State of Illinois
Pat Quinn, Governor

ILLINOIS POWER AGENCY

Draft Power Procurement Plan
September 29, 2010

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Executive Summary

Pursuant to Public Act 095-0481[1], the Illinois Power Agency ("IPA" of "Agency") submits this proposed electricity procurement plan (the "Draft 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 third Draft Plan prepared by the IPA. The IPA Act requires that a Draft Plan and a Final Plan be prepared and submitted annually.

This Draft 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 and obligations of the Renewable Portfolio Standard 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 2011 through May 2016 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 Draft Plan are limited to meeting the residual consumer demand not covered by those contracts.

Procurement Approach. The IPA proposes to maintain the core elements of the procurement approach used in the last three procurement cycles. Those elements are:

- **Request for Proposals based solicitations.** The procurement events will be facilitated through a two-stage process oriented around a Request for Proposal ("RFP") for each wholesale product sought. The first stage of the RFP will establish a pool of qualified bidders; the second stage will solicit bids for scheduled volumes of wholesale product. The resources sought through the RFP events will be:

    - **Ameren –** Energy, Capacity, Demand Response, and Renewable Energy Resources
    - **ComEd –** Energy, Demand Response, and Renewable Energy Resources

- **Timing.** The IPA proposes to hold primary procurement events during the spring of 2011 seeking the volumes of wholesale products identified in this Draft Plan. Further, the IPA proposes that optional procurements of up to an additional 10% of projected energy portfolio requirements in any month for the second and third planning year by the Final Plan that is below the 100% subscription level. The optional procurements would be triggered only when market indices demonstrate that prices for energy supply contracts for the targets months are at least 10% below the average weighted price of fixed price contracts already secured by the Utilities for those months and such prices are below the prices for the most recently completed planning year procurement event. The optional procurements would be limited to participation by bidders qualified in and the terms and conditions agreed to in the spring 2011 solicitation, and allowed only with the authorization of the Commission.

- **Procurement Administrators.** The IPA will retain the services of Procurement Administrator(s) through a Request for Qualifications ("RFQ") and subsequent RFPs. Per recommendations made to the IPA, the RFQ and RFP will solicit offers from bidders seeking to provide comprehensive Administrator responsibilities for one or both Utility procurement events (i.e. Power, Capacity, and Renewable Energy Resources for Ameren, and/or Power, Demand Response in lieu of Capacity, and Renewable Energy Resources for ComEd), as well as offers to administer single wholesale product solicitations for both Utilities (i.e. Power Resources for both Ameren and ComEd, Renewable Energy Resources for both Ameren and ComEd).

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

- **Fixed Price for fixed volumes.** The RFPs for wholesale products will seek offers for fixed volumes at fixed prices.

- **Products.** The IPA proposes to seek bids for wholesale products for the following periods:

  - **Energy Supply Resources –** Supply will be sought for the Ameren and ComEd loads on a laddered three-year forward basis. The IPA proposes to allow Energy Efficiency from programs that are evaluated in a manner equivalent to the existing Energy Efficiency Portfolio Standards programs administered by the Utilities to be treated as an energy supply resource. Price for the products would be procured after the spring 2011 solicitations for the more traditional physical and swap products through a competitive solicitation. The combined costs of traditional energy, capacity and renewable energy assets within the IPA portfolio after the spring 2011 procurement events will be used to develop a cost-effectiveness benchmark for the energy efficiency procurements. The IPA will not procure resources that are required to meet the Energy Efficiency Portfolio Standard.

  - **Capacity Resources –** Capacity Resources for ComEd will be delivered through the PJM capacity markets. For Ameren, Capacity Resources that are qualified by the Midwest Independent System Operator ("MISO") to issue Planning Resource Credits ("PRC") will be sought for the Ameren load.

  - **Demand Response Resources** – Consistent with 220 ILCS 5/16-111.5(b)(3)(ii), the IPA proposes that solicitations seeking cost-effective demand response assets occur for both Utilities. The IPA notes that as statute does not require or infer that these assets are procured in lieu of capacity, that they will be sought independent of the Capacity Resource plans specified in this Plan.

  - **Renewable Energy Resources** – Renewable Energy Credits ("REC") for a single compliance year (June 2011 through May 2012). The IPA proposes to continue the consolidation of REC procurement processes and procedures started in 2010, and seek to unify standard terms and conditions between Ameren and ComEd with regard to REC contracts. Therefore, the utilities' REC contracts should include (1) collateral requirements that equal 10% of remaining contract value; and (2) unsecured credit limits for creditworthy REC suppliers.

- **Public comment and workshops.** The IPA held public meetings seeking comment on the Draft Plan.

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 is not fully stable. 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, the IPA proposes the schedule of purchases of wholesale products to meet the needs of eligible customers.

The IPA maintains that a medium-term laddered approach to procurement for energy and capacity resources provides a high level of cost stability for consumers while still leaving room for some larger market trends – namely consumer migration from the IPA portfolio and the regulatory climate for fossil fuel power generators - to be better identified and assessed. The IPA proposes to continue the practice approved by the Commission in the 2009 and 2010 Procurement Plans of scheduling procurements of wholesale energy resources relatively evenly over three-year periods. While liquidity indicators for the 24 to 36 month horizons within wholesale energy markets have diminished somewhat, bidding activity in the Spring 2010 procurement cycle for contracts in that cycle's 24-36 month range indicates an adequate level of level of competition and bidder interest.

As prescribed in the 2009 and 2010 cycles, projections of annual procurement distributions ranging between 20% and 40% continue to indicate a sufficient mitigation of 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 proposes that the following three-year laddered procurement strategy has a high probability of yielding low risk and stable prices:

- 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.

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 third Draft 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 2011 through May 2016. The Draft Plan applies to the following Utilities: AmerenCILCO, AmerenCIPS, AmerenIP ("Ameren"), and Commonwealth Edison ("ComEd" and jointly the "Utilities").

The IPA Act requires that the Draft 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 Draft 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:*
>
> *(i) definitions of the different retail customer classes for which supply is being purchased;*

[3] 20 ILCS 3855/1-20.

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

(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 Draft 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 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.

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

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. This Draft Plan reflects these recent changes in competitive declaration status. ComEd and Ameren will procure power for customers in classes deemed competitive only in the hourly spot market and passing through those variable market prices to the competitively declared customers that choose not to select supply service from an ARES.

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 reports (May 2010 for the Utilities), only 40.7% of the total electricity usage by ComEd and Ameren customers over the period was supplied through fixed price bundled utility service. Another 4.6% was delivered at Hourly Energy Pricing, and the remaining 55.7% delivered through ARES. According to those same reports, 99.9% of ComEd and Ameren residential customers remain on bundled rates.

Increasing the role of competitive supply options within all rate classes served by the Utilities has been supported by recent developments and statutes:

- Public Act 094-1095 created the Office of Retail Market Development (ORMD) to "actively seek input from all interested parties and to develop a thorough understanding and critical analyses of the tools and techniques used to promote retail competition in other states. The Office shall monitor existing competitive conditions in Illinois, identify barriers to retail competition for all customer classes, and actively explore and propose to the Commission and to the General Assembly solutions to overcome identified barriers." Some recent ORMD activities include:
    - Rulemaking for Code Part 412. Workshops and rules drafting in support of provisions of Public Act 95-0700 (see below for more detail).
    - Launch of a website (www.PluginIllinois.org) in April 2010 to educate Illinois consumers on the options and benefits afforded by ARES.
    - Development of an Offer Comparison Website which will provide interested consumers with an unbiased comparison of the costs and benefits of multiple ARES offers.
    - Development of a Retail Choice and Referral Program designed to provide consumers with incentives to enter into a supply contract with qualified ARES.

[6] Public Act 095-0481

- Public Act 95-0700 requires the Utilities to offer to the ARES utility consolidated billing ("UCB"), the purchase of receivables ("POR") and the purchase of two billing cycles of uncollectible receivables ("POU"):
    - UCB allows for the electronic submittal of monthly ARES customer charges for power and energy to the utility which then places those charges, along with its delivery charges, on one single bill to the customer.
    - POR allows ARES to sell its receivables (the amount due to an ARES by a customer) to the Utility at a discount. The POR is designed to encourage ARES to not cherry-pick customers.
    - POU allows ARES to sell up to two billing cycles worth of uncollectible receivables to the Utility at a discount upon returning a customer back to the Utility
- Public Act 96-0176 allows municipal bodies to aggregate the load of eligible retail customers located within their jurisdiction and negotiate a retail electric contract with an ARES on their behalf.

Based on these and other indicators (e.g. the number of ARES registered with the ICC, and the number of ARES registering with intent to sell into the residential sector), the IPA anticipates that the policy of supporting competitive electricity markets will continue and strengthen, and that eligible retail consumers currently served through the IPA portfolio migrate towards ARES options.

B. Illinois Power Agency Planning Process Overview. This Draft Plan proposes 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 plan to meet the Illinois 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.

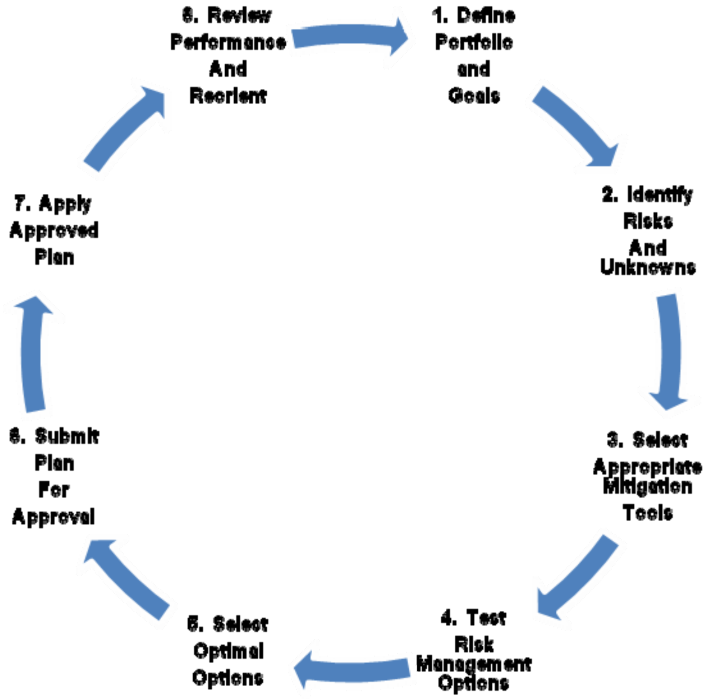
As noted above, the IPA must submit a Plan each year identifying projected loads for Eligible Retail Customers, and a plan for fulfilling those load requirements. Per the PUA, Eligible Retail Customers are defined as:

> *[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]

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.

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

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 A.

TABLE A: PROPOSED IPA PLAN SUBMISSION AND AUTHORIZATION SCHEDULE

Planning Activities	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
1. Utilities Submit Load Projections	X					
2. IPA Prepares Draft Plan						
3. IPA Submits Draft Plan		X				
4. Public Comment Period						
5. Final Plan submitted to ICC			X			
6. Objections filing period						
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.
    a. The Ameren five-year projections were received by the IPA on July 15, 2010
    b. The ComEd five-year projections were received by the IPA on July 13, 2010

2. **IPA Prepares Draft Plan.** The IPA prepared a Draft Plan for submission to the Commission with proposals designed to meet the needs of customers purchasing electricity from the Utilities.

3. **IPA Submits Preliminary Plan.** The Preliminary Plan was made available to the public for comment on the ICC and IPA websites on September 15, 2010.

4. **Public Comment Period.** The Preliminary Plan was 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 held two public hearings for the purpose of receiving public comment on the procurement plan.
    a. August 26, 2010 in Chicago at the ICC's offices at 160 N. LaSalle Street in the Main Hearing Room from 10 am to noon. A workshop was held that afternoon from 1:30-5pm in the same location to discuss this year's Draft Plan.
    b. August 31, 2010 in Springfield at the ICC's offices at 527 East Capital Avenue in the Main Hearing Room from 10 am to noon. A workshop was held that afternoon from 1:30-5pm in the same location to discuss this year's Draft Plan.

5. **Final Plan Submission to ICC.** This Final Plan was prepared by the IPA in consideration of the comments received during the public comment period.

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 is presented below in Table B below.

TABLE B: PROPOSED IPA PROCUREMENT EXECUTION SCHEDULE

Procurement Activities	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
1. Procurement Administrator RFQ Issued	X								
2. Procurement Administrator RFP issued		X							
3. Procurement Administrator Selected		X							
4. RFP and systems developed									
5. RFP Released					X				
6. Procurement Event Preparation									
7. Procurement Events									
8. Supply Contracts Executed									
9. Procured Products Delivery Begins									

1. **Procurement Administrator RFQ Issued.** The IPA Act requires that the IPA retain the services of one or more Procurement Administrators 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. The first required step in retaining the services of a Procurement Administrator is the issuance of a Request for Qualifications followed by the IPA giving notice to interested parties of those firms considered as qualified by the IPA. Interested parties can object to the inclusion of specific firms based on certain criteria.

2. **Procurement Administrator RFP Issued.** The second step in retaining the services of one or more Procurement Administrators is the issuance of a Request for Proposals. The IPA intends to solicit offers from bidders seeking to provide comprehensive Administrator responsibilities for one or both Utility procurement events (i.e. Power, Capacity, and Renewable Energy Resources for Ameren, and/or Power and Renewable Energy Resources for ComEd), as well as offers to administer single wholesale product solicitations for both Utilities (i.e. Power Resources for both Ameren and ComEd, Renewable Energy Resources for both Ameren and ComEd). The ranking of the proposals will be based on the best value presented to the IPA.

3. **Procurement Administrator selected.** The IPA must inform the ICC and receive authorization of that selection prior to entering into a contract with the Procurement Administrator(s).

4. **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]

5. **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.
6. **Procurement Event Preparation.** The Procurement Administrator will be required to establish methods and platforms to facilitate bidding on defined electricity products. The

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

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.

7. **Supply 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. **Procured Products Delivery Begins.** Supply contracts secured through the spring 2011 procurement events will commence in June of 2011 (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 2010 IPA procurement cycle.

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."*[9]

The challenge inherent in the IPA's charge is to achieve low and stable prices in a market where prices change constantly and sometimes dramatically. Complicating the task are variables that may significantly increase or decrease IPA Portfolio requirements over the short term (such as weather) or over the longer term (such as customer migration away from the IPA portfolio).

Designing the portfolio requires an appreciation of the variables that drive price and load fluctuation, and the extent to which those variables can affect price. For the purposes of the IPA's analysis and planning, risk is defined as any market condition that has the potential of rising or lowering prices relative to the fixed price contracts secured through the IPA process. Risk is also defined as any change in the size of the load of eligible retail customers served through the IPA portfolio.

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."*[10]

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.

[9] 220 ILCS 5/16-111.5(d)(4).
[10] 220 ILCS 5/16-111.5(b)(3)(v).

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 movement of physical electricity prices is due to the primary costs and risks in the electricity sector: fuel, plant efficiency, transmission, and capital investments driven by plant additions and environmental compliance all interact against variable market demand and are reflected in the day-ahead and real time prices yielded by the regional wholesale markets. These real time price patterns translate roughly into future prices for electricity as reflected in financial markets. Mitigating long-term price risk is achieved by taking multiple positions within the market. Within the context of the IPA portfolio, multiple positions are taken within the market by following a laddered approach to securing fixed price electricity contracts at different times over a medium term horizon. Some have rightly observed that while this approach can lessen the impact of accelerating prices, it also slows the delivery of benefits of falling prices. However, mitigating price risk carries a premium, and the IPA maintains that its approach provides necessary protection against longer term price volatility and escalation.

   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 are largely mitigated through the use of load averaging and securing monthly contracts against those load averages.

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. As noted in the above review of the Illinois electricity market, the policy of the State of Illinois is to support electricity choice and competitive retail markets with the IPA portfolio of fixed price contracts serving as the “default” rate provider.

   Consumption by bundled service customers is relatively inelastic, meaning that consumption does not diminish significantly when prices are high. This is due in large part to current tariff structures that do not expose customers to price variance. 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. Inclusion of demand response and energy efficiency as alternative products within the IPA procurement events could serve as effective tools in addressing price responsiveness and load shape.

   Outside of recently competitively declared rate classes, competitive supply has not taken hold in the broader Residential market in Illinois (see Tables C and D below). However, as noted in the above review of the Illinois electricity market, recent developments indicate that significant reductions to the barriers to retail competition in residential markets are on the near-term horizon.

TABLE C: DISTRIBUTION OF AMEREN CUSTOMERS UTILIZING ARES SERVICES

Supply Options Chosen by Customers of Ameren as of May 31, 2010				
Customer Supply Groups:	**Residential**	**Small C & I Accounts**	**Large C & I Accounts**	**Total**
Generally Defined As:		(Demand < 1 MW)	(Demand > 1 MW)	
Total Number of Customers	1,056,431	149,665	547	1,206,643
Taking Hourly Price Service from Ameren	9,218	609	57	9,884
Taking Fixed Price Supply Service from Ameren	1,047,101	122,616	6	1,169,723
Taking Supply Service from a Retail Electric Supplier (RES)	112	26,440	484	27,036
Percentage of Customers Receiving RES Service	**0.0106%**	**17.7%**	**88.5%**	**2.2%**
Total Monthly Customer Usage (MWH)	627,891	709,093	1,273,383	2,610,367
Of Hourly Price Service Customers	6,801	17,830	130,001	154,632
Of Ameren Fixed Price Supply Service Customers	621,029	287,938	583	909,550
Of RES Customers	61	403,325	1,142,799	1,546,185
Percentage of Usage Taking RES Supply Service	**0.0097%**	**56.9%**	**89.7%**	**59.2%**

TABLE D: DISTRIBUTION OF COMED CUSTOMERS UTILIZING ARES

Supply Options Chosen by Customers of ComEd as of May 31, 2010				
Customer Supply Groups	**Residential**	**Small C & I Accounts**	**Large C & I Accounts**	**Total**
Generally Defined As:		(Demand < 1 MW)	(Demand > 1 MW)	
Total Number of Customers	3,440,238	369,127	1,984	3,811,349
Taking Hourly Price Service from ComEd	9,664	4,032	152	13,848
Taking Fixed Price Supply Service from ComEd	3,430,355	311,903	5	3,742,263
Taking Supply Service from a Retail Electric Supplier (RES)	219	53,192	1,827	55,238
Percentage of Customers Receiving RES Service	**0.0064%**	**14.4%**	**92.1%**	**1.4%**
Total Monthly Customer Usage (MWH)	2,063,446	2,523,629	2,179,823	6,766,897
Of Hourly Price Service Customers	2,969	188,314	87,389	278,673
Of ComEd Fixed Price Supply Service Customers	2,060,319	844,681	599	2,905,600
Of RES Customers	157	1,490,633	2,091,835	3,582,625
Percentage of Usage Taking RES Supply Service	**0.0076%**	**59.1%**	**96.0%**	**52.9%**

While the scale and rate of migration away from the IPA portfolio is not known, a reference to statistics reported by the U.S. Department of Energy's Energy Information Administration the migration of natural gas customers away from bundled natural gas supply offered by Nicor, Peoples Gas, and North Shore indicates that some appetite for alternative energy supply does exist. Table E below conveys that in 2009 9.3% of eligible residential consumers received natural gas supply from Alternative Retail Gas Suppliers ("ARGS"). The IPA anticipates that higher migration rates are possible in electricity markets as tariff structure will allow ARES to make direct comparisons between their price offers and the annual fixed rate for energy available through the Utilities and sourced to the IPA portfolio.

TABLE E: ALTERNATIVE GAS SUPPLY PARTICIPATION RATES FOR PEOPLES GAS, NORTH SHORE GAS, AND NICOR

Participation in Alternative Gas Supply by Customer Class, December 2009						
Customer Type	2008 Customer Total	Eligible December 2009		Participating December 2009		
		Total	% of 2008 Customers	Total	% of 2009 Eligible	% of 2008 Customers
Residential	3,869,308	2,908,454	75.2	271,067	9.3	7
Commercial/Industrial*	322,155	254,183	78.9	49,558	19.5	15.4
Total	**4,191,463**	**3,162,637**	**75.5**	**320,625**	**10.1**	**7.6**

*All large commercial and industrial customers have the option of purchasing natural gas from suppliers other than LDCs. The "eligible" and "participating" commercial/industrial customers include all Nicor Gas commercial and industrial customers, but only small-volume commercial customers for Peoples Gas and North Shore Gas. Illinois had 298,418 commercial and 23,737 industrial customers in 2008.

Sources: **2008 Customer Total:** Energy Information Administration, *Natural Gas Annual 2008* (March 2010). **Eligibility and Participation:** Nicor Gas Company, Peoples Gas and Light Company, and North Shore Gas Company (February 2010).

Migration of eligible retail customers to ARES suppliers presents 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. our recent market experience in 2008-2009). Finally, assume that migration from the IPA portfolio to an ARES was free of barriers.

In such a situation, higher-than-market bundled rates available through the IPA portfolio would motivate switching by those customers who could be profitably served by ARESs 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. And while the Purchase of Receivables ("POR") is designed to prevent cherry-picking of customers by ARES, there is the potential that those who do migrate will be larger, more creditworthy, and responsive to marketing; leaving behind smaller, relatively poorer and more remote consumers. For this reason, laddering-in purchases over time enables the IPA to minimize risk for consumers by allowing it to adjust procurement volumes in response to changing customer needs and market conditions.

3. **Contract terms.** Contract terms related to credit requirements for the bidders and the Utilities may increase direct and indirect costs due to the premiums associated with providing credit facilities that are ultimately borne by the und-use customer. However, it is necessary to obtain such credit requirements from the bidders in order to protect end-use customers from potentially far higher costs that could be incurred in the event of a supplier default.

   Collateral Thresholds should remain at the levels used in the utilities' existing energy contracts unless there is consensus among the utilities, Procurement Administrators, Procurement Monitor and Staff that a compelling reason warrants new Collateral Thresholds. Under no circumstances should implementing new Collateral Thresholds require retroactive changes that lower the Collateral Thresholds in existing contracts entered into during past or current procurement processes.

   Contracts entered into as a result of the procurement process shall be executed through one of the following methods:

1. International Swaps and Derivatives Association ("ISDA") agreement for financial instruments such as fixed/floating rate swaps; or
2. Central counterparty clearing for standardized financial instruments on exchange traded contracts; or
3. An Edison Electric Institute ("EEI") agreement for physical products.

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.

   Compliance with the PUA leads to the following general calendar when a single procurement event is considered:

   - July – Load Forecasts submitted by Utilities to IPA
   - August – IPA submits Plan to ICC
   - September – Public comment period
   - October – Final Plan submittal
   - December – ICC authorization of substitution
   - Spring – Procurement event held
   - June - Deliveries commence

   This schedule has yielded 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 load 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. In the 2010 procurement process, revised load projections from the Utilities were submitted in response to downward projections in load requirements due to economic weakness within the region.

   Similarly, the portfolio design recommended by the IPA focuses on mitigating upside price risk, however, as seen in recent periods, prices in the wholesale market can and do move down. This being the case, the IPA recommends continuing the practice of laddered procurement over a three-year period in the cases of energy and capacity resources on an annual basis for the purpose of protecting against price escalation.

   To mitigate the risk of price decline, the IPA recommends that the ICC allow for optional procurements for energy only. These optional procurements would be limited to only an additional 10% of projected portfolio requirements in any month for the second and third planning years covered by the Final Procurement Plan that is below the 100% subscription level. The optional procurements would be triggered only when market indices demonstrate that prices for energy supply contracts for the target months are at least 10% below the average weighted price of fixed price contracts already secured by the Utilities for those months and such prices are below the prices for the most recently completed planning year procurement event. The optional procurements would be limited to participation by bidders qualified in and the terms and conditions agreed to in the Spring 2011 solicitation, and allowed only with the authorization of the Commission. After the optional procurement event(s) for energy hedges, the maximum subscription quantity shall be 100% for year 1, 80% for year 2, 45% for year 3 and 0% for years 4 and 5.

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.

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.

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. Future transmission costs will be 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.

   Past 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%.[11] Some of these costs may be offset by contributions of wind assets towards system reliability and other ancillary services. Recently, the Bonnevile Power Authority issued a final decision for its 2010 rate case. In the final rate case decision, the Authority authorized charging wind generators a "Wind Integration Rate" of $1.29/kilowatt-month (approximately $5.70/MWh). The approved rate was substantially lower than the originally requested rate of $2.79/kilowatt-month (approximately $12.00/MWh). The purpose of the fee was to cover the costs associated with the higher load balancing costs associated with facilitating the variable nature of wind asset output. In return for the lower than originally requested fee, wind generators agreed to a first-ever curtailment arrangement.[12]

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[11] "Accommodating Wind's Natural Behavior", DeMeo et al, IEEE Power & Energy Magazine, November/ December 2007, page 62.
[12] http://www.transmission.bpa.gov/Business/Rates_and_Tariff/2009WindIntegRateCAse.cfm

The IPA is limited in its ability to mitigate these growing 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 2011 – May 2016 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.

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 Draft Plan utilizes methods similar to those used by investors to manage market portfolio risks.

The Draft 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.

Existing (legacy) supply contracts dating from the 2007 rate relief agreements and the 2010 procurement cycle will supply portions of the IPA portfolio into the period covered by this Draft Plan. The IPA will be responsible for managing the procurement of that portion of the eligible-customer load not supplied by the legacy contracts.

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 multiple model runs 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 2016 as of August 10, 2010. 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 2013, 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.

   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 prices 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, 2011, 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 factor for intentional oversubscription of planned volumes in summer months (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 (fixed price and quantity), 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).

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. the 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 2013 - 2014 period, the IPA chose this time period in order 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 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, a three-year laddered procurement strategy would yield 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.

   It is important to remember that quantitative analysis is a modeling exercise based on historical patterns and assumptions about future load requirements. As such, the model cannot predict where prices will be in the next 3 to 5 year period. Instead, the model provides indications on how relative price volatility is managed under different portfolio distributions, thus meeting the IPA's charge to address price stability.

   Capturing low costs is another issue. Qualitative evaluation of the current markets indicate that regulatory compliance may force a fair amount of coal generating assets out of the market within the next decade. Replacement capacity appears to be planned, however many queue applicants are renewable energy generators with little to no baseload capacity value. At this time, the market presents the probability of meeting replacement coal capacity, future load growth, and balancing variable output renewable assets with new or converted natural gas assets. While this forecast is not a certainty, it would be imprudent to ignore the cost impacts that such a future would hold for consumers. In this environment, the IPA recommends continued layering of future purchases ahead of the time when economic growth returns and the full impact of coal asset retirement is fully realized.

Application of the Plan for the Utilities

Overview. Load projections that serve as the basis of this Draft Plan are supplied 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."*[13]

Consistent with the PUA, Ameren delivered load forecasts to the IPA on July 15, 2010 and ComEd delivered their forecasts on July 13. Per the request of the IPA, the Utilities also provided detailed descriptions of the statistical methods and assumptions underlying the projections. Copies of the Ameren and ComEd projection methodologies can be found in Attachments A and E to this Draft Plan.

[13] 220 ILCS 5/16-111.5(d)(1).

A. Ameren Illinois Utilities: June 1, 2011 – May 31, 2016.

The IPA relied on Load Forecasts from Ameren as best estimates for future consumption factored for the largely unknown variable of retail switching. Since the Ameren data projections are updated annually, the IPA readjusts load projections to account for the current view on retail switching and other factors affecting load size and shape. If during the planning process, the load projections for the Ameren portfolio require adjustments of greater than 200 MW (as indicated by the ICC DASR reports for the Ameren companies); a formal load readjustment will be requested and submitted by the Utility.

The ultimate goal of Ameren's Load Forecast provided by Ameren is not to identify the combined load of all customers of the Utility. Rather, the Ameren 5-year hourly load forecast identifies load projections for Eligible Retail Customers." Eligible Retail Customers include residential and small commercial customers entitled to purchase electricity from the Utility 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.

As detailed in Attachment A, the Ameren 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 losses, expected growth rates, retail competition switching trends, and results of statutory and other programs related to demand response and energy efficiency to yield a five-year projection of wholesale supply, capacity, and renewable energy resource requirements.

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 selected Ameren's Expected load model as the basis of the Draft Plan
In response to Section 8-103(c) of the PUA, Ameren factors its load projections to account for the Utility's demand response programs. Section 8-103(c) of the PUA directs:

> *"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."*[14]

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 8-103(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 Draft Plan, the IPA assumes that Ameren intends to implement demand response programs sufficient to achieve their targeted peak reductions. Based on Ameren's analysis, the aggregated reduction in Ameren's maximum system load requirements for eligible retail customers due to demand response programs is projected as:

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

The IPA will request validation of the ability to dispatch the Demand Response assets included in the

[14] 220 ILCS 5/8-103(c).

Ameren forecast in the near future. The IPA also notes that these Demand Resource values are effectively treated as pre-existing PRC credits within Capacity Resources projections for the Utility.

The IPA has also included the impacts of the Ameren 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:

2011	**106.8 GWh**	**2014**	**349.5 GWh**
2012	**207.7 GWh**	**2015**	**365.6 GWh**
2013	**298.2 GWh**		

The IPA will request validation of the avoided energy consumption delivered by these programs in the near future. The IPA also notes that these Energy Efficiency values are effectively treated as all other legacy supply contracts within the supply resources projections for the Utility.

1. **Ameren Energy Supply Resources.** Ameren Illinois Utilities will secure the physical energy resources to meet the combine load requirements of eligible rate payers. For the purposes of this Draft Plan, the following 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
   - **QF** – Qualified Facilities. The Company must procure energy from any qualifying facility meeting the requirements of Rider QF – Qualifying Facilities. Such qualifying purchases are considered to be preexisting purchases and shall be recovered in Accrued Expenses for the Purchased Electricity Adjustment.[15]

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

TABLE F: VOLUME PROJECTIONS PER RATE CLASS FOR AMEREN (JUNE 2011 THROUGH MAY 2014)

Contract Month	Projected Monthly Volume Requirements						
	DS1 MWH	DS2 MWH	DS3a MWH	DS5 MWH	QF MWH	Total Load MWH	Net Load MWH
June-11	1,009,692	279,200	57,565	27,766	-21,600	1,374,223	1,352,623
July-11	1,335,294	299,359	61,206	27,184	-22,320	1,723,043	1,700,723
August-11	1,333,094	296,921	60,391	27,998	-22,320	1,718,405	1,696,085
September-11	964,978	276,143	55,990	29,988	-21,600	1,327,100	1,305,500
October-11	798,363	267,637	53,874	31,788	-22,320	1,151,662	1,129,342
November-11	835,516	253,917	50,855	33,881	-21,600	1,174,169	1,152,569
December-11	1,107,141	268,221	53,156	36,520	-22,320	1,465,037	1,442,717
January-12	1,207,290	299,658	55,848	38,082	-22,320	1,600,877	1,578,557
February-12	1,042,234	265,476	49,918	34,903	-20,880	1,392,530	1,371,650
March-12	936,023	260,086	48,470	32,241	-22,320	1,276,820	1,254,500
April-12	747,656	231,751	43,955	32,097	-21,600	1,055,460	1,033,860

[15] Sheet 31.003 of the Rider PER tariff

May-12	776,769	248,105	47,731	28,990	-22,320	1,101,595	1,079,275
June-12	1,001,350	269,369	51,293	27,783	0	1,349,794	1,349,794
July-12	1,324,077	288,594	54,563	27,201	0	1,694,436	1,694,436
August-12	1,324,000	286,842	53,999	28,011	0	1,692,853	1,692,853
September-12	958,055	267,382	50,226	29,993	0	1,305,657	1,305,657
October-12	788,150	259,119	48,387	31,785	0	1,127,441	1,127,441
November-12	825,031	247,193	45,973	33,871	0	1,152,067	1,152,067
December-12	1,088,897	260,785	48,062	36,505	0	1,434,249	1,434,249
January-13	1,178,657	290,830	50,478	38,068	0	1,558,033	1,558,033
February-13	979,421	254,564	44,631	34,891	0	1,313,507	1,313,507
March-13	908,983	252,774	43,972	32,238	0	1,237,967	1,237,967
April-13	729,752	226,718	40,193	32,192	0	1,028,855	1,028,855
May-13	762,154	243,051	43,774	28,999	0	1,077,979	1,077,979
June-13	985,058	262,955	46,985	27,795	0	1,322,793	1,322,793
July-13	1,302,396	281,822	50,112	27,213	0	1,661,542	1,661,542
August-13	1,301,848	280,548	49,780	28,019	0	1,660,195	1,660,195
September-13	939,283	262,176	46,516	29,996	0	1,277,971	1,277,971
October-13	767,549	254,927	45,061	31,781	0	1,099,318	1,099,318
November-13	799,747	243,238	42,914	33,862	0	1,119,762	1,119,762
December-13	1,059,670	257,648	45,161	36,495	0	1,398,975	1,398,975
January-14	1,143,551	287,282	47,537	38,059	0	1,516,429	1,516,429
February-14	949,239	252,041	42,222	34,884	0	1,278,387	1,278,387
March-14	880,321	250,824	41,799	32,237	0	1,205,181	1,205,181
April-14	701,690	223,852	38,103	32,104	0	995,749	995,749
May-14	740,067	242,191	42,010	29,007	0	1,053,276	1,053,276

The monthly volumes presented above for the various rate classed are aggregated and set alongside the representative monthly Peak and Off-Peak Average Load in Table G below with the full 2011 to 2016 planning period presented in Attachment C.

TABLE G: AGGREGATED MONTHLY AND AVERAGE LOAD REQUIREMENTS FOR AMEREN (JUNE 2011 THROUGH MAY 2014)

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-11	714,720	637,904	2,030	1,733
July-11	842,292	858,431	2,632	2,025
August-11	936,346	759,739	2,544	2,021
September-11	678,542	626,958	2,019	1,633
October-11	554,176	575,166	1,649	1,410
November-11	581,246	571,323	1,730	1,488
December-11	688,896	753,821	2,050	1,848
January-12	757,415	821,142	2,254	2,013
February-12	690,534	681,116	2,055	1,892
March-12	617,537	636,963	1,754	1,625
April-12	513,687	520,172	1,529	1,355
May-12	552,358	526,917	1,569	1,344
June-12	721,373	628,422	2,147	1,637
July-12	846,581	847,855	2,520	2,078
August-12	934,121	758,732	2,538	2,018
September-12	590,427	715,229	1,942	1,719
October-12	588,677	538,764	1,600	1,433

November-12	569,373	582,694	1,695	1,517
December-12	647,629	786,621	2,024	1,855
January-13	782,227	775,807	2,222	1,979
February-13	660,503	653,004	2,064	1,855
March-13	584,475	653,492	1,740	1,602
April-13	534,127	493,445	1,517	1,341
May-13	550,200	527,779	1,563	1,346
June-13	666,018	656,776	2,081	1,642
July-13	875,822	785,720	2,488	2,004
August-13	884,335	775,860	2,512	1,979
September-13	604,336	673,635	1,889	1,684
October-13	575,499	523,819	1,564	1,393
November-13	523,916	595,846	1,637	1,490
December-13	655,250	743,725	1,950	1,823
January-14	753,440	762,990	2,140	1,946
February-14	645,123	633,263	2,016	1,799
March-14	563,024	642,157	1,676	1,574
April-14	513,469	482,279	1,459	1,311
May-14	508,863	544,413	1,514	1,334

Energy and financial hedges required by the Eligible Retail Customers comes from five sources. First, the swap contract with Ameren Energy Marketing provides a financial hedge on 1000 MW of Around-the- Clock (“ATC”) energy during the June 2011 – December 2012 period. Second, Ameren Illinois Utilities have some existing financial hedges in place for the period June 2011 through May 2012. Such hedges were executed as a result of the 2010 procurement process. Third, the Ameren Illinois Utilities will enter into fixed price physical supply contracts to hedge price exposure for the Residual Volumes (IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan). Fourth, the Ameren Illinois Utilities will enter into agreements to purchase Energy Efficiency as Alternative Resource (EEAR) from existing Energy Efficiency Portfolio Standard (EEPS) programs offered to eligible retail customers in the Ameren service region. Fifth, the Ameren Utilities will procure the physical energy necessary to meet their combined load requirements via the MISO day ahead and real-time energy markets.

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 the contracts for such capacity shall obligate the seller to offer capacity into the MISO markets.

However, due to uncertainty concerning the viability and practicality of financial swap contracts, primarily due to the recent passage of the Dodd–Frank Wall Street Reform and Consumer Protection Act (Public Law 111-203, H.R. 4173), the IPA shall authorize the procurement administrator to issue contracts for the physical delivery of energy, instead of a financial swap contracts, if during procurement preparations it becomes clear to the procurement administrator that contracts for the physical delivery are more likely to be in the interests of the utility and ratepayers. Furthermore, if the procurement administrator determines that financial swap contracts are still preferable to contracts for physical delivery of energy, the procurement administrator will still be instructed to fashion the swap contracts to allow for conversion to physical delivery contracts if at some point in the future such conversion is seen to be advantageous to both buyer and seller.

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's procurement administrator will issue solicitations to lock-in fixed prices for fixed quantities of energy supply, using single-month, multi-month, and/or annual contracts for on-peak, off-peak, and/or around-the-clock blocks during the period between June 2011 and May 2014, in whatever combinations are deemed appropriate by the procurement administrator, given the objectives described in this plan.. The target procurement quantities are determined by multiplying Ameren's average net load obligation (average forecasted load) 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, as well as those MWs covered as a result of the 2010 procurement plan. To the extent the calculated procurement quantity for a period is less than 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 follows (rounded to the nearest 50 MW) are found in Tables H and I. A full schedule of related planned procurement loads for Ameren can be found in Attachment D. Please note that consistent with past practice, the contract volumes in the schedule include a 10% increased purchase volume for the Peak periods in the months of July and August. This increase is included to serve as a hedge against unforeseen increases in weather-related demand during those periods.

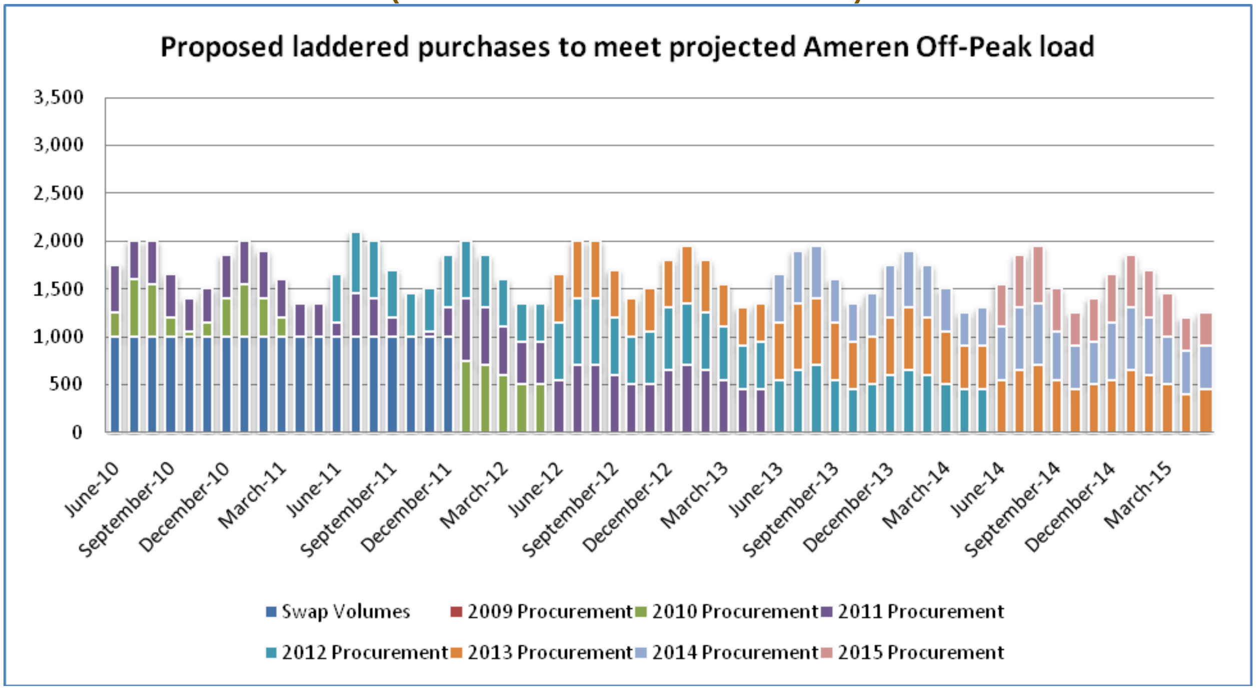
TABLE H: PROPOSED AMEREN OFF-PEAK LOAD VOLUMES TO BE SECURED IN 2011 PROCUREMENT

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

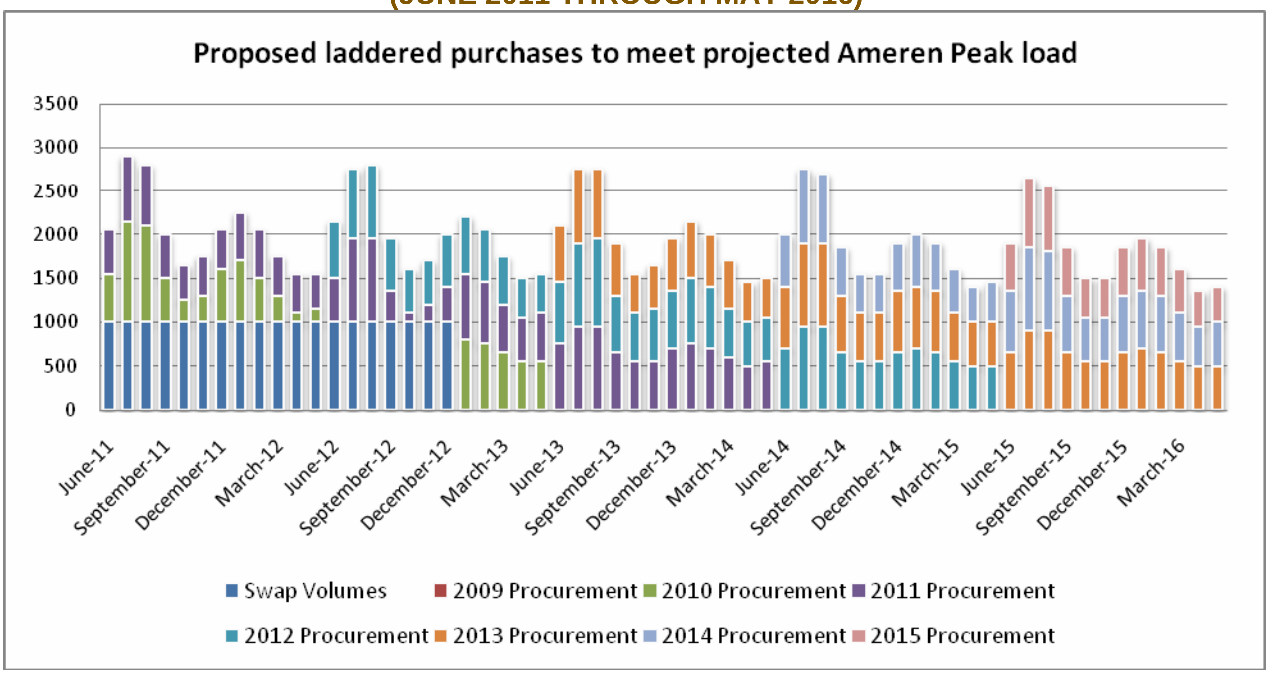
TABLE I: PROPOSED AMEREN ON-PEAK LOAD VOLUMES TO BE SECURED IN 2011 PROCUREMENT

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

GRAPH 2: PROPOSED LADDERING SCHEDULE FOR AMEREN OFF-PEAK LOAD (JUNE 2011 THROUGH MAY 2016)



GRAPH 3: PROPOSED LADDERING SCHEDULE FOR AMEREN PEAK LOAD (JUNE 2011 THROUGH MAY 2016)



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.[16]

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.

The IPA makes note that federal legislation regarding the regulation of derivatives has recently passed and is currently going through a rule making process. It is expected that such legislation will allow the CFTC to regulate derivatives (including financial swaps) and enforce position limits, margin requirements and reporting requirements. Such changes have the potential to increase costs for the AIUs, its suppliers and customers. The date of the final rule making is uncertain and it is unclear if final rules will exempt existing financial swap transactions via a "grandfather" clause. It is also uncertain whether the AIUs will be partially or completely exempt from the rule making outcome since the AIUs may be viewed as an end user and not a speculator. In summary and in light of the information currently available, the IPA recommends replacing financial swaps for the spring 2011 procurement event with those that settle physically within MISO. This would appear to be the most prudent course of action until the rule making process is better understood. The IPA will monitor the rule making process and recommend a course of action for procurement events beyond spring 2011 as the outcome of the current rule making process becomes clearer.

The IPA recommends consideration of the purchase of Energy Efficiency as Alternative Resource ("EEAR") for the Ameren portfolio. The purpose of this is twofold – first, to establish whether energy efficiency can be cost competitive with more traditional resources; and second, to establish additional benefits such as price stability can be gained through the expansion in the type of resource products placed into the Ameren portfolio. In order to assure valid results in an EEAR procurement, the IPA recommends holding workshops during the fall of 2010 to establish the scope and nature of the EEAR event with the input of interested parties.

The IPA believes that the appropriate sources for EEAR bids would be programs that are evaluated in a manner equivalent to the existing Energy Efficiency Portfolio Standard ("EEPS") programs offered to eligible retail customers in the Ameren service region. The IPA notes that the results of the EEPS programs have been factored into the Ameren load forecasts in a manner similar to that of other pre-existing supply contracts for the past two cycles. Additionally, the EEPS programs are in their third year of operation and operate under an evaluation and oversight regime supervised by the ICC. These two factors lead the IPA to

[16] 220 ILCS 5/16-111.5(e)(2).

determine that resources provided by the EEPS are reliable.

Similarly, energy efficiency resources that can show that they are evaluated in a manner equivalent to the EEPS programs, and are, consequently, equally reliable, are an appropriate source for EEAR bids. The IPA will also limit its procurement of Utility-administered resources to those resources that are not required to meet the Energy Efficiency Portfolio Standards.

The IPA proposes that EEAR assets should only be procured when the cost of the EEAR is less than the combined cost of the energy swaps, capacity, and renewable energy resource contracts held by Ameren for the contract period offered by the EEAR provider. As such, the EEAR contracts should be considered after the spring 2011 procurement events for energy resources, capacity, and renewable energy credits through a competitive solicitation.

Additional elements to the supply resources plan include:

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.[17] 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 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. Again, the IPA will work with Ameren, the Commission and procurement administrator to determine the appropriateness of rebalancing the portfolio.

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. 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.

[17] 220 ILCS 5/16-111.5(b)(4).

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.

Incremental Procurement Events. The IPA proposes that optional incremental procurements of up to an additional 10% of projected portfolio requirements in total be allowed under certain circumstances. First, the incremental procurements could seek to secure volumes for only those months that have not achieved a full 100% subscription level and only for years two and three of the plan. Second, the optional procurements would be triggered only when market indices demonstrate that prices for energy supply contracts for the targets months are at least 10% below the average weighted price of fixed price contracts already secured by the Utilities for those months. Third, such prices must be expected to be below the prices paid in the most recent procurement event. Fourth, the optional procurements would be limited to participation by bidders qualified in, and operate only under the agreed terms and conditions of the spring 2011 solicitation. Lastly, such procurement events would only occur, and the results accepted only with the authorization of the Commission.

2. **Ameren Capacity Resources.** Module E of the Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff addresses resource adequacy. Module E requires Ameren to hold the lower of the reserve requirement as specified by an annual planning process undertaken by the Midwest ISO or the requirement of the relevant state regulatory authority. 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 Planning Reserve Credits to meet or exceed its Resource Adequacy Requirement (the monthly peak load forecast plus its planning reserve margin).

   In 2009, MISO implemented significant penalties associated with a capacity deficiency event based on the Cost of New Entry (CONE). For the 2009 Planning Year, the deficiency penalty was determined by MISO to be $80/kW-Month, $90/kW-Month for 2010 and $95/kW-Month for 2011.

   The IPA makes note that significant changes to the MISO resource adequacy construct are currently being discussed at MISO. In a September 2, 2010 presentation to the Supply Adequacy Working Group, the MISO laid out the enhancements that they are currently considering for Module E. These enhancements include moving to a 3-5 year forward looking construct and shifting to annual or seasonal compliance rather than the current monthly compliance. The presentation also includes a timeline which shows opportunities for stakeholder input, MISO finalizing their proposal in mid-October, tariff changes being filed at FERC on December 8, 2010, and an effective date for the changes of June 1, 2012. Given the uncertainty around this process, it may not be possible define the Capacity product required to comply with these future requirements until at least sometime after the December 8 filing and possibly not unit such time as FERC has issued its final order. With this in mind, the IPA will only procure the Capacity resources required to fully comply with the MISO resource adequacy requirements for the 2011 planning year which are currently known and certain and not attempt to procure resources for any future years in which the MISO requirement are uncertain at this time.

   For demonstration purposes, the tables included in this plan utilize the reserve margin of 4.5% that has been effective for the planning year beginning in June 2010 through May 2011. The planning reserve margin beginning June 2011 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 2011 through May 2012) as detailed in Table I:

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

Contract Month	Peak Load	Demand Response	Transmiss. Losses	Net Peak Load	Planning Reserves	Capacity Req.	2009 Purchase	2010 Purchase	2011 Purchase	% Hedged
June-11	3,901	0	80	3,901	179	4,160	1,370	1,570	1,220	100%
July-11	4,137	12	84	4,125	189	4,398	1,630	1,570	1,200	100%
August-11	4,144	12	84	4,132	190	4,406	1,650	1,480	1,280	100%
September-11	3,998	0	82	3,998	184	4,263	1,300	1,580	1,390	100%
October-11	2,802	0	57	2,802	129	2,988	960	910	1,120	100%
November-11	2,456	0	50	2,456	113	2,619	910	930	780	100%
December-11	3,016	0	62	3,016	138	3,216	1,100	1,340	780	100%
January-12	3,172	0	65	3,172	146	3,383	1,100	1,310	980	100%
February-12	2,868	0	59	2,868	132	3,058	1,020	1,150	890	100%
March-12	2,364	0	48	2,364	109	2,521	900	1,050	580	100%
April-12	2,148	0	44	2,148	99	2,290	800	840	650	100%
May-12	2,503	0	51	2,503	115	2,669	1,040	870	760	100%

Some capacity was procured in 2010 for the 2012 planning year. Pursuant to the previous discussion regarding MISO changing its capacity construct, the IPA will not make any additional purchases in 2011 for the 2012 planning year. This will result in a hedge of approximately 35% of the capacity requirement for the 2012 planning year (June 2012 through May 2013 as detailed in Table J:

TABLE J: PROPOSED AMEREN CAPACITY CONTRACT VOLUMES TO SECURE IN 2011 CYCLE (JUNE 2012 THROUGH MAY 2013)

Contract Month	Peak Load	Demand Response	Transmiss. Losses	Net Peak Load	Planning Reserves	Capacity Req.	2009 Purchase	2010 Purchase	% Hedged
June-12	3,826	0	78	3,904	176	4,080	0	1,440	35%
July-13	4,072	16	83	4,139	186	4,325	0	1,570	36%
August-14	4,095	16	83	4,162	187	4,349	0	1,530	35%
September-12	3,951	0	81	4,032	181	4,213	0	1,410	33%
October-13	2,565	0	52	2,617	118	2,735	0	920	34%
November-12	2,413	0	49	2,462	111	2,573	0	900	35%
December-12	2,965	0	61	3,025	136	3,162	0	1,200	38%
January-13	3,096	0	63	3,160	142	3,302	0	1,180	36%
February-13	2,795	0	57	2,852	128	2,980	0	1,080	36%
March-13	2,306	0	47	2,353	106	2,459	0	950	39%
April-13	2,099	0	43	2,141	96	2,238	0	810	36%
May-13	2,670	0	54	2,725	123	2,847	0	940	33%

No capacity will be procured for the third planning year (June 2013 through May 2014.

The IPA's procurement administrator will issue solicitations to lock-in fixed prices for fixed quantities of required capacity resources, using single-month, multi-month, and/or annual contracts during the period between June 2011 and May 2014, in whatever combinations are deemed appropriate by the procurement administrator, given the objectives described in this plan.

3. **Ameren Demand Response Resources.** Section 220 ILCS 5/16-111.5(b)(3)(ii).of the IPA Act requires the Plan to include:

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]

The IPA recommends meeting the statutory obligation of procuring demand response as a free-standing obligation and not related to the replacement of Capacity Resources. The IPA proposes that the following characteristics be considered in securing these required demand response resources:

- **Product.** The IPA recommends procuring Demand Response assets that meet the statute's definitions and are registered as qualifying Planning Resource Credits ("PRC") by the Midwest Independent System Operator ("MISO"), but have not bid into MISO's Voluntary Capacity Auction.
- **Timing.** The IPA recommends that Demand Response assets be solicited as a separate procurement activity in the spring of 2011.
- **Volumes.** Consistent with statute, the IPA recommends that Demand Response Resources be procured to the extent that they meet the cost effectiveness and source requirements.
- **Term.** The IPA recommends that Demand Response Resources be secured for contract durations of between five and ten years.

4. **Ameren Renewable Energy Resources.** 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[19]

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,

[18] 220 ILCS 5/16-111.5(b)(3)(ii).
[19] 20 ILCS 3855/1-75(c)(1)

biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, 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.[20]

The IPA proposes that Ameren shall meet the renewable energy resource portfolio standard for the Plan year through the acquisition of qualifying renewable energy credits ("RECs") as defined in Section 1-10 of the IPA Act. The acquisition of RECs 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.

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.

As noted, 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 in excess of existing contract amounts would be limited or curtailed, leaving the annual volumetric goal unmet. Table K below cites the volume goals and cost limits.

TABLE K: RPS STANDARDS FOR AMEREN

Delivery period	Minimum Percentage (Annual volume goal)	Maximum Cost Standard
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
2015-2016	10% of June 1, 2013 through May 31, 2014 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 L 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 3855/1-10.

TABLE L: 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	2.00%	414,392
2009-2010	2007-2008	17,984,564	4.00%	719,383
2010-2011	2008-2009	17,217,197	5.00%	860,860
2011-2012	2009-2010	15,869,084	6.00%	952,145

Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables M and N 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, 2010-2011, and 2011-2012.

TABLE M: ANNUAL AMEREN RRB CALCULATIONS – OPTION A

Ameren RPS CALCULATIONS: Option A (Incremental increase on annual unit cost approach)				
(A) Planning Year	2008-2009	2009-2010	2010-2011	2011-2012
(B) Reference Year	2006-2007	2007-2008	2008-2009	2009-2010
(C) Reference Year Delivered Volume (MWh)	20,719,607	17,984,564	17,217,197	15,869,084
(D) Reference Year Delivered Cost	$1,801,867,729	$1,809,606,830	$1,853,574,838	$ 1,672,595,852
(E) Reference Year Unit Cost - [D / C]	$86.96	$100.62	$107.66	$105.40
(F) Planning Year Incremental RPS Cost Limit %	0.50%	0.50%	0.50%	0.50%
(G) Planning Year Incremental RPS Cost Limit Unit Price - [F * D]	$0.4348	$0.5031	$0.5383	$0.5270
(H) Planning Year Net RPS Cost Limit Unit Price	$0.4348	$0.9379	$1.4762	$2.0032
(I) Planning Year Projected Total Delivery Volume	20,719,607	17,700,274	16,525,235	15,065,960
(J) Planning Year Option A Cost Cap [I * H]	**$9,009,339**	**$16,601,474**	**$24,394,776**	**$30,180,309**

TABLE N: ANNUAL AMEREN RRB CALCULATIONS – OPTION B

Ameren RPS CALCULATIONS: Option B (Percentage Increase over Base Year unit cost approach)				
(A) Planning Year	2008-2009	2009-2010	2010-2011	2011-2012
(B) Reference Year	2006-2007			
(C) Reference Year Delivered Volume (MWh)	20,719,607			
(D) Reference Year Delivered Cost	$1,801,867,729			
(E) Reference Year Unit Cost ($/MWh) - [D / C]	$86.96			
(F) Planning Year Incremental RPS Cost Limit %	0.50%	1.00%	1.50%	2.00%
(G) Planning Year Net RPS Cost Limit Unit Price - [F * D]	$0.4348	$0.8696	$1.3045	$1.7393
(H) Planning Year Projected Total Delivery Volume	20,719,607	17,700,274	16,525,235	15,065,960
(I) Planning Year Option A Cost Cap [H * G]	**$9,009,339**	**$15,392,933**	**$21,556,602**	**$26,204,037**

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

TABLE O: AMEREN RPS TARGETS for 2011-2012

Ameren Renewable Portfolio Standard (RPS) Metrics (2011-2012)	
RPS Volume Target (MWh)	952,145
Renewable Energy Resource Budget (RRB)	$30,180,309
Average Price per Renewable Unit	$31.70
Estimated Customers Covered by RRB	1,169,723
Estimated Annual RPS Cost/Consumer	$25.80

Additional aspects of the proposed Renewable Energy Resources procurement are noted below:

- **Pricing Benchmark.** The Procurement Administrator is directed to continue to establish benchmark REC prices (as in 2009 and 2010 Procurement Plans), 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 RECs in amounts equal to the statutory requirement ensures compliance.

  PJM Environmental Information System's ("EIS") Generation Attribute Tracking System ("GATS"), the Midwest Renewable Energy Tracking System ("M-RETS") and the North American Renewables Registry ("NAR") 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, for generators located in South and North Dakota, Minnesota, Wisconsin, Iowa, Illinois and Ohio. NAR tracks renewable energy generation from facilities typically outside of the M-RETS and PJM footprints.

  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).

4. **Ameren Transmission Resources.** 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 utilizes 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 2010 ARR allocation process at MISO, Ameren received a set of ARR entitlements and were awarded ARRs for the 2010 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.

B. Commonwealth Edison: June 1, 2011 – May 31, 2016.

The IPA relied on Load Forecasts from ComEd as best estimates for future consumption factored for the largely unknown variable of retail switching. Since ComEd's data projections are updated annually, the IPA readjusts load projections to account for the current view on retail switching and other factors affecting load size and shape. If during the planning process, the load projections for the ComEd portfolio require adjustments of greater than 200 MW (as indicated by the ICC DASR reports for the Ameren companies); a formal load readjustment will be requested and submitted by the Utility.

The ultimate goal of the Load Forecast provided by ComEd is not to identify the combined load of all customers of the Utility. Rather, the ComEd 5-year hourly load forecast identifies load projections for Eligible Retail Customers." Eligible Retail Customers include residential and small commercial customers entitled to purchase electricity from the Utility under fixed-price bundled service tariffs. ComEd 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.

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. Electricity supply to ComEd customers with demand greater than 100kW is competitive. Customers with demand greater than 100kW are no longer eligible for bundled service and are not included in the forecasts.

ComEd utilizes a forecasting process based on econometric models that produce monthly sales forecasts for primary customer classes. 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.

In response to Section 8-103(c) of the PUA, ComEd factors its load projections to account for the Utility's demand response programs. Section 8-103(c) of the PUA directs:

> *"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."*[21]

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 8-103(b) and (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 Draft Plan, the IPA assumes that ComEd 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:

2011 42.0 MW
2012 53.1 MW
2013 63.6 MW
2014 74.2 MW
2015 85.0 MW

The IPA anticipates requesting validation of the ability to dispatch the Demand Response assets included in the forecast in the near future.

Section 8-103(b) of the PUA also establishes specific requirements for energy efficiency programs that reduce energy consumption of delivery services customers by 0.2% in the 2008 planning year and by an additional 0.2% each year through 2012, growing to a total decrease in energy consumption of 2.0% in 2015 and thereafter.[22] The annual aggregate reductions in ComEd's supply requirements to be acquired through the RFP process (net of customer switching) is projected to be:

2011 – 599.8 GWh
2012 – 931.1 GWh
2013 – 1,307.7 GWh
2014 – 1,683.9 GWh
2015 – 2,059.9 GWh

The IPA anticipates requesting validation of the ability to dispatch the Demand Response assets included in the forecast in the near future. The IPA also notes that these Energy Efficiency values are

[21] 220 ILCS 5/8-103(c).
[22] 220 ILCS 5/8-103(b).

effectively treated as all other legacy supply contracts within the Supply Resources projections for the Utility.

1. **ComEd Energy Supply Resources.** ComEd will meet the physical supply requirements of the projected loads for specific rate classes as identified in the Load Forecast report submitted by ComEd to the IPA a copy of which can be found in Attachment E 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 P 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 F.

TABLE P: VOLUME PROJECTIONS PER RATE CLASS FOR COMED (JUNE 2011 THROUGH MAY 2014)

Contract Month	Projected Monthly Volume Requirements									
	SF GWH	MF GWH	SFSH GWH	MFSH GWH	WH GWH	Small GWH	Condo GWH	DD GWH	GL GWH	Total GWH
June-11	2,132	442	49	102	44	600	20	15	1	3,405
July-11	2,842	585	50	112	49	662	27	15	1	4,342
August-11	2,615	551	45	102	49	662	30	16	1	4,072
September-11	1,829	395	34	76	43	584	26	16	1	3,005
October-11	1,568	340	41	82	41	552	23	18	1	2,665
November-11	1,712	358	72	131	40	541	22	18	1	2,894
December-11	2,062	408	111	212	44	603	31	19	1	3,491
January-12	2,042	396	126	258	45	618	37	19	1	3,542
February-12	1,718	355	114	235	42	573	34	17	1	3,089
March-12	1,640	344	98	201	42	579	31	17	1	2,955
April-12	1,418	302	70	139	39	524	25	15	1	2,534
May-12	1,545	334	53	106	41	558	23	16	1	2,677
June-12	2,132	443	48	100	44	568	20	15	1	3,372
July-12	2,876	593	50	111	49	631	27	16	1	4,355
August-12	2,629	555	45	101	49	629	30	17	1	4,056
September-12	1,808	391	33	74	43	550	26	17	1	2,942
October-12	1,577	343	41	81	41	531	23	19	1	2,655
November-12	1,706	357	70	128	40	514	22	19	1	2,858
December-12	2,052	407	108	208	44	572	31	20	1	3,443
January-13	2,057	398	125	256	45	593	38	20	1	3,534
February-13	1,659	342	108	224	40	528	33	17	1	2,953

March-13	1,631	341	97	197	42	550	31	17	1	2,908
April-13	1,418	302	69	137	39	502	26	16	1	2,509
May-13	1,540	333	52	104	41	531	24	16	1	2,643
June-13	2,131	443	48	99	44	567	20	16	1	3,368
July-13	2,913	600	50	111	49	634	27	16	1	4,402
August-13	2,633	556	44	100	49	626	30	17	1	4,056
September-13	1,812	392	33	73	43	552	26	17	1	2,949
October-13	1,565	340	40	79	41	532	23	19	1	2,640
November-13	1,690	353	69	125	40	512	22	19	1	2,833
December-13	2,063	408	107	206	44	575	31	20	1	3,456
January-14	2,059	399	123	253	45	593	38	20	1	3,531
February-14	1,658	342	106	220	40	528	33	17	1	2,946
March-14	1,629	341	95	194	42	550	31	18	1	2,902
April-14	1,413	301	68	135	39	502	26	16	1	2,501
May-14	1,533	332	51	102	41	529	24	16	1	2,629

The monthly volumes presented above for the various rate classed are aggregated and set alongside the representative monthly Peak and Off-Peak Average Load in Table Q below with the full 2011 to 2016 planning period presented in Attachment G.

TABLE Q: AGGREGATED MONTHLY AND AVERAGE LOAD REQUIREMENTS FOR COMED (JUNE 2011 THROUGH MAY 2014)

Contract Month	Total Load (MWh)		Average Load (MWh)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-11	1,851,927	1,553,489	5,261	4,221
July-11	2,101,193	2,241,182	6,566	5,286
August-11	2,248,679	1,823,215	6,111	4,849
September-11	1,538,391	1,466,300	4,579	3,818
October-11	1,314,273	1,350,807	3,912	3,311
November-11	1,457,566	1,436,711	4,338	3,741
December-11	1,699,468	1,791,473	5,058	4,391
January-12	1,712,873	1,829,337	5,098	4,484
February-12	1,589,745	1,499,038	4,731	4,164
March-12	1,492,749	1,461,870	4,241	3,729
April-12	1,276,826	1,257,106	3,800	3,274
May-12	1,382,300	1,294,226	3,927	3,302
June-12	1,754,034	1,617,539	5,220	4,212
July-12	2,209,367	2,145,187	6,575	5,258
August-12	2,231,981	1,823,774	6,065	4,850
September-12	1,370,867	1,571,351	4,509	3,777
October-12	1,431,746	1,223,736	3,891	3,255
November-12	1,446,176	1,411,890	4,304	3,677
December-12	1,597,860	1,844,815	4,993	4,351
January-13	1,785,338	1,748,506	5,072	4,460
February-13	1,494,489	1,458,271	4,670	4,143
March-13	1,404,947	1,503,241	4,181	3,684
April-13	1,323,024	1,186,400	3,759	3,224

May-13	1,364,882	1,277,753	3,878	3,260
June-13	1,667,633	1,700,540	5,211	4,251
July-13	2,338,424	2,063,912	6,643	5,265
August-13	2,143,946	1,912,326	6,091	4,878
September-13	1,452,023	1,496,784	4,538	3,742
October-13	1,423,870	1,216,313	3,869	3,235
November-13	1,362,688	1,469,902	4,258	3,675
December-13	1,679,913	1,776,472	5,000	4,354
January-14	1,782,457	1,748,792	5,064	4,461
February-14	1,488,920	1,457,315	4,653	4,140
March-14	1,399,091	1,502,819	4,164	3,683
April-14	1,316,233	1,184,503	3,739	3,219
May-14	1,294,450	1,334,476	3,853	3,271

Energy required by the Eligible Retail Customers comes from five sources. First, the swap contract with ExGen provides a financial hedge on 3,000 MW of ATC energy during the June 2011 – May 2013 period. Second, certain fixed price physical supply contracts were secured through the 2010 procurement process. Third, IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan. Fourth, balancing energy will be procured from the PJM-administered day-ahead and real-time energy markets. Lastly, ComEd will enter into agreements to purchase Energy Efficiency as Alternative Resource ("EEAR") from existing Energy Efficiency Portfolio Standard ("EEPS") programs offered to eligible retail customers in the ComEd service region.

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,[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's procurement administrator will issue solicitations to lock-in fixed prices for fixed quantities of energy supply, using single-month, multi-month, and/or annual contracts for on-peak, off-peak, and/or around-the-clock blocks during the period between June 2011 and May 2014, in whatever combinations are deemed appropriate by the procurement administrator, given the objectives described in this plan. 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 than 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.

[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.

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 R and S. A full schedule of related planned procurement loads for ComEd can be found in Attachment H. Please note that consistent with past practice, the contract volumes in the schedule include a 10% increased purchase volume for the Peak periods in the months of July and August. This increase is included to serve as a hedge against unforeseen increases in weather-related demand during those periods.

TABLE R: PROPOSED COMED PEAK LOAD VOLUMES TO SECURE IN 2011 PROCUREMENT CYCLE (JUNE 2011 THROUGH MAY 2014)

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

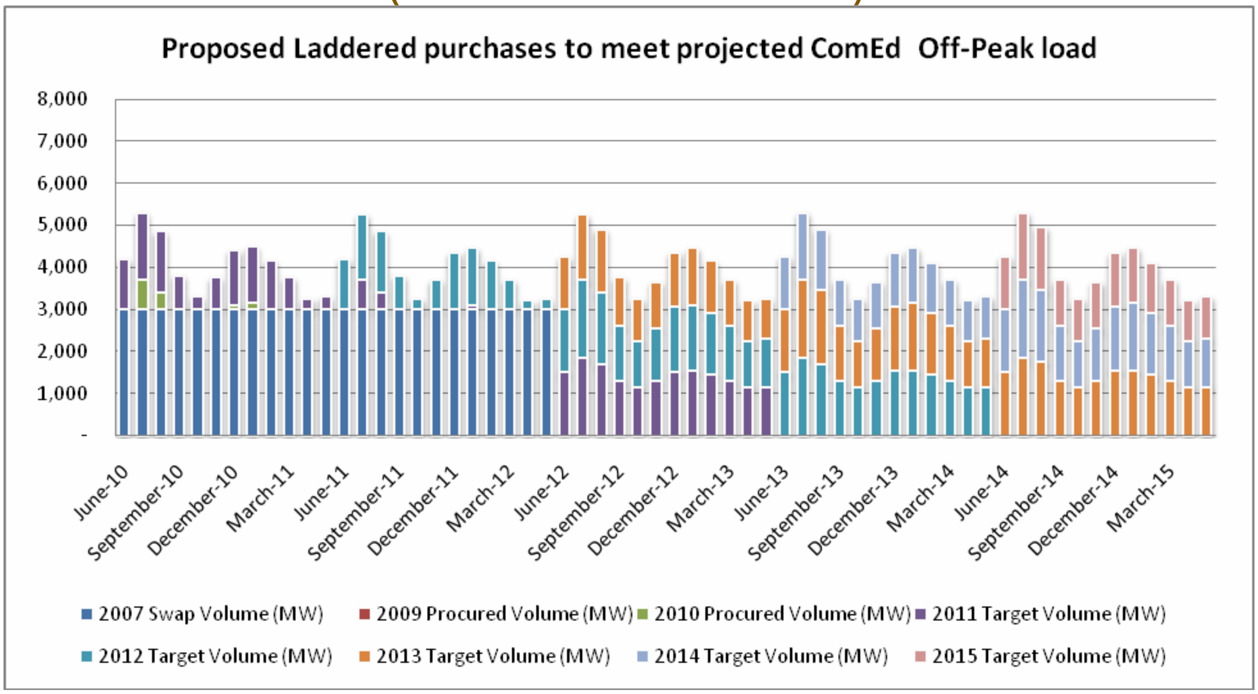
December-13	5000	0	0	5000	1750	1750	1500
January-14	5064	0	0	5064	1750	1800	1500
February-14	4653	0	0	4653	1650	1600	1400
March-14	4164	0	0	4164	1450	1450	1250
April-14	3739	0	0	3739	1300	1300	1150
May-14	3853	0	0	3853	1350	1350	1150

TABLE S: PROPOSED COMED OFF-PEAK LOAD VOLUMES TO SECURE IN 2011 PROCUREMENT CYCLE (JUNE 2011 THROUGH MAY 2014)

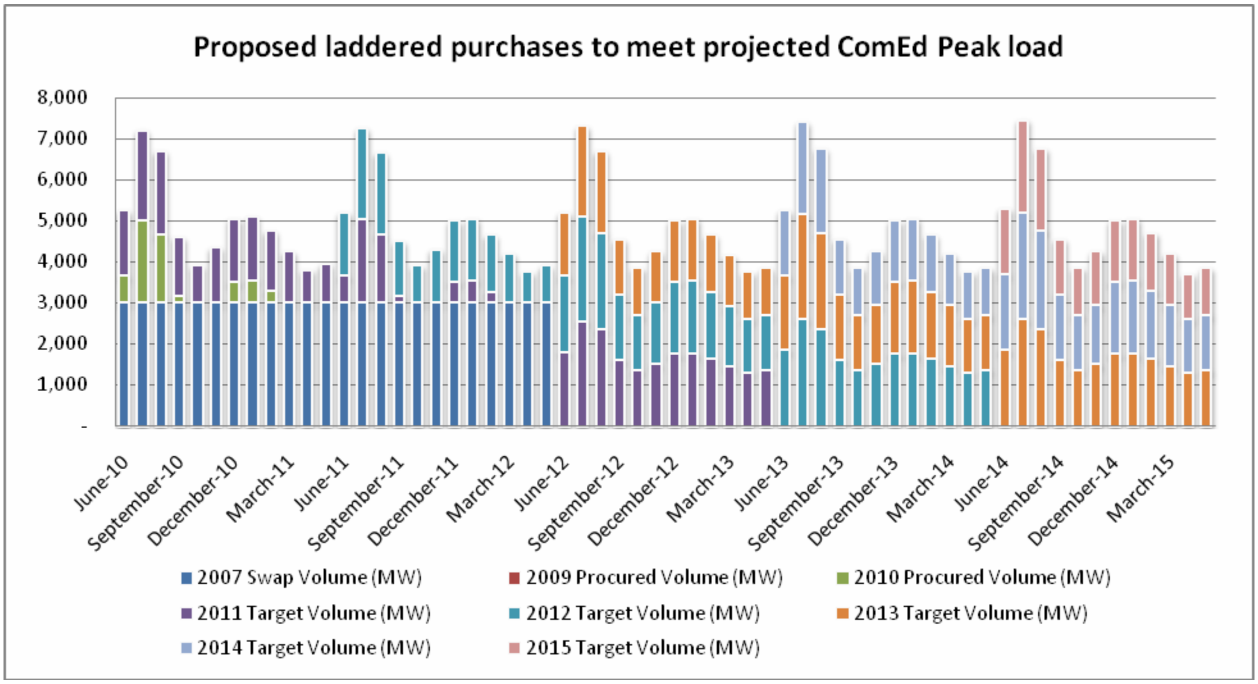
Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	4,221	3,000	0	1,221	1200	0	0
July-11	5,286	3,000	700	1,586	1600	0	0
August-11	4,849	3,000	400	1,449	1450	0	0
September-11	3,818	3,000	0	818	800	0	0
October-11	3,311	3,000	0	311	300	0	0
November-11	3,741	3,000	0	741	750	0	0
December-11	4,391	3,000	100	1,291	1300	0	0
January-12	4,484	3,000	150	1,334	1350	0	0
February-12	4,164	3,000	0	1,164	1150	0	0
March-12	3,729	3,000	0	729	750	0	0
April-12	3,274	3,000	0	274	250	0	0
May-12	3,302	3,000	0	302	300	0	0
June-12	4,212	3,000	0	1,212	0	1200	0
July-12	5,258	3,000	0	2,258	700	1550	0
August-12	4,850	3,000	0	1,850	400	1450	0
September-12	3,777	3,000	0	777	0	800	0
October-12	3,255	3,000	0	255	0	250	0
November-12	3,677	3,000	0	677	0	700	0
December-12	4,351	3,000	0	1,351	50	1300	0
January-13	4,460	3,000	0	1,460	100	1350	0
February-13	4,143	3,000	0	1,143	0	1150	0
March-13	3,684	3,000	0	684	0	700	0
April-13	3,224	3,000	0	224	0	200	0
May-13	3,260	3,000	0	260	0	250	0
June-13	4,251	0	0	4,251	1500	1500	1250
July-13	5,265	0	0	5,265	1850	1850	1550
August-13	4,878	0	0	4,878	1700	1700	1500
September-13	3,742	0	0	3,742	1300	1300	1150
October-13	3,235	0	0	3,235	1150	1100	1000
November-13	3,675	0	0	3,675	1300	1250	1100
December-13	4,354	0	0	4,354	1500	1550	1300
January-14	4,461	0	0	4,461	1550	1550	1350
February-14	4,140	0	0	4,140	1450	1450	1250
March-14	3,683	0	0	3,683	1300	1300	1100
April-14	3,219	0	0	3,219	1150	1100	950
May-14	3,271	0	0	3,271	1150	1150	950

Graphs 4 and 5 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 ComEd's Eligible Retail Customers.

GRAPH 4: PROPOSED LADDERING SCHEDULE FOR COMED OFF-PEAK LOAD (JUNE 2011 THROUGH MAY 2016)



GRAPH 5: PROPOSED LADDERING SCHEDULE FOR COMED PEAK LOAD (JUNE 2011 THROUGH MAY 2016)



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.

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

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

- 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.

The IPA recommends consideration of the purchase of Energy Efficiency as Alternative Resource ("EEAR") for the ComEd portfolio. The purpose of this is twofold – first, to establish whether energy efficiency can be cost competitive with more traditional resources; and second, to establish additional benefits such as price stability can be gained through the expansion in the type of resource products placed into the ComEd portfolio.

The IPA believes that the appropriate sources for EEAR bids would be programs that are evaluated in a manner equivalent to the existing Energy Efficiency Portfolio Standard ("EEPS") programs offered to eligible retail customers in the ComEd service region. The IPA notes that the results of the EEPS programs have been factored into the ComEd load forecasts in a manner similar to that of other pre-existing supply contracts for the past two cycles. Additionally, the EEPS programs are in their third year of operation and operate under an evaluation and oversight regime supervised by the ICC. These two factors lead the IPA to determine that resources provided by the EEPS are reliable.

Similarly, energy efficiency resources that can show that they are evaluated in a manner equivalent to the EEPS programs, and are, consequently, equally reliable, are an appropriate source for EEAR bids. The IPA will also limit its procurement of Utility-administered resources to those resources that are not required to meet the Energy Efficiency Portfolio Standards.

The IPA proposes that EEAR assets should only be procured when the cost of the EEAR is less than the combined cost of the energy swaps, capacity, and renewable energy resource contracts held by ComEd for the contract period offered by the EEAR provider. As such, the EEAR contracts should be considered after the spring 2011 procurement events. Contracts would be secured through direct negotiation between the IPA and ComEd subject to oversight and authorization by the ICC. If EEAR assets are not cost competitive, then no contracts shall be executed. In order to assure valid results in an EEAR procurement, the IPA recommends holding workshops during the fall of 2010 to establish the scope and nature of the EEAR event with the input of interested parties.

Additional elements to the supply resources plan include:

Load Balancing Procedures. Upon Commission approval of the Final Plan, 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. Again, the IPA will work with ComEd, the Commission and procurement administrator to determine the appropriateness of rebalancing the portfolio.

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.

> **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 procurement 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.

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 ten (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 ninety (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.

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.

Incremental Procurement Events. The IPA proposes that optional incremental procurements of up to an additional 10% of projected portfolio requirements be allowed under certain circumstances. First, the incremental procurements could seek to secure volumes for only those months that have not achieved a full 100% subscription level. Second, the optional procurements would be triggered only when market indices demonstrate that prices for energy supply contracts for the targets months are below the average weighted price of fixed price contracts already secured by the Utilities for those months. Third, the optional procurements would be limited to participation by bidders qualified in and operate only under the terms and conditions agreed to in the spring 2011 solicitation. Lastly, such procurement events would only occur, and the results accepted only with the authorization of the Commission.

2. **ComEd Capacity Resources.** 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 2011 - May 2014 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.

From time to time, PJM may determine that the amount of capacity it procured three years prior to the delivery year exceeds the amount actually needed in the delivery year when adjusted for updated load forecasts. In such cases, PJM may return excess capacity credits to the utility. These credits represent MW units of capacity and are not in the form of cash or cash equivalents. While these credits cannot be used to offset capacity payments to PJM, they can be used by the utility to offset shortfalls in capacity the utility previously bid and which cleared in the applicable RPM auction or they can be sold to a third party. To the extent practicable, the IPA proposes that ComEd attempt to sell any excess capacity credits it does not need and return any corresponding proceeds to customers. PJM has a bulletin board where such excess capacity credits can be made available for sale.

The IPA's procurement administrator will issue solicitations to lock-in fixed prices for fixed quantities of required capacity resources, using single-month, multi-month, and/or annual contracts during the period between June 2011 and May 2014, in whatever combinations are deemed appropriate by the procurement administrator, given the objectives described in this plan.

3. **ComEd Demand Response Resources.** Section 220 ILCS 5/16-111.5(b)(3)(ii).of the IPA Act requires the Plan to include:

> *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:*
>
> *(F) Be procured by a demand-response provider from eligible retail customers*
> *(G) 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*
> *(H) Provide for customers' participation in the stream of benefits produced by the demand-response products;*
> *(I) 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*
> *(J) Meet the same credit requirements as apply to suppliers of capacity, in the applicable regional transmission market.*[25]

The IPA recommends meeting the statutory obligation of procuring demand response as a free-standing obligation and not related to the replacement of Capacity Resources. The IPA proposes that the following characteristics be considered in securing these required demand response resources:

- **Product.** The IPA recommends procuring Demand Response assets that meet the statute's definitions and are registered as qualifying capacity resources in the PJM RPM Auction.
- **Timing.** The IPA recommends that Demand Response assets be solicited as a separate procurement activity in the spring of 2011.
- **Volumes.** Consistent with statute, the IPA recommends that Demand Response Resources be procured to the extent that they meet the cost effectiveness and source requirements.
- **Term.** The IPA recommends that Demand Response Resources be secured for contract

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

durations of between five and ten years.

4. ComEd Renewable Energy Resources. 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, tree waste, 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]

ComEd shall meet the renewable energy resource portfolio standard for the Plan year through the acquisition of qualifying renewable energy credits ("RECs") as defined in Section 1-10 of the IPA Act. The acquisition of RECs for this period meets the requirements of the IPA Act and is preferable to the direct acquisition of energy from qualifying renewable resources at this time. As the above-quoted definition makes clear, only landfill gas produced in Illinois qualifies as a renewable energy resource for purposes of this procurement of RECs.

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.

As note, 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 in excess of existing contract amounts would be limited or curtailed, leaving the annual volumetric goal unmet. Table T below cites the volume goals and cost limits.

TABLE T: RPS STANDARDS FOR COMED

Delivery period	Minimum Percentage (Annual volume goal)	Maximum Cost Standard
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

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

2015-2016	10% of June 1, 2013 through May 31, 2014 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 U 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 U: ANNUAL COMED RPS VOLUME TARGETS

ComEd 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	39,802,463	2.00%	796,049
2009-2010	2007-2008	39,109,145	4.00%	1,564,366
2010-2011	2008-2009	37,740,282	5.00%	1,887,014
2011-2012	2009-2010	35,284,241	6.00%	2,117,054

Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables V and W 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, 2010-2011, and 2011-2012.

TABLE V: 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	2011-2012
(B) Reference Year	2006-2007	2007-2008	2008-2009	2009-2010
(C) Reference Year Delivered Volume (MWh)	39,802,463	39,109,145	37,740,282	35,284,241
(D) Reference Year Delivered Cost	$3,736,750,000	$4,205,233,624	$4,462,038,949	$3,952,018,105
(E) Reference Year Unit Cost - [D / C]	$93.88	$107.53	$118.23	$112.01
(F) Planning Year Incremental RPS Cost Limit %	0.50%	0.50%	0.50%	0.50%
(G) Planning Year Incremental RPS Cost Limit Unit Price - [F * D]	$0.4694	$0.5376	$0.5912	$0.5600
(H) Planning Year Net RPS Cost Limit Unit Price	$0.4694	$1.0070	$1.5982	$2.1582
(I) Planning Year Projected Total Delivery Volume	39,837,081	39,422,473	36,095,906	35,759,281
(J) Planning Year Option A Cost Cap [I * H]	**$18,700,000**	**$39,700,000**	**$57,688,135**	**$77,176,270**

TABLE W: 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	2011-2012
(B) Reference Year	**2006-2007**			
(C) Reference Year Delivered Volume (MWh)	**39,802,463**			
(D) Reference Year Delivered Cost	**$3,736,750,000**			
(E) Reference Year Unit Cost ($/MWh) - [D / C]	**$93.88**			
(F) Planning Year Incremental RPS Cost Limit %	0.50%	1.00%	1.50%	2.00%
(G) Planning Year Net RPS Cost Limit Unit Price - [F * D]	$0.4694	$0.9388	$1.4082	$1.8776
(H) Planning Year Projected Total Delivery Volume	39,837,081	39,422,473	36,095,906	35,759,281
(I) Planning Year Option A Cost Cap [H * G]	**$18,700,000**	**$37,010,756**	**$50,831,544**	**$67,143,329**

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

TABLE X: COMED RPS TARGETS for 2011-2012

ComEd Renewable Portfolio Standard (RPS) Metrics (2011-2012)	
RPS Volume Target (MWh)	2,117,054
Renewable Energy Resource Budget (RRB)	$77,176,270
Average Price per Renewable Unit	$36.45
Estimated Customers Covered by RRB	3,742,263
Estimated Annual RPS Cost/Consumer	$20.62

The Procurement Administrator shall seek to acquire the Target amount of RECs, but no more without exceeding the RRB.

Additional aspects of the proposed Renewable Energy Resources procurement are noted below:

- **Pricing Benchmark.** The Procurement Administrator is directed to continue to establish benchmark REC prices (as in the 2009 and 2010 Plans), 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 beginning June 1, 2011 cost effective renewable energy resources be procured first from facilities in the State of Illinois or from facilities located in states adjacent to Illinois, and then from facilities located elsewhere.

- **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"), the Midwest Renewable Energy Tracking System ("M-RETS") and the North American Renewables Registry ("NAR") 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, for generators located in South and North Dakota, Minnesota, Wisconsin, Iowa, Illinois and Ohio. NAR tracks renewable energy generation from facilities typically outside of the M-RETS and PJM footprints.

  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. **ComEd Transmission Resources.** In addition to the acquisition of power and energy related products as detailed above, ComEd is obligated by the PJM Tariff to acquire certain transmission service related products and services to effectuate delivery of power and energy to the applicable loads including Ancillary Services. Further, ComEd may be allocated certain Financial Transmission/Auction Revenue Rights

- **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. PJM operates an Ancillary Services market to provide regulation service and operating reserve service (both spinning and supplemental) reserves. ComEd will secure these required services through the PJM 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 ComEd generally serves to reduce the cost of congestion borne by ComEd (and, thus, ultimately by their customers). As part of the 2010-11 ARR allocation process at PJM, ComEd received a set of ARR entitlements and was awarded ARRs for that 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.