State of Illinois
Pat Quinn, Governor

ILLINOIS
POWER AGENCY

Power Procurement Plan to the Illinois Commerce Commission
September 30, 2009

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I. Executive Summary

Pursuant to Public Act 095-0481[1], the Illinois Power Agency ("IPA") submits its proposed electricity procurement plan (the "Plan") designed "to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time…"[2]

This document and its attachments comprise the second Plan prepared by the IPA. The IPA submits this Plan to the Illinois Commerce Commission ("ICC" or "Commission") for approval in compliance with the requirements of the IPA Act. The IPA Act requires that such a Plan be prepared and submitted annually.

This Plan's purpose is to detail a procurement approach that will secure electricity commodity and associated transmission services, plus required renewable energy assets to meet the supply needs of eligible retail customers served by Ameren Illinois Utilities ("Ameren") and Commonwealth Edison Company ("ComEd" and jointly the "Utilities").

This Plan outlines a procurement strategy for the period of June 2010 through May 2015 based on detailed 5-year demand forecasts provided by the Utilities. Because existing contracts are in place for a significant portion of the load needed to meet consumers' electricity needs over the near-term, procurement activities considered in this Plan are limited to meeting the residual consumer demand not covered by those contracts. The table below identifies the annual percentages of bundled service loads that are anticipated yet to be procured pursuant to IPA plans over a 60-month horizon.

Percentages of future Annual Loads to be secured via IPA Process		
Planning Period	**Commonwealth Edison**	**Ameren Illinois Utilities**
2010-2011	26.87%	26.82%
2011-2012	33.14%	49.11%
2012-2013	33.86%	69.50%
2013-2014	100.00%	100.00%
2014-2015	100.00%	100.00%

Procurement Approach. The IPA maintains that a laddered approach to procurement using the statutory request for proposals ("RFP") bid process will provide the highest probability of cost stability and at-the-market prices for electricity.

The lowest price risk scenario is achieved when the portfolio is procured relatively evenly over three years, the current period for which there is sufficient liquidity in wholesale energy markets. As prescribed in the 2009 cycle, procurement distributions ranging between 20% and 40% continue to deliver a sufficient propensity to mitigate price risk for consumers. Because future market conditions cannot be known, the IPA proposes to employ a portfolio distribution schedule that allows between 20% and 40% of projected loads to be procured in each of the three years prior to the delivery month. Within this range, IPA modeling determined that the following three-year laddered procurement strategy has the highest probability of yielding the lowest and most stable prices, based on current market conditions:

- 35% of projected energy needs procured two years in advance of the year of delivery.
- 35% of projected energy needs procured one year in advance of delivery.
- 30% of projected energy needs procured in the year in which power is to be delivered.

[1] Referred to as the Illinois Power Agency Act, or "IPA Act".
[2] 220 ILCS 5/16-111.5(d)(4).

The Plan proposes the following changes from the last procurement cycle:

- To consolidate the procurement of renewable energy resources for the Utilities under a single procurement event.

- To conduct formal solicitations for capacity in the both the Ameren and ComEd service regions, and to open those solicitations to qualified demand response providers as consistent with 220 ILCS 5/16-111.5(b)(3)(ii).

- To conduct a separate capacity procurement event to be limited to demand response providers only in the event that no demand response providers participate in the standard capacity procurement described above. The purpose of the separate capacity procurement will be to develop contract terms and conditions that will incent the development of demand response programs that meet the stated requirements of 220 ILCS 5/16-111.5(b)(3)(ii).

- To conduct solicitations for long-term supply contracts from renewable energy providers that are cost-of-generation based, and take full advantage of federal and state incentives that are available in the near term.

Portfolio Design. To achieve low and stable prices when acquiring electricity in a market where prices change constantly (and sometimes dramatically) is the IPA's greatest challenge, particularly when the load to be served is also subject to constant flux. Designing the portfolio requires understanding the variables that drive price and load fluctuation, and assessing how those variables affect price risk. After completing its portfolio design exercise and examining the 2008 and 2009 procurement plans approved for ComEd and Ameren, this IPA's Plan proposes a series of standard electricity products to be acquired to meet the needs of eligible customers that would be augmented by market purchases if and when necessary. Schedules detailing these products and volumes for each utility are included in the Plan.

II. Introduction and Overview

Public Act 095-0481, which includes the IPA Act and certain modifications to the Public Utilities Act ("PUA") was signed into law on August 28, 2007. The IPA Act identifies four primary activities to be undertaken by the Agency:

(a)The Agency is authorized to do each of the following:

(1) develop electricity procurement plans 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, for electric utilities that on December 31, 2005 provided electric service to at least 100,000 customers in Illinois. The procurement plans shall be updated on an annual basis and shall include electricity generated from renewable resources sufficient to achieve the standards specified in the Act.

(2) conduct competitive procurement processes to procure the supply resources identified in the procurement plan, pursuant to Section 16-111.5 of the Public Utilities Act.

(3) develop electric generation and co-generation facilities that use indigenous coal or renewable resources, or both, financed with bonds issued by the Illinois Finance Authority.

(4) supply electricity from the Agency's facilities at cost to one or more of the following: municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois.[3]

This is the second Plan submitted by the IPA in accordance with the Section 16-111.5 of PUA. This Plan considers the procurement strategy for the period of June 2010 through May 2015. The Plan applies to the following Utilities: AmerenCILCO, AmerenCIPS, AmerenIP ("Ameren"), and ComEd.

The IPA Act requires that the Plan include the following general components:

Each procurement plan shall analyze the projected balance of supply and demand for eligible retail customers over a 5-year period with the first planning year beginning on June 1 of the year following the year in which the plan is filed. The plan shall specifically identify the wholesale products to be procured following plan approval, and shall follow all the requirements set forth in the Public Utilities Act and all applicable State and federal laws, statutes, rules, or regulations, as well as Commission orders[4]

Specific inclusions to the Plan are noted as follows in the IPA Act:

A procurement plan shall include each of the following components:

(1) Hourly load analysis. This analysis shall include:
(i) Multi-year historical analysis of hourly loads;
(ii) Switching trends and competitive retail market analysis;
(iii) Known or projected changes to future loads; and
(iv) Growth forecasts by customer class.

(2) Analysis of the impact of any demand side and renewable energy initiatives. This analysis shall include:
(i) the impact of demand response programs, both current and projected;
(ii) supply side needs that are projected to be offset by purchases of renewable energy resources, if any; and
(iii) the impact of energy efficiency programs, both current and projected.

(3) A plan for meeting the expected load requirements that will not be met through preexisting contracts. This plan shall include:

3 20 ILCS 3855/1-20.
4 220 ILCS 5/16-111.5(b).

(i) definitions of the different retail customer classes for which supply is being purchased;

(ii) the proposed mix of demand-response products for which contracts will be executed during the next year. The cost-effective demand-response measures shall be procured whenever the cost is lower than procuring comparable capacity products, provided that such products shall:

(A) be procured by a demand-response provider from eligible retail customers;

(B) at least satisfy the demand-response requirements of the regional transmission organization market in which the utility's service territory is located, including, but not limited to, any applicable capacity or dispatch requirements;

(C) provide for customers' participation in the stream of benefits produced by the demand-response products;

(D) provide for reimbursement by the demand-response provider of the utility for any costs incurred as a result of the failure of the supplier of such products to perform its obligations thereunder; and

(E) meet the same credit requirements as apply to suppliers of capacity, in the applicable regional transmission organization market;

(iii) monthly forecasted system supply requirements, including expected minimum, maximum, and average values for the planning period;

(iv) the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year, separately or in combination, to meet that portion of its load requirements not met through pre-existing contracts, including but not limited to monthly 5 x 16 peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity obligations, capacity purchase plan, and ancillary services;

(v) proposed term structures for each wholesale product type included in the proposed procurement plan portfolio of products; and

(vi) an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the following factors: contract terms, time frames for securing products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment; the proposed procurement plan shall also identify alternatives for those portfolio measures that are identified as having significant price risk.

(4) Proposed procedures for balancing loads. The procurement plan shall include, for load requirements included in the procurement plan, the process for:

(i) hourly balancing of supply and demand; and,

(ii) the criteria for portfolio re-balancing in the event of significant shifts in load[5].

This Plan, as submitted, meets the requirements of the IPA Act.

A. Illinois Electricity Market Background. In 1997, the Illinois General Assembly passed the Electric Service Customer Choice and Rate Relief Act, legislation that restructured electricity markets and phased in a competitive power market in Illinois. All customers of ComEd and Ameren were given the legal option to purchase electricity from Alternative Retail Energy Suppliers ("ARES") or from their local utility. Regardless of energy supplier, the Utilities were obligated to provide customers non-discriminatory delivery services. The 1997 law created a "mandatory transition period" during which retail electricity rates were reduced and then frozen, and the Utilities were allowed to transfer or sell generation assets to affiliated companies or third parties. The transition period was extended in subsequent legislation through the end of 2006. After a series of proceedings, the Commission entered Orders approving the Utilities' proposals, as modified, to

[5] 220 ILCS 5/16-111.5(b).

procure power after the transition period through a full requirements reverse auction. The auctions were conducted in fall 2006, and electricity rates for customers buying power from the Utilities were adjusted to reflect those costs as of January 2007.

SB 1592[6] was approved by the General Assembly and signed into law in the summer of 2007. In addition to providing $1 billion in temporary rate relief to consumers, and creating renewable energy and energy efficiency standards, it created the IPA to develop and manage a new power procurement process. Beginning on June 1, 2008, the Utilities were required to procure all power for eligible retail customers ("Eligible Retail Customers") who purchase electricity from the Utilities according to a Plan developed by the IPA and approved by the Commission.

The PUA provides for generation service to be declared competitive for classes of customers when the Commission finds sufficient evidence that competition for generation service within a customer class meet certain legal standards. Certain classes have been declared competitive as a matter of law by action of the General Assembly.

All ComEd commercial and industrial ("C&I") customer classes with demand greater than 100kW are deemed competitive, as are Ameren customers with demand of at least 400kW. However, the law allowed ComEd customers with demand below 400kW, and Ameren customers with demand between 400kW and 1000 kW to continue to purchase power and energy from the utility at bundled utility service rates through May 30, 2010. The law provided that no customer in a class declared competitive is allowed to return to bundled utility service after having switched to an alternative provider. After May 31, 2010, ComEd and Ameren will procure power for customers in classes deemed competitive only by purchasing electricity in the hourly spot market and passing through those variable market prices to the customers.

The IPA procurement plans are designed to accommodate the electricity needs of customers who continue buying bundled service electricity from the Utilities. According to the latest published data for the Commission's Electric Switching Statistics – DASR report (April 2009 for ComEd and May 2009 for Ameren), 44% of the total electricity usage by ComEd and Ameren customers was supplied through fixed price bundled utility service. This is the load that will be served through IPA procurement planning. According to those same reports, 99.8% of ComEd and 99.5% of Ameren residential customers remain on bundled rates.

As noted above, the IPA must submit a Plan each year identifying projected loads for Eligible Retail Customers," and a plan for fulfilling those load requirements. Per the PUA, Eligible Retail Customers are defined as:

> *[T]hose retail customers that 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 and those other customer groups specified in this Section, including self-generating customers, customers electing hourly pricing, or those customers who are otherwise ineligible for fixed-price bundled tariff service.*[7]

Existing (legacy) supply contracts dating from the 2007 rate relief agreements and the 2009 procurement cycle will supply portions of the IPA portfolio over the next three years. The IPA will be responsible for managing the procurement of that portion of the eligible-customer load not supplied by the legacy contracts. Table A identifies the annual load percentages that the IPA currently views as requiring placement through the IPA Plan over the next five years.

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[6] Public Act 095-0481

[7] 220 ILCS 5/16-111.5(a).

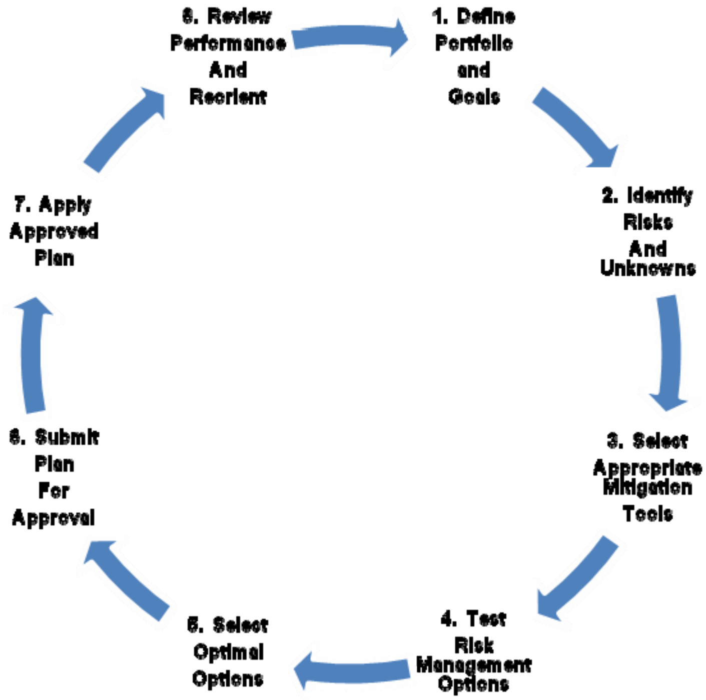
TABLE A: PERCENTAGES OF AGGREGATE LOAD TO BE PROCURED BY THE IPA

Percentages of Projected Load to be met through IPA managed Procurement		
Planning Period	**Commonwealth Edison**	**Ameren Illinois Utilities**
2010-2011	25.11%	26.82%
2011-2012	33.14%	49.11%
2012-2013	33.86%	69.50%
2013-2014	100.00%	100.00%
2014-2015	100.00%	100.00%

B. Illinois Power Agency Planning Process Overview. This document presents a Plan to secure pricing and supplies of electricity commodities and required transmission services to meet the supply requirements for Eligible Retail Customers of Ameren and ComEd. Additionally, it proposes a compliance plan to meet the State's Renewable Portfolio Standard ("RPS") for those same Eligible Retail Customers. This Plan does not address supply needs or RPS compliance methods for hourly rate customers of the Utilities, or those customers taking service from ARES.

The IPA Act requires that a Plan be submitted annually and that the IPA consider a five-year time horizon when formulating its Plan. The IPA has adopted a continuous-cycle planning process that responds to changing information and market conditions. The diagram below outlines the general stages of the IPA procurement planning process.

FIGURE 1: IPA PROCUREMENT PLANNING PROCESS



1. **Define Portfolio and Goals.** The IPA works with Utilities to define the size of the electricity needs to be supplied by the Plan. Other stakeholders also have opportunity for input into the IPA planning agenda.
2. **Identify Risks and Unknowns.** Market conditions and other factors are reviewed to identify elements that present the potential for increasing consumer prices.
3. **Select appropriate mitigation tools.** Procurement methods and products to most effectively and efficiently mitigate immediate and long-term risks are identified.

4. **Test risk management options.** Statistical models to test the performance and value of identified risk mitigating options are developed and deployed.
5. **Select optimal options.** Products and procedure most suitable for delivering the lowest and most stable costs to the Portfolio are selected.
6. **Submit for approval.** IPA submits Plan for approval by ICC.
7. **Apply Approved plan.** IPA, Procurement Administrator, and the Utilities coordinate procurement according to the approved Plan.
8. **Review Plan performance and reorient.** Performance of the Plan with regard to prices and stability is closely monitored, and subsequent Plan is reoriented to address current market conditions, new risks and opportunities.

The IPA Act requires several steps in the Plan approval process. A timeframe for those steps is presented in Table B.

TABLE B: IPA PLAN SUBMISSION AND AUTHORIZATION SCHEDULE

Planning Activities	July					August				September				October					November				December				
1. Utilities Submit Load Projections			X																								
2. IPA Prepares Preliminary Plan																											
3. IPA Submits Preliminary Plan								X																			
4. Public Comment Period																											
5. Final Plan submitted to ICC													X														
6. Objections filing period														X													
7. ICC Hearings determination																											
8. ICC review of Plan																											
9. ICC confirms or modifies Plan																											X

1. **Utilities Submit Load Forecasts.** The IPA Act requires the Utilities to submit detailed hourly projections of the load to be supplied by the Utilities ("Load Forecast"). The projections extend out for five years and are adjusted for customer switching, as well as Utility-sponsored Demand Response, and Energy Efficiency Programs.
2. **IPA Prepares Preliminary Plan.** The IPA Act requires the IPA to develop and submit a Plan that would secure volumes of electricity sufficient to meet the needs of customers purchasing electricity from the Utilities.
3. **IPA Submits Preliminary Plan.** The Preliminary Plan is submitted to the ICC for review.
4. **Public Comment Period.** The Preliminary Plan is made available to the public for comment. As required by the PUA, during the 30-day period allowed for utilities and other interested entities to submit comments on the IPA's draft plan, the IPA will hold at least one public hearing within each utility's service area for the purpose of receiving public comment on the procurement plan.
5. **Final Plan Submission to ICC.** A Final Plan is prepared by the IPA in consideration of the comments received during the public comment period. The Final Plan is submitted to the ICC for approval.
6. **Objections Filing Period.** Objections to the Plan must be filed within five (5) days after the plan is filed with the ICC.
7. **ICC Hearings Determination.** ICC has ten (10) days after the plan is filed to determine whether hearings on the Plan are required.
8. **ICC Review of Final Plan.** ICC may take up to ninety (90) days to review the Final Plan.

9. **ICC Approves a Procurement Plan.** The Final Plan is either approved by a vote of the ICC, or an alternative to the IPA Final Plan is approved by the ICC.

The IPA Act requires the following activities in order to execute the recommendations contained in the approved Plan. A timeframe for those steps as they relate to the procurement of energy, capacity, and the RPS is presented below in Table C below.

TABLE C: IPA PROCUREMENT SPRING CYCLE A EXECUTION SCHEDULE

Procurement Activities	December					January				February				March				April				May				June			
A1. Procurement Administrator Selected	X																												
A2. RFP and systems developed																													
A3. RFP Released										X																			
A4. Procurement Event Preparation																													
A5. Procurement Events for Cycle A																													
A6. Supply Contracts from Procurement Cycle A Executed																													
A7. Procured Products Delivery Begins																													

A1. Procurement Administrator Selected. The IPA Act requires that the IPA retain the services of a Procurement Administrator to facilitate execution of the Plan. This third party entity serves as a coordinator of the bidding and contracting activities between the Utilities, bidders, the IPA and the ICC.

A2. RFP and Systems Developed. The Procurement Administrator must develop and submit a series of standard bidder qualifications, submittal documents, industry standard contracts, and bid evaluation forms and methods to facilitate the issuance of the RFP required by the IPA Act.[8]

A3. RFP Released. Upon completion of the required preparations and authorizations, the Procurement Administrator will issue a series of RFP's to potential wholesale bidders. Bids will be submitted according to the standard products specifications developed by the Procurement Administrator, the Utilities, and the IPA.

A4. Procurement Event Preparation. The Procurement Administrator will be required to establish methods and platforms to facilitate bidding on defined electricity products. The Procurement Administrator also will be required to facilitate capacity procurement as well as the purchase of renewable energy requirements as specified in the approved Plan.

A5. Procurement Events for Cycle A. The Procurement Administrator will manage the receipt, validation, and evaluation of sealed bids, including the option of post-bid price negotiations with bidders within 24 hours of bid opening for those products let to bid in cycle A of the 2010 procurement year.

A6. Contracts Executed. The Procurement Administrator has two days to submit a confidential recommendation regarding whether the low bids meet market-based benchmarks and should be accepted. The ICC then has two days to accept or reject the recommendations, and the utility then has three days to sign bilateral supply agreements with successful bidders.

[8] 220 ILCS 5/16-111.5(e).

A7. Procured Products Delivery Begins. Contracts secured through the procurement events for cycle A held in Spring 2010 will start in June of 2010 (and some contracts may be effective at a later date). These procured volumes will be in addition to those electricity supplies already secured via legacy contract sources from the swap contracts resulting from the 2007 rate settlement agreement, and the 2009 IPA procurement cycle.

Section 16-111.5(b)(3)(ii) requires that capacity be procured from qualified demand response resources whenever the cost of such resources is less than the cost of traditional capacity. 220 ILCS 5/16-111.5(b)(3)(ii). The IPA recommends that demand response sourced capacity be included an approved alternative traditional capacity resources in the Cycle A procurement events. Further, the IPA recommends that a secondary procurement event (Cycle B) be undertaken in the Fall of 2010 in the event that Cycle A procurements fail to identify and award capacity supply contracts to demand response capacity resource providers. A timeframe for those steps as they relate to the procurement of capacity from demand response sources providers is , and the RPS is presented in Table D below.

TABLE D: IPA FALL 2010 CYCLE B PROCUREMENT EVENT SCHEDULE

Procurement Activities	September					October				November			
B1. Draft Requests for Proposals for specified products													
B2. Release RFP's			X										
B3. Procurement Event Preparation													
B4. Procurement Events for Cycle B													
B5. Supply Contracts from Procurement Cycle B Executed													

B1. Draft Requests for Proposals for Specified Products Potential vendors will be solicited for input in the development of the Requests for Proposals.

B2. Release RFP's. Upon completion of the required preparations and authorizations, the Procurement Administrator will issue a series of RFP's to potential wholesale bidders. Bids will be submitted according to the standard products specifications developed by the Procurement Administrator, the Utilities, and the IPA.

B3. Procurement Event Preparation. The Procurement Administrator will be required to establish methods and platforms to facilitate bidding on defined electricity products. The Procurement Administrator also will be required to facilitate capacity procurement as specified in the approved Plan.

B4. Procurement Events for Cycle B. The Procurement Administrator will manage the receipt, validation, and evaluation of sealed bids, including the option of post-bid price negotiations with bidders within 24 hours of bid opening for those products let to bid in Cycle B of the 2010 Procurement.

B5. Supply Contracts from Procurement Cycle B Executed. The Procurement Administrator has two days to submit a confidential recommendation regarding whether the low bids meet market-based benchmarks and should be accepted. The ICC then has two days to accept or reject the recommendations, and the utility then has three days to sign bilateral capacity agreements with successful bidders.

III. Load Forecast for the Period June 1, 2010 – May 31, 2015

The Procurement Portfolio is defined by the Load Forecasts provided to the IPA by the Utilities. The PUA requires:

> *"Beginning in 2008, each Illinois utility procuring power pursuant to this Section shall annually provide a range of load forecasts to the Illinois Power Agency by July 15 of each year, or such other date as may be required by the Commission or Agency. The load forecasts shall cover the 5-year procurement planning period for the next procurement plan and shall include hourly data representing a high-load, low-load and expected-load scenario for the load of the eligible retail customers. The utility shall provide supporting data and assumptions for each of the scenarios."*[9]

Consistent with the PUA, on July 15, 2009, ComEd and Ameren prepared and submitted to the IPA separate Load Forecasts. Per the request of the IPA, the Utilities also provided detailed descriptions of the statistical methods and assumptions underlying the projections. The Load Forecast model and results provided by the Utilities has not been independently validated by the IPA. Copies of the Utilities' submittals can be found in Attachment A and C to this Plan.

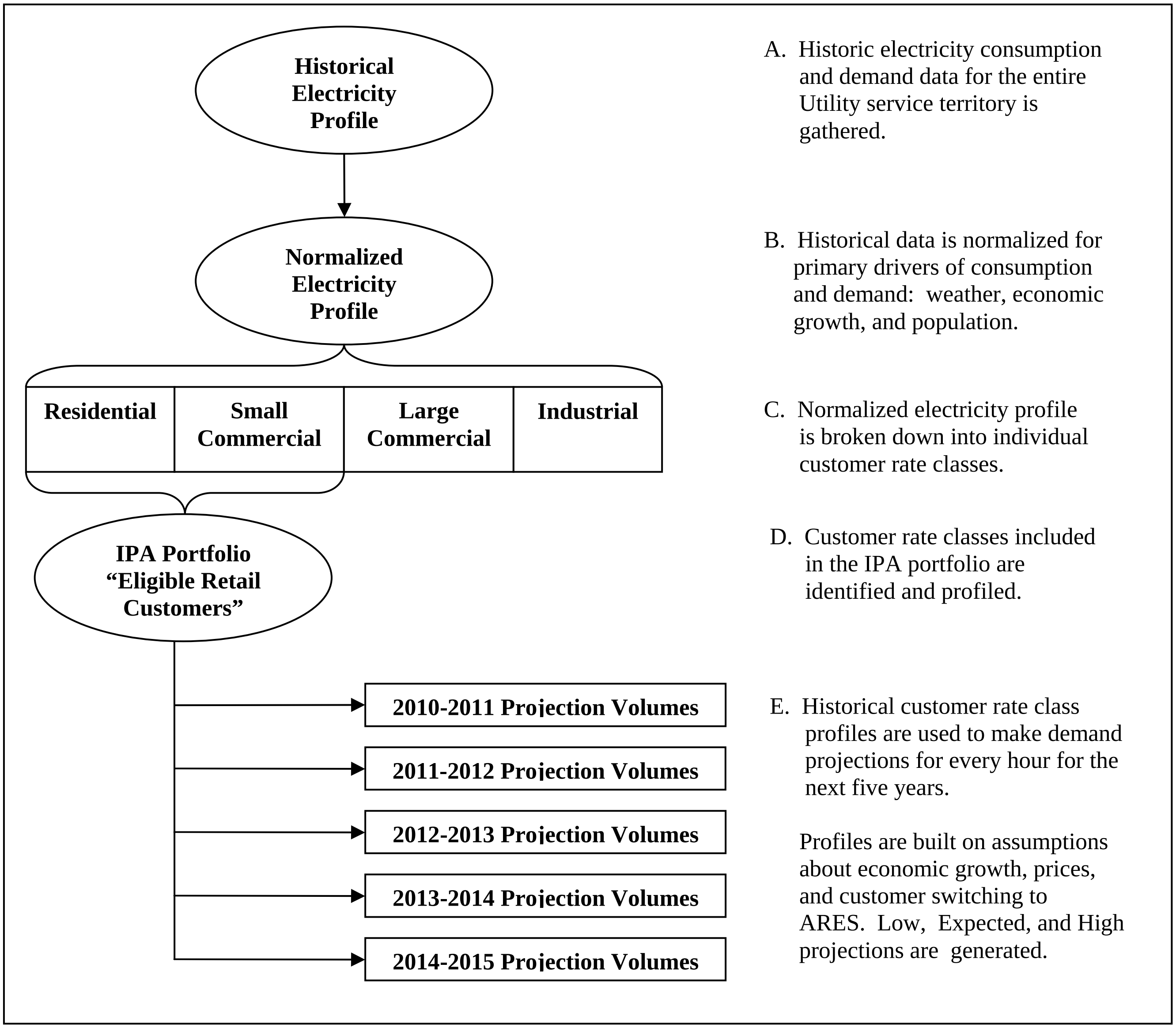
Overview. The IPA relied on Load Forecasts from the Utilities as best estimates for future consumption factored for the largely unknown variable of retail switching. The creation of the Office of Retail Market Competition within the Illinois Commerce Commission, and the passage of legislation to facilitate retail competition indicate the potential for significant changes in retail switching among eligible retail customers.

Since the Utilities' data projections are updated annually, the IPA will readjust load projections should retail switching differ significantly from the Utilities' projections. For the purpose of this load projection readjustment a difference will be deemed to be significant if the adjustment would result in a 200 MW or larger change in the supply quantity. This readjustment will be based on the impact of retail switching among eligible retail customers based on ICC generated reports.

The ultimate goal of the Load Forecasts provided by the Utilities to the IPA is not to identify the combined load of all customers of the Utilities. Rather, it is to identify the load requirements of the Eligible Retail Customers for each Utility.

[9] 220 ILCS 5/16-111.5(d)(1).

FIGURE 2: LOAD FORECAST SCHEMATIC



The load forecasting process begins with a multi-year analysis of historical loads. Recorded hourly loads are correlated to weather to generate a normalized full requirements load projection for each customer class. The normalized full requirements load projection for each customer class is then adjusted by expected growth rates, retail competition switching trends, and results of statutory and other programs related to demand response and energy efficiency.

The results of this analysis and modeling are 5-year summary hourly load projections for each customer class within each Utility.

A. Load Forecasting. The IPA Act requires the Utilities to file Load Forecasts each July 15. These projections serve as the basis of the Plan and associated portfolio and risk management.

1. Ameren Illinois Utilities. The Ameren 5-year hourly load forecast identifies load projections for Eligible Retail Customers." Eligible Retail Customers include residential and other customers who are entitled to purchase electricity from the Utilities under fixed-price bundled service tariffs. Ameren utilizes a statistically adjusted end use model as the basis of its load forecasting process. After adjusting consumption data weather, seasonal variables, and economic conditions, a detailed core consumption model was developed.

The statistical models are measured for accuracy against past period consumption volumes for each customer class. Comparisons between predicted and actual consumption volumes are highly correlated and are the best models available for forecasting loads for the eligible retail customers.

Forecasted portfolio volumes are generated by altering model variables within expected ranges and examining model outputs. Resulting High, Expected, and Low volume scenarios are generated. The IPA selects the Expected load model as the basis of the procurement Plan for the Ameren portfolio. Because the PUA declares retail customers with peak demand of 1000kW and above to be competitive as of May 2008, the Plan does not include these volumes.

The PUA also declares electricity supply to all customers with demand above 400kW to be competitive. As a result, customers of 400kW taking service from an ARES as of the effective date of PUA, or who subsequently switch to an ARES, are no longer eligible to take bundled service under tariffs offered by Ameren. Further, those customers above 400kW who continue to receive bundled utility service will be placed on the Ameren tariff Rider HSS (Hourly Supply Service) if they do not choose to take service from an ARES by June 1, 2010. This plan therefore does not include these volumes.

Section 16-111.5(b) of the PUA requires that the procurement plan shall include an analysis of the impact of demand side initiatives established by Section 12-103(c) of the PUA. Those demand side initiatives include the impact of demand response programs (both current and projected) and the impact of energy efficiency programs (both current and projected)

For the purpose of projecting loads for this year's Plan, the IPA has included the impacts of demand response programs based on the Utility's analysis of the current and projected programs. The effective reduction in Ameren's maximum system load requirements for eligible retail customers due to demand response programs is projected to be:

2010 4 MW
2011 13 MW
2012 17 MW
2013 21 MW
2014 24 MW

The IPA has also included the impacts of the Utilities' energy efficiency programs based on their analysis of the current and projected programs. The annual incremental reductions in Ameren's supply requirements to be acquired through the RFP process (net of customer switching) is projected to be:

2010 103.9 GWh
2011 132.3 GWh
2012 161.53 GWh
2013 220.5 GWh
2014 274.6 GWh

An analysis of the accuracy of the usage projections generated by Ameren for the 2008-2009 planning period indicates that, adjusted for weather, the Ameren load forecasting methodology was accurate within 0.235% of actual recorded consumption by the portfolio.

2. **Commonwealth Edison.** ComEd's 5-year hourly Load Forecast is based on the PUA's definition of Eligible Retail Customers. However, the ComEd customer classes deemed competitive by the PUA are different in maximum demand from those served by Ameren. Rather than a 400kW threshold, electricity supply to ComEd customers with demand greater than 100kW is competitive. Customers with demand of greater than 100kW are no longer eligible for bundled service and are not included in the load forecasts.

ComEd utilizes a forecasting process based on econometric models that produce monthly sales forecasts for primary customer classes including: Residential, Small C&I and Large C&I. Those base monthly forecasts are normalized for primary load variables (weather, economic growth, population, etc.) and combined with the hourly models to obtain on-peak and off-peak quantities for each month and each delivery service class.

The statistical models are measured for accuracy against past period consumption volumes for each customer class. Comparisons between predicted and actual consumption volumes are highly correlated and are the best models available for forecasting loads for the eligible retail customers.

Forecasted portfolio volumes are generated by altering model variables within expected ranges and examining model outputs. Resulting High, Expected, and Low volume scenarios are generated. The IPA selects the Expected Load Model as the basis of the procurement plan for the ComEd portfolio.

Section 12-103(c) of the PUA also establishes specific requirements for utility company demand response programs as follows:

> *"Electric Utilities shall implement cost-effective demand-response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Sections 16-111.5 of this Act and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive. This requirement commences June 1, 2008 and continues for 10 years."*[10]

Section 16-111.5(b) of the PUA requires that the procurement plan shall include an analysis of the impact of demand side initiatives established by Section 12-103(c) of the PUA. Those demand side initiatives include the impact of demand response programs both current and projected) and the impact of energy efficiency programs (both current and projected).

For the purpose of projecting loads for this year's Plan, the IPA assumes that each utility intends to implement demand response programs sufficient to achieve their targeted peak reductions. Based on ComEd's analysis, the effective aggregated reduction in ComEd's maximum system load requirements for eligible retail customers due to demand response programs is projected to be:

2010 32.8 MW
2011 43.3 MW
2012 53.9 MW
2013 64.8 MW
2014 75.7 MW

Section 12-103(b) of the PUA also establishes specific requirements for energy efficiency programs that reduce energy consumption of delivery services customers by 0.2% in 2008 planning year and by an additional 0.2% each year through 2012, growing to a total decrease in energy consumption of 1.8% in 2013.[11] The annual aggregate reductions in ComEd's supply requirements to be acquired through the RFP process (net of customer switching) is projected to be:

2010 – 347.4 GWh
2011 – 600.3 GWh
2012 – 933.0 GWh
2013 – 1,309.5 GWh
2014 – 1,687.2 GWh

[10] 220 ILCS 5/12-103(c). This section was revised by Public Act 096-0159 to include the load of the hourly service customers in this calculation. This load will be included in the next three-year plan that the Utilities file with the Commission for approval pursuant to Section 12-103(f).
[11] 220 ILCS 5/12-103(b).

An analysis of the accuracy of the usage projections generated by ComEd for the 2008-2009 planning period indicates that, adjusted for weather, the ComEd load forecasting methodology was accurate within -5.5% of actual recorded consumption by the portfolio.

B. Expected Five-Year Load Forecasts. The Utilities submitted Five-Year Load Forecasts to the IPA on July 15, 2009 for each customer class for which supply will be procured.

1. Ameren. A complete copy of the load forecast report submitted by Ameren to the IPA can be found in Attachment A of this document. The tables below present the consolidated consumption projections for the five-year period covered in this Plan.

Ameren customer rate classes for which supply will be procured are defined as follows:

- **DS-1** – Residential
- **DS-2** – Non residential, less than 150 kW peak demand
- **DS-3a** – Non residential, between 151 kW and 400 kW peak demand
- **DS-5** – Lighting service

Table E presents Ameren's consolidated monthly volume schedule for each rate class for the first of the years covered by this five-year Plan. Tabular data for all sixty (60) months covered by this plan for Ameren can be found in Attachment B.

TABLE E: VOLUME PROJECTIONS PER RATE CLASS FOR AMEREN ILLINOIS UTILITIES (JUNE 2010 THROUGH MAY 2011)

Contract Month	Projected Monthly Volume Requirements				
	DS1 (MWH)	DS2 (MWH)	DS3a (MWH)	DS5 (MWH)	Total (MWH)
June-10	1,008,660	347,505	77,523	26,486	1,460,174
July-10	1,406,031	371,276	82,040	26,072	1,885,420
August-10	1,397,256	360,261	79,361	27,051	1,863,930
September-10	988,751	335,257	73,744	28,776	1,426,528
October-10	831,061	317,239	69,476	30,463	1,248,240
November-10	872,701	308,655	67,153	31,707	1,280,217
December-10	1,194,509	329,882	71,032	33,681	1,629,104
January-11	1,275,491	359,851	73,282	34,965	1,743,589
February-11	1,039,906	326,514	66,888	32,916	1,466,224
March-11	952,611	313,819	63,980	30,593	1,361,003
April-11	739,411	289,056	59,668	29,846	1,117,980
May-11	767,063	298,121	62,625	27,102	1,154,910

Volumes include on-peak, as well as, off-peak periods, and are factored for eligibility and competitive declaration (e.g. Classes DS-3b and DS-4 are declared competitive and not eligible for inclusion in the IPA Portfolio).

1. Commonwealth Edison. A complete copy of the Load Forecast report submitted by ComEd to the IPA can be found in Attachment C of this document. The Tables below present the consolidated consumption projections for the five year period covered in the Plan. ComEd customer rate classes are defined as follows:

- **SF** - Single-family residential, non-electric space heating
- **MF** - Multi-family residential, non-electric space heating
- **SFSH** - Single-family residential, electric space heating

- **MFSH** - Multi-family residential, electric space heating
- **WH** –Watt-Hour, non-residential, consumption of less than 2,000 kWh per billing period
- **Small** – Small Load, non-residential, less than 100 kW peak demand
- **DD** – Dusk to Dawn Lighting
- **GL** – General Lighting

Table F presents ComEd's consolidated monthly volume schedule for each rate class for the first 12 months of the period covered by this Plan. Volumes include on-peak as well as off-peak periods, and are adjusted for eligibility and projected switching activity. Tabular data for all sixty (60) months covered by this plan can be found in Attachment D.

TABLE F: VOLUME PROJECTIONS PER RATE CLASS FOR COMMONWEALTH EDISON (JUNE 2010 THROUGH MAY 2011)

Contract Month	Projected Monthly Volume Requirements									
	SF (MWH)	MF (MWH)	SFSH (MWH)	MFSH (MWH)	WH (MWH)	Small (MWH)	Condo (MWH)	DD (MWH)	GL (MWH)	Total (MWH)
June-10	2,126,944	447,709	42,154	81,949	48,183	742,216	20,065	10,929	818	3,520,966
July-10	2,769,891	586,264	50,588	111,752	53,061	817,390	27,429	11,219	839	4,428,434
August-10	2,537,030	548,696	47,383	106,405	52,795	802,948	30,439	11,896	890	4,138,481
September-10	2,537,030	395,481	40,195	85,003	46,820	704,769	26,956	12,308	921	3,849,482
October-10	1,544,167	336,399	54,049	101,644	44,317	654,882	23,097	13,301	995	2,772,850
November-10	1,671,808	348,202	87,945	173,979	43,398	639,805	22,462	13,707	1,025	3,002,331
December-10	2,003,464	403,471	125,250	282,726	47,906	702,332	30,978	14,844	1,111	3,612,081
January-11	2,007,425	410,134	139,126	270,785	48,908	709,935	37,391	14,545	1,088	3,639,337
February-11	1,680,947	356,638	115,360	206,699	44,039	630,195	33,392	12,565	940	3,080,776
March-11	1,656,897	358,394	99,285	195,766	46,387	648,367	31,923	13,012	974	3,051,006
April-11	1,443,454	318,047	63,882	124,747	42,634	581,735	25,921	11,758	880	2,613,058
May-11	1,561,644	341,718	46,970	93,260	45,148	604,842	23,937	11,593	867	2,729,979

IV. Portfolio Design

The IPA is responsible for developing and implementing a Plan to secure electricity supplies for Eligible Retail Customers for Ameren and ComEd. The schedule of monthly electricity volumes and prices for those volumes is based on the IPA portfolio design. The IPA Act provides the priorities for the portfolio design are:

> *"… 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."*[12]

The challenge inherent in the IPA's charge is to achieve low and stable prices when acquiring electricity in a market where prices change constantly and sometimes dramatically. Complicating the task is the fact that the volumes of electricity that will be needed in the IPA portfolio are merely estimates (e.g. a hot summer or a cold winter can cause significant deviation from the expected forecast). Therefore, the IPA must arrange purchases of electricity from the wholesale market in a manner that accommodates both changing prices and load requirements.

Designing the portfolio requires an understanding of the variables that drive price and load fluctuation, and the extent to which those variables can affect price. That includes risk. For the purposes of the IPA's analysis and planning, risk is defined as any market condition or internal and external processes that have the potential of raising prices or increasing their volatility.

A. Risk Discussion. The PUA identifies the primary categories of risk exposure to the portfolio when it requires the IPA to include in the Plan the following:

> *"an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the following factors: contract terms, time frames for securing products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment; the proposed procurement plan shall also identify alternatives for those portfolio measures that are identified as having significant price risk."*[13]

The following is not an exhaustive list of risks that can affect the IPA portfolio, as market developments can create or eliminate risks, or reorder known risks.

1. **Price Risk.** The portfolio is exposed to price risk on two levels: (1) long-term cost trend risk, and (2) short term clearing risk. The average upward movement of electricity prices is due to rising costs for multiple elements in the electricity sector: fuel costs, capacity costs, transmission costs, and the cost of plant additions and construction all put upward pressure on future prices for electricity. The ability to enter the market with some flexibility as to timing enhances the dollar-cost averaging approach to procurement and can slow the long term upward price trend.

   Short term clearing risk occurs when excess electricity purchased on behalf of the portfolio is not used and is sold back to the market at a loss, or when electricity above the projected volumes is required, and additional volumes must be purchased from the market at spot prices that might be high relative to the average price of electricity already secured for the portfolio. Short term risks can be mitigated by arranging procurement events as close to the expected load volumes as possible. Additionally, the IPA recommends some oversubscription of

[12] 220 ILCS 5/16-111.5(d)(4).
[13] 220 ILCS 5/16-111.5(b)(3)(v).

electricity for the peak periods of July and August. Historically, July and August have the highest potential to generate instances of forced buying in high spot markets.

2. **Load Uncertainty.** The portfolio is exposed to load uncertainty risk due to inelasticity of demand among many portfolio participants, and the unknown pace of migration of eligible customers to ARES suppliers over time.

   Consumption by bundled service customers is relatively inelastic, meaning that usage of electricity does not diminish significantly when prices are high, in large part because customers are not directly exposed to these prices. Inelasticity of demand represents risk insofar as portfolio participants who do continue to use large volumes of electricity when prices are high (e.g., running air conditioning units during hot summer afternoons) do not carry the full direct cost of their usage. Instead, the cost of their consumption during high cost periods is averaged across the entire portfolio. The IPA does not presently have tools with which to address this issue. This could be addressed, in part, by changing utility rate structures so that individual ratepayers are exposed to the real costs of consumption during peak cost periods, or conversely, are rewarded for reducing demand during system peaks. Implementation of demand response programs and the advent of "Smart Grid" systems may provide effective tools to address the need to reshape loads. Unpredicted migration to ARES suppliers presents some level of risk to the portfolio insofar as migration can cause cost spiraling under certain conditions. For example, assume that a high percentage of anticipated long-term load requirements for the IPA portfolio were secured with fixed volume contracts. Further, assume that market prices decreased in the future (e.g. the California experience of locking in prices when markets are at their high).

   In such a situation, higher-than-market bundled rates would motivate switching by those customers who could be profitably served by ARES's at the relatively lower market prices. As the number of bundled service customers eroded, those remaining on bundled rates would effectively be paying not only for the cost of their consumption, but also the costs of disposing of the volumes secured for customers who have switched to other suppliers. Over time, bundled-rate customers could see high rate volatility, as well as, potential inverse market price signals (bundled rates would be rising while market prices were falling). For this reason, laddering-in purchases over time enables the IPA to minimize risk for consumers by allowing the Agency to adjust procurement volumes in response to changing customer needs and market conditions.

3. **Contract terms.** Contract terms present risk to the portfolio to the extent that the underlying credit requirements for the bidders and the utility may increase costs that are ultimately borne by the end-use customer.

   Contracts entered into as a result of the procurement process shall be through either an International Swaps and Derivatives Association ("ISDA") agreement for financial instruments such as fixed/floating rate swaps or an Edison Electric Institute ("EEI") agreement for physical products such as energy or capacity. Individual transactions shall be memorialized utilizing standard transaction specification sheets, such that, to the extent practicable, purchasing decisions shall be made on the basis of price, rather than non-price factors.

4. **Time Frames for securing Products and services.** Time frames for securing products and services present risk to the portfolio insofar as the underlying volatility in electricity markets places a premium on time.

   Particular risks in this area are the annual planning cycle, time between procurement events, and time between bid and contract execution.

   i. **Annual planning cycle.** Compliance with PUA leads to procurement events that occur as many as nine months after load projections are made and eight months after the initial Plan is developed. Changes in loads due to retail switching and other factors, and changes in market conditions during that extended period could limit the value of the forecasts and expose customers to unnecessary risk.

ii. Time distance between bid and contract execution. The PUA allows a period of four business days for review of the bids submitted during the procurement event (two business days for the Procurement Administrators and Procurement Monitors to submit reports, and two business days for the Commission to review and consider the reports).[14] The time lag between the submission of wholesale electricity bids and their acceptance creates risk for bidders, which translates into higher costs for consumers.

In order to lay off the potential liability in the event that market prices rise between the time a bidder submits a bid and the contract is executed, bidders may purchase five day option contracts to guarantee the price they submit to the IPA. The insurance has a premium, and that premium is embedded in the bid price of the electricity.

A five-day option premium is estimated to cost between $1.40 and $1.60/MWh. If underlying volatility increases in the market (e.g. loss of baseload generating units), or if market prices increase generally (e.g. carbon tax costs are levied), then premium costs will increase. As the volumes of electricity purchased through the IPA process increase over time due to the expiration of legacy supply contracts, the total cost premiums built into wholesale bids increase. Table G displays current estimates of the premium costs being borne by Illinois consumers because of the four-day hold option.

Over the next three procurement cycles, the IPA estimates the total cost of the embedded premiums to exceed $166 million.

To mitigate this risk, the IPA recommends that review processes be abbreviated and automated to an extent that allows for approval of bids to occur on the same day they are submitted. The IPA recommends that the Commission, its procurement monitor, and the procurement administrator work together to devise a timely process to address this risk while maintaining appropriate oversight functions, and detail any revisions in the process to bidders in the relevant RFPs.

TABLE G: ESTIMATED COSTS ASSOCIATED WITH PRICE APPROVAL MECHANISMS

Options Premiums related to Time Distance between Bid and Contract			
	2010	**2011**	**2012**
Ameren			
Volume Procured (MWh)	10,269,600	17,781,600	8,147,211
Option Premium ($/MWh)	$1.50	$1.50	$1.50
Cost to Portfolio	$15,404,400	$26,672,400	$12,220,816
ComEd			
Volume Procured (MWh)	12,453,600	43,413,200	19,720,011
Option Premium ($/MWh)	$1.50	$1.50	$1.50
Cost to Portfolio	$18,680,400	$65,119,800	$29,580,016
Combined			
Combined Volume Procured (MWh)	22,723,200	61,194,800	27,867,222
Option Premium ($/MWh)	$1.50	$1.50	$1.50
Cost to Portfolio	$34,084,800	$91,792,200	$41,800,832

[14] 220 ILCS 5/16-111.5(f).

5. **Fuel Costs.** Fuel costs present risk to the portfolio insofar as fuel costs are the primary drivers of generation costs. Even more important is the effect on market prices of rising fuel costs when they occur in a market such as PJM or MISO, in which market clearing prices are set by the marginal producer.

   Natural gas fueled plants are the marginal producers during the summer months in both the PJM and MISO regions. Coal fueled plants are the marginal producers for the majority of hours in PJM and MISO.

   Electricity market prices incorporate fuel price risk. Mitigation options outside of the proposed portfolio design would have limited utility as the portfolio design is geared towards mitigating general electricity price risk. However, renewable energy resources that have zero fuel costs, such as wind power, can be cost-effective hedges against rising fuel costs for conventional resources.

6. **Weather Patterns.** Weather patterns present risk to the portfolio because weather-related changes in demand and supply correlate with spot prices. Particular risks include the possibility of having to sell electricity contracted for at relatively high fixed prices at a time of low spot market prices, or in the opposite case, having to purchase extra volumes at high spot prices.

   i. **Selling fixed price electricity back into a low spot price market.** Electricity consumption is highly correlated to weather (e.g. hot summer temperatures drive up summer cooling load). If mild summer weather were to reduce regional cooling loads, spot prices for electricity would drop. With mild weather effectively reducing demand for electricity, consumption would drop below projections based on average temperatures. Excess energy procured through block contracts would have to be sold back into the market, likely at a price lower than what was originally paid. The resulting financial losses would be applied against the portfolio.

   ii. **Purchasing spot price electricity from a high spot market.** If warm summer weather were to increase regional cooling loads, spot prices for electricity would rise. With warmer weather effectively increasing demand for electricity within the portfolio, consumption would increase above projections that were based on an assumption of marginally lower average temperatures. Excess energy would need to be procured from the spot market to meet portfolio requirements, likely at a price higher than what was paid for fixed price purchases executed through the standard procurement process. The resulting increased costs would be applied against the portfolio.

   Oversubscription for peak hours in the July and August delivery periods has been used to mitigate weather risk in the last two procurement plans. However, analysis of the results of this approach over the past two years indicates that the strategy has cost consumers more than what it has saved. Therefore, the IPA proposes to procure at the 100% subscription level for all months in this Plan.

7. **Transmission Costs.** The Utilities operate in separate regional transmission organization ("RTO") markets: Ameren in MISO and ComEd in PJM. Risks associated with these markets are new transmission asset related costs, and higher integration costs associated with wind energy developments.

   Recent projections indicate plans for billions of dollars in transmission investments throughout the MISO and PJM regions. Some of the transmission system upgrades propose to extend transmission between wind generating regions in the western spans of the MISO region and larger population centers in the eastern reaches of MISO as well as PJM. Existing and future transmission costs are already being borne by MISO and PJM participants via tariff.

   The rapid development of wind-based renewable electricity generation in the PJM and MISO regions will likely cause upward pressure on transmission costs because wind facilities tend to be in remote locations that may not have adequate existing transmission to bring power to load centers. In addition, system operators will need to alter system operations to accommodate the intermittent nature of wind energy. Estimates of costs relative to integrating wind assets into regional transmission portfolios range from as low as $2.11/MWh for 15% wind penetration within the portfolio to $4.41/MWh for a penetration level of 25%.[15] Some of these costs may be offset by contributions of wind assets towards system reliability and other ancillary services.

The IPA is limited in its ability to mitigate these risks outside of factoring them into cost modeling over the longer range horizon and seeking offsetting cost avoidance elsewhere within the Portfolio. However, transmission cost allocation is a subject of federal regulation and any changes in transmission costs will likely be borne by all customers regardless of supplier.

8. **Market Conditions.** Market conditions generally relate to the drivers of market prices, customer usage, and customer switching levels. These variables are included in the statistical modeling conducted by the IPA relative to the portfolio design.

9. **Alternatives for those portfolio measures that are identified as having significant price risk.** While no analysis can cover every possible risk, the above analysis provides a reasonable representation of the significant risks associated with the June 2010 – May 2011 horizon. The Plan provides reasonable protection for customers from likely risk factors. As a result, given the guidance provided under the PUA, the IPA does not recommend an alternative to its recommended portfolio.

10. **Carbon Liabilities.** The advent of federal legislation that proposes to apply a comprehensive national "Cap and Trade" system for the regulation of greenhouse gas emissions represents a new price risk for the IPA portfolio. While estimates vary, a recent report to the National Association of Regulatory Utility Commissioners (NARUC) by Synapse Energy Economics Inc. projects a ratepayer cost impact range of between $0.94 and $13.12/MWH with the variance explained by uncertainty as to how credit allocations are applied in the final regulatory scheme.

    To mitigate this risk to consumers, the IPA proposes to include energy from renewable energy resource providers into the portfolio as a hedge against the higher market costs expected as a result of greenhouse gas regulatory structures. Renewable energy generation assets typically generate power at costs higher than those available in the market today, and are generally developed only when supported by longer term power purchase agreements. The IPA recommends soliciting proposals from renewable energy providers under longer term contracts with the Utilities.

    Further, substantial federal and state assistance in the form of various subsidies are available to offset a portion of the premiums associated with such providers. The IPA recommends taking advantage of the current financial climate to issue solicitations for longer term renewable energy supply contracts. Assuming bid prices are acceptable when compared to a market benchmark developed by the IPA in consultation with the ICC, deliveries of energy would likely begin sometime during the 2011-2012 planning year. Target volumes for Ameren would range around 600,000 MWH/annum, and 140,000,000 MWH/annum representing approximately 3.5% of annualized load volumes for each Utility.

    As some renewable assets are variable in their output (wind, hydro, and solar), the IPA recommends that the laddered volumes of traditionally sourced energy contracts specified in this plan noted as 'Short term portfolios' be maintained, and that future procurement plans be adjusted to reflect the output realities of the renewable assets selected (if any) in the 2010 renewable energy solicitations.

[15] "Accommodating Wind's Natural Behavior", DeMeo et al, IEEE Power & Energy Magazine, November/ December 2007, page 62.

B. Modeling and Portfolio Design. The options for electric energy products fall into two general categories: fixed price and variable price products. Fixed price products allow the purchase of known volumes of electricity to be delivered at some time in the future at a set price. Forward purchases, futures contracts, swaps, and options are examples of fixed price products. Fixed price products offer price certainty, but may turn out to be relatively costly if the market price drops prior to delivery, or if too much power is purchased and the excess must be sold back to the market at a loss.

Variable price products allow the purchase of electricity at prices set by supply and demand for electricity at the time of consumption. Locational marginal prices ("LMP") provided through RTOs are the basis of variable price products in organized wholesale markets. Variable price products offer the ability to buy only the amount of electricity needed at any moment, but may turn out to be relatively costly if high market prices exist at the time of usage.

In order to manage procurement for a variable population with uncertain loads in an unpredictable market, this Plan utilizes methods similar to those used by investors to manage market portfolio risks.

The Plan begins by first defining the portfolio and potential risks; then identifying measures that will mitigate those risks; and finally, measuring the relative effectiveness of the risk management measures. The risk profile of the IPA portfolio changes over time. Accordingly, the IPA will be making process improvements that allow for continuous monitoring and annual adjustments to the portfolio strategy as each Plan is developed.

The following are the premises upon which the IPA constructed its portfolio and risk management approach:

- **Physical and financial product parity:** A physical product is one in which the contract requires furnishing of a specified volume of electricity under the terms and conditions of the contract. A financial product is an agreement to guarantee the price for a specified volume of electricity. The IPA views prices for physical electricity products to be equivalent to financially based electricity products, insofar as suppliers of physical products price offers based on forward price curves determined in futures markets.
- **Three year market liquidity horizon:** The IPA views existing forward markets as providing sufficient liquidity to assure price competition for up to three years. Trading volume in the periods greater than three years into the future are presently insufficient to assure that observed prices are available, reliable, and representative.
- **Historical price volatility as a guide to future volatility:** Past market performance with regard to price volatility, trending, and correlations is the basis of the assumptions incorporated into IPA modeling and evaluations.
- **Today's optimal portfolio distribution may not be optimal tomorrow.** The IPA seeks to identify price risk measured by the following three metrics:

  Metric A: Year-over-Year Price Variance – the extent to which prices change from one year to the next.
  Metric B: Mark-to-Market Price Variance – the extent to which prices agreed to in prior years vary from index prices in the current market
  Metric C: Longitudinal Variance – the extent to which prices in the latter years of a plan vary from current futures market prices.

To establish a model portfolio for each Utility, a Monte Carlo model using Excel® and Crystal Ball® was developed and applied to each Utility's respective load projections to illustrate the trade-offs between risks and benefits associated with different procurement approaches and ratios of Forward and Index purchases. With efficient market prices, all portfolios should have the same expected value; however, price stability (measured as standard deviation) can vary. To evaluate the price stability of the different portfolios, volatility in the three metrics noted above (Year-over-Year Price

Variance, Mark-to-Market Price Variance, and Longitudinal Variance) was measured and combined to generate a composite risk metric for use in the evaluation.

The composite metric created is the square root of the average of (A) Year-over-Year Price Variance, (B) Mark-to-Market Price Variance, and (C) Longitudinal Variance:

Composite Metric = Square Root [(SDA^2 + SDB^2 + SDC^2)/3]
Where "SD" is Standard Deviation

A set of potential portfolios was evaluated with model runs of 5,000 iterations against the risk metric defined above. There are three main sections to the model, the first of which is the price section.

1. **Pricing.** The model uses monthly forward peak and off-peak New York Mercantile Exchange ("NYMEX") pricing through 2013 as of August 10, 2009. The IPA views NYMEX as an appropriate indicator of future prices in the nearer term where market liquidity is sufficient to generate pricing competition. For periods after 2012, the monthly prices indicated on the NYMEX for those periods were escalated at 2% per year to account for market unknowns.

   To test how each portfolio will perform under various market conditions, the forward price curves are assumed to vary over time. Prices for forward energy products are highly volatile, meaning that the price observed today for a product may be quite different than the price of that same product when observed at some point in the future. Analysis of the historical movements in prices of the front end of the forward energy curve reveals annualized volatilities of 24% and 18% for peak and wrap contracts, respectively.

   These volatilities include changes in prices due to all factors, including fuel price movements. Market prices volatility was selected as the appropriate representative of market price risk as the Utilities do not own generation and therefore cannot control significant variables such as fuel expense.

   Price movements in delivery periods beyond the first year of the forward curve were modeled to move proportionately to movements of the first year but with somewhat lower volatility. The magnitude of these proportional movements is based on an historical analysis of how prices in years 2-6 of the forward curve moved relative to the magnitude in movements in the price of the first year of the forward curve. Consequently the forward prices in the analysis move together but with a muted effect as one goes out in time.

   The process captures how the forward curve moves between annual procurement processes that are assumed to occur each March. The model then uses the same annual volatility estimates to estimate potential price movements from the March procurement date until the future delivery month. Once forward prices are estimated for each month as of the beginning of the month (i.e. the close of the forward product), monthly spot prices are then developed based on the historical volatility observed between the price of the forward at the beginning of the month and the realized average spot price observed for each month. This process can be summarized as:

Spot Price = FPT + Pchg (T_T+1) + Pchg (March _ Delivery Month) + Pchg (Delivery Forward _ Spot)
Where FP means Forward Price and Pchg means Price Change

2. **Estimated Load Requirements.** As market prices are uncertain and will deviate from estimates, so too will the actual supply required by eligible customers deviate from even the best forecast. To capture this risk, the model starts with the base load estimates for eligible retail customers supplied by the Utilities on July 15, 2009 and then allows the Monte Carlo simulation to vary the loads based on both weather and non-weather (economy and retail switching) factors. The model assumes a triangular distribution for the loads based on the high/low load forecasts supplied by the Utilities.

For each month for both peak and non-peak (wrap) periods, the model takes the included load for the scenario and estimates the net open requirements by subtracting (1) the load previously awarded through the auction process (2) the amount hedged through the swap arrangements. In addition, the model does allow for the adjustment of the amount purchased for summer (July and August) and non-summer periods to investigate whether procuring more or less than 100% of net open requirements would reduce a model portfolio's risk.

3. **Average Cost to Serve.** The last major section of the model estimates the average cost to serve the included customers. For each iteration, the model sets a random load and price based on the distributions and correlations discussed above. The model then estimates the effective cost associated with the swap contracts (price and quantity fixed), the cost of any RFP purchases, transmission costs for ancillaries and capacity and finally, the cost associated with any spot purchases or sales to balance the procured quantities with those actually required. A blended portfolio price is calculated for each iteration and at the end of the run a distribution of potential outcomes is presented.

   A key factor in the analysis is the cost associated with load shape that results from customers using relatively more energy when prices are high and relatively less energy when prices are low. This relationship between expected prices and expected demand generally has the effect of raising the cost to serve load above the level of the straight average price during a delivery period. Since the procurement plan is using monthly block products that provide the same amount of energy every hour (i.e. not sculpted to match expected customer demand), the cost difference between supply provided by these block products and actual customer load profile is picked up through a price/load gross-up factor.

   A simple example of a price/load gross-up factor would be to assume a world with three hours where the customer loads were typically 10, 20 and 30 MW and the corresponding prices $50, $100, and $150/MWH. The average load is 20 MW and the average price is $100/MWH. However, since the price is highest when loads are highest, the actual average cost to serve the load is:

   (10*50+20*100+30*150)/60 or $116.7/mWh

   In this example, the load/price gross-up factor is 16.7% ($116.7/$100 – 1).

   Based on an analysis of historical monthly spot prices and loads, average monthly gross-up factors were estimated for both the peak and the wrap periods. For the peak period, the gross-up factors were approximately 10% in summer and 3% in other months. For the wrap period, gross up factors were approximately 14% in summer and 6% in other months. The same historical analysis also shows these gross-up factors are highly variable over time.

   The level of gross-up variability, and how strongly those variations are correlated to movements in price and load, can play an important role in determining the desirability of one model portfolio versus another. If the correlation is very strong (i.e. when changes in monthly spot prices are high the change in the gross-up factors are also high), the analysis would show that risk-minimizing hedge ratios would be higher than if the correlation were weak or non-existent. A historical analysis of monthly gross-up factors, spot prices, and loads suggests that any relationships between gross-ups and price or between gross-ups and load may be relatively weak. While this result may not be intuitive, note that on a daily basis, the correlation between prices and gross-up factors is fairly strong, but when gross-ups and price/loads are measured over monthly intervals the strength of the relationship appears to diminish.

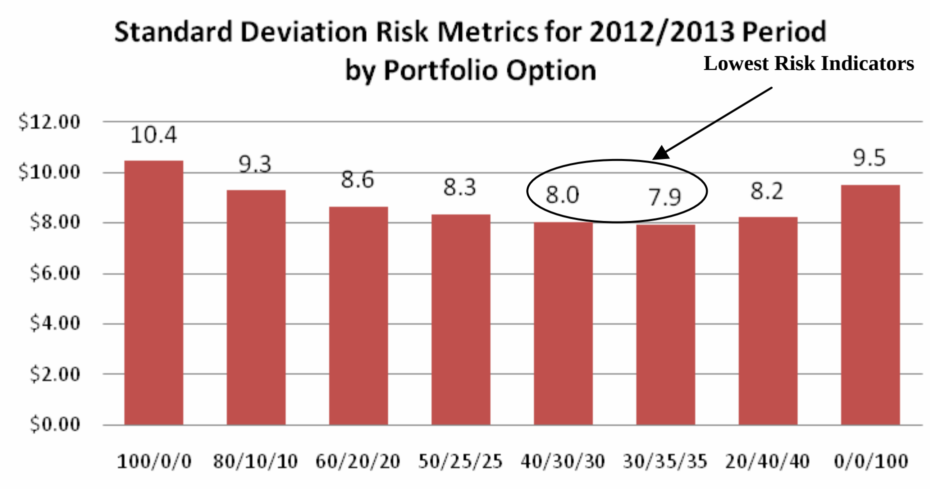
4. **Results.** The model was designed to help identify whether some portfolios may be superior to other portfolios when looking at specific risk metrics. For conceptual ease, the IPA separated portfolio characteristics into two categories:

1) The composition of the portfolio (i.e. what mix of products)
2) The scale of the procurement (i.e. the volume purchased relative to the expected future load requirement)

Several portfolio structures were tested in the model to help identify whether one was of relatively lower risk than the others when evaluated using the composite risk metric. The portfolio structures analyzed ranged from all requirements being purchased in the RFP just prior to the beginning of the delivery period to all requirements being purchased three years in advance (the extent of assumed market price liquidity). Each of these portfolios was scaled to provide 100% of the expected load requirement so that scale effects could be disassociated from composition effects.

For the portfolio structure analysis, the IPA focused on the 2012 - 2013 period, the IPA chose to look out this far to get past legacy contracts including the swaps which tend to distort near term results in an attempt to illustrate the level of risk each portfolio would produce in a 'Steady State'. The resulting risk metrics for the various portfolios are shown in Graph 1:

GRAPH 1: CURRENT MARKET CONDITIONS INDICATE THAT 20-40% ANNUAL DISTRIBUTIONS YIELD BEST COST RISK EXPOSURE



Note: Portfolio (30/35/35) secures 30% 1 yr forward, 35% 2 yrs forward, a35% 3 yrs forward

The lowest price risk scenario is achieved when the portfolio is procured relatively evenly over three years, the current period for which there is sufficient liquidity in wholesale energy markets. Procurement distributions ranging between 20% and 40% per procurement cycle were determined to be relatively comparable in their capacity to mitigate risk. Because future market conditions are unknown, the IPA employs a portfolio distribution schedule that allows between 20% and 40% of projected loads to be procured in each of the three years prior to the delivery month. Within this range, the following three-year laddered procurement strategy would yield the lowest and most stable prices, based on current market conditions:

- 35% of projected energy needs procured two years in advance of the year of delivery;
- 35% of projected energy needs procured one year in advance of delivery;
- 30% of projected energy needs procured in the year in which power is to be delivered.

Such a ladder provides a reasonable hedge while allowing sufficient flexibility in future procurement cycles to incorporate longer-term contracts for certain products should the planning process find that they are appropriate elements of the portfolio.

5. **Discussion of the results.** The analysis supports a recommendation of fixing the price of 30% of requirements in the procurement immediately prior to the delivery period, 35% one year earlier, and 35% two years earlier. This 30/35/35 model portfolio is analogous to dollar cost averaging in investing. This laddering of energy supply contracts does not apply to the purchase of renewable energy credits.

   Given the high-level nature of this analysis, the 30/35/35 recommendation can be thought of as representative of a range of procurement portfolios that may have very similar risk profiles. Leaving 5-10% of the procurement uncovered (i.e. taking it to spot) does not significantly increase risk exposure to customers based on model results. However, because buying wholesale block products to meet the customer load shape already subjects the Utilities to a significant amount of load balancing transactions in the spot market, additional exposure to the spot market is not recommended at this time.

C. Application of the Plan to Ameren Illinois Utilities

1. Definition of Retail Customer Classes to be Supplied. This portion of the Plan explains how the power and energy will be procured for delivery from June 1, 2010, through May 31, 2013, for Ameren's eligible retail customers, as these customers are defined by the PUA.

Generally, the portfolio includes residential, commercial and industrial customers that have a peak demand less than 400 kW. Specifically, this includes customers from the following supply groups as defined in Ameren's currently effective General Terms and Conditions:

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

2. Monthly Forecasted System Supply Requirements

i. Energy. Table H includes the forecasted monthly supply requirements (in MWh) for the period June 1, 2010 through May 31, 2011. This forecast includes anticipated normal weather, the effect of competitive declarations, energy efficiency and demand response programs, and the impact of forecast customer switching.

TABLE H: AMEREN FORECASTED SYSTEM SUPPLY REQUIREMENTS (JUNE 2010 THROUGH MAY 2011)

Contract Month	Total Load (MWh)		Average Load (MWh)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-10	779,952	680,221	2,216	1,848
July-10	962,074	923,346	2,863	2,263
August-10	972,635	891,295	2,763	2,274
September-10	742,449	684,079	2,210	1,781
October-10	616,307	631,933	1,834	1,549
November-10	636,263	643,953	1,894	1,677
December-10	854,143	774,962	2,321	2,061
January-11	817,614	925,975	2,433	2,270
February-11	721,585	744,639	2,255	2,115
March-11	713,785	647,218	1,940	1,721
April-11	554,568	563,412	1,651	1,467
May-11	558,272	596,638	1,662	1,462

ii. Capacity. Module E of the Midwest ISO's Open Access Transmission and Energy Markets Tariff addresses resource adequacy. Under Module E, the Midwest ISO will develop a Planning Reserve Margin ("PRM") for each Load Serving Entity ("LSE"). If higher or lower PRMs are mandated by a state regulatory authority, then the Midwest ISO shall recognize and incorporate such PRMs for any affected LSE(s). Nothing in Module E affects existing state jurisdiction over the construction of additional Capacity or the authority of states to set and enforce compliance with standards for adequacy. At present, the State of Illinois has not mandated a PRM different than the one developed by MISO. Module E, along with the associated business practice manual, also requires Ameren to provide an annual forecast of monthly loads adjusted for transmission losses and subsequently confirm on a month-ahead basis that Ameren has enough capacity to meet or exceed its monthly peak load forecast plus its planning reserve margin.

The planning reserve margin beginning June 2010 has yet to be established; therefore, the IPA recommends that the 5.35% that has been effective for the period June 2009 through May 2010 be used for this Plan, with the caveat that future adjustments can be made once reserve margins are reset by MISO at a later date.

iii. Pre-Existing Contracts. The load forecast presented in Table H is a forecast of the expected full energy requirements of the Eligible Retail Customers. However, Ameren will not need to procure that amount of energy in order to serve that load due to pre-existing contracts for supply that Ameren has previously executed.

Pursuant to Section 16-111.5(k) of the PUA, Ameren entered into a Five-year swap contract with Ameren Energy Marketing that became effective on the effective date of the amendment to the PUA.[16] This contract provides price certainty for 1000 MW of Around-The-Clock ("ATC") energy that Ameren will procure through the MISO spot markets for the period of June 1, 2010 through December 31, 2012.

Additional fixed price contracts for the June 2010 through May 2011 period were secured as a result of the 2009 Procurement Cycle.

iv. Residual Load. Tables I1 and I2 identify the Monthly Residual Load volumes for the Ameren portfolio over the Procurement Period. Monthly Residual Load Volumes are derived by subtracting pre-existing contract volumes from projected load volumes. A full schedule of Ameren's Residual Volumes can be found in Attachment F.

TABLE I1: AMEREN RESIDUAL PEAK SUPPLY REQUIREMENTS (JUNE 2010 THROUGH MAY 2011)

Contract Month	Peak			
	Projected Volume (MW)	Swap Volumes (MW)	2009 Procurement Volumes (MW)	Residual Volumes (MW)
June-10	2,216	1,000	750	466
July-10	3,150	1,000	1,050	1,100
August-10	3,039	1,000	1,000	1,039
September-10	2,210	1,000	650	560
October-10	1,834	1,000	450	384
November-10	1,894	1,000	450	444
December-10	2,321	1,000	650	671
January-11	2,433	1,000	750	683
February-11	2,255	1,000	600	655
March-11	1,940	1,000	450	490
April-11	1,651	1,000	300	351
May-11	1,662	1,000	300	362

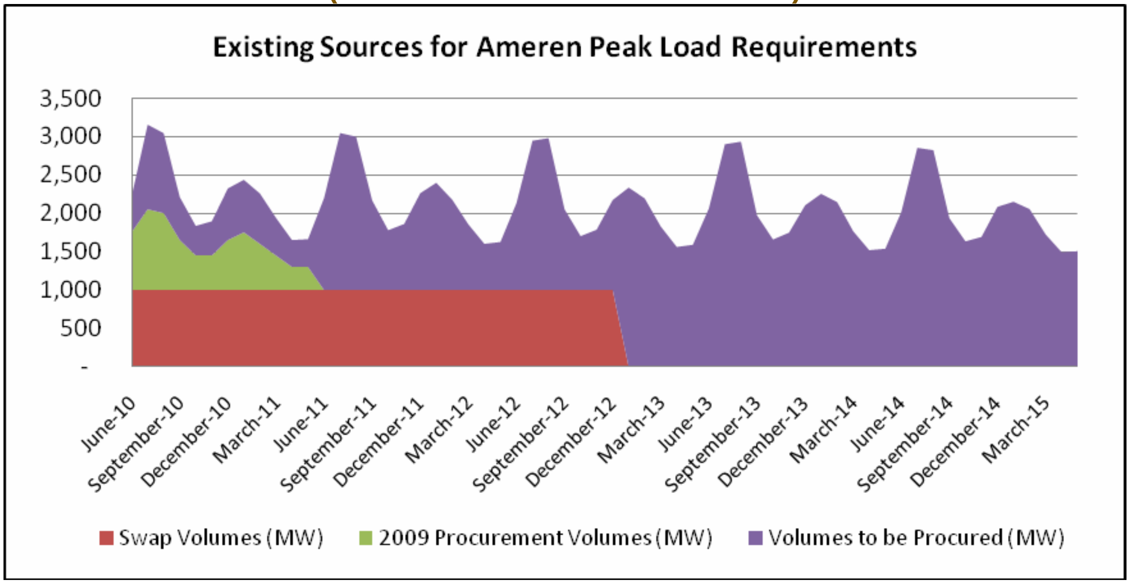
[16] 220 ILCS 5/16-111.5(k).

TABLE I2: AMEREN RESIDUAL OFF-PEAK SUPPLY REQUIREMENTS (JUNE 2010 THROUGH MAY 2011)

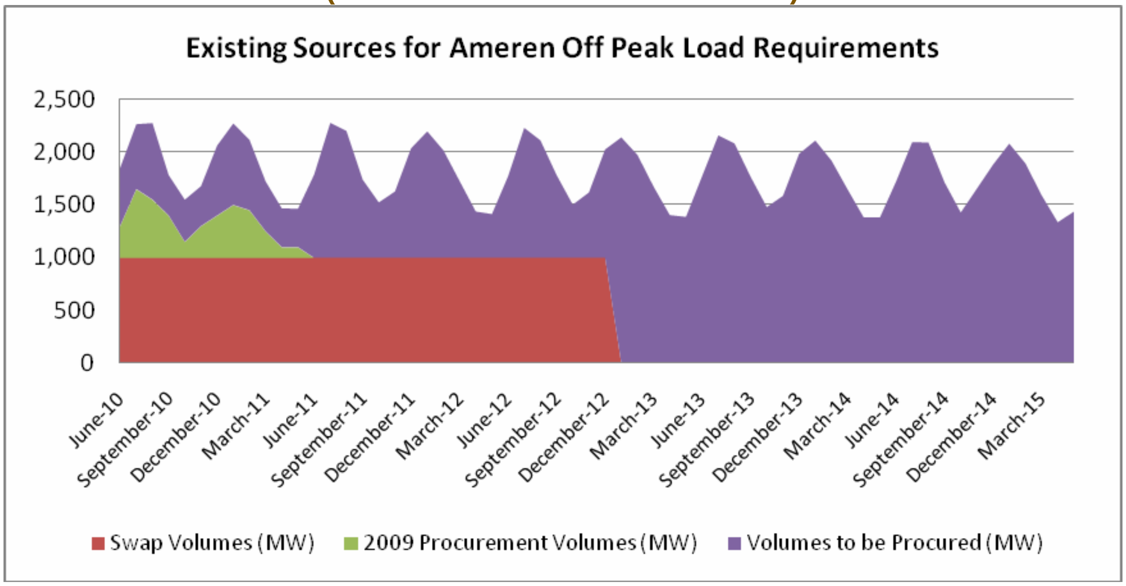
Contract Month	Off Peak			
	Projected Volume (MW)	Swap Volumes (MW)	2009 Procurement Volumes (MW)	Residual Volumes (MW)
June-10	1,848	1,000	300	548
July-10	2,263	1,000	650	613
August-10	2,274	1,000	550	724
September-10	1,781	1,000	400	381
October-10	1,549	1,000	150	399
November-10	1,677	1,000	300	377
December-10	2,061	1,000	400	661
January-11	2,270	1,000	500	770
February-11	2,115	1,000	450	665
March-11	1,721	1,000	250	471
April-11	1,467	1,000	100	367
May-11	1,462	1,000	100	362

Graphs 2 and 3 identify the sources of the electricity for eligible customers taking supply service from Ameren for their homes and small commercial accounts. As time goes on, larger volumes of electricity will be sourced from IPA managed procurement activity.

GRAPH 2: AMEREN PEAK LOAD PORTFOLIO SOURCES (JUNE 2010 THROUGH MAY 2015)



GRAPH 3: AMEREN OFF-PEAK LOAD PORTFOLIO SOURCES
(JUNE 2010 THROUGH MAY 2015)



3. Wholesale Products to be Procured

i. Energy. The IPA recommends a two part method for meeting the energy requirements of eligible customers: a short term portfolio and a long term portfolio. The short term portfolio will center on the application of the laddered volume approach discussed in the portfolio section of this document. The Long term portfolio will center on securing as much as 600,000 MWH of annual energy supply from renewable energy resources with a first delivery date expected to occur during the 2011-2012 plan year.

a. Short term portfolio. Ameren Illinois Utilities will utilize 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.

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.

The use of financial swaps 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.

Energy required by the Eligible Retail Customers comes from three sources. First, the swap contract with Ameren Energy Marketing provides a financial hedge on 1,000 MW of ATC energy during the June 2010 – December 2012 period. Second, various fixed price swap contracts were secured through the 2009 procurement cycle that will be in effect during the June 2010 through may 2011 period. Third, Ameren Illinois Utilities will meet their combined physical load requirements via the MISO day ahead and real-time energy markets, and will enter into financial swap contracts to hedge price exposure for Residual Volumes (IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan).

In determining the granularity of the standard wholesale products to be procured through the RFP, the IPA recognized that if the products are defined in a way such that the megawatt amount contracted in each given hour is equal to the actual customer load in that hour, then the wholesale products will effectively provide price stability for customers because the fluctuations in the cost to supply the load will effectively be hedged. Yet, standard products traded in the wholesale market do not involve delivery quantities that vary within the twenty-four (24) monthly on-peak/off-peak periods throughout the year, so the quantities of energy procured in the form of standard wholesale products cannot approximate customer load shapes on a more granular basis than a monthly on-peak/off-peak basis.

Given these facts, the IPA will issue solicitations for monthly on-peak and off-peak standard wholesale block energy products (or their equivalent volumes in seasonal or varietal strips) for delivery during the June 2010 - May 2013 period. The target procurement quantities are determined by multiplying Ameren's average load obligation in each monthly on-peak/off-peak period by the targeted hedge position after the procurement event is completed (i.e. 35% for requirements two years out, 70% for requirements one year out, and 100% for requirements in the year in which power is delivered). Next, MWs covered by the Ameren Energy Marketing swap are subtracted from the target requirements. To the extent the calculated procurement quantity for a period is less that zero, no energy will be procured for that period and existing positions will be maintained. Also note that calculations in the model are rounded to the nearest 50 MW. By procuring a portfolio of the most granular standard wholesale products available and in quantities reflective of forecasted loads, the forecasted net amount of energy transacted in the volatile spot market will be minimized.

Bidders will be provided an opportunity to bundle their bids for various products as determined by the procurement administrator after consulting with the IPA, utilities, the procurement monitor and the Commission. By providing some flexibility for bundled bids, bidders will be better able to bid on the products for which they can offer the most competitive prices. The procurement administrator will accept the bids that together represent the lowest cost portfolio of products that provide the desired monthly on-peak and off-peak quantities being solicited through the RFP, provided that other legal standards in the PUA are followed.

Based on the current load forecast, the quantities of standard wholesale energy products to be procured through the sealed-bid RFP are as shown (rounded to the nearest 50 MW) in Table J-1 and J-2. A full schedule of related planned procurement loads for Ameren can be found in Attachment G.

TABLE J-1: AMEREN PEAK LOAD VOLUMES TO SECURE IN 2010 SHORT TERM PORTFOLIO PROCUREMENT CYCLE

Contract Month	Peak Contract Volumes to Secure (MW)				
	Projected Volume (MW)	Swap Volumes (MW)	2009 Procurement Volumes (MW)	Residual Volumes (MW)	2010 IPA Procurement (MW)
June-10	2216	1000	750	466	450
July-10	3150	1000	1050	1100	1100
August-10	3039	1000	1000	1039	1050
September-10	2210	1000	650	560	550
October-10	1834	1000	450	384	400
November-10	1894	1000	450	444	450
December-10	2321	1000	650	671	650
January-11	2433	1000	750	683	700

February-11	2255	1000	600	655	650
March-11	1940	1000	450	490	500
April-11	1651	1000	300	351	350
May-11	1662	1000	300	362	350
June-11	2194	1000	0	1194	550
July-11	3041	1000	0	2041	1150
August-11	2994	1000	0	1994	1100
September-11	2166	1000	0	1166	500
October-11	1778	1000	0	778	250
November-11	1859	1000	0	859	300
December-11	2259	1000	0	1259	600
January-12	2395	1000	0	1395	700
February-12	2173	1000	0	1173	500
March-12	1854	1000	0	854	300
April-12	1601	1000	0	601	100
May-12	1626	1000	0	626	150
June-12	2130	1000	0	1130	0
July-12	2942	1000	0	1942	0
August-12	2975	1000	0	1975	0
September-12	2051	1000	0	1051	0
October-12	1702	1000	0	702	0
November-12	1785	1000	0	785	0
December-12	2171	1000	0	1171	0
January-13	2332	0	0	2332	800
February-13	2191	0	0	2191	750
March-13	1826	0	0	1826	650
April-13	1561	0	0	1561	550
May-13	1589	0	0	1589	550

TABLE J-2: AMEREN OFF-PEAK LOAD VOLUMES TO SECURE IN 2010 SHORT TERM PORTFOLIO PROCUREMENT CYCLE

Contract Month	Off-Peak Contract Volumes to Secure (MW)					
	Projected Volume (MW)	Swap Volumes (MW)	2009 Procurement Volumes (MW)	Residual Volumes (MW)	2010 IPA Procurement (MW)	2010 IPA Procurement Cycle A (MW)
June-10	1,848	1,000	300	548	550	550
July-10	2,263	1,000	650	613	600	600
August-10	2,274	1,000	550	724	700	700
September-10	1,781	1,000	400	381	400	400
October-10	1,549	1,000	150	399	400	400
November-10	1,677	1,000	300	377	400	400
December-10	2,061	1,000	400	661	650	650
January-11	2,270	1,000	500	770	750	750
February-11	2,115	1,000	450	665	650	650
March-11	1,721	1,000	250	471	450	450
April-11	1,467	1,000	100	367	350	350
May-11	1,462	1,000	100	362	350	350
June-11	1,786	1,000	0	786	250	300
July-11	2,275	1,000	0	1,275	600	500
August-11	2,200	1,000	0	1,200	550	450

September-11	1,740	1,000	0	740	200	250
October-11	1,523	1,000	0	523	50	150
November-11	1,626	1,000	0	626	150	150
December-11	2,035	1,000	0	1,035	400	300
January-12	2,195	1,000	0	1,195	550	350
February-12	2,015	1,000	0	1,015	400	250
March-12	1,725	1,000	0	725	200	150
April-12	1,437	1,000	0	437	0	50
May-12	1,412	1,000	0	412	0	100
June-12	1,771	1,000	0	771	0	0
July-12	2,228	1,000	0	1,228	0	0
August-12	2,110	1,000	0	1,110	0	0
September-12	1,782	1,000	0	782	0	0
October-12	1,502	1,000	0	502	0	0
November-12	1,617	1,000	0	617	0	0
December-12	2,024	1,000	0	1,024	0	0
January-13	2,138	0	0	2,138	750	400
February-13	1,972	0	0	1,972	700	400
March-13	1,671	0	0	1,671	600	350
April-13	1,403	0	0	1,403	500	300
May-13	1,386	0	0	1,386	500	300

The PUA provides that it is the duty of the Procurement Administrator, in consultation with the Commission, Ameren, and other interested parties, to develop the standard contract form that will be used for the standard wholesale products to be procured through the RFP.[17]

The standard wholesale products to be procured through the RFP could be settled physically or financially. In both cases, Ameren would contract to purchase or hedge specific quantities of energy at fixed prices.

In the case of financial settlement, Ameren would procure energy in the day-ahead or real-time markets, and debit or credit a dollar amount to the seller based on the difference between the agreed-upon fixed contract price and an index price, whereby the index price would be specified in the contract to be either the day-ahead or real-time energy price. Financial contracts are generally referred to as “contracts for differences”. The swap contract with Ameren Energy Marketing is an example of a financially-settled contract.

In the case of physical settlement, the contracting parties would transact through MISO. In this case, both parties must be MISO members in good standing. Ameren and the seller would execute an agreement, under which the seller transfers energy to Ameren via a MISO process. Ameren would then directly pay the seller the agreed-upon fixed contract price for the specified amount of energy.

The choice between settling physically and financially does not affect service reliability. Whether the products settle physically or financially, MISO will still dispatch the system in such a way to ensure that customers’ requirements are met. The decision to settle physically or financially affects the logistics regarding cash flows, the administrative tasks that are required of the various parties involved, the non-performance risks and the standard of legal review.

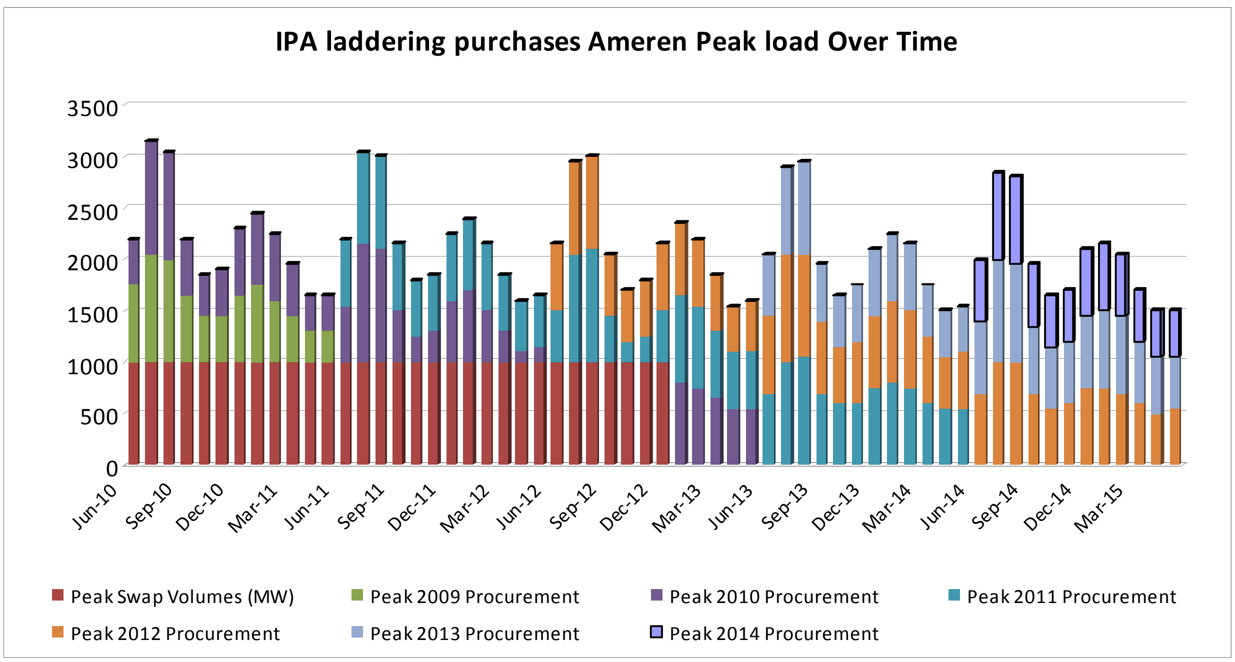
[17] 220 ILCS 5/16 – 111.5(c)(1)(v); 220 ILCS 5/16-111.5(e)(2).

The IPA recommends that the contracts to be procured through the RFP be settled financially for Ameren volumes for the following reasons:

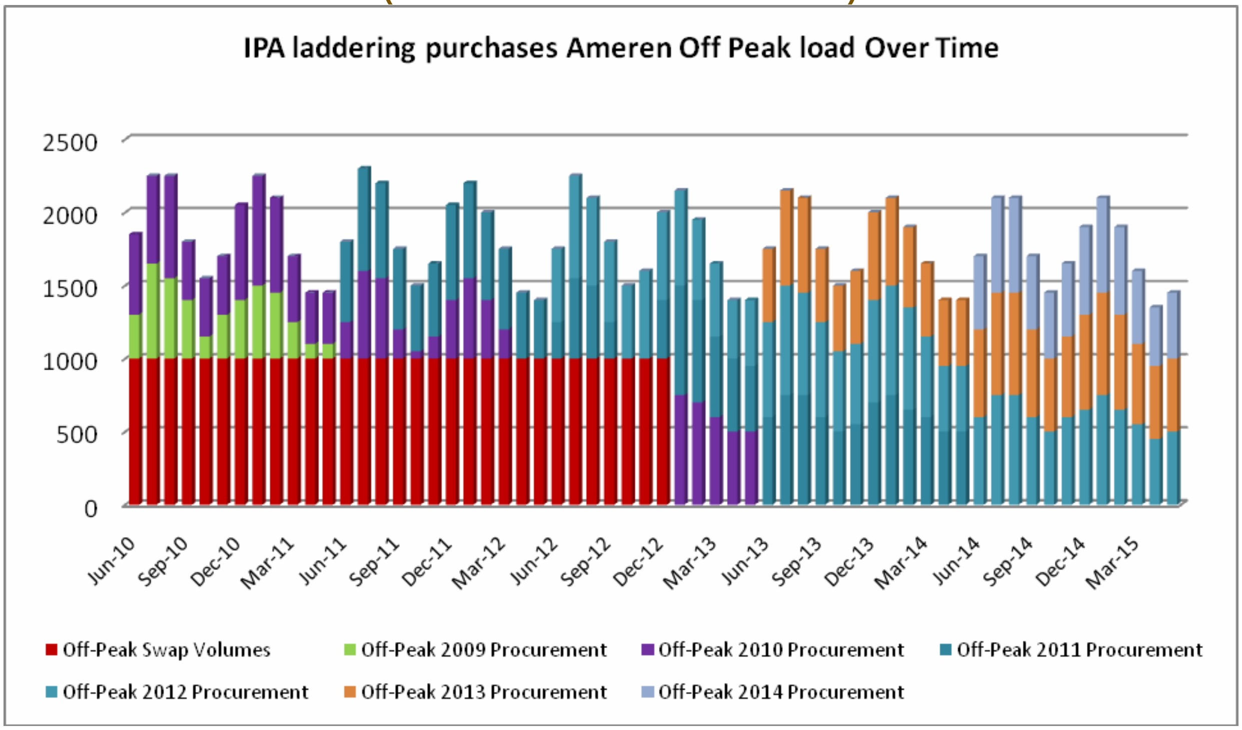
- The MISO market rules do not maintain the same credit requirements found in the PJM market. Therefore, financial swaps are a standard method used by multiple entities within the MISO market for securing fixed cost pricing for loads.
- With the ability to settle prices financially without added premium, the IPA believes that a larger, more diverse, and competitive bidder pool will be interested in bidding on Ameren requirements.

Graphs 4 and 5 represent how the Plan anticipates securing load for Ameren's eligible customers by laddering in purchases so that no one month or season is purchased all at one time. By dollar-cost averaging in this manner, the IPA mitigates risk to Ameren's eligible customers.

GRAPH 4: LADDERING SCHEDULE FOR AMEREN PEAK LOAD (JUNE 2010 THROUGH MAY 2015)



GRAPH 5: LADDERING SCHEDULE FOR AMEREN OFF-PEAK LOAD (JUNE 2010 THROUGH MAY 2015)



b. Long term portfolio. The IPA recommends issuing solicitations for longer term power purchase agreements ("PPAs") with renewable energy providers. Long Term PPAs can serve as a hedge against potential cap and trade legislation that would serve as an additional tax on fossil fuel costs. Further, grants, loans and credit enhancement available currently from US Department of Energy, Department of Commerce and Economic Opportunity and the Illinois Finance Authority will result in lower cost renewable energy projects that are developed now through the end of 2012 due to the public grants and financing.

Given these factors, the IPA believes it is prudent to solicit proposals from renewable energy providers to capitalize on available funding and secure a modest level of renewable energy under longer term PPAs if deemed cost effective. As neither the cost liabilities nor the availability of other hedging options associated with cap and trade are unknown, the IPA seeks to limit their use in the Ameren portfolio to 600,000 MWH per annum starting as early as the 2011-2012 planning year. The use of a MWH goal for these contracts is due to the variable output nature of some renewable assets that may be selected through the solicitation process (i.e. hydro, wind, and solar).

The IPA recommends that bids be evaluated through a process similar to that used to evaluate bids in the short term portfolio: standard terms and conditions regarding performance guarantees and penalties are agreed to by bidders prior to solicitation, bidders must pre-qualify to be allowed into the bidder pool, application of a cost benchmark to reject above market value bids, and scoring of submitted bids according to a methodology that considers and ranks proposals on the basis of output, capacity value, financing costs, transmission and capital costs, fixed cost vs. escalators offers, return on equity and other normalizing factors.

ii. Capacity. Module E of the Midwest ISO's Open Access Transmission and Energy Markets Tariff addresses resource adequacy. Under Module E, the Midwest ISO will develop a Planning Reserve Margin ("PRM") for each Load Serving Entity ("LSE"). If higher or lower PRMs are mandated by a state regulatory authority, then the Midwest ISO shall recognize and incorporate such PRMs for any affected LSE(s). Nothing in Module E affects existing state jurisdiction over the construction of additional Capacity or the authority of states to set and enforce compliance with standards for adequacy. At present, the State of Illinois has not mandated a PRM different than the one developed by MISO. Module E, along with the associated business practice manual, also requires Ameren to provide an annual forecast of monthly loads adjusted for transmission losses and subsequently confirm on a month-ahead basis that Ameren has enough capacity to meet or exceed its monthly peak load forecast plus its planning reserve margin.

For demonstration purposes, the tables included in this plan utilize the reserve margin of 5.35% that has been effective for the period June 2009 through May 2010. The planning reserve margin beginning June 2010 has yet to be established and therefore the IPA recommends that the Commission authorize the IPA's procurement administrator, in consultation with the IPA, the Commission Staff, the procurement monitor, and the Ameren Illinois Utilities, to adjust the quantities of capacity to acquire to comply with the applicable planning reserve requirements. Furthermore, to the extent to which it is impractical or impossible for the procurement administrator to modify its capacity RFP to fully account for all applicable capacity requirements the applicable planning reserve requirements, the IPA recommends that the Commission authorize the Ameren Illinois Utilities to make up the difference through one or more supplemental procurement processes.

100% of the monthly capacity requirements will be acquired for the first planning year (June 2010 through May 2011) as detailed in Table K:

TABLE K: AMEREN CAPACITY CONTRACT VOLUMES TO SECURE IN 2010 CYCLE (JUNE 2010 THROUGH MAY 2011)

Month	Peak Load	Demand Response	Trans-mission Losses	Net Peak Load	Planning Reserves	Capacity Require ment	2009 Purchases	2010 Purchases	% Hedge
June-10	3,992	0	81	4,073	218	4,291	2,110	2,190	100%
July-10	4,363	4	89	4,448	238	4,686	2,530	2,160	100%
August-10	4,276	4	87	4,358	233	4,592	2,500	2,100	100%
September-10	3,906	0	80	3,986	213	4,199	1,980	2,220	100%
October-10	2,549	0	52	2,601	139	2,740	1,480	1,270	100%
November-10	2,510	0	51	2,561	137	2,698	1,430	1,270	100%
December-10	3,336	*0*	68	3,404	182	3,586	1,690	1,900	100%
January-11	3,298	0	67	3,366	180	3,546	1,670	1,880	100%
February-11	3,009	0	61	3,071	164	3,235	1,560	1,680	100%
March-11	2,667	0	54	2,721	146	2,867	1,370	1,500	100%
April-11	2,243	0	46	2,289	122	2,411	1,240	1,180	100%
May-11	2,612	0	53	2,665	143	2,808	1,590	1,220	100%

Sufficient capacity will be procured such that 70% of the monthly capacity requirements will be acquired for the second planning year (June 2011 through May 2012 as detailed in Table L:

TABLE L: AMEREN CAPACITY CONTRACT VOLUMES TO SECURE IN 2010 CYCLE (JUNE 2011 THROUGH MAY 2012)

Month	Peak Load	Demand Response	Trans-mission Losses	Net Peak Load	Planning Reserves	Capacity Require ment	2009 Purchases	2010 Purchases	% Hedge
June-11	3,938	0	80	4,019	215	4,234	1,370	1,600	70%
July-11	4,295	13	87	4,369	234	4,603	1,630	1,600	70%
August-11	4,201	13	85	4,274	229	4,503	1,650	1,510	70%
September-11	3,846	0	78	3,925	210	4,135	1,300	1,600	70%
October-11	2,499	0	51	2,550	136	2,686	960	930	70%
November-11	2,454	0	50	2,504	134	2,638	910	940	70%
December-11	3,263	0	67	3,329	178	3,508	1,100	1,360	70%
January-12	3,221	0	66	3,287	176	3,463	1,100	1,330	70%
February-12	2,903	0	59	2,962	158	3,121	1,020	1,170	70%
March-12	2,608	0	53	2,662	142	2,804	900	1,070	70%
April-12	2,193	0	45	2,238	120	2,358	800	860	70%
May-12	2,551	0	52	2,603	139	2,743	1,040	880	70%

Sufficient capacity will be procured such that 35% of the monthly capacity requirements will be acquired for the third planning year (June 2012 through May 2013 as detailed in Table M:

TABLE M: AMEREN CAPACITY CONTRACT VOLUMES TO SECURE IN 2010 CYCLE (JUNE 2012 THROUGH MAY 2013)

Month	Peak Load	Demand Response	Trans-mission Losses	Net Peak Load	Planning Reserves	Capacity Require ment	2009 Purchases	2010 Purchases	% Hedge
June-12	3,856	0	79	3,935	211	4,146	0	1,460	35%
July-12	4,203	17	85	4,271	229	4,500	0	1,580	35%
August-12	4,111	17	84	4,177	223	4,401	0	1,550	35%
September-12	3,771	0	77	3,847	206	4,053	0	1,420	35%
October-12	2,446	0	50	2,496	134	2,630	0	930	35%
November-12	2,399	0	49	2,448	131	2,579	0	910	35%
December-12	3,190	0	65	3,255	174	3,429	0	1,210	35%
January-13	3,145	0	64	3,209	172	3,381	0	1,190	35%
February-13	2,869	0	59	2,928	157	3,084	0	1,080	35%
March-13	2,544	0	52	2,596	139	2,735	0	960	35%
April-13	2,147	0	44	2,191	117	2,308	0	810	35%
May-13	2,500	0	51	2,551	136	2,687	0	950	35%

0% of the monthly capacity requirements will be acquired for the fourth and fifth planning years (June 2013 through May 2015 as detailed in Table N:

TABLE N: AMEREN CAPACITY CONTRACT VOLUMES NOT TO BE SECURED IN 2010 CYCLE (JUNE 2013 THROUGH MAY 2015)

Month	Peak Load	Demand Response	Trans-mission Losses	Net Peak Load	Planning Reserves	Capacity Requirement	2009 Purchases	2010 Purchases	% Hedge
June-13	3,784	0	77	3,861	207	4,068	0	0	0%
July-13	4,121	21	84	4,184	224	4,408	0	0	0%
August-13	4,031	21	82	4,092	219	4,311	0	0	0%
September-13	3,693	0	75	3,769	202	3,970	0	0	0%
October-13	2,395	0	49	2,444	131	2,575	0	0	0%
November-13	2,345	0	48	2,393	128	2,521	0	0	0%
December-13	3,112	0	64	3,175	170	3,345	0	0	0%
January-14	3,068	0	63	3,131	168	3,298	0	0	0%
February-14	2,799	0	57	2,856	153	3,009	0	0	0%
March-14	2,482	0	51	2,533	136	2,669	0	0	0%
April-14	2,096	0	43	2,139	114	2,254	0	0	0%
May-14	2,444	0	50	2,494	133	2,627	0	0	0%
June-14	3,691	0	75	3,766	201	3,968	0	0	0%
July-14	4,024	24	82	4,081	218	4,300	0	0	0%
August-14	3,936	24	80	3,991	214	4,205	0	0	0%
September-14	3,600	0	73	3,674	197	3,870	0	0	0%
October-14	2,336	0	48	2,383	128	2,511	0	0	0%
November-14	2,281	0	47	2,327	124	2,452	0	0	0%
December-14	3,015	0	62	3,077	165	3,241	0	0	0%
January-15	2,973	0	61	3,034	162	3,196	0	0	0%
February-15	2,718	0	55	2,774	148	2,922	0	0	0%
March-15	2,414	0	49	2,463	132	2,595	0	0	0%
April-15	2,042	0	42	2,083	111	2,195	0	0	0%
May-15	2,384	0	49	2,432	130	2,563	0	0	0%

With regard to the capacity, the Act cites the following required inclusion the Plan:

the proposed mix of demand-response products for which contracts will be executed during the next year. The cost-effective demand-response measures shall be procured whenever the cost is lower than procuring comparable capacity products, provided that such products shall:

(A) Be procured by a demand-response provider from eligible retail customers
(B) At least satisfy the demand-response requirements of the regional transmission organization market in which the utility's service territory is located, including, but not limited to, any applicable capacity or dispatch requirements
(C) Provide for customers' participation in the stream of benefits produced by the demand-response products;
(D) Provide for reimbursement by the demand-response provider of the utility for any costs incurred as a result of the failure of the supplier of such product to perform its obligations thereunder; and
(E) Meet the same credit requirements as apply to suppliers of capacity, in the applicable regional transmission market.[18]

[18] 220 ILCS 5/16-111.5(b)(3)(ii).

The IPA recommends that the initial solicitation of demand response as an alternative to standard capacity be conducted in the 2010 Procurement Cycle in the following manner:

- **Timing.** The IPA recommends that Demand Response be specified as a bid alternate in the spring 2010 solicitation for capacity. In the event that Demand Response providers do not exist or do not participate in the Spring solicitation, then a secondary solicitation will be conducted in the Fall of 2010 that will seek to establish capacity contracts that will incent the development of demand response programs within the Ameren service territory.
- **Volumes.** Per the statute, qualified demand response bids submitted in the spring procurement that are of lesser cost than comparable capacity sources will be selected as winning bidders. 220 ILCS 16-111.5(b)(3)(ii). The IPA recommends that if the secondary solicitation described above is necessary, then the total volume of capacity to be awarded not exceed a maximum contract volume basis of 500 megawatts in any given month.
- **Term.** The IPA recommends that demand response providers participating in the spring capacity solicitation be allowed to bid on all months and volumes under the same terms and conditions as other traditional suppliers. If the secondary solicitation is necessary, offers from bidders that extend over a five (5) year period from the time of first contract obligation or delivery will be considered.

The IPA will work with interested stakeholders to ensure that demand response resource providers are adequately notified of the IPA's solicitation and that the solicitation process is not unnecessarily complex or burdensome on any party.

iii. Transmission. In addition to the acquisition of power and energy related products as detailed above, Ameren is 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 Services. Further, Ameren may be allocated certain Financial Transmission/Auction Revenue Rights

- **Network Integrated Transmission Service.** Network Integrated Transmission Service ("NITS") is described in Section III of Module B to the MISO Tariff. Ameren 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.

  Ameren has acquired the necessary NITS in accordance with the tariff. The cost for this service shall be established in the applicable MISO tariff schedules.

- **Ancillary Services.** Ancillary Services are services that are necessary to support capacity and the transmission of energy from resources to loads while maintaining reliable operation of the transmission system. Effective January 2009, the Midwest ISO implemented an Ancillary Services market to provide regulation service and operating reserve service (both spinning and supplemental) reserves. The Ameren Illinois Utilities procure these required services through 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 Ameren generally serves to reduce the cost of congestion borne by Ameren (and, thus, ultimately by their customers).

As part of the 2009 ARR allocation process at MISO, Ameren received a set of ARR entitlements and were awarded ARRs for the 2009 planning year.

For future planning years, Ameren shall continue to actively participate in the MISO ARR nomination and allocation process and shall seek to nominate those ARRs with an expected positive value. Ameren recognizes they may not be allocated all of the ARRs requested and they may be required by the MISO to accept certain ARRs which do not have an expected positive value.

Ameren shall retain the allocated ARRs and receive associated credits for its customers. Ameren should make no further changes 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, Ameren 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.

iv. Load Balancing Procedures. Upon Commission approval of this Plan, Ameren will be entering into financial swap transactions to hedge the energy price risk of the portfolio. 100% of the energy required to supply the load included in this Plan will be purchased in the MISO energy markets. Ameren will forecast respective load requirements for each delivery day in accordance with industry standards and practices 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 Rebalancing in the Event of Significant Shifts in Load.** The PUA requires that the IPA provide the criteria for portfolio rebalancing in the event of significant shifts in load.[19] In the event that Ameren's annual forecast increases above the High Forecast or decreases below the Low Forecast during the active delivery year of an approved Procurement Plan, Ameren shall promptly notify the IPA. The IPA will subsequently convene a meeting with Ameren, Commission, and Procurement Administrator to determine whether it is appropriate to rebalance the portfolio, and if so, to what extent and how such a rebalancing can be achieved.

  Over the term of this Plan, the most significant driver of load shifting levels is customer switching. If customer switching levels are significantly different from forecasted levels, a re-balancing of the portfolio may be warranted.

- **Intercompany Dynamics Cost and Resource Sharing.** As noted in section I, Ameren will procure power under this single Procurement Plan, for the combined needs of its Illinois utilities. To the extent permitted by the applicable legal and regulatory authorities, Ameren 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.

[19] 220 ILCS 5/16-111.5(b)(4).

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

v. Renewable Portfolio Standard. Section 1-75(c) of the IPA Act establishes that:

The procurement plans shall include cost-effective renewable energy resources. A minimum percentage of each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act[20]

The statute defines renewable energy resources as follows:

"Renewable energy resources" includes ***energy and its associated renewable energy credit or renewable energy credits*** *from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, trees and tree trimmings, hydropower that does not involve new construction or significant expansion of hydropower dams, and other alternative sources of environmentally preferable energy. For purposes of this Act, landfill gas produced in the State is considered a renewable energy resource.*[21] ***[Emphasis added]***

The statute establishes a methodology for calculating annual volumetric goals for the portfolio as well as establishing a Renewable Energy Resource Budget (RRB) that serves as a maximum cost cap for meeting those goals. In the event that the cost cap is met, purchases of renewable energy resources are to be curtailed, leaving the annual volumetric goal unmet. Table O below cites the volume goals and cost limits.

TABLE O: RPS STANDARDS FOR AMEREN

Delivery period	Minimum Percentage (Annual volume goal)	Maximum Cost Standard
2010-2011	5% of June 1, 2008 through May 31, 2009 eligible retail customer load	The greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2009 or 1.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007
2011-2012	6% of June 1, 2009 through May 31, 2010 eligible retail customer load	The greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2010 or 2.0% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007
2012-2013	7% of June 1, 2010 through May 31, 2011 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011
2013-2014	8% of June 1, 2011 through May 31, 2012 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011
2014-2015	9% of June 1, 2012 through May 31, 2013 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011

Table P below presents the Annual Volume Targets resulting from the application of the statute's standards to the Ameren portfolio for planning years 2008-2009, 2009-2010, and 2010-2011.

[20] 20 ILCS 3855/1-75(c)(1)
[21] 20 ILCS 3855/1-10.

TABLE P: ANNUAL AMEREN RPS VOLUME TARGETS

Ameren RPS Volume Targets				
Planning Year	**Reference Year**	**Reference Year Delivered Volume (MWh)**	**Planning Year RPS % Target**	**Planning Year RPS Volume Target (MWh)**
2008-2009	2006-2007	20,719,607	2.0%	414,392
2009-2010	2007-2008	17,984,564	4.0%	719,383
2010-2011	2008-2009	17,217,197	5.0%	860,860

Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables Q and R below presents the Annual Renewable Energy Resource Budgets resulting from the application of the statute's standards to the Ameren portfolio for planning years 2008-2009, 2009-2010, and 2010-2011.

TABLE Q: ANNUAL AMEREN RRB CALCULATIONS – OPTION A

2010-2011 RPS CALCULATIONS: Option A (Incremental increase on annual unit cost approach)			
(A) Planning Year	2008-2009	2009-2010	2010-2011
(B) Reference Year	2006-2007	2007-2008	2008-2009
(C) Reference Year Delivered Volume (MWh)	20,719,607	17,984,564	17,217,197
(D) Reference Year Delivered Cost	$1,801,867,729	$1,809,606,830	$1,853,574,838
(E) Reference Year Unit Cost - [D / C]	$86.96	$100.62	$107.66
(F) Planning Year Incremental RPS Cost Limit %	0.500%	0.500%	0.500%
(G) Planning Year Incremental RPS Cost Limit Unit Price - [F * D]	$0.434822	$0.503100	$0.538292
(H) Planning Year Net RPS Cost Limit Unit Price	$0.434822	$0.937922	$1.476214
(I) Planning Year Projected Total Delivery Volume	20,719,607	17,700,274	16,525,235
(J) Planning Year Option A Cost Cap [I * H]	**$9,009,339**	**$16,601,474**	**$24,394,776**

TABLE R: ANNUAL AMEREN RRB CALCULATIONS – OPTION B

2010-2011 RPS CALCULATIONS: Option B (Percentage Increase over Base Year unit cost approach)			
(A) Planning Year	**2008-2009**	**2009-2010**	**2010-2011**
(B) Reference Year	**2006-2007**	**2006-2007**	**2006-2007**
(C) Reference Year Delivered Volume (MWh)	20,719,607	17,984,564	17,217,197
(D) Reference Year Delivered Cost	$1,801,867,729	$1,801,867,729	$1,801,867,729
(E) Reference Year Unit Cost ($/MWh) - [D / C]	$86.96	$100.62	$107.66
(F) Planning Year Incremental RPS Cost Limit %	0.500%	1.000%	1.500%
(G) Planning Year Net RPS Cost Limit Unit Price - [F * D]	$0.434822	$0.869644	$1.304466
(H) Planning Year Projected Total Delivery Volume	20,719,607	17,700,274	16,525,235
(I) Planning Year Option A Cost Cap [H * G]	**$9,009,339**	**$15,392,933**	**$21,556,601**

Table S below displays the results of the RPS calculations for Planning Year 2010-2011 for the Ameren Illinois Utilities.

TABLE S: AMEREN RPS TARGETS for 2010-2011

Ameren Renewable Portfolio Standard (RPS) Metrics (2010-2011)	
RPS Volume Target (MWh)	860,860
Renewable Energy Resource Budget (RRB)	$24,394,776
Average Price per Renewable Unit	$28.34
Estimated Customers Covered by RRB	1,190,808
Estimated Annual RPS Cost/Consumer	$20.49

Specific aspects for meeting the RPS requirements detailed above are noted below:

- **Products to be Procured.** Ameren shall meet the renewable energy resource portfolio standard for the Plan year through the acquisition of qualifying renewable energy credits ("REC's") as defined in Section 1-10 of the IPA Act. The acquisition of REC's for this period meets the requirements of the IPA Act and are preferable to the direct acquisition of energy from qualifying renewable resources at this time.

  The Plan selects the purchase of REC's to satisfy the RPS requirements based on the following:

  - The RPS can be met only by procuring either of the following:
    - RPS Option A - Energy (from a qualified resource) and its associated renewable energy credit; or
    - RPS Option B - Renewable energy credits
  - Based on the Volume goals and RBB, the average unit price that can be paid for each renewable energy resources is $28.34
  - The available funds under the RPS are not sufficient to meet the RPS volume requirements.

  Sufficient RECs to comply with the quantities established by 1-75 (c) (1) of the IPA Act shall be acquired on the basis of (1) the requirements established in 1-75 (c) (3) of the IPA Act and (2) price, as determined by comparing qualifying bids meeting approved benchmarks. Such acquisitions of renewable energy credits shall be memorialized with a Master Renewable Energy Certificate Purchase and Sale Agreement.

- **Pricing Benchmark.** The Procurement Administrator is directed to continue to establish benchmark REC prices (as was done in 2009), and to reject bids priced above the benchmarks. The benchmarks shall be set at levels that consider relevant market prices and the economic development benefits of in-state resources. The benchmark prices shall be confidential, but shall be provided to, and will be subject to, Commission review and approval prior to solicitations of REC bids.

- **Preferences.** Section 1-75 (c) (3) of the IPA Act requires that until June 1, 2011 cost effective renewable energy resources be procured first from facilities in the State of Illinois, then from facilities located in states adjacent to Illinois, then from facilities located elsewhere.

- **Compliance Tracking.** The acquisition of renewable energy credits (RECs) in amounts equal to the statutory requirement ensures compliance.

  PJM Environmental Information System's ("EIS") Generation Attribute Tracking System ("GATS") and the Midwest Renewable Energy Tracking System ("M-RETS") will be utilized to independently verify the location of generation, resource type and month and year of generation. GATS tracks generation attributes and the ownerships of the attributes as they are traded or used to meet renewable portfolio standards ("RPS") and other programs, typically for generators whose energy is settled in the PJM market or whose facility is located in the PJM footprint. M-RETS tracks renewable energy generation and assists in verifying compliance with individual state/provincial RPS requirements or voluntary programs, typically for generators located in the MISO footprint and other RTOs outside of PJM.

  Each agreement for the acquisition of a REC shall have a specified term. All RECs used by Ameren to comply with the statutory requirements shall be retired in compliance with 1-75 (c) (4).

vi. Contingency Procurement Plan. Ameren Rider PER (Purchased Energy Recovery) (Electric Service Schedule Ill.CC. No. 18) will serve as the basis of the Contingency Procurement Plan.

D. Application of the Plan to Commonwealth Edison

1. Definition of Retail Customer Classes to be Supplied. This portion of the Plan explains how the power and energy will be procured for delivery from June 1, 2010, through May 31, 2013, for ComEd's Eligible Retail Customers.

Generally, the portfolio includes residential, commercial and industrial customers that have a peak demand less than 100 kW. Specifically, this includes customers from the following supply groups as defined in ComEd's currently effective General Terms and Conditions:

Residential Customer Group. Residential Customer Group means the customer supply group applicable to any retail customer in the residential sector and using electric service for residential purposes.

Watt-Hour Customer Group. Watt-Hour Customer Group means the customer supply group applicable to any retail customer in the nonresidential sector, using electric service for nonresidential purposes, and for which no metering equipment or only watt-hour metering equipment is installed at the retail customer's premises. Generally, a retail customer in this customer supply group uses less than 2,000 kWh during a monthly billing period.

Demand Customer Group. Beginning with 2008 monthly billing period, Demand Customer Group means the customer supply group applicable to any retail customer in the nonresidential sector, using electric serves for nonresidential purposes, and for which (a) the Self-Generating Customer Group is not applicable, (b) the Competitively Declared Customer Group is not applicable, and (c) demand metering is installed at the retail customer's premises.

Dusk to Dawn Lighting Customer Group. Dusk-to-Dawn Lighting Customer Group means the customer supply group applicable to (a) any retail customer in the lighting sector and using electric service for a street lighting system that operates on a dusk to dawn basis, or (b) the portion of electric service provided to a retail customer in the residential sector or nonresidential sector, located outside the City of Chicago, and using such portion for private, outdoor, fixture-included, dusk to dawn lighting purposes, provided that the Competitively Declared Customer Group is not applicable to the retail customer described in item (a) or (b).

General Lighting Customer Group. General Lighting Customer Group means the customer supply group applicable to any retail customer (a) in the lighting sector, (b) using electric service for a lighting system other than a lighting system that operates on a dusk to dawn basis, and (c) to which the Competitively Declared Customer Group is not applicable.

2. Monthly Forecasted System Supply Requirements

i. Energy. The table below includes the forecasted monthly supply requirements (in MWh) for the period June 1, 2010 through May 31, 2011. This forecast anticipates normal weather, competitive declarations, energy efficiency and demand response programs, and the impact of customer switching. Table T below notes the first twelve months worth of forecasted supply requirements for the ComEd portfolio. Greater detail can be found in Attachment H.

TABLE T: COMED FORECASTED SYSTEM SUPPLY REQUIREMENTS (JUNE 2010 THROUGH MAY 2011)

Contract Month	Total Volume (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-10	1,896,921	1,624,045	5,389	4,413
July-10	2,231,242	2,197,192	6,641	5,385
August-10	2,169,255	1,969,226	6,163	5,024
September-10	1,588,361	1,512,634	4,727	3,939
October-10	1,357,368	1,415,482	4,040	3,469
November-10	1,501,640	1,500,691	4,469	3,908
December-10	1,916,427	1,695,654	5,208	4,510
January-11	1,752,398	1,886,938	5,215	4,625
February-11	1,557,990	1,522,786	4,869	4,326
March-11	1,599,912	1,451,093	4,348	3,859
April-11	1,301,326	1,311,732	3,873	3,416
May-11	1,330,118	1,399,860	3,959	3,431

ii. Capacity. ComEd will procure the capacity and ancillary services required by the "Eligible Retail Customers" directly from PJM-administered markets. Under the Reliability Pricing Model ("RPM") program approved by the FERC and administered by PJM, ComEd is able to purchase capacity directly from PJM-administered markets. The RPM capacity prices for the June 2010 - May 2013 period have already been determined through a competitive bid process, so direct procurement from PJM results in a reasonable approach to procuring capacity for these customers. Furthermore, the PJM-administered markets for ancillary services are the most visible and easily accessible markets for these services so direct procurement from these markets is a reasonable approach for providing these services to customers.

While the IPA recognizes that PJM procures demand-response measures in the RPM auction for capacity resources, the IPA believes it necessary to certify that additional sources of demand response sources capacity are not available at less than the current RPM forward price curve.

iii. Pre-Existing Contracts. The Load Forecast includes the expected full energy requirements of the Eligible Retail Customers. However, ComEd will not need to procure that amount of energy in order to serve that load due to pre-existing contracts for supply that ComEd has previously executed.

Pursuant to section 16-111.5(k) of the PUA, ComEd entered into a five-year swap contract with Exelon Generation ("ExGen"). This agreement provides price certainty for 3,000 MW of around-the-clock ("ATC") energy that ComEd will procure through the PJM spot markets for the period June 1, 2010 through May 31, 2013.

Additional fixed price contracts for the June 2010 through May 2011 period were secured as a result of the 2009 procurement cycle.

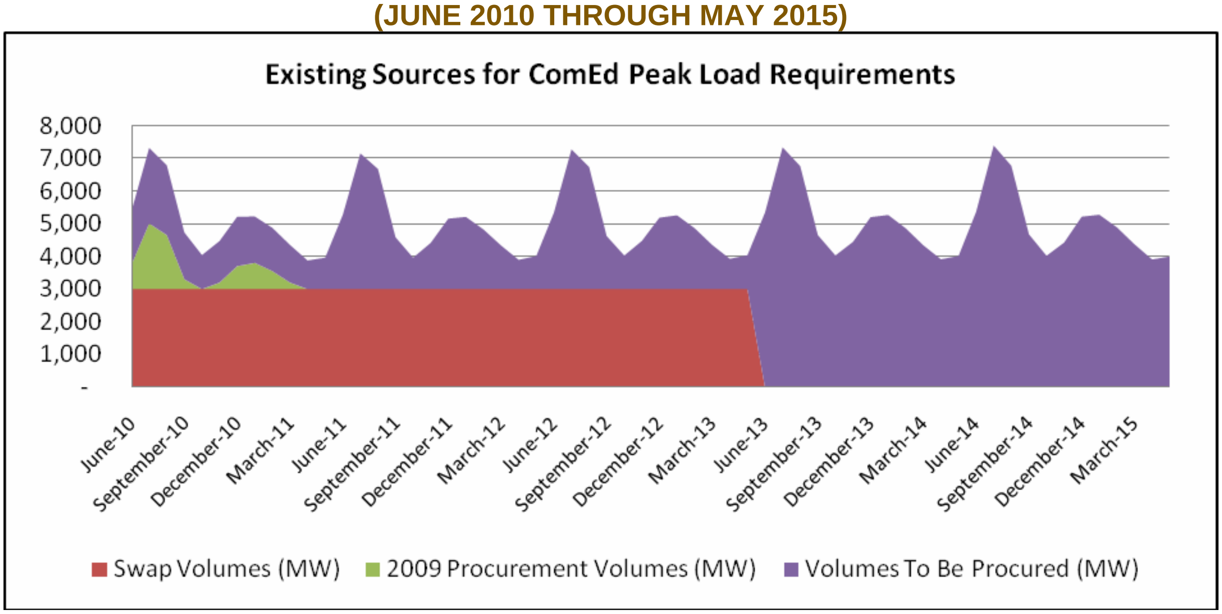
iv. Residual Load. Table U identifies the Monthly Residual Load volumes for ComEd over the procurement period. Monthly Residual Load Volumes are derived by subtracting pre-existing contract volumes from projected load volumes. A full schedule of ComEd's supply requirements can be found in Attachment I.

TABLE U: COMED RESIDUAL SUPPLY REQUIREMENTS (JUNE 2010 THROUGH MAY 2011)

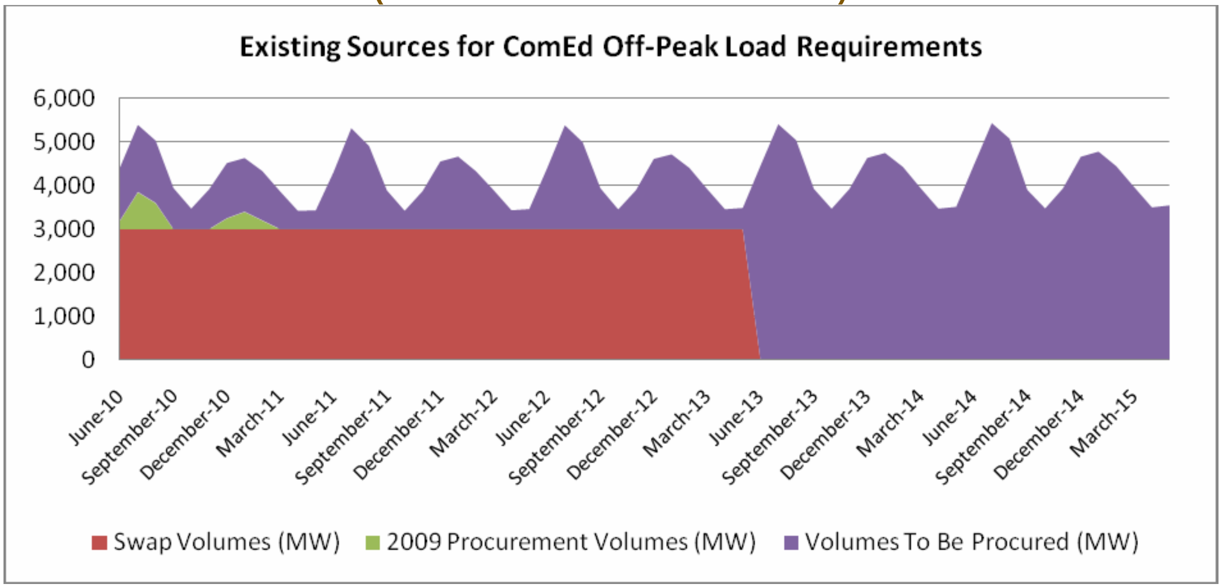
Contract Month	Peak				Off Peak			
	Projected Volume (MW)	Swap Volumes (MW)	2009 Procurement Volumes (MW)	Residual Volumes (MW)	Projected Volume (MW)	Swap Volumes (MW)	2009 Procurement Volumes (MW)	Residual Volumes (MW)
June-10	5,389	3,000	750	1,639	4,413	3,000	200	1,213
July-10	7,306	3,000	2,000	2,306	5,385	3,000	850	1,535
August-10	6,780	3,000	1,650	2,130	5,022	3,000	600	1,422
September-10	4,728	3,000	300	1,428	3,938	3,000	0	938
October-10	4,040	3,000	0	1,040	3,469	3,000	0	469
November-10	4,470	3,000	200	1,270	3,908	3,000	0	908
December-10	5,208	3,000	700	1,508	4,510	3,000	250	1,260
January-11	5,215	3,000	800	1,415	4,625	3,000	400	1,225
February-11	4,868	3,000	550	1,318	4,326	3,000	200	1,126
March-11	4,348	3,000	200	1,148	3,859	3,000	0	859
April-11	3,872	3,000	0	872	3,417	3,000	0	417
May-11	3,960	3,000	0	960	3,430	3,000	0	430

Graphs 6 and 7 identify the sources of the electricity used to supply Eligible Retail Customers who buy electricity from ComEd for their homes and small commercial accounts. As time goes on, larger volumes of electricity will be sourced from IPA managed procurement activity.

GRAPH 6: COMED PEAK LOAD PORTFOLIO SOURCES (JUNE 2010 THROUGH MAY 2015)



GRAPH 7: COMED OFF-PEAK LOAD PORTFOLIO SOURCES (JUNE 2010 THROUGH MAY 2015)



2. **Wholesale Products to be Procured.** In order to meet the requirements of the Eligible Retail Customers, certain wholesale supply products must be procured. These include energy, capacity, and ancillary services. The determination of the appropriate portfolio (i.e., form, term-lengths, and mix) of these products is guided by the specific goals for this Plan as defined in the PUA:

> *The Commission shall approve the procurement plan if the Commission determines that it will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.*[22]

These goals helped guide the decisions associated with the recommended portfolio design.

i. Energy. The IPA recommends a two part method for meeting the energy requirements of eligible customers: a short term portfolio and a long term portfolio. The short term portfolio will center on the application of the laddered volume approach discussed in the portfolio section of this document. The Long term portfolio will center on securing as much as 1,400,000 MWH of annual energy supply from renewable energy resources with a first delivery date expected to occur during the 2011-2012 plan year.

a. **Short term portfolio.** Energy required by the Eligible Retail Customers comes from four sources. First, the swap contract with ExGen provides a financial hedge on 3,000 MW of ATC energy during the June 2010 – May 2013 period. Second, certain fixed price physical supply contracts were secured through the 2009 procurement process. Third, IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan. Finally, balancing energy will be procured from the PJM-administered day-ahead and real-time energy markets.

In determining the granularity of the standard wholesale products to be procured through the RFP, the IPA recognized that if the products are defined in a way such that the megawatt amount contracted in each given hour is equal to the actual customer load in that hour, then the wholesale products will effectively provide price stability for customers

[22] 220 ILCS 5/16-111.5(d)(4).

because the fluctuations in the cost to supply the load will effectively be hedged. Yet, standard products traded in the wholesale market do not involve delivery quantities that vary within the twenty-four (24) monthly on-peak/off-peak periods throughout the year,[23] so the quantities of energy procured in the form of standard wholesale products cannot approximate customer load shapes on a more granular basis than a monthly on-peak/off-peak basis.

Given these facts, the IPA will issue solicitations for monthly on-peak and off-peak standard wholesale block energy products (or their equivalent volumes in seasonal or varietal strips) for delivery during the June 2010 - May 2013 period. The target procurement quantities are determined by multiplying ComEd's average forecasted load obligation in each monthly on-peak/off-peak period by the targeted hedge position after the procurement event is completed (i.e. 35% for requirements two years out, 70% for requirements one year out, and 100% for requirements in the year in which power is delivered). Next, MWs covered by previous RFPs and the ExGen swap are subtracted from the target requirements. To the extent the calculated procurement quantity for a period is less that zero, no energy will be procured for that period and existing positions will be maintained. Also note that calculations in the model are rounded to the nearest 50 MW. By procuring a portfolio of the most granular standard wholesale products available in quantities reflective of forecasted loads, the forecasted net amount of energy transacted in the volatile spot market will be minimized.

Bidders will be provided an opportunity to bundle their bids for various products. By providing some flexibility for bundled bids, bidders will be better able to bid on the products for which they can offer the most competitive prices. The procurement administrator will accept the bids that together represent the lowest cost portfolio of products that provide the desired monthly on-peak and off-peak quantities being solicited through the RFP.

Based on the current load forecast, the quantities of standard wholesale energy products to be procured through the sealed-bid RFP are as follows (rounded to the nearest 50 MW) are found in Table V-1 and V-2. A full schedule of related planned procurement loads for ComEd can be found in Attachment J.

TABLE V-1: COMED PEAK LOAD VOLUMES TO SECURE IN 2010 PROCUREMENT CYCLE (JUNE 2010 THROUGH MAY 2013)

Contract Month	Peak Contract Volumes to Secure (MW)				
	Projected Volume (MW)	Swap Volumes (MW)	2009 Procurement Volumes (MW)	Residual Volumes (MW)	2010 IPA Procurement (MW)
June-10	5389	3000	750	1639	1650
July-10	7306	3000	2000	2306	2300
August-10	6780	3000	1650	2130	2150
September-10	4728	3000	300	1428	1450
October-10	4040	3000	0	1040	1050
November-10	4470	3000	200	1270	1250
December-10	5208	3000	700	1508	1500
January-11	5215	3000	800	1415	1400
February-11	4868	3000	550	1318	1300

[23] Both the NYMEX and the Intercontinental Exchange, Inc. ("ICE"), the two most visible platforms on which to trade electricity products, report prices for products with delivery periods that are no more granular than by monthly on-peak/off-peak period.

March-11	4348	3000	200	1148	1150
April-11	3872	3000	0	872	850
May-11	3960	3000	0	960	950
June-11	5263	3000	0	2263	700
July-11	7139	3000	0	4139	2000
August-11	6664	3000	0	3664	1650
September-11	4584	3000	0	1584	200
October-11	3960	3000	0	960	0
November-11	4410	3000	0	1410	100
December-11	5150	3000	0	2150	600
January-12	5203	3000	0	2203	650
February-12	4821	3000	0	1821	350
March-12	4330	3000	0	1330	50
April-12	3894	3000	0	894	0
May-12	4011	3000	0	1011	0
June-12	5329	3000	0	2329	0
July-12	7261	3000	0	4261	0
August-12	6726	3000	0	3726	0
September-12	4616	3000	0	1616	0
October-12	4025	3000	0	1025	0
November-12	4472	3000	0	1472	0
December-12	5185	3000	0	2185	0
January-13	5252	3000	0	2252	0
February-13	4860	3000	0	1860	0
March-13	4346	3000	0	1346	0
April-13	3924	3000	0	924	0
May-13	4033	3000	0	1033	0

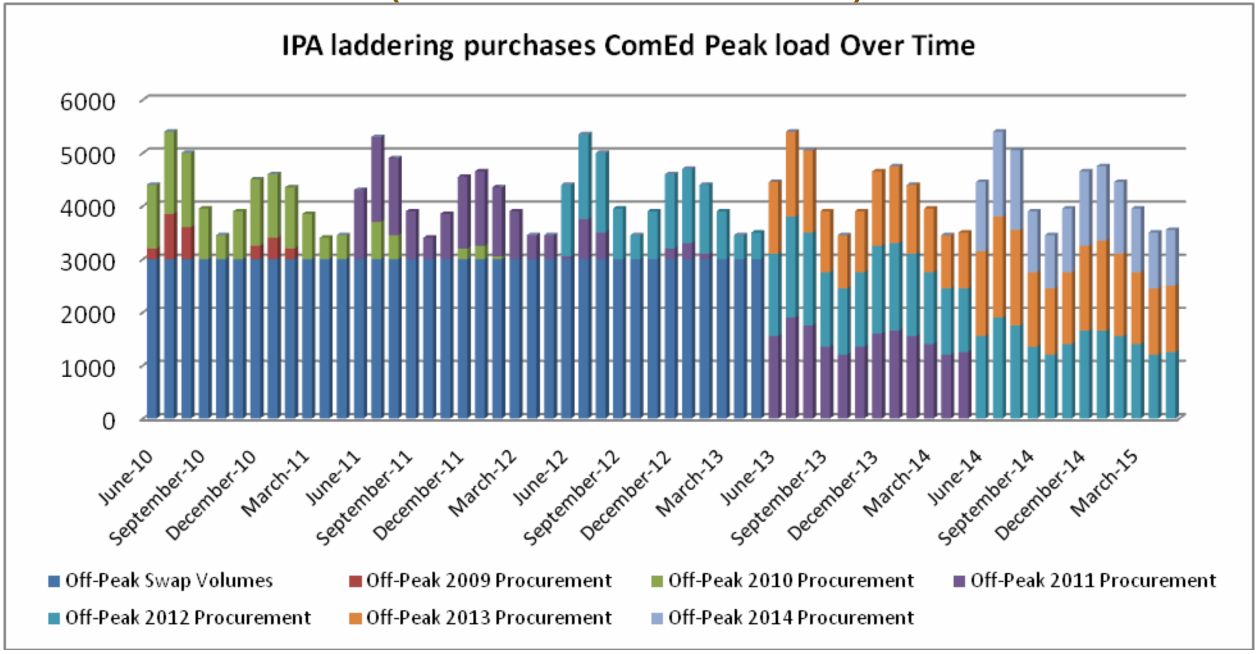
TABLE V-2: COMED OFF-PEAK LOAD VOLUMES TO SECURE IN 2010 PROCUREMENT CYCLE (JUNE 2010 THROUGH MAY 2013)

Contract Month	Off-Peak Contract Volumes to Secure (MW)					
	Projected Volume (MW)	Swap Volumes (MW)	2009 Procurement Volumes (MW)	Residual Volumes (MW)	2010 IPA Procurement (MW)	2010 IPA Procurement Cycle A (MW)
June-10	4,413	3,000	200	1,213	1200	1200
July-10	5,385	3,000	850	1,535	1550	1550
August-10	5,022	3,000	600	1,422	1400	1400
September-10	3,938	3,000	0	938	950	950
October-10	3,469	3,000	0	469	450	450
November-10	3,908	3,000	0	908	900	900
December-10	4,510	3,000	250	1,260	1250	1250
January-11	4,625	3,000	400	1,225	1200	1200
February-11	4,326	3,000	200	1,126	1150	1150
March-11	3,859	3,000	0	859	850	850
April-11	3,417	3,000	0	417	400	400
May-11	3,430	3,000	0	430	450	450
June-11	4,304	3,000	0	1,304	0	0
July-11	5,308	3,000	0	2,308	700	350
August-11	4,896	3,000	0	1,896	450	250

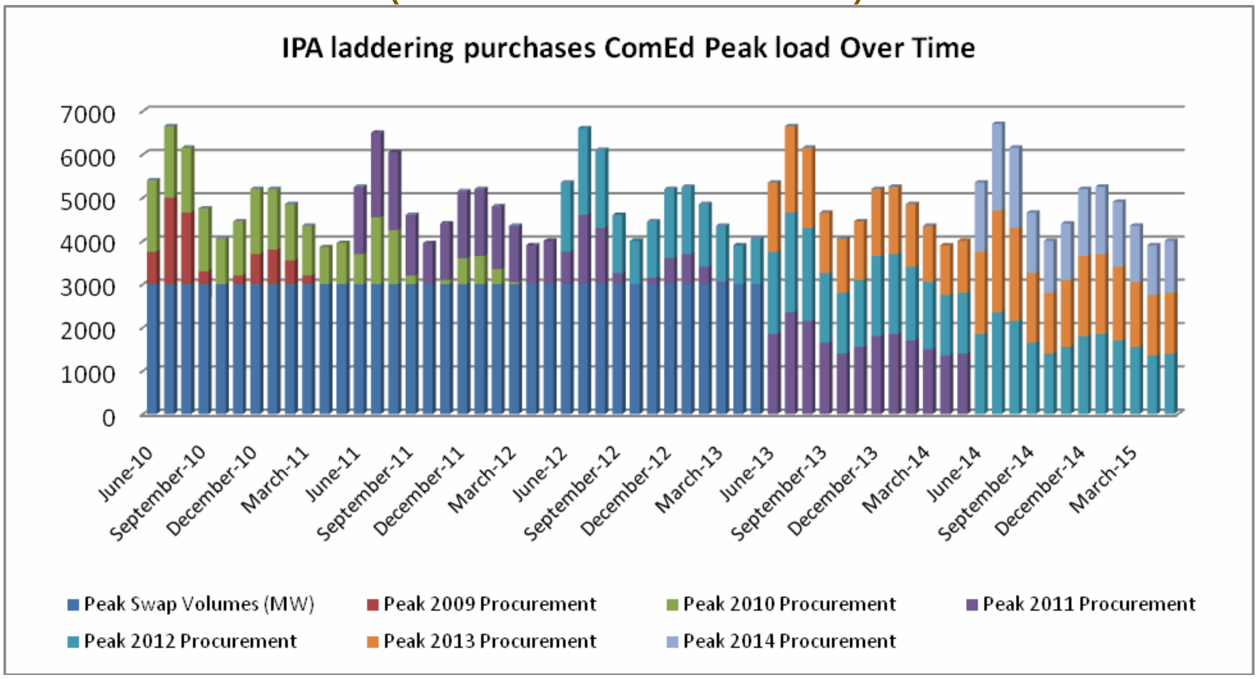
September-11	3,885	3,000	0	885	0	0
October-11	3,421	3,000	0	421	0	0
November-11	3,867	3,000	0	867	0	0
December-11	4,546	3,000	0	1,546	200	100
January-12	4,658	3,000	0	1,658	250	150
February-12	4,326	3,000	0	1,326	50	50
March-12	3,890	3,000	0	890	0	0
April-12	3,431	3,000	0	431	0	0
May-12	3,458	3,000	0	458	0	0
June-12	4,387	3,000	0	1,387	0	0
July-12	5,374	3,000	0	2,374	0	0
August-12	4,991	3,000	0	1,991	0	0
September-12	3,933	3,000	0	933	0	0
October-12	3,451	3,000	0	451	0	0
November-12	3,891	3,000	0	891	0	0
December-12	4,605	3,000	0	1,605	0	0
January-13	4,709	3,000	0	1,709	0	0
February-13	4,400	3,000	0	1,400	0	0
March-13	3,916	3,000	0	916	0	0
April-13	3,454	3,000	0	454	0	0
May-13	3,484	3,000	0	484	0	0

Graphs 8 and 9 represent how the Plan anticipates securing load for Eligible Retail Customers by laddering in purchases so that no one month or season is purchased all at one time. By dollar-cost averaging in this manner, the IPA mitigates risk to Com Ed's Eligible Retail Customers.

GRAPH 8: LADDERING SCHEDULE FOR COMED OFF-PEAK LOAD (JUNE 2010 THROUGH MAY 2015)



GRAPH 9: LADDERING SCHEDULE FOR COMED PEAK LOAD (JUNE 2010 THROUGH MAY 2015)



The PUA provides that it is the duty of the Procurement Administrator, in consultation with the Commission, ComEd, and other interested parties, to develop the standard contract form that will be used for the standard wholesale products to be procured through the RFP.[24]

The standard wholesale products to be procured through the RFP could be settled physically or financially. In both cases, ComEd would contract to purchase or hedge specific quantities of energy at fixed prices.

In the case of financial settlement, ComEd would procure energy in the day-ahead or real-time markets and debit or credit a dollar amount to the seller based on the difference between the agreed-upon fixed contract price and an index price, whereby the index price would be specified in the contract to be either the day-ahead or real-time energy price. Financial contracts are generally referred to as "contracts for differences" ("CFD"). The swap contract with ExGen is an example of a financially settled contract.

In the case of physical settlement, the contracting parties would transact through PJM. In this case, both parties must be PJM members in good standing. ComEd and the seller would execute an agreement, under which the seller transfers energy to ComEd via a PJM eSchedule. ComEd would then directly pay the seller the agreed-upon fixed contract price for the specified amount of energy.

The choice between settling physically and financially does not affect service reliability. Whether the products settle physically or financially, PJM will still dispatch the system in such a way to ensure that customers' requirements are met. The decision to settle physically or financially affects the logistics regarding cash flows, the administrative tasks that are required of the various parties involved, the non-performance risks and the standard of legal review.

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[24] 220 ILCS 5/16 – 111.5(c)(1)(v); 220 ILCS 5/16-111.5(e)(2).

The IPA recommends that the contracts to be procured through the RFP be settled physically for ComEd volumes for the following reasons:

- Physical contracts are lower risk in the event of supplier default. The exposure of a supplier under a CFD is limited only by the PJM energy price cap of $999 per MWh. While it would be very rare for prices for a sustained period to be at or near the energy price cap, a primary value of a hedge is to protect against such occurrences. It is not inconceivable that a supplier may in fact be unable to pay the difference between spot and contract prices if there is a sustained price spike. If the contract is physical, the supplier will be liable to PJM, and until the supplier's PJM market privileges are revoked, ComEd will receive the energy at the contract price. Default costs would be spread over PJM.

  In the event of a default under a CFD, ComEd would owe PJM the high spot prices and would bear the cost of the supplier being unable to pay the difference. While increased collateral may reduce this risk, it is not clear that there are adequate credit provisions to equalize this risk; therefore the physical contract is lower risk for customers.

- Physical contracts reduce ComEd credit requirements and overall credit costs. Under a financial contract, ComEd would be considered by PJM to be buying all loads in the spot market and would have to provide credit for all volumes. Under a physical contract, the supplier is responsible to provide credit for all volumes. While the credit cost is not eliminated it may be reduced as some suppliers may have lower financing costs, especially in the event that the supplier is maintaining offsetting long positions within PJM.

b. Long term portfolio. The IPA recommends issuing solicitations for longer term power purchase agreements (PPAs) with renewable energy providers. Long Term PPAs can serve as a hedge against potential cap and trade legislation that would serve as an additional tax on fossil fuel costs. Further, grants, loans and credit enhancement available currently from US Department of Energy, Department of Commerce and Economic Opportunity and the Illinois Finance Authority will result in lower cost renewable energy projects that are developed now through the end of 2012 due to the public grants and financing.

Given these factors, the IPA believes it is prudent to solicit proposals from renewable energy providers to capitalize on available funding and secure a modest level of renewable energy under longer term PPAs if deemed cost effective. As neither the cost liabilities nor the availability of other hedging options associated with cap and trade are unknown, the IPA seeks to limit their use in the Ameren portfolio to 1,400,000 MWH per annum starting as early as the 2011-2012 planning year. The use of a MWH goal for these contracts is due to the variable output nature of some renewable assets that may be selected through the solicitation process (i.e. hydro, wind, and solar).

The IPA recommends that bids be evaluated through a process similar to that used to evaluate bids in the short term portfolio: standard terms and conditions regarding performance guarantees and penalties are agreed to by bidders prior to solicitation, bidders must pre-qualify to be allowed into the bidder pool, application of a cost benchmark to reject above market value bids, and scoring of submitted bids according to a methodology that considers and ranks proposals on the basis of output, capacity value, financing costs, transmission and capital costs, fixed cost vs. escalators offers, return on equity and other normalizing factors.

ii. Capacity and Ancillary Services. ComEd will continue to procure the capacity and ancillary services required by the Eligible Retail Customers directly from PJM-administered markets. Under the RPM program approved by the FERC and administered by PJM, ComEd is able to purchase capacity directly from PJM-administered markets. The RPM capacity prices for the June 2010 - May 2013 period have already been determined through a competitive bid process administered by PJM, so direct procurement from PJM results in a reasonable approach to procuring capacity for these customers. Furthermore, the PJM-administered markets for ancillary services are the most visible and easily accessible markets for these services so direct procurement from these markets is a reasonable approach for providing these services to customers.

With regard to the capacity, the Act cites the following required inclusion in the Plan:

> *the proposed mix of demand-response products for which contracts will be executed during the next year. The cost-effective demand-response measures shall be procured whenever the cost is lower than procuring comparable capacity products, provided that such products shall:*
>
> *(A) Be procured by a demand-response provider from eligible retail customers*
> *(B) At least satisfy the demand-response requirements of the regional transmission organization market in which the utility's service territory is located, including, but not limited to, any applicable capacity or dispatch requirements*
> *(C) Provide for customers' participation in the stream of benefits produced by the demand-response products;*
> *(D) Provide for reimbursement by the demand-response provider of the utility for any costs incurred as a result of the failure of the supplier of such product to perform its obligations thereunder; and*
> *(E) Meet the same credit requirements as apply to suppliers of capacity, in the applicable regional transmission market.*[25]

While the IPA recognizes that PJM procures demand-response measures in the RPM auction for capacity resources, the IPA believes it necessary to certify that additional sources of demand response sources capacity are not available at less than the current RPM forward price curve. The IPA recommends that the initial solicitation of demand response as an alternative to standard capacity be conducted in the 2010 Procurement Cycle in the following manner:

- **Timing.** The IPA recommends that Demand Response be specified as a bid alternate in the spring 2010 solicitation for capacity. In the event that Demand Response providers do not exist or do not participate in the Spring solicitation, then a secondary solicitation will be conducted in the Fall of 2010 that will seek to establish capacity contracts that will incent the development of demand response programs within the Ameren service territory.
- **Volumes.** Per the statute, qualified demand response bids submitted in the spring procurement that are of lesser cost than comparable capacity sources will be selected as winning bidders. 220 ILCS 16-111.5(b)(3)(ii). The IPA recommends that if the secondary solicitation described above is necessary, then the total volume of capacity to be awarded not exceed a maximum contract volume basis of 500 megawatts in any given month.
- **Term.** The IPA recommends that demand response providers participating in the spring capacity solicitation be allowed to bid on all months and volumes under the same terms and conditions as other traditional suppliers. If the secondary solicitation is necessary, offers from bidders that extend over a five (5) year period from the time

[25] 220 ILCS 5/16-111.5(b)(3)(ii).

of first contract obligation or delivery will be considered.

The IPA will work with interested stakeholders to ensure that demand response resource providers are adequately notified of the IPA's solicitation and that the solicitation process is not unnecessarily complex or burdensome on any party.

iii. Auction Revenue Rights.

Auction Revenue Rights ("ARRs") are not a power and energy resource. However, the nomination and subsequent allocation of such rights to ComEd generally serves to reduce the cost of congestion borne by ComEd (and, thus, ultimately by their customers).

As part of the 2009 ARR allocation process at PJM, ComEd received a set of ARR entitlements and were awarded ARRs for the 2009 planning year.

For future planning years, ComEd shall continue to actively participate in the PJM ARR nomination and allocation process and shall seek to nominate those ARRs with an expected positive value. ComEd recognizes they may not be allocated all of the ARRs requested and they may elect certain ARRs which ultimately do not have a positive value.

ComEd shall retain the allocated ARRs and receive associated credits for its customers. All proceeds and costs of such sales, including costs incurred to evaluate and execute such a strategy, will be passed to customers through Rider PE.

iv. Load Balancing Procedures

Hourly Balancing of Supply and Demand. ComEd will utilize the PJM-administered day-ahead and real-time energy markets to balance its loads. On a daily basis, ComEd will report to PJM its estimate of its total load requirements for the following day. ComEd will then submit its day-after estimate to PJM via a daily load responsibility schedule and the estimate will in turn be settled by PJM based on the real time market prices.

If the delivered physical power exceeds the day-ahead estimate, PJM will credit the difference to ComEd at the day-ahead price; if the delivered physical power is less than the day-ahead estimate, PJM will charge ComEd the difference at the day-ahead price.

When ComEd submits its day-after estimate to PJM, PJM will perform a similar settlement function in the PJM real-time market. To the extent the day-ahead estimate reported by ComEd is less than the day-after estimate; PJM will charge ComEd the difference at the real-time price. To the extent that the day-ahead estimate reported by ComEd is greater than the day-after estimate, PJM will credit ComEd with the difference at the real-time price.

Portfolio Rebalancing in the Event of Significant Shifts in Load. The PUA requires that the IPA provide the criteria for portfolio rebalancing in the event of significant shifts in load. In the event that ComEd's annual forecast increases above the High Forecast or decreases below the Low Forecast during the active delivery year of an approved Procurement Plan, ComEd shall promptly notify the IPA. The IPA will subsequently convene a meeting with ComEd, the Commission, and the Procurement Administrator to determine whether it is appropriate to rebalance the portfolio, and if so, to what extent and how such a rebalancing can be achieved.

Over the term of this Plan, the most significant driver of load shifting levels is customer switching. If customer switching levels are significantly different from forecasted levels, a re-balancing of the portfolio may be warranted.

v. Renewable Portfolio Standard. Section 1-75(c) of the IPA Act establishes that:

> *The procurement plans shall include cost-effective renewable energy resources. A minimum percentage of each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act*[26]

The statute defines renewable energy resources as follows:

> *"Renewable energy resources" includes* ***energy and its associated renewable energy credit or renewable energy credits*** *from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, trees and tree trimmings, hydropower that does not involve new construction or significant expansion of hydropower dams, and other alternative sources of environmentally preferable energy. For purposes of this Act, landfill gas produced in the State is considered a renewable energy resource.*[27] ***[Emphasis added]***

The statute establishes a methodology for calculating annual volumetric goals for the portfolio as well as establishing a Renewable Energy Resource Budget (RBB) that serves as a maximum cost cap for meeting those goals. In the event that the cost cap is met, purchases of renewable energy resources are to be curtailed, leaving the annual volumetric goal unmet. Table W below cites the volume goals and cost limits.

TABLE W: RPS STANDARDS FOR COM ED

Delivery period	Minimum Percentage (Annual volume goal)	Maximum Cost Standard
2010-2011	5% of June 1, 2008 through May 31, 2009 eligible retail customer load	The greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2009 or 1.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007
2011-2012	6% of June 1, 2009 through May 31, 2010 eligible retail customer load	The greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2010 or 2.0% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007
2012-2013	7% of June 1, 2010 through May 31, 2011 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011
2013-2014	8% of June 1, 2011 through May 31, 2012 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011
2014-2015	9% of June 1, 2012 through May 31, 2013 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011

Table X below presents the Annual Volume Targets resulting from the application of the statute's standards to the ComEd portfolio for planning years 2008-2009, 2009-2010, and 2010-2011.

TABLE X: ANNUAL COM ED RPS VOLUME TARGETS

ComEd RPS Volume Targets				
Planning	Reference	Reference Year	Planning	Planning Year

[26] 20 ILCS 3855/1-75(c)(1).
[27] 20 ILCS 3855/1-10.

Year	Year	Delivered Volume (MWh)	Year RPS % Target	RPS Volume Target (MWh)
2008-2009	2006-2007	39,802,463	2.0%	796,049
2009-2010	2007-2008	39,109,145	4.0%	1,564,366
2010-2011	2008-2009	37,740,282	5.0%	1,887,014

Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables Y and Z below presents the Annual Renewable Energy Resource Budgets resulting from the application of the statute's standards to the ComEd portfolio for planning years 2008-2009, 2009-2010, and 2010-2011.

TABLE Y: ANNUAL COMED RRB CALCULATIONS – OPTION A

ComEd RPS CALCULATIONS: Option A (Incremental increase on annual unit cost approach)			
(A) Planning Year	2008-2009	2009-2010	2010-2011
(B) Reference Year	2006-2007	2007-2008	2008-2009
(C) Reference Year Delivered Volume (MWh)	39,802,463	39,109,145	37,740,282
(D) Reference Year Delivered Cost	$3,736,750,000	$4,205,233,624	$4,462,037,717
(E) Reference Year Unit Cost - [D / C]	$93.88	$107.53	$118.23
(F) Planning Year Incremental RPS Cost Limit %	0.50%	0.50%	0.50%
(G) Planning Year Incremental RPS Cost Limit Unit Price - [F * D]	$0.469412	$0.537628	$0.591151
(H) Planning Year Net RPS Cost Limit Unit Price	$0.469412	$1.007040	$1.598190
(I) Planning Year Projected Total Delivery Volume	39,837,081	39,422,473	36,445,657
(J) Planning Year Option A Cost Cap [I * H]	**$18,700,000**	**$39,700,000**	**$58,247,099**

TABLE Z: ANNUAL COMED RRB CALCULATIONS – OPTION B

ComEd RPS CALCULATIONS: Option B (Percentage Increase over Base Year unit cost approach)			
(A) Planning Year	2008-2009	2009-2010	2010-2011
(B) Reference Year	2006-2007	2006-2007	2006-2007
(C) Reference Year Delivered Volume (MWh)	39,802,463	39,109,145	37,740,282
(D) Reference Year Delivered Cost	$3,736,750,000	$4,205,233,624	$4,462,037,717
(E) Reference Year Unit Cost ($/MWh) - [D / C]	$93.88	$107.53	$118.23
(F) Planning Year Incremental RPS Cost Limit %	0.50%	1.00%	1.50%
(G) Planning Year Net RPS Cost Limit Unit Price - [F * D]	$0.469412	$0.938824	$1.408236
(H) Planning Year Projected Total Delivery Volume	39,837,081	39,422,473	36,445,657
(I) Planning Year Option A Cost Cap [H * G]	**$18,700,000**	**$37,010,756**	**$51,324,076**

Table AA below displays the results of the RPS calculations for Planning Year 2010-2011 for ComEd.

TABLE AA: COMED RPS TARGETS FOR 2010-2011

ComEd Renewable Portfolio Standard (RPS) Metrics (2010-2011)	
RPS Volume Target (MWh)	1,887,014
Renewable Energy Resource Budget (RRB)	$58,247,099
Average Price per Renewable Unit	$30.87
Estimated Consumers Covered by RRB	3,746,747
Estimated Annual RPS Cost/Consumer	$15.55

Specific aspects for meeting the RPS requirements detailed above are noted below:

- **Products to be Procured.** ComEd shall meet the renewable energy resource portfolio standard for the Plan year through the acquisition of qualifying renewable energy credits ("REC's") as defined in Section 1-10 of the IPA Act. The acquisition of REC's for this period meets the requirements of the IPA Act and are preferable to the direct acquisition of energy from qualifying renewable resources at this time.

  The Plan selects the purchase of REC's to satisfy the RPS requirements based on the following:

  - The RPS can be met only by procuring either of the following:
    - RPS Option A - Energy (from a qualified resource) and its associated renewable energy credit; or
    - RPS Option B - Renewable energy credits
  - Based on the Volume goals and RBB, the average unit price that can be paid for each renewable energy resources is $30.87
  - The available funds under the RPS are not sufficient to meet the RPS volume requirements.

  Sufficient RECs to comply with the quantities established by 1-75 (c) (1) of the IPA Act shall be acquired on the basis of (1) the requirements established in 1-75 (c) (3) of the IPA Act and (2) price, as determined by comparing qualifying bids meeting approved benchmarks. Such acquisitions of renewable energy credits shall be memorialized with a Master Renewable Energy Certificate Purchase and Sale Agreement.

- **Pricing Benchmark.** The Procurement Administrator is directed to continue to establish benchmark REC prices (as was done in 2009), and to reject bids priced above the benchmarks.[28] The benchmarks shall be set at levels that consider relevant market prices and the economic development benefits of in-state resources. The benchmark prices shall be confidential, but shall be provided to, and will be subject to, Commission review and approval prior to solicitations of REC bids.

- **Preferences.** Section 1-75 (c) (3) of the IPA Act requires that until June 1, 2011 cost effective renewable energy resources be procured first from facilities in the State of Illinois, then from facilities located in states adjacent to Illinois, then from facilities located elsewhere.

  Additionally, prior to June 1, 2015, at least 75% of the renewable energy resources procured must be sourced from wind assets and 25% from other qualified assets.

- **Compliance Tracking.** The acquisition of RECs in amounts equal to the statutory requirement ensures compliance.

  PJM Environmental Information System's ("EIS") Generation Attribute Tracking System ("GATS") and the Midwest Renewable Energy Tracking System ("M-RETS") will be utilized to independently verify the location of generation, resource type and month and year of generation. GATS tracks generation attributes and the ownerships of the attributes as they are traded or used to meet RPS and other programs, typically for generators whose energy is settled in the PJM market or whose facility is located in the PJM footprint. M-RETS tracks renewable energy generation and assists in verifying compliance with individual state/provincial RPS

[28] The revisions to Section 1-75(c)(1) of the IPA Act by the Clean Coal Portfolio Standard Law (Public Act 095-1027) now require the development of benchmarks.

requirements or voluntary programs, typically for generators located in the MISO footprint and other RTOs outside of PJM.

Each agreement for the acquisition of a REC shall have a specified term. All RECs used by ComEd to comply with the statutory requirements shall be retired in compliance with 1-75 (c) (4).

4. **Contingency Procurement Plan.** The following is the plan to procure power and energy for ComEd's "Eligible Retail Customer" load should all or any part of that load not be met due to the advent of: 1) supplier default; 2) insufficient supplier participation; 3) Commission rejection of procurement results; or 4) any other cause. The plan is based on the contingency plan as specified in the IPA Act and Section 16-111.5(e)(5)(i) of the PUA.

   i. **Supplier Default.** In the event of a supplier default that results in contract termination where the amount of load provided by that supplier is 200 MW or greater and there are more than 60 calendar days remaining on the defaulted contract term, ComEd will immediately notify the IPA, ICC Staff and the Procurement Administrator that another procurement event must be administered. The Procurement Administrator will execute a procurement event to replace the same products and amounts as that initially approved by the ICC in this plan. The ICC Staff and its monitor will oversee the event. The replacement plan will to the maximum degree possible seek to replace the defaulted products with the same or similar products to those that were defaulted on. This substitute plan would continue to seek energy only standard block products. All ancillaries, capacity and load balancing requirements will continue to be procured through the PJM administered markets. During the interim time period beginning at time of default and continuing through the contingency procurement process, all electric power and energy will be procured by the utility through PJM administered markets. Notwithstanding, if a particular required product is not available through PJM it shall be purchased in the wholesale market.

   In the event of a supplier default that results in contract termination where the amount of load provided by that supplier is less than 200 MW or there are less than 60 calendar days remaining on the defaulted contract term, ComEd will procure the required power and energy directly from the PJM administered markets. This procurement would include day ahead and/or real time energy, capacity, and ancillary services. Should a required product not be available directly through the PJM administered markets, it shall be procured through the wholesale markets.

   ii. **ICC Rejection of Initial Procurement Results or Insufficient Supplier Participation.** In the advent that the ICC rejects the results of the initial procurement event or the initial procurement event results in under subscription, a meeting of the Procurement Administrator, the Procurement Monitor, and the ICC Staff shall occur within 10 calendar days to assess the potential causes and to consider what remedies, if any, could be put in place to either address the ICC's concerns or would result in full subscription to the load. If revisions to the procurement event are identified that would likely either address the ICC's concerns or enhance the possibility of having a fully subscribed load, the Procurement Administrator will implement those changes and run a procurement event predicated on a schedule established within the aforementioned meeting. The new procurement event will be executed by the Procurement Administrator within 90 calendar days of the date that the initial procurement process is deemed to have failed.

   Should a procurement event be required subsequent to the initial event, the Procurement Administrator and the Procurement Monitor will separately submit a confidential report to the ICC within 2 business days after opening the sealed bids. The Procurement Administrator's report will put forth a recommendation for acceptance or rejection of bids based on the established benchmarks as well as other observed factors to include any modifications necessary to run a subsequent procurement event if necessary.

ii. **Other scenarios.** In all cases where the factors are such that, either for an interim period or otherwise, there would be insufficient power and energy to serve the required load, ComEd will procure the required power and energy requirements for the eligible load through the PJM administered markets. Direct procurement activities would thus include day ahead and/or real time energy, along with the normal direct procurement of capacity and ancillary services. Also, in the case that a particular required product is not available through PJM, ComEd will purchase that product through the wholesale market.