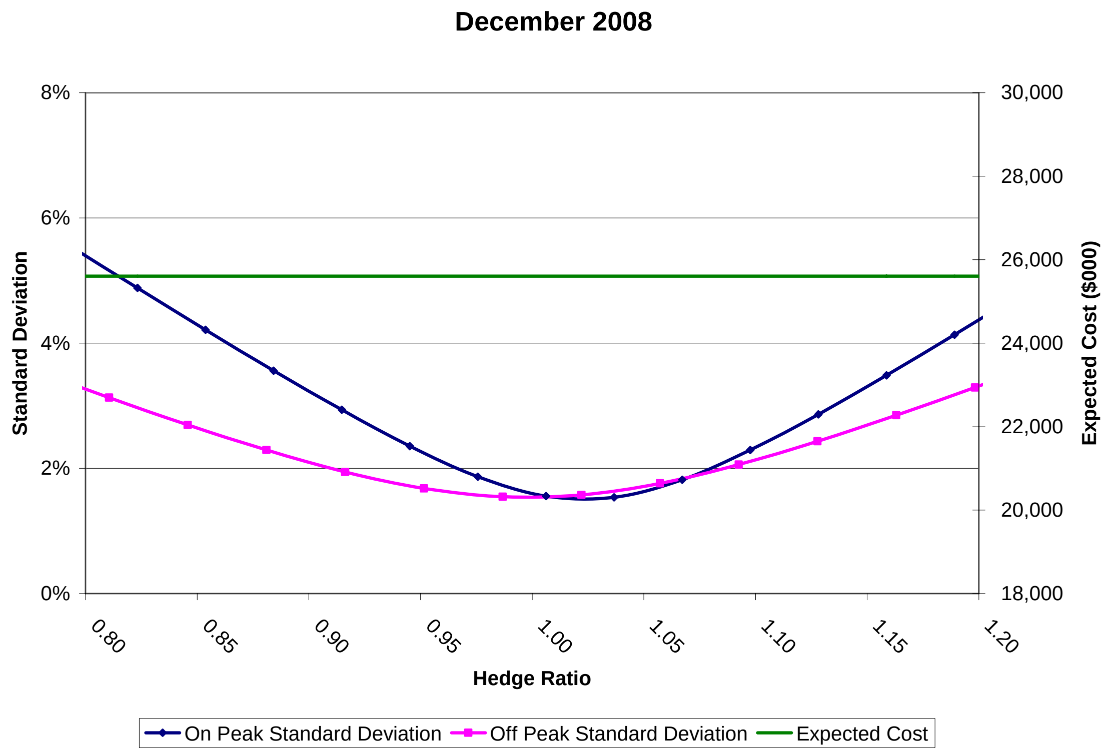

September 2008
Standard Deviation
8%
6%
4%
2%
0%
Expected Cost ($000)
28,000
26,000
24,000
22,000
20,000
18,000
16,000
0.80
0.85
0.90
0.95
1.00
1.05
1.10
1.15
1.20
Hedge Ratio
On Peak Standard Deviation
Off Peak Standard Deviation
Expected Cost

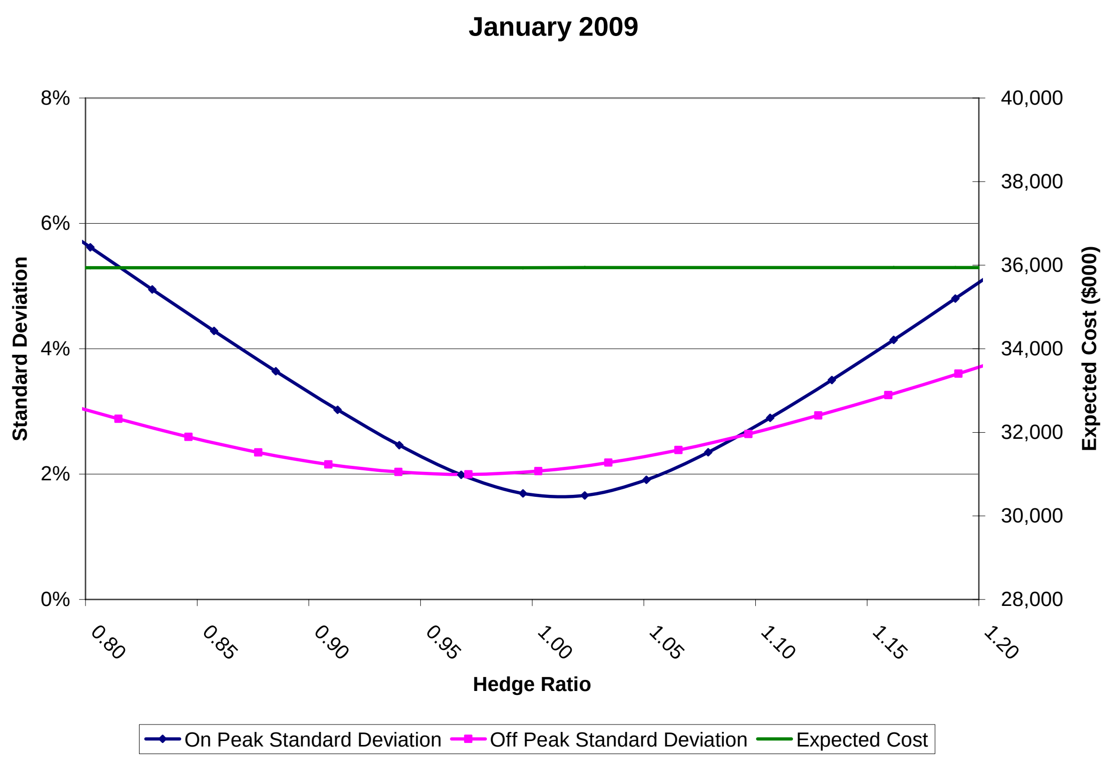
October 2008



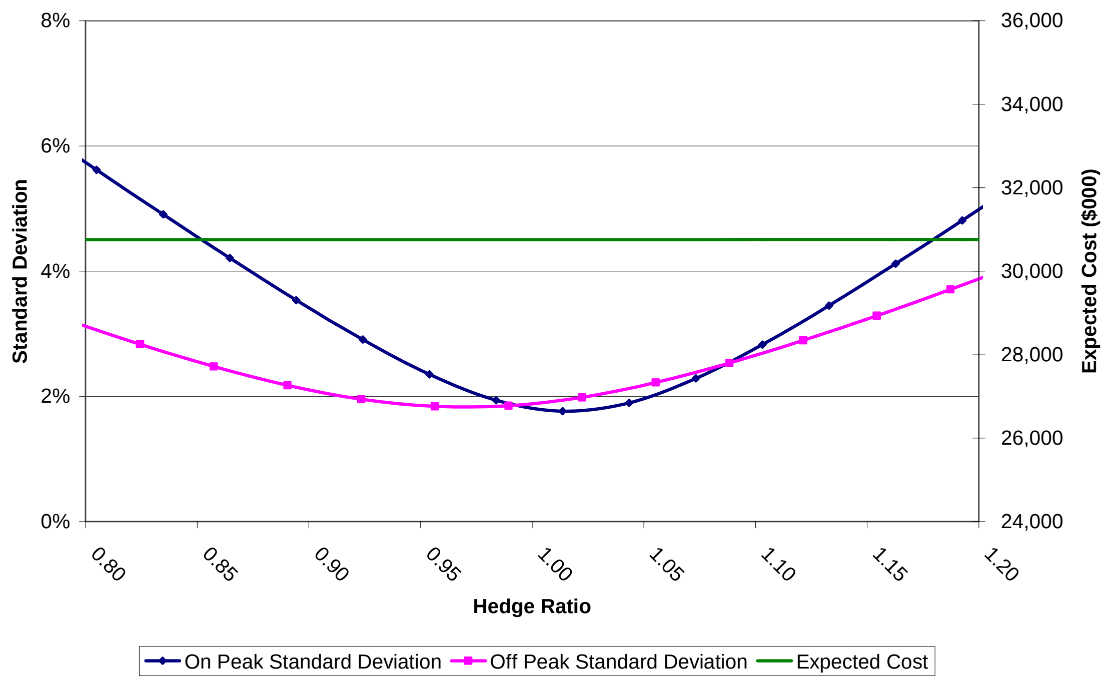
November 2008



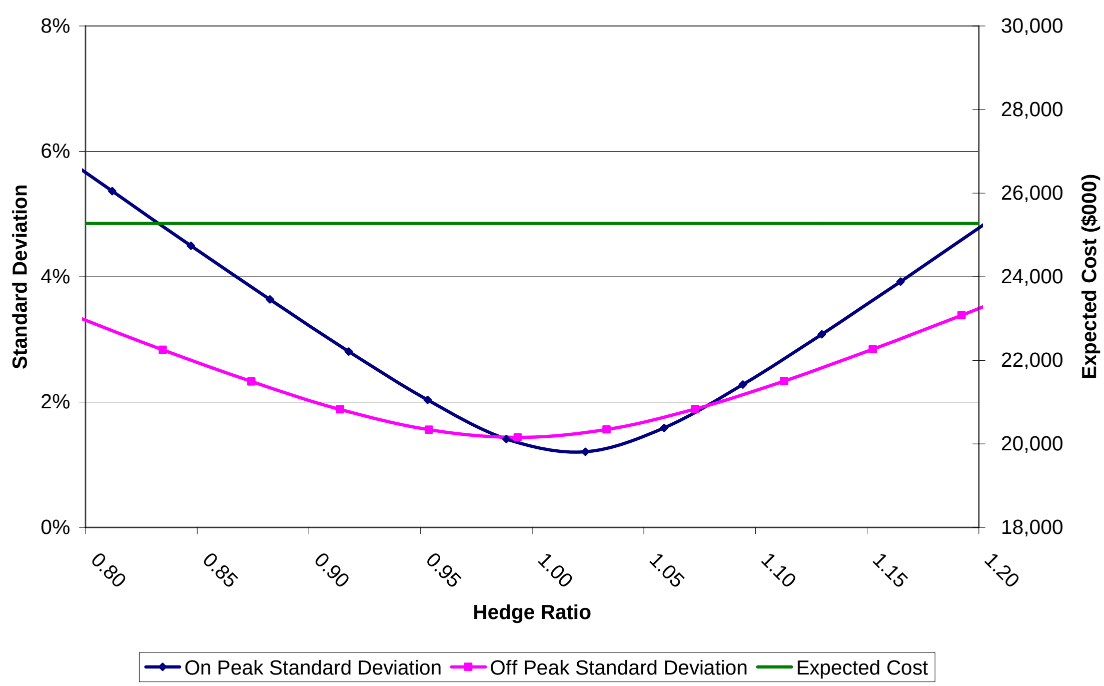

December 2008
8%
6%
4%
2%
0%
Standard Deviation
30,000
28,000
26,000
24,000
22,000
20,000
18,000
Expected Cost ($000)
0.80
0.85
0.90
0.95
1.00
1.05
1.10
1.15
1.20
Hedge Ratio
On Peak Standard Deviation
Off Peak Standard Deviation
Expected Cost

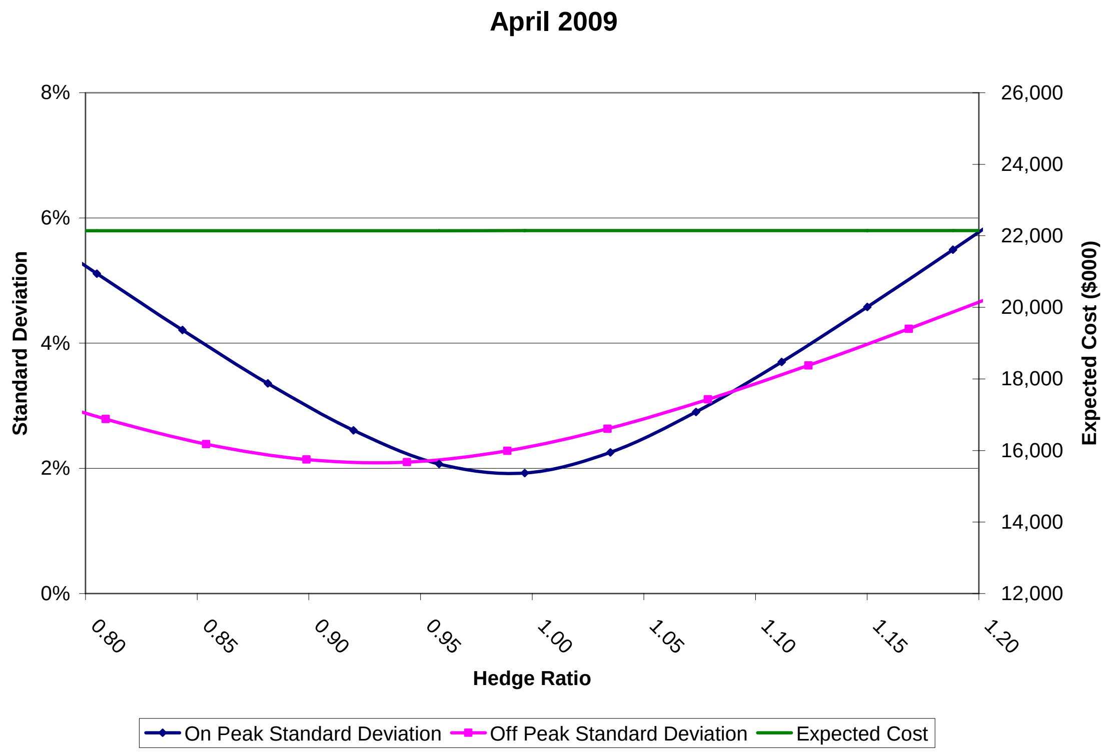

January 2009
8%
6%
4%
2%
0%
Standard Deviation
40,000
38,000
36,000
34,000
32,000
30,000
28,000
Expected Cost ($000)
0.80
0.85
0.90
0.95
1.00
1.05
1.10
1.15
1.20
Hedge Ratio
On Peak Standard Deviation
Off Peak Standard Deviation
Expected Cost

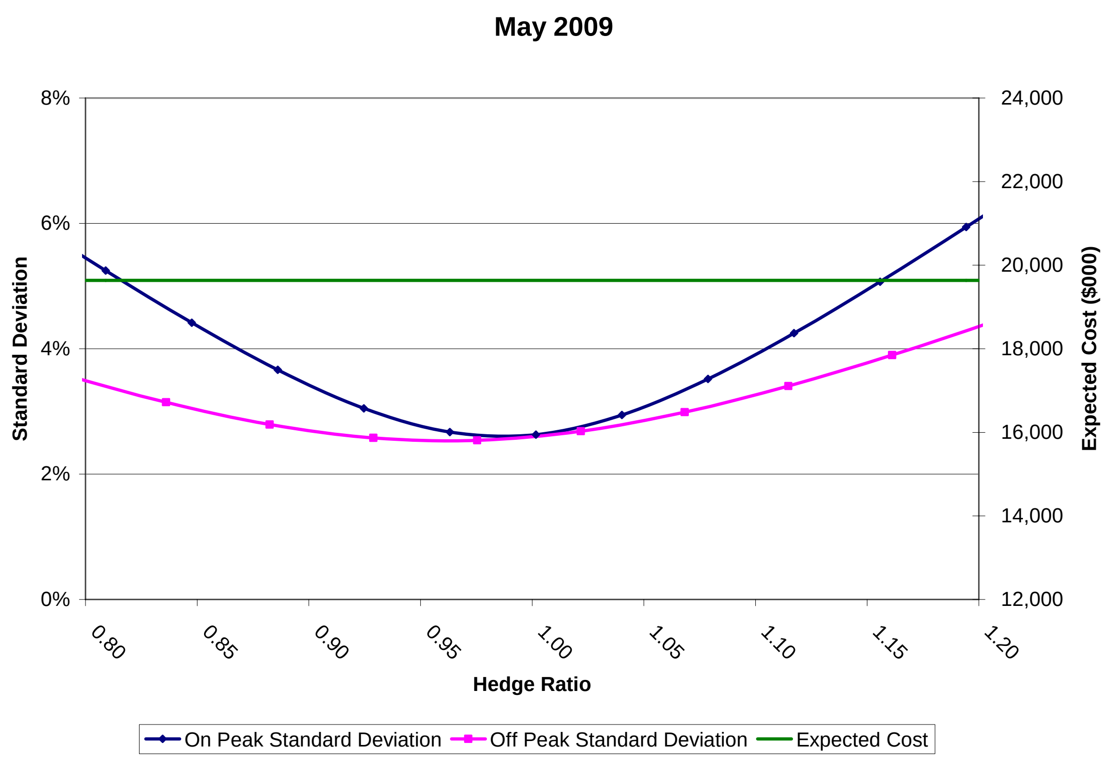
February 2009



March 2009




April 2009
Standard Deviation
8%
6%
4%
2%
0%
Expected Cost ($000)
26,000
24,000
22,000
20,000
18,000
16,000
14,000
12,000
0.80
0.85
0.90
0.95
1.00
1.05
1.10
1.15
1.20
Hedge Ratio
On Peak Standard Deviation
Off Peak Standard Deviation
Expected Cost


May 2009
Standard Deviation
8%
6%
4%
2%
0%
Expected Cost ($000)
24,000
22,000
20,000
18,000
16,000
14,000
12,000
0.80
0.85
0.90
0.95
1.00
1.05
1.10
1.15
1.20
Hedge Ratio
On Peak Standard Deviation
Off Peak Standard Deviation
Expected Cost

100% Spot Purchases

	Minimize Peak Standard Deviation						Minimize Off Peak Standard Deviation					
	MW	Cost	Std Dev	Avg Peak Load	# Peak Days	**Ratio**	MW	Cost	Std Dev	Avg Off Peak Load	Days in Month	**Ratio**
June-08	400	$19,957,373	$2,551,000	289,780	21	**0.46**	400	$7,892,938	$446,492	269,532	30	**0.57**
July-08	400	$30,296,315	$4,385,582	357,144	22	**0.39**	400	$12,737,684	$740,394	311,899	31	**0.50**
August-08	400	$27,450,849	$3,983,280	325,589	21	**0.41**	400	$13,139,314	$764,614	320,932	31	**0.51**
September-08	400	$17,141,439	$2,105,677	274,910	21	**0.49**	400	$7,405,641	$432,993	260,879	30	**0.59**
October-08	400	$14,350,023	$1,348,139	249,004	23	**0.59**	400	$6,564,082	$279,337	216,458	31	**0.69**
November-08	400	$13,131,311	$1,445,031	223,732	19	**0.54**	400	$7,956,618	$396,864	261,914	30	**0.64**
December-08	400	$17,045,777	$2,134,016	288,612	22	**0.49**	400	$8,558,985	$556,128	278,075	31	**0.56**
January-09	400	$21,378,997	$3,136,844	303,657	21	**0.44**	400	$14,562,886	$964,802	325,490	31	**0.50**
February-09	400	$18,959,864	$2,612,114	268,337	20	**0.48**	400	$11,797,099	$806,613	266,829	28	**0.53**
March-09	400	$16,569,045	$1,920,789	249,280	22	**0.56**	400	$8,708,456	$496,061	246,589	31	**0.64**
April-09	400	$14,970,647	$1,480,298	229,553	22	**0.61**	400	$7,176,830	$275,610	204,680	30	**0.72**
May-09	400	$13,042,764	$1,286,523	207,657	20	**0.62**	400	$6,596,610	$271,488	228,219	31	**0.74**
	Total	$224,294,404	$28,389,293	12.66%				$113,097,143	$6,431,395	5.69%		
Peak & Off Peak Total		**$337,391,547**	**$34,820,688**	10.32%								

Plan A

	Minimize Peak Standard Deviation						Minimize Off Peak Standard Deviation					
	MW	Cost	Std Dev	Avg Peak Load	# Peak Days	**Ratio**	MW	Cost	Std Dev	Avg Off Peak Load	Days in Month	**Ratio**
June-08	675	$19,957,389	$1,142,085	289,780	21	**0.78**	550	$7,892,936	$306,466	269,532	30	**0.78**
July-08	825	$30,296,345	$1,574,422	357,144	22	**0.81**	550	$12,737,693	$535,874	311,899	31	**0.69**
August-08	825	$27,450,840	$1,342,178	325,589	21	**0.85**	550	$13,139,325	$572,998	320,932	31	**0.70**
September-08	675	$17,141,438	$843,568	274,910	21	**0.82**	550	$7,405,652	$287,175	260,879	30	**0.81**
October-08	600	$14,350,028	$395,620	249,004	23	**0.89**	550	$6,564,079	$97,261	216,458	31	**0.96**
November-08	600	$13,131,323	$628,128	223,732	19	**0.82**	550	$7,956,614	$155,372	261,914	30	**0.87**
December-08	600	$17,045,781	$1,181,566	288,612	22	**0.73**	550	$8,558,984	$306,825	278,075	31	**0.78**
January-09	700	$21,378,979	$1,346,725	303,657	21	**0.77**	550	$14,562,826	$621,531	325,490	31	**0.69**
February-09	700	$18,959,837	$930,378	268,337	20	**0.83**	550	$11,797,045	$480,376	266,829	28	**0.73**
March-09	550	$16,569,055	$1,035,105	249,280	22	**0.78**	550	$8,706,970	$202,726	246,589	31	**0.87**
April-09	550	$14,970,856	$630,173	229,553	22	**0.84**	550	$7,173,443	$163,541	204,680	30	**0.99**
May-09	550	$13,044,272	$576,114	207,657	20	**0.85**	550	$6,592,205	$177,024	228,219	31	**1.02**
	Total	$224,296,143	$11,626,061	5.18%				$113,087,773	$3,907,171	3.45%		
Peak & Off Peak Total		**$337,383,915**	**$15,533,232**	4.60%								

Plan B

	Minimize Peak Standard Deviation						Minimize Off Peak Standard Deviation					
	MW	Cost	Std Dev	Avg Peak Load	# Peak Days	**Ratio**	MW	Cost	Std Dev	Avg Off Peak Load	Days in Month	**Ratio**
June-08	775	$19,957,397	$683,211	289,780	21	**0.90**	600	$7,892,935	$275,945	269,532	30	**0.85**
July-08	925	$30,296,350	$1,002,097	357,144	22	**0.91**	600	$12,737,694	$478,400	311,899	31	**0.75**
August-08	925	$27,450,839	$866,309	325,589	21	**0.95**	600	$13,139,330	$521,518	320,932	31	**0.76**
September-08	775	$17,141,434	$514,117	274,910	21	**0.95**	600	$7,405,659	$256,723	260,879	30	**0.88**
October-08	675	$14,350,027	$193,601	249,004	23	**1.00**	600	$6,564,077	$121,187	216,458	31	**1.04**
November-08	675	$13,131,326	$340,070	223,732	19	**0.92**	600	$7,956,610	$110,215	261,914	30	**0.95**
December-08	675	$17,045,780	$832,004	288,612	22	**0.82**	600	$8,558,988	$230,672	278,075	31	**0.85**
January-09	800	$21,379,139	$778,454	303,657	21	**0.89**	600	$14,562,750	$515,658	325,490	31	**0.75**
February-09	800	$18,961,184	$446,195	268,337	20	**0.95**	600	$11,796,882	$380,390	266,829	28	**0.79**
March-09	600	$16,569,210	$744,913	249,280	22	**0.85**	600	$8,705,648	$135,929	246,589	31	**0.95**
April-09	600	$14,972,192	$390,399	229,553	22	**0.92**	600	$7,172,978	$222,576	204,680	30	**1.08**
May-09	600	$13,045,249	$397,852	207,657	20	**0.92**	600	$6,591,082	$224,361	228,219	31	**1.11**
	Total	$224,300,126	$7,189,222	3.21%				$113,084,634	$3,473,573	3.07%		
Peak & Off Peak Total		**$337,384,760**	**$10,662,795**	3.16%								

Plan C

	Minimize Peak Standard Deviation						Minimize WRAP Standard Deviation					
	MW	Cost	Std Dev	Avg Peak Load	# Peak Days	**Ratio**	MW	Cost	Std Dev	Avg Off Peak Load	Days in Month	**Ratio**
June-08	825	$19,957,397	$508,809	289,780	21	**0.96**	625	$7,892,935	$265,545	269,532	30	**0.89**
July-08	975	$30,296,356	$787,031	357,144	22	**0.96**	625	$12,737,691	$452,883	311,899	31	**0.79**
August-08	975	$27,450,840	$740,038	325,589	21	**1.01**	625	$13,139,329	$499,267	320,932	31	**0.79**
September-08	825	$17,141,432	$471,087	274,910	21	**1.01**	625	$7,405,660	$247,149	260,879	30	**0.92**
October-08	700	$14,350,027	$242,638	249,004	23	**1.03**	625	$6,564,077	$150,217	216,458	31	**1.09**
November-08	700	$13,131,329	$256,626	223,732	19	**0.95**	625	$7,956,608	$110,621	261,914	30	**0.99**
December-08	700	$17,045,781	$718,216	288,612	22	**0.85**	625	$8,558,988	$196,252	278,075	31	**0.88**
January-09	850	$21,379,880	$526,576	303,657	21	**0.94**	625	$14,562,568	$466,030	325,490	31	**0.78**
February-09	850	$18,962,271	$334,215	268,337	20	**1.01**	625	$11,796,821	$334,293	266,829	28	**0.82**
March-09	625	$16,569,475	$603,001	249,280	22	**0.88**	625	$8,704,780	$125,268	246,589	31	**0.99**
April-09	625	$14,973,482	$309,903	229,553	22	**0.96**	625	$7,172,588	$261,359	204,680	30	**1.12**
May-09	625	$13,045,551	$348,403	207,657	20	**0.96**	625	$6,590,683	$257,037	228,219	31	**1.16**
	Total	$224,303,820	$5,846,545	2.61%				$113,082,727	$3,365,921	2.98%		
Peak & Off Peak Total		**$337,386,547**	**$9,212,466**	2.73%								

Plan D

	Minimize Peak Standard Deviation						Minimize Off Peak Standard Deviation					
	MW	Cost	Std Dev	Avg Peak Load	# Peak Days	**Ratio**	MW	Cost	Std Dev	Avg Off Peak Load	Days in Month	**Ratio**
June-08	875	$19,957,400	$437,719	289,780	21	**1.01**	650	$7,892,933	$258,947	269,532	30	**0.93**
July-08	1025	$30,296,360	$685,311	357,144	22	**1.01**	650	$12,737,694	$430,031	311,899	31	**0.82**
August-08	1025	$27,450,836	$748,274	325,589	21	**1.06**	650	$13,139,333	$479,780	320,932	31	**0.83**
September-08	875	$17,141,432	$548,056	274,910	21	**1.07**	650	$7,405,660	$241,999	260,879	30	**0.96**
October-08	750	$14,350,026	$439,617	249,004	23	**1.11**	650	$6,564,077	$184,266	216,458	31	**1.13**
November-08	750	$13,131,332	$176,176	223,732	19	**1.02**	650	$7,956,609	$128,000	261,914	30	**1.03**
December-08	750	$17,045,778	$500,376	288,612	22	**0.91**	650	$8,558,988	$166,337	278,075	31	**0.92**
January-09	900	$21,381,283	$361,872	303,657	21	**1.00**	650	$14,562,389	$419,622	325,490	31	**0.81**
February-09	900	$18,963,747	$433,524	268,337	20	**1.07**	650	$11,796,638	$292,474	266,829	28	**0.86**
March-09	650	$16,569,934	$465,319	249,280	22	**0.92**	650	$8,704,131	$136,195	246,589	31	**1.03**
April-09	650	$14,974,696	$288,343	229,553	22	**1.00**	650	$7,172,162	$303,271	204,680	30	**1.17**
May-09	650	$13,045,825	$343,185	207,657	20	**1.00**	650	$6,590,423	$293,188	228,219	31	**1.21**
	Total	$224,308,649	$5,427,772	2.42%				$113,081,038	$3,334,110	2.95%		
Peak & Off Peak Total		**$337,389,687**	**$8,761,883**	2.60%								

Plan E

	Minimize Peak Standard Deviation						Minimize Off Peak Standard Deviation					
	MW	Cost	Std Dev	Avg Peak Load	# Peak Days	**Ratio**	MW	Cost	Std Dev	Avg Off Peak Load	Days in Month	**Ratio**
June-08	875	$19,957,400	$437,719	289,780	21	**101.5%**	675	$7,892,931	$256,444	269,532	30	**96.2%**
July-08	1025	$30,296,360	$685,311	357,144	22	**101.0%**	775	$12,737,700	$371,320	311,899	31	**97.4%**
August-08	1025	$27,450,836	$748,274	325,589	21	**105.8%**	775	$13,139,339	$435,145	320,932	31	**98.5%**
September-08	875	$17,141,432	$548,056	274,910	21	**106.9%**	675	$7,405,665	$241,559	260,879	30	**99.4%**
October-08	750	$14,350,026	$439,617	249,004	23	**110.8%**	600	$6,564,077	$121,187	216,458	31	**104.2%**
November-08	750	$13,131,332	$176,176	223,732	19	**101.9%**	600	$7,956,610	$110,215	261,914	30	**95.3%**
December-08	750	$17,045,778	$500,376	288,612	22	**91.5%**	600	$8,558,988	$230,672	278,075	31	**84.6%**
January-09	900	$21,381,283	$361,872	303,657	21	**99.6%**	750	$14,560,908	$296,231	325,490	31	**94.0%**
February-09	900	$18,963,747	$433,524	268,337	20	**107.3%**	750	$11,795,225	$218,248	266,829	28	**98.9%**
March-09	650	$16,569,934	$465,319	249,280	22	**91.8%**	550	$8,706,970	$202,726	246,589	31	**87.4%**
April-09	650	$14,974,696	$288,343	229,553	22	**99.7%**	550	$7,173,443	$163,541	204,680	30	**98.9%**
May-09	650	$13,045,825	$343,185	207,657	20	**100.2%**	550	$6,592,205	$177,024	228,219	31	**102.2%**
	Total	$224,308,649	$5,427,772	2.42%				$113,084,061	$2,824,312	2.50%		
Peak & Off Peak Total		**$337,392,710**	**$8,252,084**	2.45%								

Ameren Services Company
on behalf of
AmerenCILCO
AmerenCIPS
AmerenIP

St. Louis, MO

REQUEST FOR PROPOSALS

FOR

PROCUREMENT ADMINISTRATOR

The Ameren Illinois Utilities
Request for Proposals for Procurement Administrator

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1.0 Purpose of Request for Proposals

Ameren Services Company, on behalf of the Illinois operating companies, namely 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 (collectively “the Ameren Illinois Utilities”) is soliciting bids for a Procurement Administrator (PA). The PA will be responsible for administering a competitive procurement process in accordance with a pre-established, Illinois Commerce Commission approved procurement plan for the acquisition of a portfolio of standard energy products to be used by the Ameren Illinois Utilities to serve the native load requirements.

2.0 Background

As a result of the Electric Service Customer Choice and Rate Relief Law of 1997 (the "Customer Choice Law"), traditional bundled service retail customers were provided the opportunity to purchase their power and energy (but not delivery service) requirements from alternative suppliers. It also contained various provisions and incentives which resulted in a fundamental restructuring of the State's electric power industry – including the divestiture of virtually all generation by the State’s major utilities. The Customer Choice Law provided a transition period prior to mandatory unbundling of full requirements service (power, energy, transmission and distribution services), during which retail rates were frozen (after first being significantly discounted in accordance with the Law). During this period, the Ameren Illinois Utilities utilized long-term purchased power agreements (PPAs) to provide power, energy and certain ancillary services to their full requirements customers. This transition period and the PPAs used to supply service, ended January 1, 2007 and December 31, 2006, respectively.

In anticipation of the end of the transition period and the coincident expiration of the PPAs, the Ameren Illinois Utilities participated in a reverse auction (“the Illinois Auction”) in September, 2006, to procure the full requirements (power, energy and ancillary services) supply needed to serve those retail customers who continued to take supply from the Ameren Illinois Utilities following the end of the transition period. At the conclusion of the Illinois Auction, for those customers with peak demands of 1MW or less, contracts were executed with winning suppliers for terms of 17 months for roughly 1/3 of the load, 29 months for roughly 1/3 of the load and 41 months for roughly 1/3 of the load. For customers with peak demands in excess of 1MW, contracts were executed with winning suppliers for a term of 17 months.

When the transition period expired Ameren’s rates to customers were unfrozen and customers were exposed to prices arising from the auction, resulting in the first rate increases to customers in 15 to 25 years. Significant customer switching has occurred for those customers with peak demands of 400 kW and greater.

As a result of the rate increases, legislation was introduced and ultimately passed in the Illinois General Assembly, which among other things, replaced the Illinois Auction with a portfolio procurement process, declared those customer classes with peak demands of 400 kW or more to be competitive and established the Illinois Power Agency (IPA), to administer a procurement process beginning in June 2009. The Ameren Illinois Utilities have oversight responsibility for developing their individual plan and for administering the procurement process for planning year 2008 (for supply delivery dates spanning [minimally] June 1, 2008 through May 31, 2009). Responsibility shifts to the IPA and its administrator starting with planning year 2009.

The Procurement Administrator, awarded as a result of this RFP, will design and implement a competitive procurement process in accordance with the provisions in the new legislation, to acquire capacity and energy products as provided for in the Illinois Commerce Commission approved procurement plan for the time period of June 1, 2008, through May 31, 2009, for those quantities necessary to replace that currently provided via the 17 month Illinois Auction contracts that will expire on May 31, 2008. In addition, the PA will work with the Ameren Illinois Utilities renewable team to design and implement a competitive procurement process to acquire the renewable energy credits as provided in the procurement plan. The PA shall not be responsible for the administration of those portions of the procurement plan related to the power and energy requirements of customers with peak demand requirements of 1 MW or greater.

The PA shall be provided with the plan outlining the required energy products prior to its commencement of activities to design and implement the competitive procurement process.

3.0 Instructions to Bidders

3.1 General

3.1.1 Subject to 3.1.2, all proposals submitted to the Ameren Illinois Utilities pursuant to this RFP shall become the exclusive property of the Ameren Illinois Utilities and may be used for any reasonable purpose by the Ameren Illinois Utilities.

3.1.2 The Ameren Illinois Utilities shall consider materials provided by Bidders in response to this RFP to be confidential only if such materials are clearly designated as "Confidential". Bidders should be aware that their proposal, even if marked “Confidential”, may be subject to discovery and disclosure in regulatory or judicial proceedings that may or may not be initiated by the Ameren Illinois Utilities. Bidders may be required to justify the requested confidential treatment under the provisions of a protective order issued in such proceedings. If required by an order of an agency or court of competent jurisdiction, the Ameren Illinois Utilities may produce the material in response to such order without prior consultation with the bidder.

3.1.3 Bidders are to provide time and material rates to perform the required duties of the Procurement Administrator.

3.2 Overview of the Procurement Process.

3.2.1 The procurement process utilized by the Procurement Administrator must be in accordance with the directives provided by the Federal Energy Regulatory Commission including those commonly referred to as the Edgar Standards (55 FERC 61,382 (1991)) and the Allegheny Model (108 FERC 61,082 (2004)). FERC provides additional guidance in FERC Docket Nos. EC03-53-000 and EC03-53-001 applicable to the referenced procurement process as follows:

> The fundamental objective of the solicitation guidelines is that the affiliate should have no undue advantage over non-affiliates in the solicitation process. Adhering to the guidelines will ensure that wholesale customers receive the benefit of the marketplace, including an unbiased assessment of the full range of choices, whether the soliciting utility provides service at cost- or market-based rates.
>
> The solicitation guidelines have four principles:
>
> a. Transparency: the competitive solicitation process should be open and fair.
>
> b. Definition: the product or products sought through the competitive solicitation should be precisely defined.
>
> c. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders.
>
> d. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the Ameren Illinois Utilities' selection.

3.2.2 The Procurement Administrator shall:

(i) Review and provide comments on the portfolio of capacity, energy and renewable energy products included in the procurement plan, designed by the Ameren Illinois Utilities, prior to such plan being filed with the Commission.

(ii) Design the final procurement process in accordance with Section 1-75 of the Illinois Power Agency Act and section 16-111.5(e) of the PUA, (The above referenced sections can be found in the PDF document, starting at pages 29 and 171, at the following site: http://www.ilga.gov/legislation/fulltext.asp?DocName=&SessionId=51&GA=95&DocTypeId=SB&DocNum=1592&GAID=9&LegID=29675&SpecSess=&Session=). The procurement process shall include each of the following components:

a) **Solicitation, pre-qualification and registration of bidders.** The procurement administrator shall disseminate information to potential bidders that promotes a procurement event, notify potential bidders that the procurement administrator may enter into a post-bid price negotiation with bidders that meet the applicable benchmarks, provide supply requirements, and otherwise explain the competitive procurement process. In addition to such other publication as the procurement administrator determines is appropriate, this information shall be posted on the Commission's website. The procurement administrator shall also administer the prequalification process, including evaluation of credit worthiness, compliance with procurement rules, and agreement to the standard form contract developed pursuant to paragraph (b) [immediately below]. The procurement administrator shall then identify and register bidders to participate in the procurement event.

b) **Standard contract forms and credit terms and instruments.** 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. 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.

c) **Establishment of a market-based price benchmark.** As part of the development of the procurement process, the procurement administrator, in consultation with the Commission staff and the Commission's procurement monitor, shall establish benchmarks for evaluating the final prices in the contracts for each of the products that will be procured through the procurement process. The benchmarks shall be based on price data for similar products for the same delivery period and same delivery hub, or other delivery hubs after adjusting for that difference. The price benchmarks may also be adjusted to take into account differences between the information reflected in the underlying data sources and the specific products and procurement process being used to procure power for the Illinois utilities. The benchmarks shall be confidential but shall be provided to, and will be subject to Commission review and approval, prior to a procurement event.

d) **Request for proposals competitive procurement process.** The procurement administrator shall design and issue a request for proposals to supply electricity in accordance with the [Ameren Illinois utilities] procurement plan, as approved by the Commission. 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.

e) **A plan for implementing contingencies in the event of supplier default or failure of the procurement process to fully meet the expected load requirement due to insufficient supplier participation, commission rejection of results, or any other cause.**

(1) Event of supplier default: In the event of supplier default, the utility shall review the contract of the defaulting supplier to determine if the amount of supply is 200 megawatts or greater, and if there are more than 60 days remaining of the contract term. If both of these conditions are met, and the default results in termination of the contract, the utility shall immediately notify the Illinois Power Agency that a request for proposals must be issued to procure replacement power, and the procurement administrator shall run an additional procurement event. If the contracted supply of the defaulting supplier is less than 200 megawatts or there are less than 60 days remaining of the contract term, the utility shall procure power and energy from the applicable regional transmission organization market, including ancillary services, capacity, and day-ahead or real time energy or both, for the duration of the contract term to replace the contracted supply; provided, however, that if a needed product is not available through the regional transmission organization market it shall be purchased from the wholesale market.

(2) Failure of the procurement process to fully meet the expected load requirement: If the procurement process fails to fully meet the expected load requirement due to insufficient supplier participation or due to a Commission rejection of the procurement results, the procurement administrator, the procurement monitor, and the Commission staff shall meet within 10 days to analyze potential causes of low supplier interest or causes for the Commission decision. If changes are identified that would likely result in increased supplier participation, or that would address concerns causing the Commission to reject the results of the prior procurement event, the procurement administrator may implement those changes and rerun the request for proposals process according to a schedule determined by those parties and consistent with Section 1-75 of the Illinois Power Agency Act and this subsection. In any event, a new request for proposals process shall be implemented by the procurement administrator within 90 days after the determination that the procurement process has failed to fully meet the expected load requirement.

(3) In all cases where there is insufficient supply provided under contracts awarded through the procurement process to fully meet the electric utilities load requirement, the utility shall meet the load requirement by procuring power and energy from the applicable regional transmission organization market, including ancillary services, capacity, and day-ahead or real time energy, or both; provided however, that if a needed product is not available through the regional transmission organization market it shall be purchased form the wholesale market.

(iii) Develop benchmarks to be used to evaluate bids; these benchmarks shall be submitted to the Commission for review and approval on a confidential basis prior to the procurement event;

(iv) Serve as interface between the utility and suppliers;

- The list of RFP recipients will be developed by the PA and will include as many entities qualified to and capable of performance within the MISO, as practical. To ensure the list is comprehensive, the PA will provide the list of proposed RFP recipients to the Ameren Illinois Utilities and Staff for review prior to RFP distribution.
- The PA will be responsible for developing and maintaining a website that contains the RFP and a list of questions and answers from potential respondents. The PA will require that questions be submitted in writing to a private email address and both questions and subsequent responses will be posted to the website (the name of the counterparty

asking a question will be redacted from the website posting). In no circumstances should questions be directed to the Ameren Illinois Utilities and Staff. The PA may solicit a review of questions from the Ameren Illinois Utilities and Staff so long as respondent confidentiality is retained.

(v) Manage the bidder pre-qualification and registration process;

(vi) Obtain the electric utilities' agreement to the final form of all supply contracts and credit collateral agreements;

(vii) Administer the request-for-proposals process;

(viii) 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; any post-bid negotiations with bidders shall be limited to price only and shall be completed within 24 hours of opening the sealed bids and shall be conducted in a fair and unbiased manner; in conducting the negotiations, there shall be no disclosure of any information derived from proposals submitted by competing bidders; if information is disclosed to any bidder, it shall be provided to all competing bidders;

(ix) Maintain confidentiality of supplier and bidding information in a manner consistent with all applicable laws, rules, regulations and tariffs,

(x) Submit a confidential report to the Commission recommending acceptance or rejection of bids;

(xi) Notify the utility of contract counterparties and contract specifics, and

(xii) Administer related contingency procurement events.

3.3 Procurement Administrator Qualifications. In order to qualify an expert or expert consulting firm must have:

3.3.1 Direct previous experience assembling large-scale power supply plans or portfolios for end-use customers;

3.3.2 An advanced degree in economics, mathematics, engineering, risk management, or a related area of study;

3.3.3 Ten years of experience in the electricity sector, including managing supply risk;

3.3.4 Expertise in wholesale electricity market rules, including those established by the Federal Energy Regulatory Commission and regional transmission organizations; and

3.3.5 Expertise in credit and contract protocols;

3.3.6 Adequate resources to perform and fulfill the required functions and responsibilities; and

3.3.7 The absence of a conflict of interest and inappropriate bias for or against potential bidders or the affected electric utilities.

3.4 Deadline and Method for Submitting Proposals

3.4.1 All proposals submitted in response to this RFP must be received no later than close of business on September 10, 2007.

3.4.2 Provide a preliminary work plan covering all aspects of the project. The work plan must provide for active participation and coordination with Ameren Illinois Utilities' and ICC Staff. The work plan shall include the necessary steps to cover the Scope of Work, including the Procurement Process Components and the Additional Procurement Administrator Responsibilities. The focus of this and future work-plans is to function as a project management tool to assure the Ameren Illinois Utilities' that the Administrator has an adequate understanding of the requirements of the contract and can allocate resources reasonably to meet the requirements of the contract as well as provide appropriate performance benchmarks. Proposals should demonstrate how the requested services would be managed. Provide Organizational charts.

3.4.3 Provide your proposed resource commitment by specific identification of the individuals who will be assigned to work on this project, their position in your organization, their expected role in the project, their hourly fully loaded billing rates and their current curriculum vitae. Please provide an estimated percentage breakdown of the time commitment of personnel to the project.

3.4.4 Provide a complete statement of your qualification and experience (the firm and its proposed staff and/or subcontractors) for all items listed in Section 3.3.

3.4.5 Proposals should be mailed to the address listed below.

Ameren Services

1901 Chouteau Ave
PO Box 66149, MC 1450
St. Louis, MO 63166-6149

Attn: Dave Brueggeman

3.6 Questions and requests for interpretation of RFP can be emailed to:

DLPowerSupplyAcquisition@ameren.com

4.0 Schedule

4.1 Sample Project Schedule (actual dates will be determined by the PA and the Ameren Illinois Utilities)

4.1.1	Finalize Procurement Process	November 16, 2007
4.1.2	Develop Benchmarks	December 14, 2007
4.1.3	Bidder Registration	Nov 30 – Jan 11, 2008
	4.1.3.1 Solicitation – Issue RFP	November 30, 2007
	4.1.3.2 Registration	January 11, 2008
4.1.4	Procurement Event #1	Jan 21 – Feb 8, 2008
	4.1.4.1 Bids Due	February 1, 2008
	4.1.4.2 Submit Confidential Report	February 4, 2008
	4.1.4.3 Notify Winning Bidders	February 6, 2008
	4.1.4.4 Contract Execution Deadline	February 8, 2008
4.1.5	Procurement Event #2 (if needed)	Feb 11 - Feb 29, 2008
	4.1.5.1 Bids Due	February 21, 2008
	4.1.5.2 Submit Confidential Report	February 25, 2008
	4.1.5.3 Notify Winning Bidders	February 27, 2008
	4.1.5.4 Contract Execution Deadline	February 29, 2008
4.1.6	Procurement Event #3 (if needed)	Mar 3 – Mar 21, 2008
	4.1.6.1 Bids Due	March 13, 2008
	4.1.6.2 Submit Confidential Report	March 17, 2008
	4.1.6.3 Notify Winning Bidders	March 19, 2008
	4.1.6.4 Contract Execution Deadline	March 21, 2008
4.1.7	Contract Delivery Periods begin	June 1, 2008

4.2 Procurement Administrator RFP Schedule

4.2.1	Issue RFP	August 17, 2007
4.2.2	Bids Due	September 10, 2007
4.2.3	Award Contract	September 21, 2007

5.0 Evaluation

Will be based on bidder qualifications related to Section 3.3 and pricing considerations.