State of Illinois
Pat Quinn, Governor

ILLINOIS
POWER AGENCY

Draft 2012 Power Procurement Plan

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1.0 Executive Summary

Pursuant to Public Act 095-0481[1] ("IPA Act"), the Illinois Power Agency ("IPA" of "Agency") submits this draft electricity procurement plan (the "Draft Plan") to the public for comment. Comments can be submitted to the IPA by the following:

- E-mail at: mark.pruitt@illinois.gov and JOost@KelleyDrye.com
- In writing at: 160 North LaSalle Street, Chicago, Illinois 60601
- In Person: at open public meetings to be scheduled and announced at www.illinois.gov/ipa

This document and its attachments comprise the fourth Draft Plan prepared by the IPA. The IPA Act requires that a Draft Plan and subsequent Final Plan be prepared annually. The procurement methods and specifications recommended in this Draft Plan are designed to fulfill the requirements of the Act to "ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time…"[2]

The annual Draft Plan's purpose is to detail procurement approaches that will secure electricity commodity and associated transmission services, plus required renewable energy assets to meet the supply needs and obligations of the eligible retail customers served by Ameren Illinois Utilities ("Ameren") and Commonwealth Edison Company ("ComEd" and jointly the "Utilities"). Public comments and recommendations on the proposals contained in the Draft Plan are sought, and will be considered prior to the submittal of a Final Plan to the Illinois Commerce Commission.

This Draft Plan outlines a procurement strategy for the period of June 2012 through May 2017 based on detailed 5-year supply forecast requirements provided by the Utilities (see Attachments A and B). Because existing contracts are in place to satisfy a portion of the consumer load requirements, procurement activities considered in this Draft Plan are limited to meeting the residual consumer demand not covered by those contracts.

The Draft Plan presents the following core procurement elements:

- **Request for Proposals.** The procurement events are organized around a two-stage process governed by a Request for Proposal ("RFP") for each wholesale product sought. The first stage of each RFP will establish a pool of qualified bidders; the second stage will solicit price bids for scheduled volumes of wholesale product.
- **Price and Volume solicitations.** The RFPs will request bids for fixed price and fixed volume contract offers.
- **Schedule.** The IPA proposes to hold the procurement events during the early spring of 2012 to secure the volumes of wholesale products identified in this Plan.
- **Procurement Administrators.** The IPA proposes to extend the contracts of the current procurement administrators: National Economic Research Associates (to administer the ComEd solicitations), and Levitan and Associates (to administer the Ameren solicitations).
- **Products.** The IPA proposes to seek bids for wholesale products:
  - **Energy Supply Resources –** Supply will be sought for the Ameren and ComEd loads on a laddered three-year forward basis in volumes described in this Draft Plan.
  - **Capacity Resources –** Capacity Resources for ComEd will be delivered primarily 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 solictiations seeking cost-effective demand response assets occur for both utilities. For ComEd, demand response capacity provided by eligible ComEd residential and small business customers will be procured through a separate RFP process. For Ameren, the IPA will allow demand response capacity to bid in response to the RFP for capacity resources. The RFP for Ameren capacity will be designed to acquire sufficient cost-effective demand response resources to reduce Ameren's peak demand for Eligible Retail Customers by 0.1% per year over the prior year, as required by Section 8-103(c) of the Public Utilities Act. (220 ILCS 5/8-103(c)).
  - **Renewable Energy Resources** – Renewable Energy Credits ("REC") for multiple compliance years will be sought. Due to potential customer migration and the structure of the Long-Term Power Purchase Agreements for renewable energy in effect for the 2012-2013 through 2032-2033 compliance periods, specific annual Renewable Resource Budgets are variable. The proposed process will establish a confidential budget threshold for a 12 year budget horizon, and utilize those budgets to structure REC

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

contracts consistent with the solar and wind carve-outs specified in the Renewable Portfolio Standard. IPA will seek to establish common REC contract terms including (1) collateral requirements that equal 10% of remaining contract value; and (2) unsecured credit limits for creditworthy REC suppliers, unless an alternative proposal is acceptable to the procurement administrators, the utilities, the IPA, Commission Staff and the procurement monitor.
  - **Clean Coal Resources –** Federal incentives to support the repowering of an existing power plant in Illinois as a Clean Coal Generation facility are available. The IPA proposes to solicit proposals from developers of such a plant to meet the state Clean Coal Portfolio Standard.
- **Public comment and workshops.** The IPA will hold public meetings seeking comment on the Plan.

2.0 Introduction and Overview

The Illinois Power Agency ("IPA") is required by statute to meet the electricity supply needs of the bundled rate customers of Commonwealth Edison ("ComEd") and the Ameren Illinois Company ("Ameren"). It does so by developing and implementing electricity procurement plans designed to "ensure adequate, reliable, affordable, efficient and environmentally sustainable" electric service at the "total lowest cost over time,"[3] while taking into account "any benefits of price stability."[4] In the 2011-2012 planning year, the IPA portfolios will supply approximately 40 million MWH to almost 4.5 million "eligible customers" of ComEd and Ameren.[5]

Illinois is in transition from an industry dominated by vertically integrated public utilities to one that relies on deregulated generation and wholesale commodity markets. To optimize portfolio design, the IPA must closely monitor wholesale electricity markets, particularly the PJM Interconnection ("PJM"), in which ComEd participates, and the Midwest Independent System Transmission Operator ("MISO"), in which Ameren participates.[6] In addition, the IPA must also closely monitor the retail markets in Illinois to understand the scale and scope of its tasks. The dynamic nature of these unique and evolving wholesale and retail markets poses challenges to efficient and effective procurement planning.

2.1 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.

SB 1592[7] 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

[3] 20 ILCS 3855/1-5.

[4] *Id*.

[5] "Eligible customers" are defined by law as those retail customers that purchase power and energy from the electric utility under fixed-price bundled service tariffs. 220 ILCS 5/16-111.5(a). These are customers that take both delivery and supply service from their electric utility.

[6] PJM interconnection coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia, including the ComEd service territory. MISO coordinates the movement of wholesale electricity in all or parts of 11 Midwestern states, including the Ameren service territory.

[7] Public Act 095-0481

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 current 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.

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

- The Office of Retail Market Development (ORMD) within the Illinois Commerce Commission continues to pursue its mission 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 Obligations of Retail Electric suppliers and Internet Enrollment
    - Renewable Portfolio and Clean Coal Standards for Alternative Retail Electric Suppliers and Utilities operating outside of their service areas.
    - Development of an online "Price to Compare" service of Illinois Consumers to research retail price offers from Alternative Retail Electric Suppliers operating in the Ameren and Commonwealth Edison region at http://www.pluginillinois.org/fixedrate.aspx

- Local communities are moving forward with Municipal Aggregation plans. Municipal Aggregation occurs when local communities select an Alternative Retail Electric Supplier for the eligible retail customers that reside within their municipal boundaries. The following communities have taken direct steps to establish their own aggregations:

TABLE A: CURRENT STATUS OF MUNICIPAL AGGREGATION IN ILLINOIS

Community	Status
Compton Hills	Referendum Passed
Crest Hill	Supplier - Direct Energy, Rate - 5.89 cents per kWh through September 2013
Elburn	Supplier - Direct Energy, Rate - 5.99 cents per kWh through October 2012
Erie	Supplier - Nordic Energy Services, Term - 3 years
Fox River Grove	Supplier - Direct Energy, Rate - 5.99 cents per kWh through September 2013
Fulton	Supplier - FirstEnergy Solutions, Rate - 6.23 cents per kWh (residential) through July 2014
Glenwood	Supplier - Direct Energy, Rate - 5.99 cents per kWh through September 2013
Grayslake	Referendum Passed
Harvard	Supplier - Direct Energy
Lincolnwood	Referendum Passed
Milledgeville	Supplier -FirstEnergy Solutions, Rate - 5.90 cents per kWh, Term - 3 years
Morris	Referendum Passed
Mount Morris	Referendum Passed
New Lenox	Supplier -Direct Energy, Rate - 5.89 cents per kWh through September 2013
North Aurora	Supplier -Integrys, Rate 5.75 cents per kWh (residential), Term - 2 years
Oak Brook	Referendum Passed
Oak Park	Referendum Passed
Polo	Referendum Passed
Sugar Grove	Supplier -Direct Energy, Rate - 5.99 cents per kWh through September 2013
Wood Dale	Referendum Passed

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 supporting competitive electricity markets will continue and strengthen, and that a portion of the eligible retail consumers currently served through the IPA portfolio will migrate towards ARES options.

2.2 Procurement Approach.

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:

(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.[8]

This is the fourth Draft Plan submitted by the IPA in accordance with the Section 16-111.5 of PUA. This Draft Plan considers the procurement strategy for the period of June 2012 through May 2017. 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 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[9]

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

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

8 20 ILCS 3855/1-20.
9 220 ILCS 5/16-111.5(b).

(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 requirement 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[10].

This Draft Plan meets the requirements of the IPA Act.

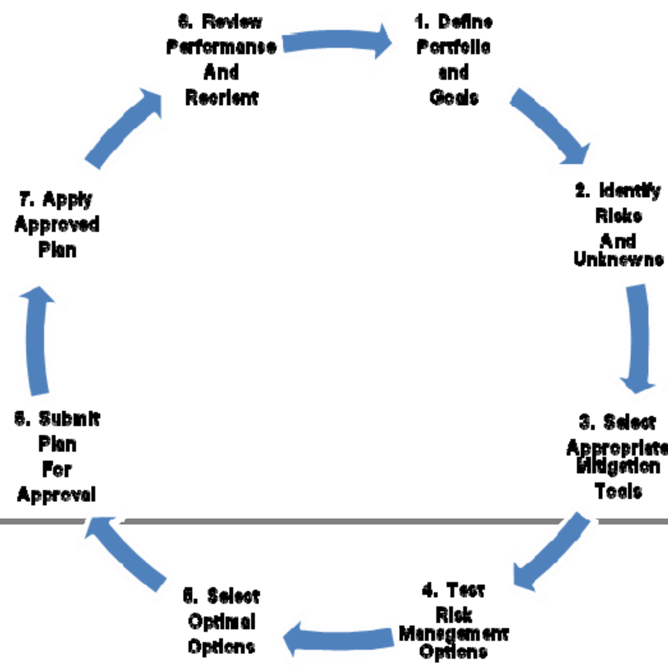
2.3 Planning Process. This Draft Plan proposes to secure pricing and supplies of electricity commodities, and required transmission services to meet the supply requirements for Eligible Retail Customers of Ameren and ComEd. Additionally, it proposes a plan to meet the Illinois Renewable Portfolio Standard ("RPS") for those same Eligible Retail Customers. This Draft Plan also addresses RPS compliance methods for hourly rate customers of the Utilities.

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.[11]

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

FIGURE 1: IPA PROCUREMENT PLANNING PROCESS



[10] 220 ILCS 5/16-111.5(b).

[11] 220 ILCS 5/16-111.5(a).

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 the 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 Plans are reoriented to address current market conditions, new risks and opportunities.

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

TABLE B: PROPOSED IPA PLAN SUBMISSION AND AUTHORIZATION SCHEDULE

Planning Activities	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
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. The Ameren five-year projections were received by the IPA on July 15, 2011, and the ComEd five-year projections were received by the IPA on July 13, 2011.
2. **IPA Prepares Draft Plan.** The IPA prepared this Draft Plan for publication on the IPA website at www.illinois.gov/ipa for the purposes of alerting the public of the procurement methods the IPA is considering prior to formal submittal to the Illinois Commerce Commission.
3. **IPA Submits Preliminary Plan.** The Preliminary Plan will be made available to the public for comment on the ICC and IPA websites on August 15, 2011.
4. **Public Comment Period.** The Preliminary Plan is made available to the public for comment. As required by the PUA, during the 30-day period allowed for utilities and other interested entities to submit comments on the IPA's draft plan, the IPA will hold two public hearings for the purpose of receiving public comment on the procurement plan.

a. In Chicago at the IPA's offices at 160 N. LaSalle Street. A specific date and time for the proceeding will be published on the IPA website at www.illinois.gov/ipa.

b. In Springfield at a location yet to be determined. A specific date and time for the proceeding will be published on the IPA website at www.illinois.gov/ipa.

5. **Final Plan Submission to ICC.** A Final Plan will be prepared by the IPA in consideration of the comments received during the public comment period and filed with the Illinois Commerce Commission on September 28, 2011.
6. **Objections Filing Period.** Objections to the Plan must be filed within five (5) days after the plan is filed.
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 C below.

TABLE C: PROPOSED IPA PROCUREMENT EXECUTION SCHEDULE

Procurement Activities	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
1. Procurement Administrator contracts renewed	X								
2. RFP and systems developed									
3. RFP Released					X				
4. Procurement Event Preparation									
5. Procurement Events									
6. Supply Contracts Executed									
7. Procured Products Delivery Begins									

1. **Procurement Administrator contract renewed.** 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 IPA Act allows the IPA to retain the services of procurement administrators under one-year contracts with a single one-year extension option. The IPA retained the services of National Economic Research Associates and Levitan and Associates in spring 2011. The IPA intends to execute one-year extensions on those contracts in October 2011.
2. **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.[12]
3. **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.
4. **Procurement Event Preparation.** The Procurement Administrator will be required to establish methods and platforms to facilitate bidding on defined electricity products. The Procurement Administrator also will be required to facilitate capacity procurement as well as the purchase of renewable energy requirements as specified in the approved Plan.
5. **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.
6. **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.

[12] 220 ILCS 5/16-111.5(e).

2.4 Portfolio Design.

2.4 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 to be purchased 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."*[13]

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 elevating 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.

After completing its portfolio design exercise, the IPA proposes the schedule of purchases of wholesale products to meet the needs of eligible customers.

2.3.1 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."*[14]

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

2.3.1.1 Price Risk.

All elements of the portfolio are exposed to price risk on two primary 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.

2.3.1.2 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

[13] 220 ILCS 5/16-111.5(d)(4).
[14] 220 ILCS 5/16-111.5(b)(3)(v).

suppliers over time. As noted in the above, 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 only recently taken hold in the broader Residential market in Illinois. However, recent developments indicate that significant reductions to the barriers to retail competition in residential markets are on the near-term horizon.

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 current 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.

2.3.1.3 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 2011 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.

2.3.1.4 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 several 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 and 2011 procurement processes, revised load projections from the Utilities were submitted in response to downward projections in load requirements due to economic weakness within the region.

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.

2.3.1.5 Fuel Costs. Fuel costs present risk to the portfolio insofar as fuel costs are a 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. Fortunately for consumers, natural gas prices have been low and subdued over the past few years, resulting in lower marginal (and thereby futures) prices for electricity. Part of the natural gas equation is the development of natural gas fracking methods. Potential regulation of the process may change the price dynamic for natural gas, and thereby electricity within the region.

In September of 2010, EPA took the first step in regulating natural gas hydraulic fracturing ("fracking") by issuing a voluntary information request to fracking firms which requested disclosure of chemicals used in the fracking process.[15] Although compliance is voluntary, EPA expects to use any information provided in their ongoing effort to study fracking by publishing a comprehensive study by "late 2012."[16]

Generally, EPA has authority under the Safe Drinking Water Act ("SDWA") to protect underground drinking wells, however, the Energy Policy Act of 2005 specifically exempted "the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operation related to oil, gas, or geothermal production activities" from regulation.[17] The proposed "Fracturing Responsibility and Awareness of Chemicals Act of 2011" attempts to remove this exemption, but it is currently receiving Committee attention in the House of Representatives.[18]

Meanwhile, some states have attempted to limit the location of fracking operations through zoning regulations.[19] However, state regulation of the ability of fracking operations to use undisclosed chemicals is specifically preempted by the SDWA.[20] Therefore, permits to start and maintain fracking operations continue to be approved by state regulators.

If fracking operations continue without additional regulation that adds cost to fuel extraction, such operations would tend to put downward pressure on the price of electricity, by increasing the supply of natural gas.[21] Any stricter federal or state regulations will likely increase the price of electricity by adding costs to natural gas production. Although hydraulic fracturing operations are not a major source of natural gas supply in Illinois, the nation-wide regulation of those operations will likely affect the price for natural gas supply in Illinois. The IPA should monitor the regulatory approach to fracking and anticipate an increase in natural gas costs if the EPA or other states increase regulation of fracking operations.

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.

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[15] EPA, Letter to Fracking Industry (accessed May 10, 2011 at http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/HFvoluntaryinformationrequest.pdf).

[16] See http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm.

[17] Pub. L. 109-58, title III, Sec. 322, 119 Stat. 694 (Aug. 8, 2005).

[18] http://www.gpo.gov/fdsys/pkg/BILLS-111s1215is/pdf/BILLS-111s1215is.pdf.

[19] *Huntley & Huntley, Inc. v. Borough Council of Oakmont*, 964 A.2d 855, 865-69 (Pa. 2009).

[20] Hannah Wiseman, *Trade Secrets, Disclosure, and Dissent in a Fracturing Energy Revolution*, 111 Colum. L. Rev. Sidebar 1 (Jan. 27, 2011).

[21] There is some debate over the economics of fracking. Current production is less than originally expected and some argue that true economic fracking potential is much more limited than what is currently predicted.

2.3.1.6 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.

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.

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.

2.3.1.7 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, tariff rules, and the potential for cost sharing on super-regional transmission lines.

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.

Midwest ISO Proposal for Pre-Certification of Transmission Paths for Export Transactions. On September 22, 2010 MISO filed proposed tariff revisions with FERC that provide an additional study option for firm "point-to-point" transmission service, to facilitate the export of generation from MISO to an external border.[22] According to MISO, the proposal was in response to stakeholder comments advocating enhanced ability to export excess generation from the MISO footprint in transactions that cross MISO's borders.[23] In MISO's view, making additional transmission services studies available to generators will promote the use of existing generation that might otherwise be mothballed or retired, because there would be less delay and uncertainty for exporting customers in negotiating multiple, individual transactions.[24] Ameren, which intervened in the FERC proceeding to ask for more detail from MISO, contended that development of a cross-border deliverability agreement, or a common/joint capacity market, would be necessary to better facilitate cross-border transactions.[25] Pointing to statements from MISO that lack of a common market mechanism interferes with the sale of MISO capacity into other markets, Ameren argued that FERC should direct MISO to better align its proposed studies, including its deliverability study periods, with the capacity planning years in MISO and adjoining markets.[26]

FERC conditionally agreed to accept MISO's proposal, but agreed with Ameren and others that more detail was needed in MISO's tariffs.[27] The Commission agreed that facilitating export transactions to the MISO border will provide benefits to market participants, but rejected Ameren's notion of a joint market agreement between PJM and MISO if any changes to the existing Joint Operating Agreement between the two RTOs were needed.[28] MISO was further directed to adjust its proposed annual review to ensure that generators

[22] *In Re Midwest Independent Transmission System Operator, Inc.*, FERC Docket No. ER10-2869-000, Order Feb. 17, 2011 ("Export Transmission Order").

[23] Export Transmission Order at 2.

[24] *Id.* at 2-3.

[25] *Id.* at 4.

[26] *Id.* at 5.

[27] *Id.* at 10.

[28] *Id.* at 11.

seeking to export will have an accurate assessment of the amount of capacity available on pre-certified paths, to avoid overselling transmission service.[29]

Changes in transmission pathways for excess generation will affect not only transmission planning, and supply/capacity prices, but will affect generation investment in the MISO region.

While this proposal does not impact any existing variable directly, it could impact the prices of generation across the seam that exists between PJM and MISO, the economics of cross-border prices, and possibly prices within the RTOs. These effects could affect the prices that the IPA pays for power and energy. The effects will need to be monitored closely, as the true impact is likely directly related to the criteria developed for final implementation.

Midwest Independent Transmission System Operator, Inc. Resource Adequacy Construct. Over the past several years MISO has undertaken a "resource adequacy planning" process to examine the ways in which it ensures that adequate electricity resources are available for use at all times on the MISO system. Beginning in 2009, MISO has used the threat of financial penalties on load serving entities ("LSEs") who do not demonstrate to MISO that they have procured adequate resources based on an annual Loss of Load Expectations ("LOLE") study.[30] The resulting resource adequacy requirement is expressed as a "Planning Reserve Margin" ("PRM") in excess of the forecasted system coincident peak. Each year LSEs submit an annual resource plan that specifies what planning resource credits ("PRCs") will be used to meet the reserve margin for any given month. Planning resources generally fall into two categories: capacity resources (such as internal and external generation and demand response resources) and load modifying resources (such as demand resources that respond to prices and behind-the-meter-generation). Demand response resources are dispatched on the supply side of the market like generators; load modifying resources are allowed to participate as price-responsive demand and would be treated on the demand side of the market.[31]

In 2009, FERC examined MISO's long-term resource adequacy plan, and in February 2009 FERC required MISO to develop a permanent approach to address congestion that limits aggregate deliverability and to examine whether a locational capacity requirement would be needed to ensure reliability.[32] The Commission ordered MISO to evaluate a locational capacity approach to addressing the deliverability issue, like those used in PJM, ISO New England and the California Independent System Operator.[33] Over the course of 2009, MISO met with stakeholders, who could not agree on the best approach to resolving the issue, and who, in MISO's opinion, did not offer much support for adopting the local capacity requirements used by other regional transmission operators.[34] MISO concluded that its existing tariffs were sufficient to address any congestion issues that might limit deliverability, and filed its conclusions before FERC. MISO also concluded that its system-wide planning reserve margin approach was sufficient to maintain reliability, based on MISO's loss of load expectations ("LOLE") studies.[35] Several generators intervened to contest MISO's conclusions. Among them was Ameren, which requested a substantive explanation and information on how MISO would provide sufficient data concerning congestion and import-constrained zones within the MISO footprint to enable market participants to provide solutions to aggregate deliverability problems.[36] MISO responded to such concerns by noting its planning process shows no upcoming issues related to the delivery of planning resources through 2018.[37] MISO further maintained that locational capacity requirements are not appropriate for the MISO area and would only add uncertainty while not improving reliability.[38] Any approach based on locational capacity, MISO argued, would be inconsistent with the "energy-only resource adequacy" construct MISO had previously adopted.[39]

[29] *Id.*

[30] "Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements," The Brattle Group, January 19, 2010.

[31] *Id.* at 19.

[32] *In Re Midwest Independent Transmission System Operator, Inc*., Order on Compliance Filing ("Compliance Filing Order") FERC Docket ER08-394-024, June 8, 2010.

[33] Compliance Filing Order at 2.

[34] *Id.* at 3.

[35] *Id.*

[36] *Id.* at 4.

[37] *Id.* at 6.

[38] *Id.*

[39] *Id.*

FERC, however, concluded differently. MISO's compliance filing was rejected, because it did not identify a permanent approach to address congestion that limits deliverability in the resource adequacy markets.[40] FERC had expected MISO to use as a starting point the market mechanisms utilized by other RTOs – mechanisms such as locational pricing and locational market rules that provide incentives for market participants to obtain sufficient local resources to secure reliability.[41] The Commission determined that the existing LOLE and other study processes were not sufficient, and that for MISO and its stakeholders to fail to develop market mechanisms that address locational resource adequacy simply because "market participants desire a more convenient auction tool" than approaches used by other RTOs would sacrifice long-term locational reliability.[42] The Commission directed MISO to develop a plan that allows auction planning credits and locational market mechanisms, which would coexist in MISO's resource adequacy plan.[43]

As a result, over the past two years, MISO has begun moving towards a forward capacity market, akin to structures in place in PJM and other eastern regional transmission organizations, to satisfy requirements imposed by FERC related to locational resource adequacy and reliability. The key components of MISO's approach are similar to centralized resource planning,[44] including:

- Establishing system planning reserve requirements with zonal definitions based on planning studies;
- Using annual coincident peak demand forecasts from LSEs and electric distribution companies;
- Qualifying planning resources on a five-year forward basis; and
- Recognizing those resources approved by state integrated resource planning resources.

Energy efficiency and price responsive demand are being pursued in parallel with this planning effort, and will be included as planning resources when measurement and verification details have been determined.[45]

MISO proposes to establish seven local resource zones, with capacity requirements met with planning resources located within each zone or from outside the zone if transmission capacity is sufficient. Within each zone, local clearing requirements will be put in place, along with capacity import and export limits, which will be established for each zone. LSEs will meet those requirements through participation in the annual Planning Resource Auction." The auction will use a declining price auction procedure to determine capacity clearing prices for each local zone and to establish competitive capacity prices, which will settle on a daily basis.[46]

MISO has integrated demand resources that operate as supplemental capacity on peak days into its planning. Demand resources, demand response resources and behind-the-meter generation contributed more than 8500 MW of unforced capacity during the peak month of June 2008 – making up 6.8% of all planning resources.[47] This would put MISO on a par with other RTOs who integrate demand response and energy efficiency into their supply or capacity markets. For example, for the 2012/2013 planning year, demand response and energy efficiency represented 5.9% of the total committed resources in PJM and 7.8% in ISO New England; the share of capacity from the demand side in NY ISO was 6.4% for the summer of 2009.

If MISO does establish a working capacity market, the resulting financial incentives to invest in demand response resources should create new products and increasing amounts of demand response activities aimed at lowering peak demand.

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[40] *Id.* at 7.

[41] *Id.*, noting that if MISO had believed its existing tariffs were sufficient to address any congestion issues, MISO could have – and should have – requested rehearing of that Commission order.

[42] Compliance Filing Order at 8.

[43] *Id.*; FERC clarified in an order on April 27, 2011 that MISO should evaluate locational capacity approaches along with any other approaches, to address the aggregate deliverability issue in the MISO footprint.

[44] "Midwest ISO Resource Adequacy Enhancements Proposal," Todd P. Hillman, Supply Adequacy Working Group, December 9, 2010.

[45] "Midwest ISO Resource Adequacy Proposal for 2013/2014 Planning Year," Supply Adequacy Working Group, February 17, 2011.

[4646] MISO has noted that an open issue in its planning process is the creation of hedging mechanisms for new capacity positions with firm transmission service. Feb. 17, 2011 presentation at 16.

[47] Energy efficiency is not included in the supply side for MISO, as it has been in forward capacity markets such as PJM and ISO New England. Brattle Report at 27. Both systems count energy efficiency as a supply resource for two reasons – first, doing so allows third-party providers of energy efficiency services to capture the peak-reducing value of their projects. Second, it ensures the peak-reducing value of the measure is recognized in a timely manner, rather than waiting to observe the effects on load, then incorporating the effects in the following forward auction for delivery three years later. There is no threat of such lags in MISO, where the resource adequacy requirement is months, not years, ahead.

Midwest ISO Proposal for Dispatchable Intermittent Resources. In February, 2011, FERC approved a proposal by MISO to create a new category of resources, Dispatchable Intermittent Resources ("DIRs"), which would be treated similarly to other generation resources in MISO's real-time energy market.[48] The goal of MISO's proposal was to utilize the capability of some variable resources to respond to instructions to reduce output to address market and operational inefficiencies caused by the manual curtailment of intermittent resources, in turn increasing the participation of variable resources in the MISO markets.[49] The proposal would take effect after a two-year transition period, at which time qualified resources would set market prices and receive real-time credits based upon the maximum megawatt levels the resources could provide for each five-minute interval in the real-time energy market.[50] FERC conditionally accepted MISO's proposal to improve market efficiency and reliability.[51] However, FERC limited the scope of the proposal to wind resources only and further limited the ability of resources to switch between status as Intermittent Resources or DIRs.[52] Resources qualified as DIRs will be subject to excessive/deficient energy deployment charges since these charges would provide an incentive for updating the forecasted loads as accurately and as often as possible.[53] Finally, among other tariff changes, MISO was directed to file at FERC a study of whether DIRs should be eligible to provide supplemental spinning and/or regulating reserves.[54]

This proposal could encourage investment in renewable resources. It will need to be monitored closely, as its true value is directly related to the criteria developed for final implementation.

Issuance of Final Rule on Demand Response (DR) Compensation. In response to Congressional directives to "encourage DR and to remove barriers to the participation of DR in energy markets,"[55] FERC has issued new rules regarding compensation for demand response resources to "ensure that rates are just and reasonable in the organized wholesale energy markets."[56] On March 18, 2010 FERC proposed a rule that would require Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") to pay the "Locational Marginal Price" ("LMP") for particular types of energy that respond to demand changes.[57] After a year-long comment period, FERC issued the final DR rule on March 15, 2011.[58] The rule is intended to improve the functioning and competitiveness of the organized wholesale energy market, either through a reduction in customer demand (as demand responds to high prices for peak loads) or by providing demand response as a resource in organized wholesale energy markets, to balance supply and demand.[59]

Under the new rules, ISOs and RTOs have to pay demand response resources the full LMP for energy that: (1) "has the capability to balance supply and demand as an alternative to a generation resource;" and (2) "is cost-effective as determined by the net benefits test."[60]

The net benefits test mandated by the second criterion for full LMP payment ensures that "the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources."[61] In connection with this new net benefits test, FERC directs RTOs and ISOs to "develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective."[62] While RTOs and ISOs are permitted to

[48] *In Re Midwest Independent Transmission System Operator, Inc.*, FERC Docket No. ER11-1991-000, Order Feb. 28, 2011 ("Dispatchable Intermittent Resources Order").

[49] Dispatchable Intermittent Resources Order at 2.

[50] *Id.* at 3, 5.

[51] *Id.* at 5.

[52] *Id.*

[53] *Id.* at 32.

[54] *Id.* at 42.

[55] Energy Policy Act of 2005 § 1252(f).

[56] DR Rule at 3.

[57] *Demand Response Compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, FERC Stat. & Regs. ¶ 32,656 (2010) ("NOPR").

[58] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011) ("DR Rule").

[59] *Id.* at 7.

[60] *Id.* at 2.

[61] *Id.* at 3-4.

[62] *Id.* at 4.

show how their existing practices are consistent with the net benefits criterion, any mechanism must ensure that "the monthly threshold price corresponding to the point along the supply stack beyond which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources."[63]

All tariff changes required to implement the new rule must be made on or before July 22, 2011.[64] Each RTO's or ISO's compliance filing will become effective after FERC issues an order addressing that filing.[65] Each RTO and ISO is required to file a study with FERC on or before September 21, 2012 "examining the requirements for and impacts of implementing a dynamic approach which incorporates the billing unit effect in the dispatch algorithm to determine when paying demand response resources at the LMP results in net benefits to customers in both the day-ahead and real-time energy markets."[66]

FERC anticipates that the DR Rule will provide more just and reasonable energy prices, because RTOs and ISOs can better balance supply and demand by reducing dispatch of higher-priced resources that satisfy loads for which customers can curtail demand.[67] If more demand is responsive to higher market prices, the greater competition to provide those loads is predicted to place "downward pressure … on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high."[68] Finally, FERC's rule should support system reliability and address adequacy and management challenges by providing a quick balancing of the electricity grid.[69]

Before adoption of this new rule, each RTO and ISO was free to develop its own compensation methodologies for resources participating in day-ahead and real-time energy markets.[70] As a result, the level of compensation for DR varies significantly among RTOs and ISOs.[71] This rule will likely require that PJM increase compensation, since its previous compensation scheme was for less than full LMP; MISO's level of compensation will likely stay the same. The overall price of electricity in PJM will likely rise, since PJM can no longer compensate these resources at previously lower prices. Although the price of demand response resources will likely also increase in the PJM market, the systemic benefits identified by FERC (better balance of supply and demand, reduction of high-priced loads, greater competition, greater reliability) may offset those increases. It is possible that the increased reliability, reduction in demand of high-priced loads, and greater competition in the wholesale energy market may place sufficient downward pressure on prices in the PJM and MISO markets to offset any increase in compensation required by the DR Rule. The IPA should continue to monitor the effect on prices for wholesale electricity in both interconnections, anticipating a slight increase in the PJM interconnection's price for demand response resources.

2.3.1.8 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. The current supply mix in Illinois has remained largely unchanged over the last decade, with the majority of the state's electricity generated by nuclear and coal fired plants located within the state. Coal is the marginal fuel for most hours in the year, with wind depressing prices during some nighttime hours and natural gas setting prices during system peaks.

Greenhouse Gas Regulation. On April 2, 2007, the United States Supreme Court ("Supreme Court") held that greenhouse gases ("GHGs") are "air pollutants" under the Clean Air Act ("CAA"), and that the Environmental Protection Agency ("EPA") could not refuse to regulate these gases[72] As a result, the EPA was directed to decide whether GHGs from motor vehicles "cause, or contribute to, air pollution which may

[63] *Id.*

[64] *Id.* at 5.

[65] *Id.*

[66] *Id.* at 6.

[67] *Id.* at 8.

[68] *Id.*

[69] *Id.* at 9 (citing an ERCOT incident on February 26, 2008 when a drop in power supplied by wind generators was balanced by 1200 MW of Load acting as Resource, see Oak Ridge Nat'l Lab. Nat'l Renewable Energy Lab., Tech. Rep. NREL/TP-500-43373 (Jul. 2008)).

[70] *Id.* at 11.

[71] *Id.* at 11-12 (noting that the MISO demand response program pays LMP and the PJM demand response program pays LMP minus generation and transmission portions of the retail rate).

[72] *Massachusetts v. Envtl Prot. Agency*, 549 US. 497 (2007).

reasonably be anticipated to endanger public health or welfare."[73] Subsequently, on December 15, 2009, the EPA published an endangerment finding, concluding that motor vehicle emissions of GHGs endanger public health and welfare.[74] In particular, EPA found that emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) may reasonably be anticipated to endanger public health and welfare.[75] While lawsuits challenging the endangerment finding were filed by industry groups, EPA has moved forward with regulating GHGs for mobile and stationary sources of the six GHGs identified above. Stationary sources include "power plants, chemical plants, oil refineries, manufacturing facilities, and other industrial facilities" that are non-moving, fixed-site emitters of pollutants subject to CAA regulation.[76]

Under the CAA, the Prevention of Significant Deterioration Program ("PSD") applies to new and modified major stationary sources that potentially emit 100 to 250 tons of GHGs per year.[77] PSD regulations require new major stationary sources to undertake a Best Available Control Technology ("BACT") analysis "for each regulated [New Source Review] ("NSR") pollutant that it would have the potential to emit in significant amounts."[78] A "regulated NSR pollutant" is "any pollutant that … is subject to regulation under the Act [with immaterial exceptions]."[79] EPA believes that the combination of these provisions means that the six GHGs became PSD-regulated pollutants on January 2, 2011.[80]

To avoid regulation of smaller sources of GHG emissions, where the costs could be so burdensome as to force them to cease operation, the EPA published a "Tailoring Rule" on June 3, 2010. That rule increased the threshold for regulation of GHG emissions from a band of 100 to 250 tons per year to a total output of 75,000 tons per year, expressed in the common metric of CO2 equivalents ("CO2e").[81] In addition, the rule establishes a multi-phase approach to GHG regulation under the PSD program. In Phase 1 (between January 2, 2011 and June 30, 2011), only new and modified sources[82] that would be subject to PSD permitting due to their emissions for pollutants other than GHGs would be subject to PSD requirements for GHGs (and then only if the source potentially emits 75,000 tons per year of CO2e).[83] In Phase 2 (between July 1, 2011 to June 30, 2013), new sources that potentially emit 100,000 tons per year of CO2e and modified sources that potentially emit 100,000 tons per year of CO2e with modification-induced emission increases of 75,000 tons per year of CO2e will require PSD permits for GHG emissions.[84] In Phase 3 (from July 1, 2013 forward) EPA will undertake another rulemaking beginning in 2011 and concluding by July 1, 2012 to phase-in smaller sources of GHG emissions, but will not require permitting for sources that emit less than 50,000 tons per year of CO2e.[85]

On November 10, 2010, EPA issued guidance on the PSD process for new sources, either those undertaking new construction or sufficiently modifying their facilities to become new sources under the CAA.[86] This EPA guidance explains the BACT analysis that facilities requiring PSD permits must undertake with respect to GHGs. EPA does not establish a presumptive BACT nor does it offer a new approach for selecting BACT.[87] EPA does, however, focus on the energy efficiency of technologies to determine which approach constitutes BACT for the particular source, noting that while carbon capture and storage is a promising technology that

[73] *Id.* (citing CAA § 202(a)(1)).

[74] 74 Fed. Reg. 66,495 (Dec. 15, 2009).

[75] *Id.*

[76] http://www.epa.gov/apti/course422/ap3b.html (accessed May 17, 2011).

[77] Clean Air Act § 165.

[78] 40 C.F.R. § 52.21(J)(2).

[79] 40 C.F.R. § 52.21(b)(50)(iv).

[80] 75 Fed. Reg. 31,522-23.

[81] 75 Fed. Reg. 31,513 (June 3, 2010).

[82] Under the CAA, "new" and "modified" sources are those stationary sources that begin construction of their source or sufficiently modify their source after the date of promulgation of New Source Performance Standards for that particular source category. 42 U.S.C. § 7411.

[83] *Id.* at 31,516.

[84] *Id.*

[85] *Id.* at 31,575; 31,578.

[86] *PSD and Title V Permitting Guidance for Greenhouse Gases* (Nov. 2010), EPA-HQ-OAR-2010-0841-0001, (accessed May 10, 2011 at http://www.epa.gov/region4/air/permits/GHG%20Permitting%20Guidance%20-%2011-10-10%20public.pdf) ("GHG Guidance").

[87] *Id.* at 1.

merits consideration, it will unlikely constitute BACT due to technical feasibility and cost.[88] Having well-defined BACT specifications can help sources in affected categories by providing regulatory certainty regarding installation of technology to comply with federal and state pollution control laws. However, industry commentators note that for the initial PSD permits, compliance with the new GHG related requirements are "likely to be a time-consuming, complicated and expensive process for regulated entities."[89] In addition to new sources subject to PSD requirements, existing sources with Title V permits under the CAA will be required to address GHGs as part of their continuing Title V permit obligations (such as renewals) under the timetable set forth in the Tailoring Rule.[90]

In determining BACT, the EPA has deferred for three years its decision on whether it will issue a supplemental rule exploring separate accounting rules for different types of feedstock for sources of biogenic GHG emissions.[91] Since add-on controls to reduce GHG-emissions are not as well-advanced for as for most combustion-derived pollutants, energy-efficient measures will serve as the "foundation for a BACT analysis for GHGs."[92] In addition, EPA believes that "performance benchmarking" should be used to compare a unit's energy performance to determine whether additional gains in energy efficiency are achievable.[93] Significantly, the EPA recommends using "output-based metrics" instead of input-based metrics in Step 3 of BACT analyses to more fully consider thermal efficiency and power demand in ranking control options based on total CO2e instead of total mass.[94] In Step 4 of BACT analyses, permitting authorities will have greater discretion to consider a wide range of various direct and indirect economic, energy, and environmental impacts of the control options.[95] Finally, in Step 5 of the BACT analyses, EPA recommends a focus on metrics relying on longer-term averages (e.g., 365 rolling average) to reflect the cumulative impact of GHGs in the environment.[96]

Sources not subject to PSD, such as pollution sources that were constructed before the new source performance standards ("NSPS") for their source category were promulgated or sources that have not been sufficiently modified, have distinct requirements. For those sources, the GHG BACT must be incorporated into a Title V permit if the source: (1) potentially emits GHGs that equal or exceed 100,000 tons per year on a CO2e basis; and (2) potentially emits GHGs in amounts that equal or exceed 100 tons per year of GHGs on a mass basis.[97]

EPA's GHG regulations would likely increase the cost of generating for fossil-fueled electricity and therefore increase the market price of electricity, particularly in hours when fossil-fueled power plants are on the margin. To provide greater guidance for the largest GHG emitters, and as a result of a lawsuit by citizens groups and states, EPA entered a settlement agreement binding it to rulemakings regarding electric generating units at fossil fuel-fired power plants and refineries.[98] This settlement requires EPA to propose regulations for new source performance standards and emission guidelines by July 26, 2011 (to be finalized by May 26, 2012) for natural gas, oil, and coal-fired electric generating units ("EGUs").[99] For refineries, EPA has agreed to issue proposed regulations establishing NSPS and emission guidelines for existing refineries by December 10, 2011 (to be finalized by November 10, 2012).[100] Despite these proposed rulemakings,

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[88] *Id.*

[89] Robert Wyman, *EPA's PSD and Title V Permitting Guidance for Greenhouse Gases: Overview and Analysis*, Practising Law Institute Order No. 29209 (Feb. 9, 2011).

[90] GHG Guidance at 2, 3 n.6 (explaining that EPA does not intend to required PSD permits issued prior to January 2, 2011 to address GHGs, regardless of their effective date); 75 Fed. Reg. 17,004.

[91] Deferral for CO2 Emissions From Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs, 76 Fed. Reg. 43490 (July 20, 2011).

[92] GHG Guidance at 30-31 (explaining that EPA does not intend to required PSD permits issued prior to January 2, 2011 to address GHGs, regardless of their effective date); 75 Fed. Reg. 17,004.

[93] *Id.* at 22-23, App. J.

[94] *Id.* at 39.

[95] *Id.* at 44-45.

[96] *Id.* at 46-47.

[97] *Id.* at 52-53.

[98] EPA, Settlement Agreement to Address Greenhouse Gas Emissions From Electric Generating Units and Refineries, Fact Sheet (accessed May 10, 2011 at http://www.epa.gov/airquality/pdfs/settlementfactsheet.pdf).

[99] *Id.* at 1.

[100] *Id.* at 2.

states have the ability to apply less stringent standards or longer compliance schedule if they demonstrate that the federal requirements are "unreasonably cost-prohibitive, physically impossible, or that there are other factors that reasonably preclude meeting the guidelines."[101]

Regardless of what happens with these Congressional proposals, EPA's proposed GHG regulations will likely increase the cost of fossil-fueled electricity generation. Even the most far-reaching proposals limiting EPA's authority to regulate the emission of GHGs preserve EPA's authority to propose fuel-economy standards jointly with the DOT. In the meantime, by imposing new requirements on the largest emitters of GHGs, EPA's GHG rules require new and modified sources to immediately implement new control technologies to meet the BACT standards. Because such technologies are largely untested and relatively new, their selection and implementation will likely impose a large cost on GHG emitters. Even for existing sources of GHGs, EPA's rules will eventually require BACT for general operating permits. Additionally, the sources subject to EPA's settlement regarding NSPS and emission limitations for EGUs and refineries are some of the largest providers of electricity supply. Requiring new equipment or control methods for their GHG emissions will raise the cost of supply from these generators and, thus, will likely increase the unit-cost of electricity. Because the GHG Rules are being applied to energy sources that were not the direct target of the fuel-economy standards, existing regulatory impact analyses do not address the costs, burdens, and timetables required of power plants subject to the rules.

Mercury Regulation. On March 29, 2005, EPA promulgated a final rule concluding that it was neither appropriate nor necessary to regulate coal and oil fired electrical generating units ("EGUs") under Section 112 of the Clean Air Act ("CAA").[102] Subsequently, on May 18, 2005, EPA issued the Clean Air Mercury Rule ("CAMR") establishing standards of performance for emissions of mercury from new and existing coal-fired EGUs under Section 111 of the CAA.[103] Ensuing litigation has since vacated the CAMR on the grounds that EPA's assumption that there would be no Section 112 regulation of EGUs was incorrect, rendering the Section 111 standards null and void.[104] Environmental and public health organizations thus filed suit against the EPA, alleging that it failed to perform a nondiscretionary duty when it failed to promulgate standards for hazardous air pollutants ("HAPs") emitted from coal and oil fired EGUs pursuant to Section 304(a)(2) of the CAA.[105] The consent decree resolving that litigation requires EPA to propose rules regarding emission standards for coal and oil fired EGUs, to be finalized November 2011.[106]

On May 3, 2011, EPA proposed a *National Emission Standard for HAPs from Coal and Oil Fired EGUs and Standards of Performance for Fossil-Fuel-Fired EGUs* ("National Emission Standard").[107] Because mercury is shown to deposit in higher quantities close to emissions sources, EPA determined that depositions near EGUs constituted a threat to public health and welfare.[108] Moreover, EPA has determined that "currently available control technologies for Hg [Mercury], acid gases, and non-Hg metal HAP shows that significant reductions in these pollutants can be achieved from EGUs."[109] In EPA's estimation, application of available Hg controls in 2016 would reduce Hg emissions by seventy-nine percent (79%) for EGUs.[110]

The National Emission Standard proposes to require approximately 1,200 existing "coal-fired" and 150 existing "oil-fired" EGUs at about 525 power plants to conform to more stringent emission limitations for mercury and other toxic metals.[111] Specifically, the National Emission Standard establishes numerical emission limits for mercury, PM (a surrogate for toxic non-mercury metals) and HCl (a surrogate for toxic acid

[101] *Id.*

[102] 70 Fed. Reg. 15,994; EGUs are defined as fossil fuel-fired combustion units of more than 25 megawatts electric (MWe) that serve a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also an electric utility steam generating unit.

[103] 70 Fed. Reg. 28,606.

[104] *New Jersey v. Envt'l Prot. Agency*, 517 F.3d 574 (D.C. Cir. 2008).

[105] 76 Fed. Reg. 24,986.

[106] *Id.*

[107] *Id.* at 24,976.

[108] *Id.* at 25,013.

[109] *Id.* at 25,014.

[110] *Id.* at 25,015.

[111] EPA, Proposed Mercury and Air Toxics Standards, Fact Sheet at 2 (accessed May 17, 2011 at http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposalfactsheet.pdf).

gases).[112] Compliance with these new emission limits may require installation of dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and baghouses.[113] The proposed rule provides facilities with up to four (4) years to come into compliance.[114] By 2016, EPA estimates that the National Emission Standard will annually cost $10.9 billion.[115]

By 2015, EPA estimates that the annual incremental cost of compliance with the National Emission Standard will be $10.9 billion, or a 3.5% increase in costs to generate, transmit, and distribute electricity to end-use consumers.[116] At the same time, EPA estimates that about 9.9 GW of coal-fired capacity will become uneconomic to maintain due to the standard, reducing total coal-fired capacity by roughly 3%.[117] Coal production for electricity generation is expected to decline modestly as a result, however, demand for bituminous coals is expected to increase slightly.[118] Thus, EPA predicts that by 2015, the average retail electricity price will increase by 3.7%, falling to a 2.6% increase by 2020.[119] Comments on the proposed standard will be accepted until July 5, 2011, the final rule will be promulgated in the months thereafter with no specific deadline imposed by law. The IPA will continue to monitor the rulemaking for its potential effects on electricity prices.

Carbon Capture and Sequestration Regulation. On July 25, 2008, EPA proposed a Carbon Dioxide Injection and Geologic Sequestration Rule addressing the injection of GHGs into the ground.[120] The proposed rule noted that the Safe Drinking Water Act ("SDWA") did not provide EPA with the authority to develop regulations for all areas related to Carbon Sequestration, but it does provide authority to the extent necessary to protect underground drinking water wells.[121] In December of 2010, the EPA Administrator promulgated a final rule titled *Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geological Sequestration Wells* ("UIC Rule").[122]

The UIC Rule establishes new federal requirements for the underground injection of carbon dioxide for the purpose of long-term underground storage.[123] To address the "unique nature" of CO2 injection with regard to its relative buoyancy, corrosivity, impurities, and mobility, the UIC Rule applies to operators of wells used to inject CO2 into the subsurface for purposes of long-term storage.[124] The UIC Rule thus requires owners, in addition to complying with existing UIC rules, to:

- Perform geologic site characterizations;
- Construct and operate wells with injectate-compatible[125] materials and automatic shutoff systems;
- Develop, implement, and update plan to manage sequestration projects;
- Periodically monitor operational data to verify that CO2 is moving as predicted;
- Test the mechanical integrity of the injection well;
- Extend monitoring to track the location of the injected CO2 until it can be demonstrated that drinking wells are no longer endangered; and

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[112] *Id.*

[113] *Id.*

[114] *Id.* at 3.

[115] *Id.* at 4.

[116] EPA, *Regulatory Impact Analysis of Proposed Toxics Rule* at 401 (accessed May 31, 2011 at http://www.epa.gov/ttnecas1/ToxicsRuleRIA.pdf).

[117] *Id.* at 405.

[118] *Id.* at 408.

[119] *Id.* at 410.

[120] 73 Fed. Reg. 43,491.

[121] *Id.* at 43,493.

[122] 75 Fed. Reg. 77,230.

[123] EPA, *Underground Injection Control (UIC) Program Requirements for Geologic Sequestration of Carbon Dioxide Final Rule*, Fact Sheet at 1 (accessed May 10, 2011 at http://water.epa.gov/type/groundwater/uic/class6/upload/uicprogramrequirementsforGSofco2factsheet.pdf).

[124] *Id.* at 2.

[125] "Injectate-compatible materials" are construction materials that can withstand fluids with which those materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards. 40 C.F.R. § 146.86.

- Ensure funds will be available for corrective action, well plugging, site care, closure, and emergency response.[126]

To distinguish these new requirements from the state and federal permit applications for differing well classes, the UIC Rule creates a new class of wells under the SDWA (Class VI Wells) to promote transparency and national consistency in permitting.[127]

After promulgation of this final rule, state permitting authorities must apply to EPA for "primacy approval" under Section 1422 of the SDWA, which allows states to issue permits enforceable by courts.[128] States have nine months following promulgation to apply for primacy approval. If states do not apply or if states submit inadequate applications, then EPA will impose a "Federal UIC Class VI program."[129] In the meantime, states with existing Section 1422 primacy programs may issue permits under Class I or Class V well status.[130]

EPA estimates the total cost of implementation of the final rule to be between $31 and $38 million, representing approximately three percent (3%) of the total cost of carbon capture and storage.[131] Because of new requirements that specially account for CO2's unique properties, the UIC Rule will likely increase the cost of carbon storage and sequestration. Increasing the cost of carbon sequestration will directly raise the price for electricity sources using geological sequestration. Additionally, the UIC Rule will likely indirectly increase the price of electricity for consumers by increasing the price of coal generated electricity. However, to the extent that carbon sequestration could be considered BACT, and to the extent it proves cheaper than existing BACT options for sources subject to EPA's GHG Rules, the UIC Rule may slightly decrease the cost of compliance with GHG Rules.

While carbon capture, storage, and sequestration is in the initial stages of development, Illinois' legislative actions suggest a significant interest in using these methods to decrease emissions associated with coal-fired electricity generation. The IPA will monitor whether Illinois applies for primacy for its Class VI well permits, and whether the EPA approves or denies such primacy, to determine the specific requirements imposed on Class VI well owners and operators.

2.3.1.9 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 2012 – May 2017 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.

[126] *Id.*

[127] *Id.*

[128] *Id.* At this time, US EPA Region V has no listing of any states that have applied for permits; application are not due until August, 2011.

[129] *Id.* at 3.

[130] *Id.*

[131] *Id.*

3.0 Procurement Design

The IPA is charged with developing a plan that mitigates risk while ensuring low stable prices for consumers. Taking into account the risks noted above, the IPA has designed a procurement plan to address risk and price issues for energy, capacity, renewable energy, and transmission resources.

3.1 Energy Resource.

The IPA relies on Load Forecasts from ComEd and Ameren as the best estimates for future consumption factored for the largely unknown variable of retail switching. Since Utility 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 either Utility 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 is not to identify the combined load of all customers of the Utility. Rather, the 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. The Utilities apply statistically adjusted end use models as the basis of its load forecasting process. After adjusting consumption data weather, seasonal variables, and economic conditions, detailed core consumption models are developed.

The econometric models 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.

TABLE D: OVERVIEW OF KEY ENERGY RESOURCE ISSUES

Key Energy Resource Issues	
Volume	Price
▪ The IPA portfolio is expected to decline over time as consumers migrate to alternative supply options. ▪ Use of alternative supply options will likely increase as long as the IPA prices remains above the current market price for power. ▪ A portion of future IPA portfolio needs will be met through existing standard supply contracts; those volumes and delivery schedules are fixed. ▪ A portion of future IPA portfolio needs will be met through existing Long-Term Renewable Energy contracts; volumes and delivery are variable. ▪ **Securing excess supply can lead to losses through forced sell-back of volumes to the**	▪ Underlying commodity costs face upward pressure due to inflation and gradual increase in economic activity. ▪ Generators anticipate elevated operating costs resulting from compliance with USEPA transport and Mercury rules. ▪ Owners of generation units within the region that cannot afford or finance upgrades to their existing coal-fueled resources may close - driving up clearing prices. ▪ A portion of future IPA portfolio needs will be met through existing Long-Term Renewable Energy contracts; costs escalate 2% per year over 20 years. ▪ **Securing excess future supply today can lead to higher than necessary costs if future prices**

market; securing insufficient supply can lead to higher prices through forced spot-market purchases to meet actual use.	**decrease; securing less future supply today can lead to higher prices if future prices rise.**

TABLE E: OVERVIEW OF PRIMARY PLAN INCLUSIONS FOR ENERGY RESOURCES

Primary Energy Resource Measures	
Volume	Price
▪ Utilize the base (median) projection volumes for both Utilities as planning volumes	▪ Maintain procurement selection on the basis of price for standard products.

3.1.1 Background. 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, 2010 and 2011 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 2011 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, 2010, and 2011 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.

3.1.2 Evaluation. 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.

A model portfolio for each Utility 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 subsequent procurement cycles will supply portions of the IPA portfolio into the period covered by this 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 2014 as of August 12, 2011. 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 2014, 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 manipulates 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.

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 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 (or at least escalate their operating costs). Replacement baseload capacity has not appeared in the market. Most new "capacity" cited in reports is actually due to the high numbers of variable output wind and solar assets under development. While these assets are assigned a capacity factor, these assets are not suitable or sufficient to meet baseload electricity needs.

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.

3.4.1 Recommendations. The IPA recommends applying the standard laddered procurement approach to the Ameren and ComEd portfolios.

3.4.1.1 Ameren Illinois Utilities. The IPA selected Ameren's Expected load model as the basis of the Plan. The Expected model volumes are adjusted to account for energy efficiency program results, but not for Demand Response. Additionally, the contract volumes attributable to Long-term Power Purchase Agreements entered into by Ameren in December 2010 are not factored out of the projection as physical delivery of those contracted volumes are not guaranteed to the Utility (the electricity under the contracts will be delivered to the transmission system as it is generated).

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."*[132]

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 and the impact of energy efficiency programs (both current and projected). Recent activity in ICC Docket No. 10-0568 leads the IPA to conclude that Ameren does not have a valid demand response program. Specifically, the IPA notes that the Commission rejected Ameren's request for a proposed Voltage Optimization program, stating it was "not convinced" that by implementing energy efficiency measures Ameren would meet the Section 8-103(c) demand response requirements:[133]

> *"The Commission is of the opinion that it would be appropriate to institute a pilot of the Voltage Optimization Program, to determine what the benefits would be of a wider adoption of this program. The Commission agrees with Staff that the pilot should include testing not only the demand response capabilities of the program, but also the energy efficiency capabilities, if implemented on a continuous basis. The Commission suggests Ameren conduct a pilot of the Voltage Optimization Program on a heavily loaded feeder that is able to support a significant reduction in voltage in order to maximize the cost-effectiveness of the pilot. The Commission further suggests Ameren design a number of tests using industry best practices that can be used to ensure the demand response capabilities of the pilot program will actually work. The Commission believes that the adoption of a pilot program, with the remainder of the funds directed toward greater energy efficiency, along with other possible demand-response measures, will be appropriate at this time. With these measures in place, the Commission does not find it necessary at this time to direct the IPA to acquire demand response, although this may become necessary in the future."*

For the purpose of projecting loads for this year's Plan, the IPA assumes that Ameren will not deliver the required demand response reductions to the portfolio as in the 2009, 2010, and 2011 plan years.

The IPA has 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 for 2012 (159,162 MWh) for 2013 (134,341 MWh), for 2014 (130,399 MWh) for 2015 (127,850 MWh), and for 2016 (124,204 MWh).

[132] 220 ILCS 5/8-103(c).

[133] Final Order at 27-28, ICC Docket No. 10-0568.

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.

Ameren Illinois Company will secure the physical energy resources to meet the combine load requirements of eligible retail customers. For the purposes of this 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. Such qualifying purchases are considered to be preexisting purchases and shall be recovered in Accrued Expenses for the Purchased Electricity Adjustment.[134]

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 C. It should be noted that Ameren's DS-3a rate class was declared competitive on May 1, 2011. The declaration allows for a three year transition period such that effective May 1, 2014 all load for this rate class must be served by ARES or Ameren real time pricing tariffs.

TABLE F: VOLUME PROJECTIONS PER RATE CLASS FOR AMEREN (JUNE 2012 THROUGH MAY 2015)

Contract Month	Projected Monthly Volume Requirements						
	DS1 MWh	DS2 MWh	DS3a MWh	DS5 MWh	QF MWh	Total Load MWh	Net Load MWh
June-12	1,022,865	254,093	41,607	25,401	(41,040)	1,343,967	1,302,927
July-12	1,350,795	280,461	44,838	24,942	(42,408)	1,701,035	1,658,627
August-12	1,341,043	276,897	43,077	26,165	(42,408)	1,687,182	1,644,774
September-12	944,279	239,119	39,201	29,237	(41,040)	1,251,835	1,210,795
October-12	782,362	221,773	38,825	31,413	(42,408)	1,074,373	1,031,965
November-12	852,695	210,878	36,133	35,090	(41,040)	1,134,795	1,093,755
December-12	1,165,240	239,457	37,568	38,497	(42,408)	1,480,761	1,438,353
January-13	1,252,963	245,367	36,701	41,282	(42,408)	1,576,314	1,533,906
February-13	1,020,207	228,306	33,480	36,275	(38,304)	1,318,268	1,279,964
March-13	938,300	226,332	34,150	32,566	(42,408)	1,231,348	1,188,940
April-13	720,992	201,155	30,802	30,265	(41,040)	983,214	942,174
May-13	752,873	210,272	32,765	27,218	(42,408)	1,023,128	980,720
June-13	1,020,401	239,745	34,785	25,265	0	1,320,196	1,320,196
July-13	1,346,850	265,731	37,956	24,625	0	1,675,162	1,675,162
August-13	1,336,876	263,837	36,994	26,008	0	1,663,714	1,663,714
September-13	939,644	229,335	34,187	28,742	0	1,231,909	1,231,909
October-13	775,213	213,917	34,370	31,249	0	1,054,748	1,054,748
November-13	845,311	204,839	32,503	34,847	0	1,117,500	1,117,500
December-13	1,158,061	233,223	34,226	38,396	0	1,463,906	1,463,906
January-14	1,241,899	239,096	29,508	41,178	0	1,551,680	1,551,680
February-14	1,010,818	223,844	23,342	36,164	0	1,294,168	1,294,168
March-14	928,863	221,628	19,874	32,372	0	1,202,737	1,202,737
April-14	713,151	197,215	14,396	30,137	0	954,898	954,898
May-14	744,921	206,388	0	27,132	0	978,441	978,441
June-14	1,009,188	235,005	0	25,174	0	1,269,366	1,269,366

[134] Sheet 31.003 of the Rider PER tariff.

July-14	1,332,754	260,195	0	24,542	0	1,617,491	1,617,491
August-14	1,322,128	258,262	0	25,890	0	1,606,281	1,606,281
September-14	927,680	224,542	0	28,640	0	1,180,862	1,180,862
October-14	763,383	209,444	0	31,186	0	1,004,013	1,004,013
November-14	831,725	200,235	0	34,777	0	1,066,737	1,066,737
December-14	1,139,956	228,086	0	38,315	0	1,406,358	1,406,358
January-15	1,198,307	234,597	0	41,097	0	1,474,001	1,474,001
February-15	973,733	219,087	0	36,069	0	1,228,889	1,228,889
March-15	894,204	216,857	0	32,295	0	1,143,357	1,143,357
April-15	687,773	192,950	0	30,094	0	910,818	910,818
May-15	721,162	201,802	0	27,053	0	950,017	950,017

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 2012 to 2017 planning period presented in Attachment C.

TABLE G: AGGREGATED MONTHLY AND AVERAGE LOAD REQUIREMENTS FOR AMEREN (JUNE 2012 THROUGH MAY 2015)

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-12	706,304	596,622	2,102	1,554
July-12	845,824	812,803	2,517	1,992
August-12	916,387	728,387	2,490	1,937
September-12	582,396	628,399	1,916	1,511
October-12	561,884	470,081	1,527	1,250
November-12	558,006	535,749	1,661	1,395
December-12	663,693	774,661	2,074	1,827
January-13	758,759	775,148	2,156	1,977
February-13	645,854	634,110	2,018	1,801
March-13	567,825	621,115	1,690	1,522
April-13	493,068	449,105	1,401	1,220
May-13	505,104	475,617	1,435	1,213
June-13	672,794	647,401	2,102	1,619
July-13	889,453	785,709	2,527	2,004
August-13	901,404	762,310	2,561	1,945
September-13	600,567	631,341	1,877	1,578
October-13	564,108	490,640	1,533	1,305
November-13	532,278	585,222	1,663	1,463
December-13	695,392	768,514	2,070	1,884
January-14	764,344	787,337	2,171	2,009
February-14	649,673	644,495	2,030	1,831
March-14	564,017	638,721	1,679	1,565
April-14	496,940	457,958	1,412	1,244
May-14	464,482	513,959	1,382	1,260
June-14	649,077	620,289	1,932	1,615
July-14	861,885	755,606	2,449	1,928
August-14	817,377	788,904	2,433	1,934
September-14	594,745	586,117	1,770	1,526
October-14	533,745	470,267	1,450	1,251
November-14	475,149	591,587	1,563	1,422
December-14	700,389	705,969	1,990	1,801
January-15	686,400	787,601	2,043	1,930

February-15	610,967	617,922	1,909	1,755
March-15	563,897	579,459	1,602	1,478
April-15	475,995	434,823	1,352	1,182
May-15	432,198	517,820	1,351	1,221

Energy and financial hedges required by the Eligible Retail Customers comes from six sources. First, the swap contract with Ameren Energy Marketing provides a financial hedge on 1,000 MW of Around-the-Clock ("ATC") energy during the June 2012 – December 2012 period. Second, financial hedges are in place for the period June 2012 through May 2013 with such hedges resulting from the 2010 procurement processes. Third, fixed price physical supply contracts for the period June 2012 through May 2014 resulted from the 2011 procurement process. Fourth, Ameren Illinois Company will hedge price exposure for Residual Volumes (IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan) using fixed price physical supply contracts. Fifth, long term renewable contracts resulting from the 2010 procurement process are in place for both energy and RECs (twenty year term). The long term renewable contracts do not require delivery of physical energy to the Utility according to a schedule; therefore their volumes cannot be subtracted from the projections. Sixth, the Ameren Illinois 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, Ameren Illinois desires to pay a fixed price, and will settle all loads with the MISO at LMP. Under a swap transaction Ameren Illinois 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 Ameren Illinois to the MISO is offset by the LMP received from the supplier, leaving Ameren Illinois 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 Ameren Illinois 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, after consultation with the IPA, Utilities, Commission, and procurement monitor, 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 2012 and May 2015, 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 and 2011 procurement plans. These procurement plans included block purchases using both swaps and physical settlement, as well as variable purchases of energy from renewable facilities. 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, Ameren Illinois, 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.

TABLE H: PROPOSED AMEREN OFF-PEAK LOAD VOLUMES TO BE SECURED IN 2012 CYCLE

Contract Month	Off-Peak Contract Volumes to Secure (MW)					
	Projected Volumes (MW)	Swap Volume (MW)	2010 Portfolio Volume (MW)	2011 Portfolio Volume (MW)	Residual Volume (MW)	2012 IPA Event (MW)
Jun-12	1,554	1,000	-	150	404	400
Jul-12	1,992	1,000	-	450	542	550
Aug-12	1,937	1,000	-	400	537	550
Sep-12	1,511	1,000	-	200	311	300
Oct-12	1,250	1,000	-	-	250	250
Nov-12	1,395	1,000	-	50	345	350
Dec-12	1,827	1,000	-	300	527	550
Jan-13	1,977	-	750	250	1,727	1,000
Feb-13	1,801	-	700	250	1,551	850
Mar-13	1,522	-	600	500	1,022	400
Apr-13	1,220	-	500	450	770	250
May-13	1,213	-	500	450	763	250
Jun-13	1,619	-	-	550	1,069	600
Jul-13	2,004	-	-	700	1,304	700
Aug-13	1,945	-	-	700	1,245	650
Sep-13	1,578	-	-	600	978	500
Oct-13	1,305	-	-	500	805	400
Nov-13	1,463	-	-	500	963	500
Dec-13	1,884	-	-	650	1,234	650
Jan-14	2,009	-	-	700	1,309	700
Feb-14	1,831	-	-	650	1,181	650
Mar-14	1,565	-	-	550	1,015	550
Apr-14	1,244	-	-	450	794	400
May-14	1,260	-	-	450	810	450
Jun-14	1,615	-	-	-	1,615	550
Jul-14	1,928	-	-	-	1,928	650
Aug-14	1,934	-	-	-	1,934	700
Sep-14	1,526	-	-	-	1,526	550
Oct-14	1,251	-	-	-	1,251	450
Nov-14	1,422	-	-	-	1,422	500
Dec-14	1,801	-	-	-	1,801	650

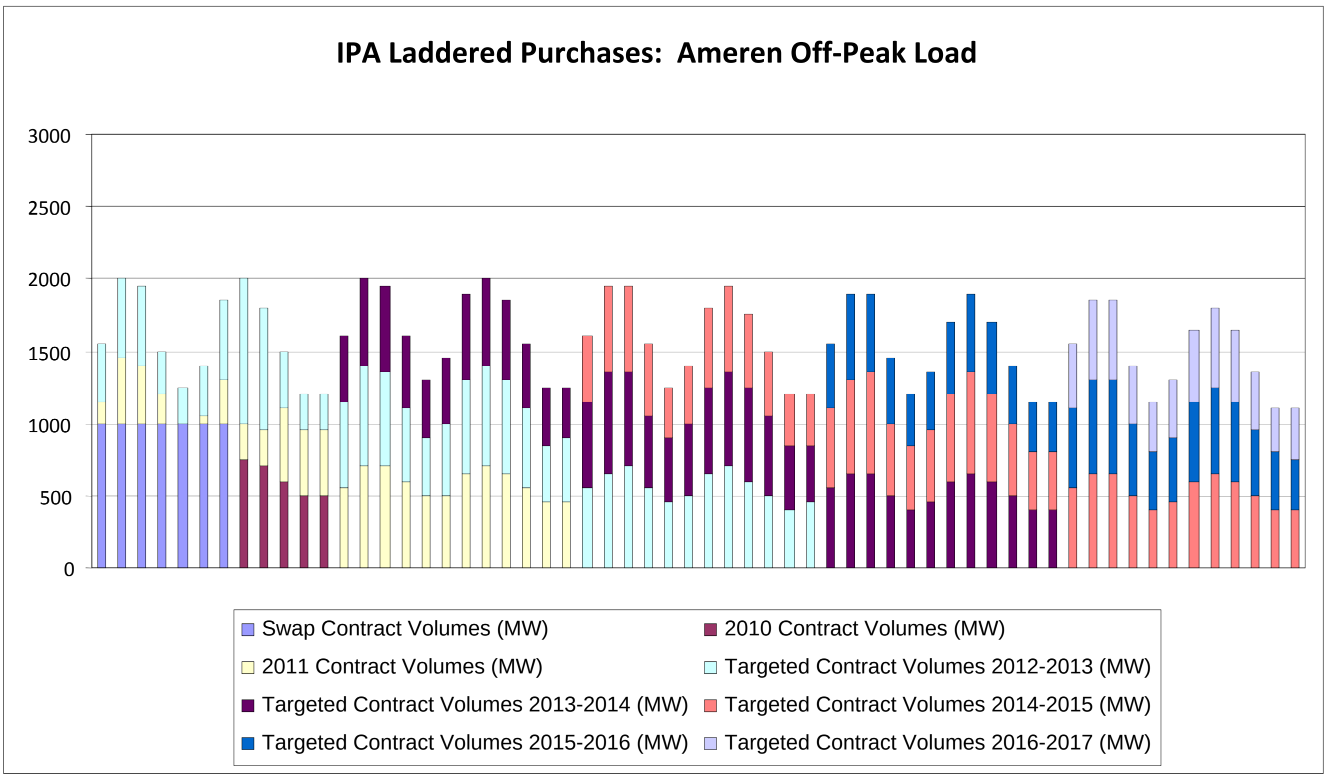
Jan-15	1,930	-	-	-	1,930	700
Feb-15	1,755	-	-	-	1,755	600
Mar-15	1,478	-	-	-	1,478	500
Apr-15	1,182	-	-	-	1,182	400
May-15	1,221	-	-	-	1,221	450

TABLE I: PROPOSED AMEREN ON-PEAK LOAD VOLUMES TO BE SECURED IN 2012 CYCLE

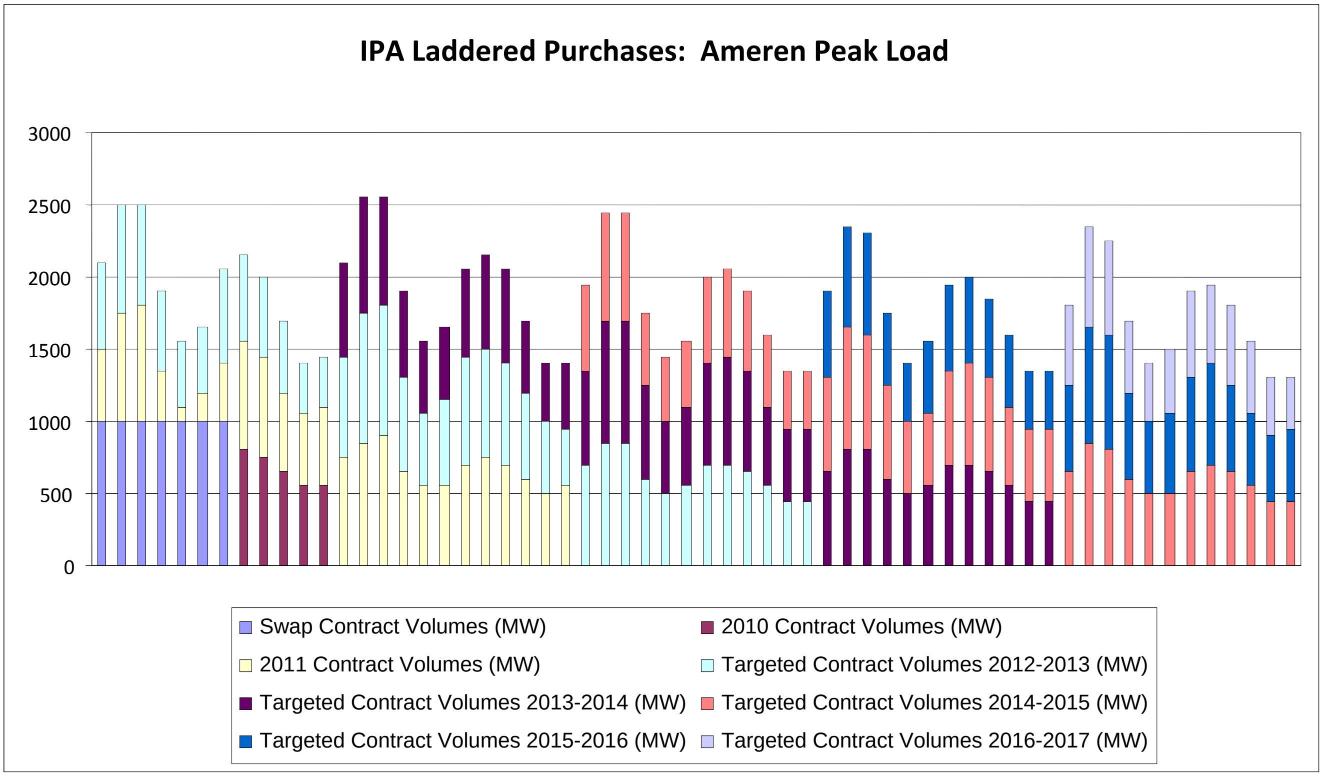
Contract Month	Peak Contract Volumes to Secure (MW)					
	Projected Volumes (MW)	Swap Volume (MW)	2010 Portfolio Volume (MW)	2011 Portfolio Volume (MW)	Residual Volume (MW)	2012 IPA Event (MW)
Jun-12	2,102	1,000	-	500	602	600
Jul-12	2,517	1,000	-	750	767	750
Aug-12	2,490	1,000	-	800	690	700
Sep-12	1,916	1,000	-	350	566	550
Oct-12	1,527	1,000	-	100	427	450
Nov-12	1,661	1,000	-	200	461	450
Dec-12	2,074	1,000	-	400	674	650
Jan-13	2,156	-	800	750	1,406	600
Feb-13	2,018	-	750	700	1,318	550
Mar-13	1,690	-	650	550	1,140	500
Apr-13	1,401	-	550	500	901	350
May-13	1,435	-	550	550	885	350
Jun-13	2,102	-	-	750	1,352	700
Jul-13	2,527	-	-	850	1,677	900
Aug-13	2,561	-	-	900	1,661	900
Sep-13	1,877	-	-	650	1,227	650
Oct-13	1,533	-	-	550	983	500
Nov-13	1,663	-	-	550	1,113	600
Dec-13	2,070	-	-	700	1,370	750
Jan-14	2,171	-	-	750	1,421	750
Feb-14	2,030	-	-	700	1,330	700
Mar-14	1,679	-	-	600	1,079	600
Apr-14	1,412	-	-	500	912	500
May-14	1,382	-	-	550	832	400
Jun-14	1,932	-	-	-	1,932	700
Jul-14	2,449	-	-	-	2,449	850
Aug-14	2,433	-	-	-	2,433	850
Sep-14	1,770	-	-	-	1,770	600
Oct-14	1,450	-	-	-	1,450	500
Nov-14	1,563	-	-	-	1,563	550
Dec-14	1,990	-	-	-	1,990	700
Jan-15	2,043	-	-	-	2,043	700
Feb-15	1,909	-	-	-	1,909	650
Mar-15	1,602	-	-	-	1,602	550
Apr-15	1,352	-	-	-	1,352	450

May-15	1,351	-	-	-	1,351	450

GRAPH 2: PROPOSED LADDERING SCHEDULE FOR AMEREN OFF-PEAK LOAD (JUNE 2012 THROUGH MAY 2017)



GRAPH 3: PROPOSED LADDERING SCHEDULE FOR AMEREN PEAK LOAD (JUNE 2012 THROUGH MAY 2017)



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.[135]

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 Ameren Illinois, 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 Ameren Illinois will be

[135] 220 ILCS 5/16-111.5(e)(2).

partially or completely exempt from the rule making outcome since Ameren Illinois 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 2012 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. However, if the procurement administrator, after consultation with the IPA, utilities, Commission, and procurement monitor, determines that financial swap contracts are preferable to contracts for physical delivery of energy, the procurement administrator will be instructed to fashion the swap contract, as previously noted in the Plan. The IPA will monitor the rule making process and recommend a course of action for procurement events beyond spring 2012 as the outcome of the current rule making process becomes clearer.

Additional elements to the supply resources plan include:

Load Balancing Procedures. Upon Commission approval of this Plan, Ameren will enter into fixed price transactions that settle physically within MISO. This will act as a hedge for the energy price risk of the portfolio since 100% of the actual energy required to supply the load included in this Plan will be purchased in the MISO energy markets with such pricing varying from hour to hour. 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.[136] 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. In late 2010, Ameren completed an internal merger of its three legacy Illinois utilities into Ameren Illinois Company. Therefore, Ameren will purchase as one entity and the previous language regarding intercompany dynamics cost and resource sharing is therefore no longer applicable.

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.

3.4.1.2 Commonwealth Edison. The IPA selects the Expected Load Model as the basis of the procurement plan for the ComEd portfolio. The Expected Load model volumes are adjusted to account for energy efficiency program and demand response results. Additionally, the contract volumes attributable to Long-term Power Purchase Agreements entered into by ComEd in December 2010 are not factored out of the projection as physical delivery of those contracted volumes to the Utility was not a contract requirement.

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*

[136] 220 ILCS 5/16-111.5(b)(4).

customers have not been declared competitive. This requirement commences June 1, 2008 and continues for 10 years."[137]

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 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 for 2012 (10.7 MW), for 2013 (10.8 MW), for 2014 (7.0 MW), for 2015 (7.0 MW), and for 2016 (7.1 MW).

The IPA anticipates requesting validation of the ability to dispatch the Energy Efficiency 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.[138] The annual aggregate reductions in ComEd's supply requirements to be acquired through the RFP process (net of customer switching) is projected to be for 2012 (756 GWh), for 2013 (934 GWh), for 2014 (1,117 GWh), for 2015 (1,288 GWh), and for 2016 (1,471 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 effectively treated as all other legacy supply contracts within the Supply Resources projections for the Utility.

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 J 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.

[137] 220 ILCS 5/8-103(c).
[138] 220 ILCS 5/8-103(b).

TABLE J: VOLUME PROJECTIONS PER RATE CLASS FOR COMED (JUNE 2012 THROUGH MAY 2015)

Contract Month	Projected Monthly Volume Requirements									
	SF MWh	MF MWh	SFSH MWh	MFSH MWh	WH MWh	Small MWh	Condo MWh	DD MWh	GL MWh	Total MWh
Jun-12	1,862,408	406,428	44,038	97,637	42,543	546,523	11,071	8,152	1,265	3,020,066
Jul-12	2,308,488	501,215	42,282	100,687	43,337	560,897	12,205	8,385	1,301	3,578,797
Aug-12	1,948,506	435,148	34,800	85,839	38,771	512,556	12,123	8,857	1,375	3,077,976
Sep-12	1,948,506	282,873	23,681	58,735	30,669	409,066	10,540	8,837	1,372	2,774,278
Oct-12	1,073,729	249,209	29,361	64,552	29,462	391,219	10,213	9,774	1,517	1,859,037
Nov-12	1,170,272	262,658	51,282	103,705	28,671	383,287	9,983	10,002	1,552	2,021,413
Dec-12	1,403,676	299,516	78,815	168,815	31,403	431,962	13,906	10,623	1,649	2,440,366
Jan-13	1,409,167	294,672	91,373	210,436	32,484	448,003	14,478	10,627	1,649	2,512,889
Feb-13	1,133,697	253,192	79,072	183,970	28,757	397,864	12,871	9,190	1,426	2,100,039
Mar-13	1,112,592	252,065	70,417	161,802	30,014	414,301	13,487	9,459	1,468	2,065,604
Apr-13	965,201	222,497	50,248	112,290	27,613	374,125	9,853	8,767	1,361	1,771,956
May-13	1,055,635	246,575	38,222	85,534	29,240	396,049	10,469	8,779	1,362	1,871,865
Jun-13	1,464,954	328,580	34,784	81,793	31,060	423,015	11,117	8,408	1,305	2,385,016
Jul-13	1,963,195	436,418	35,984	90,024	34,320	469,240	12,363	8,711	1,352	3,051,608
Aug-13	1,757,854	400,443	31,305	80,269	33,428	459,594	12,181	9,117	1,415	2,785,607
Sep-13	1,199,617	280,177	22,930	58,418	28,967	404,310	10,695	9,171	1,423	2,015,708
Oct-13	1,040,964	244,952	28,183	63,616	27,706	386,564	10,327	10,090	1,566	1,813,969
Nov-13	1,134,686	257,798	49,164	101,952	27,013	377,989	10,037	10,250	1,591	1,970,480
Dec-13	1,384,969	298,666	76,797	168,459	29,879	429,476	14,121	10,974	1,703	2,415,046
Jan-14	1,383,258	291,369	88,144	207,563	30,977	446,062	14,657	10,922	1,695	2,474,646

Feb-14	1,113,628	250,177	76,260	181,225	27,508	396,274	13,016	9,455	1,467	2,069,012
Mar-14	1,092,901	248,983	67,900	159,298	28,837	414,292	13,645	9,754	1,514	2,037,124
Apr-14	946,198	219,387	48,369	110,357	26,627	374,294	9,968	9,056	1,406	1,745,660
May-14	1,029,024	242,029	36,670	83,730	28,150	394,593	10,530	9,031	1,402	1,835,160
Jun-14	1,452,415	328,052	33,948	81,433	30,302	425,724	11,283	8,726	1,354	2,373,237
Jul-14	1,945,337	435,409	35,097	89,553	33,587	471,768	12,483	8,992	1,396	3,033,621
Aug-14	1,732,279	397,174	30,356	79,365	32,837	461,857	12,246	9,364	1,453	2,756,932
Sep-14	1,187,395	279,009	22,329	57,985	28,957	408,913	10,854	9,494	1,473	2,006,409
Oct-14	1,020,532	241,716	27,228	62,592	27,785	390,548	10,430	10,380	1,611	1,792,822
Nov-14	1,107,445	253,085	47,250	99,771	26,924	378,707	10,075	10,471	1,625	1,935,353
Dec-14	1,369,285	296,810	74,719	166,852	30,358	436,377	14,327	11,309	1,755	2,401,792
Jan-15	1,351,739	286,137	84,775	203,173	31,204	449,047	14,740	11,142	1,729	2,433,686
Feb-15	1,092,068	246,487	73,589	177,975	27,792	400,067	13,128	9,694	1,505	2,042,303
Mar-15	1,076,652	246,482	65,833	157,178	29,284	420,315	13,832	10,061	1,561	2,021,196
Apr-15	925,595	215,766	46,588	108,177	26,869	377,465	10,043	9,307	1,444	1,721,255
May-15	1,003,006	237,302	35,210	81,828	28,248	395,825	10,548	9,242	1,434	1,802,644

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 K below with the full 2012 to 2017 planning period presented in Attachment G.

TABLE K: AGGREGATED MONTHLY AND AVERAGE LOAD REQUIREMENTS FOR COMED (JUNE 2012 THROUGH MAY 2015)

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-12	1,568,749	1,451,317	4,669	3,779
July-12	1,809,454	1,769,343	5,385	4,337
August-12	1,688,548	1,389,427	4,588	3,695
September-12	954,040	1,102,331	3,138	2,650
October-12	999,814	859,223	2,717	2,285
November-12	1,020,449	1,000,964	3,037	2,607
December-12	1,129,692	1,310,674	3,530	3,091
January-13	1,264,666	1,248,223	3,593	3,184
February-13	1,058,886	1,041,153	3,309	2,958
March-13	993,346	1,072,258	2,956	2,628
April-13	930,291	841,665	2,643	2,287
May-13	963,004	908,861	2,736	2,319
June-13	1,175,669	1,209,348	3,674	3,023
July-13	1,612,265	1,439,343	4,580	3,672
August-13	1,464,536	1,321,071	4,161	3,370
September-13	986,577	1,029,132	3,083	2,573
October-13	974,360	839,609	2,648	2,233
November-13	943,983	1,026,497	2,950	2,566
December-13	1,169,558	1,245,488	3,481	3,053
January-14	1,242,992	1,231,654	3,531	3,142
February-14	1,040,543	1,028,468	3,252	2,922

March-14	976,649	1,060,475	2,907	2,599
April-14	913,947	831,714	2,596	2,260
May-14	898,386	936,775	2,674	2,296
June-14	1,224,319	1,148,917	3,644	2,992
July-14	1,605,164	1,428,456	4,560	3,644
August-14	1,386,463	1,370,469	4,126	3,359
September-14	1,033,636	972,772	3,076	2,533
October-14	962,032	830,789	2,614	2,210
November-14	880,123	1,055,230	2,895	2,537
December-14	1,214,847	1,186,945	3,451	3,028
January-15	1,167,389	1,266,297	3,474	3,104
February-15	1,029,790	1,012,513	3,218	2,876
March-15	1,014,723	1,066,474	2,883	2,721
April-15	898,846	822,409	2,554	2,235
May-15	838,075	964,569	2,619	2,275

Energy required by the Eligible Retail Customers comes from four sources. First, the swap contract with ExGen provides a financial hedge on 3,000 MW of ATC energy during the June 2012 – 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.

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,[139] 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 2012 and May 2015, 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.

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.

[139] 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.

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 L and M. A full schedule of related planned procurement loads for ComEd can be found in Attachment H[140].

TABLE L: PROPOSED COMED PEAK LOAD VOLUMES TO SECURE IN 2012 CYCLE (JUNE 2012 THROUGH MAY 2015)

Contract Month	Peak Contract Volumes to Secure (MW)				
	Projected Volume (MW)	Swap Volumes (MW)	2011 Procurement Volumes (MW)	Residual Volumes (MW)	2012 IPA Procurement (MW)
June-12	4,669	3,000	600	1,069	1,050
July-12	5,385	3,000	1,500	885	900
August-12	4,588	3,000	1,150	438	450
September-12	3,138	3,000	-	138	150
October-12	2,717	3,000	-	(283)	-
November-12	3,037	3,000	-	37	50
December-12	3,530	3,000	-	530	550
January-13	3,593	3,000	-	593	600
February-13	3,309	3,000	-	309	300
March-13	2,956	3,000	-	(44)	-
April-13	2,643	3,000	-	(357)	-
May-13	2,736	3,000	-	(264)	-
June-13	3,674	-	1,800	1,874	750
July-13	4,580	-	2,250	2,330	950
August-13	4,161	-	2,100	2,061	800
September-13	3,083	-	1,300	1,783	850
October-13	2,648	-	1,350	1,298	500
November-13	2,950	-	1,450	1,500	600

December-13	3,481	-	1,750	1,731	700
January-14	3,531	-	1,500	2,031	950
February-14	3,252	-	1,600	1,652	700
March-14	2,907	-	1,400	1,507	650
April-14	2,596	-	1,300	1,296	500
May-14	2,674	-	1,350	1,324	500
June-14	3,644	-	-	3,644	1,300
July-14	4,560	-	-	4,560	1,600
August-14	4,126	-	-	4,126	1,450
September-14	3,076	-	-	3,076	1,100
October-14	2,614	-	-	2,614	900
November-14	2,895	-	-	2,895	1,000
December-14	3,451	-	-	3,451	1,200
January-15	3,474	-	-	3,474	1,200
February-15	3,218	-	-	3,218	1,150
March-15	2,883	-	-	2,883	1,000
April-15	2,554	-	-	2,554	900
May-15	2,619	-	-	2,619	900

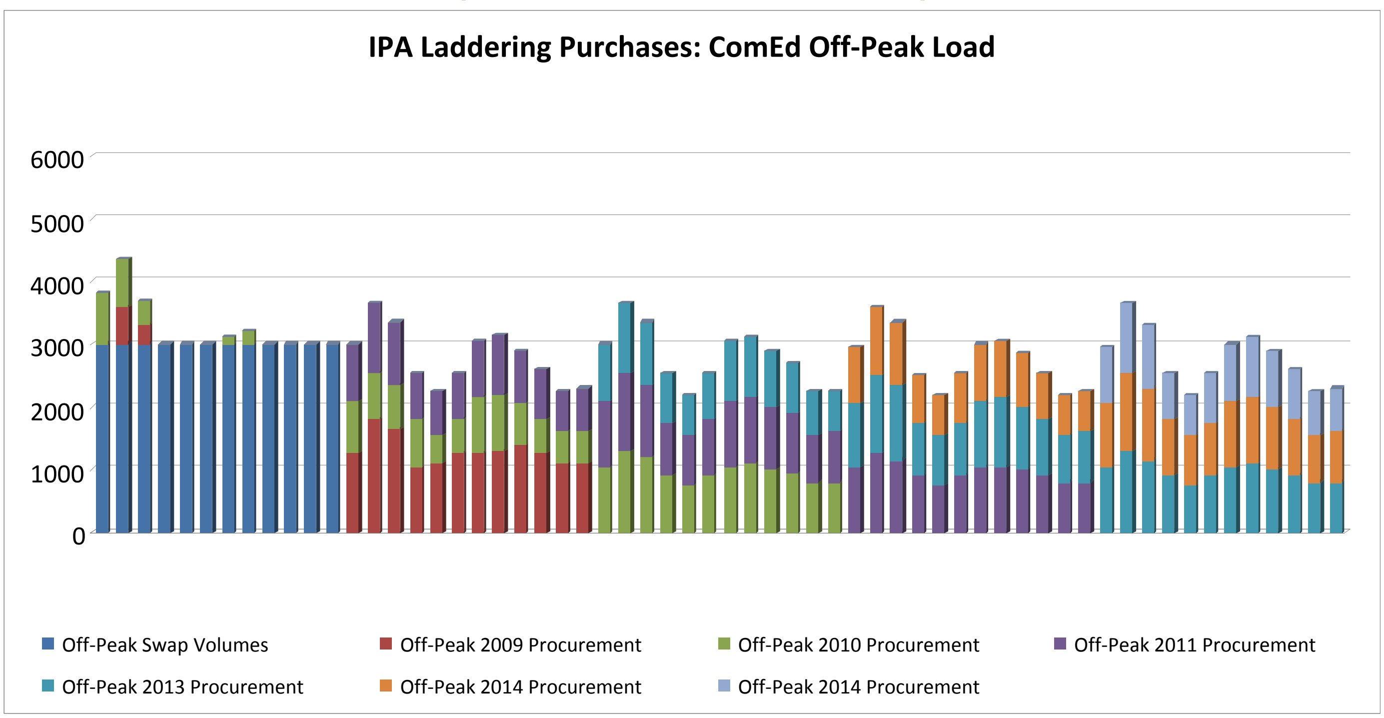
TABLE M: PROPOSED COMED OFF-PEAK LOAD VOLUMES TO SECURE IN 2012 CYCLE (JUNE 2012 THROUGH MAY 2015)

Contract Month	Off-Peak Contract Volumes to Secure (MW)				
	Projected Volume (MW)	Swap Volumes (MW)	2011 IPA Procurement (MW)	Residual Volumes (MW)	2012 IPA Procurement (MW)
June-12	3,779	3,000	-	779	800
July-12	4,337	3,000	600	737	750
August-12	3,695	3,000	300	395	400
September-12	2,650	3,000	-	(350)	-
October-12	2,285	3,000	-	(715)	-
November-12	2,607	3,000	-	(393)	-
December-12	3,091	3,000	-	91	100
January-13	3,184	3,000	-	184	200
February-13	2,958	3,000	-	(42)	-
March-13	2,628	3,000	-	(372)	-
April-13	2,287	3,000	-	(713)	-
May-13	2,319	3,000	-	(681)	-
June-13	3,023	-	1,250	1,773	850
July-13	3,672	-	1,800	1,872	750
August-13	3,370	-	1,650	1,720	700
September-13	2,573	-	1,050	1,523	750
October-13	2,233	-	1,100	1,133	450
November-13	2,566	-	1,250	1,316	550

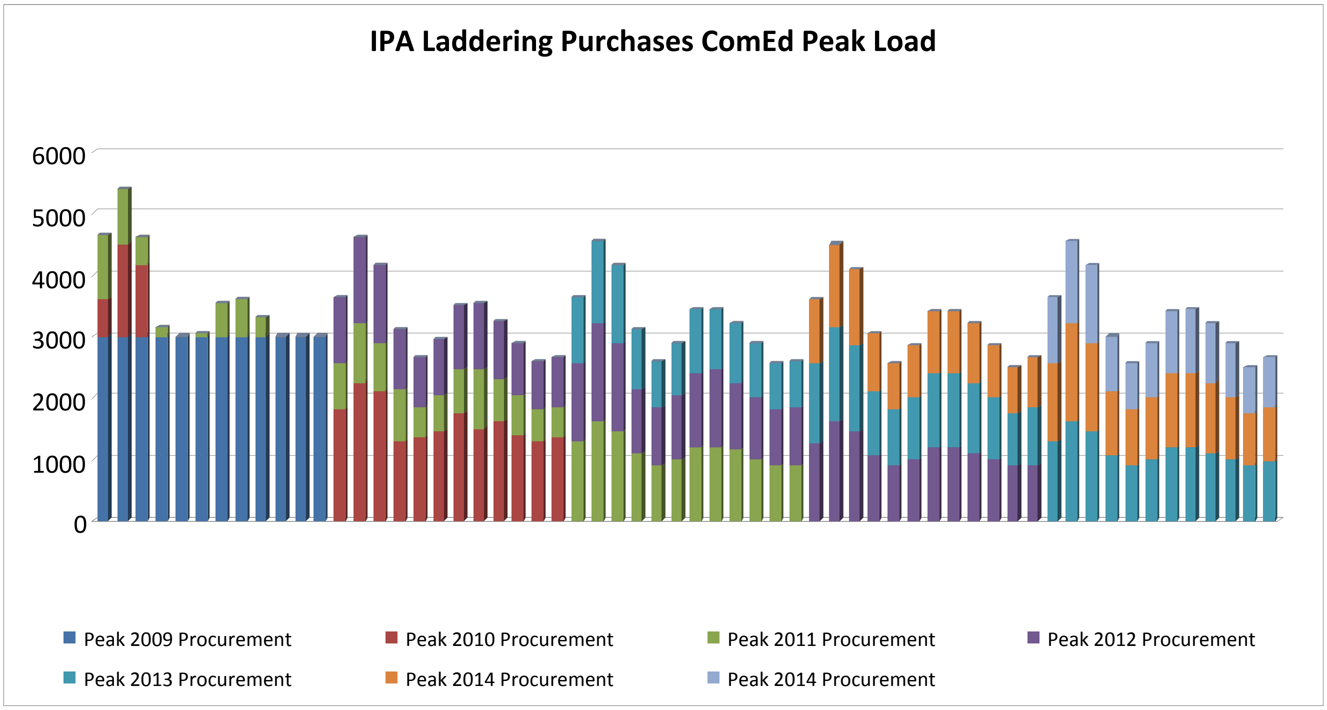
December-13	3,053	-	1,250	1,803	900
January-14	3,142	-	1,300	1,842	900
February-14	2,922	-	1,400	1,522	650
March-14	2,599	-	1,250	1,349	550
April-14	2,260	-	1,100	1,160	500
May-14	2,296	-	1,100	1,196	500
June-14	2,992	-	-	2,992	1,050
July-14	3,644	-	-	3,644	1,300
August-14	3,359	-	-	3,359	1,200
September-14	2,533	-	-	2,533	900
October-14	2,210	-	-	2,210	750
November-14	2,537	-	-	2,537	900
December-14	3,028	-	-	3,028	1,050
January-15	3,104	-	-	3,104	1,100
February-15	2,876	-	-	2,876	1,000
March-15	2,721	-	-	2,721	950
April-15	2,235	-	-	2,235	800
May-15	2,275	-	-	2,275	800

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 2012 THROUGH MAY 2017)



GRAPH 5: PROPOSED LADDERING SCHEDULE FOR COMED PEAK LOAD (JUNE 2012 THROUGH MAY 2017)



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.[141]

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:

[141] 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.

While the IPA recommended the procurement of Energy Efficiency as Alternative Resource ("EEAR"), the Commission did not approve it for inclusion in this Plan. The IPA may recommend future consideration of the purchase of 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.

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.

3.5 Capacity Resource.

Special challenges as associated with meeting the Illinois Renewable Portfolio Standard. Capacity resources must be secured to support wholesale supply contracts entered into by the Utilities. Tables N and O below outline those challenges and the general procurement approaches the IPA recommends for use in satisfying capacity requirements.

TABLE N: OVERVIEW OF KEY ENERGY RESOURCE ISSUES

Key Capacity Resource Issues	
Ameren Illinois Utilities	Commonwealth Edison

▪ Capacity markets are bilateral ▪ MISO has proposed a forward capacity market ▪ MISO capacity market proposal may be litigated ▪ **Existing Demand Response (DR) programs do not appear to be in operation.**	▪ Capacity markets are centralized within PJM ▪ PJM RPM process provides 3-year forward curve ▪ Capacity costs rise through 2012, 2013, and 2014 ▪ **Existing Demand Response (DR) programs appear to reduce IPA portfolio capacity requirements.**

TABLE O: OVERVIEW OF PRIMARY PLAN INCLUSIONS FOR ENERGY RESOURCES

Primary Capacity Resource Measures	
Ameren Illinois Utilities	Commonwealth Edison
▪ IPA secure capacity through direct solicitation ▪ Secure one-year capacity requirements ▪ Do not reduce capacity procurement volumes by projected DR program performance.	▪ Utility secure capacity via the PJM RPM offering ▪ Secure capacity requirements as necessary ▪ Reduce capacity procurement volumes by projected DR program

3.5.1 Background. Ameren and ComEd acquire capacity resources to meet ISO requirements tied to reliability.

3.5.2 Evaluation. Ameren and ComEd are obligated by the MISO and PJM Tariffs to secure specific capacity resource volumes. PJM has created and maintains a forward market to set prices for capacity; securing capacity resources for ComEd load via this market tool is a means by which the resources can be secured at a competitive rate~~ with no need for a separate procurement event~~. MISO operates on a bi-lateral contracting basis; the only option for Ameren is to conduct a procurement event.

3.5.3 Recommendations. The IPA recommends the following measures with regard to Ameren and ComEd transmission arrangements:

3.5.3.1 Ameren Illinois Utilities. 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 filed at FERC. Initially planned to be filed in December of 2010, MISO ultimately filed tariff modifications and enhancements to Module E on July 20, 2011. These enhancements include moving to an annual forward construct and thus moving away from the current monthly construct. The new modifications also address zonal delivery and pricing concepts. MISO has requested FERC order an effective date of October 1, 2012 and has requested an order from FERC no later than February 29, 2012 which will be after the Commission order relative to this Plan.

For the planning year 2012, MISO will utilize its existing tariff which is based on monthly resource requirements. The IPA will therefore procure 100% of the Capacity required to fully comply with the MISO resource adequacy requirements for the 2012 planning year with such quantities based on monthly requirements. For planning years 2013 and 2014, the IPA proposes to procure 50% and 35% respectively of the annual Capacity based on MISO's anticipated change to an annual forward construct. The IPA notes that FERC has not ordered on the MISO proposal and it's possible that the MISO proposal may be modified or rejected outright. As a solution, the IPA proposes that the Commission approve the IPA proposal to pursue annual Capacity for 2013 and 2014. But the IPA also asks that the Commission acknowledge the dynamic nature of the MISO proposal and therefore authorize the IPA to make modifications to this plan as warranted during the 2012 procurement process after consultation with the Procurement Administrator, Procurement

Monitor, ICC Staff and Ameren Illinois.

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

Contract Month	Peak Load	Transmiss. Losses	Net Peak Load	Planning Reserves	Capacity Req.	2009 Purchase	2010 Purchase	2011 Purchase	% Hedged
June-12	3,675	83	143	3,901	0	1,440	0	2,470	100%
July-12	4,139	93	161	4,393	0	1,570	0	2,830	100%
August-12	4,181	94	163	4,438	0	1,530	0	2,910	100%
September-12	3,573	80	139	3,792	0	1,410	0	2,390	100%
October-12	2,490	56	97	2,643	0	920	0	1,730	100%
November-12	2,314	52	90	2,456	0	900	0	1,560	100%
December-12	2,781	63	108	2,952	0	1,200	0	1,760	100%
January-13	2,949	66	115	3,130	0	1,180	0	1,950	100%
February-13	2,702	61	105	2,868	0	1,080	0	1,790	100%
March-13	2,225	50	87	2,361	0	950	0	1,420	100%
April-13	2,056	46	80	2,182	0	810	0	1,380	100%
May-13	2,619	59	102	2,780	0	940	0	1,840	100%

The IPA proposes undertaking capacity procurement into future years during the 2012 procurement cycle. This will result in a hedge of approximately 50% of the capacity requirement for the 2013 planning year (June 2013 through May 2014), and 35% of the capacity requirement for the 2014 planning year (June 2014 through May 2015) as detailed in Table Q:

TABLE Q: PROPOSED AMEREN CAPACITY CONTRACT VOLUMES TO SECURE IN 2012 CYCLE (JUNE 2013 THROUGH MAY 2015)

<table>
<tr><th>Contract Month</th><th>Peak Load</th><th>Transmission Losses</th><th>Planning Reserves</th><th>Capacity Requirement</th><th>2009 Purchases</th><th>2010 Purchases</th><th>2011 Purchases</th><th>2012 Purchases</th><th>% Hedged</th></tr>
<tr><td>June-13</td><td>3,679</td><td>83</td><td>143</td><td>3,906</td><td>0</td><td>0</td><td>0</td><td rowspan="12">2,230</td><td rowspan="12">50%</td></tr>
<tr><td>July-13</td><td>4,130</td><td>93</td><td>161</td><td>4,384</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>August-13</td><td>4,189</td><td>94</td><td>163</td><td>4,447</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>September-13</td><td>3,567</td><td>80</td><td>139</td><td>3,786</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>October-13</td><td>2,497</td><td>56</td><td>97</td><td>2,651</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>November-13</td><td>2,341</td><td>53</td><td>91</td><td>2,485</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>December-13</td><td>2,799</td><td>63</td><td>109</td><td>2,971</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>January-14</td><td>2,954</td><td>66</td><td>115</td><td>3,136</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>February-14</td><td>2,718</td><td>61</td><td>106</td><td>2,885</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>March-14</td><td>2,229</td><td>50</td><td>87</td><td>2,366</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>April-14</td><td>2,052</td><td>46</td><td>80</td><td>2,178</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>May-14</td><td>2,571</td><td>58</td><td>100</td><td>2,729</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>June-14</td><td>3,557</td><td>80</td><td>139</td><td>3,776</td><td>0</td><td>0</td><td>0</td><td rowspan="12">1,520</td><td rowspan="12">35%</td></tr>
<tr><td>July-14</td><td>4,004</td><td>90</td><td>156</td><td>4,250</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>August-14</td><td>4,071</td><td>92</td><td>159</td><td>4,321</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>September-14</td><td>3,454</td><td>78</td><td>135</td><td>3,666</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>October-14</td><td>2,390</td><td>54</td><td>93</td><td>2,537</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>November-14</td><td>2,242</td><td>50</td><td>87</td><td>2,380</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>December-14</td><td>2,695</td><td>61</td><td>105</td><td>2,861</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>January-15</td><td>2,822</td><td>63</td><td>110</td><td>2,996</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>February-15</td><td>2,588</td><td>58</td><td>101</td><td>2,747</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>March-15</td><td>2,122</td><td>48</td><td>83</td><td>2,252</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>April-15</td><td>1,957</td><td>44</td><td>76</td><td>2,078</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>May-15</td><td>2,514</td><td>57</td><td>98</td><td>2,668</td><td>0</td><td>0</td><td>0</td></tr>
</table>

3.5.3.2 Commonwealth Edison. 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 2012 - May 2015 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.

3.6 Renewable Energy Resource. Special challenges are associated with meeting the Illinois Renewable Portfolio Standard. Tables R and S below outline those challenges and the general procurement approaches the IPA recommends for use in satisfying the RPS goal.

TABLE R: OVERVIEW OF KEY RENEWABLE ENERGY RESOURCE ISSUES

Key Renewable Energy Resource Issues
Ameren Illinois Utilities and Commonwealth Edison
▪ The Renewable Portfolio Standard (RPS) may be met by securing Renewable Energy Credits (RECs) or RECs plus the associated power outputs. ▪ The RPS must be satisfied with a 75% carve-out for wind power, and an eventual 6% carve-out for solar. ▪ In the current market, wind RECs demand a very low price while solar RECs carry a very high price. ▪ The annual Renewable Resources Budget (RRB) establishes a cap that prevents the RPS from increasing consumer costs by more than 2.015% ▪ The annual RRB is expected to decline over time as the total IPA portfolio volumes decline ▪ Approximately 1.9 million RECs of variable costs are to be delivered to the Utilities between June 2012 and May 2033 ▪ **Commitments to purchase Renewable Energy Resources <u>cannot</u> exceed the annual RRB**

TABLE S: OVERVIEW OF PRIMARY RENEWABLE ENERGY RESOURCE MEASURES

Primary Renewable Energy Resource Measures
Ameren Illinois Utilities and Commonwealth Edison
▪ Project conservative annual Renewable Resources Budget (RRB) for the next 20 compliance years ▪ Utilize statutory thresholds and a confidential future price curve generated by the IPA and submitted to the ICC to back out Long Term Power to yield a Net Renewable Resources Budget (NRRB) for ▪ Factor each annual NRRB by 50% and solicit RECs bids for up to the 20 year horizon using the factored NRRB as a hard budget limit. ▪ Sort bids according to price and source (solar, wind, etc.) ▪ Select bids in a manner that yields at least the minimum carve out requirements are met when the LTPPA volume are added to the new REC volumes.

3.5.4 Background. 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[142]

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.[143]

The statute also applies a cost cap to the process where the cost of compliance must not exceed a formula rate. The annual volume and cost cap standards are presented in the following table:

TABLE T: RPS STANDARDS FOR AMEREN AND COMED

Delivery period	Minimum Percentage (Annual volume goal)	Maximum Cost Standard
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, 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
2015-2016	10% 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
2016-2017	11.5% 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

It is important to note that the volume goals and cost caps for the IPA are variable. As retail competition develops in Illinois, the IPA expects that the RPS volume goals as the available budgets will diminish over time.

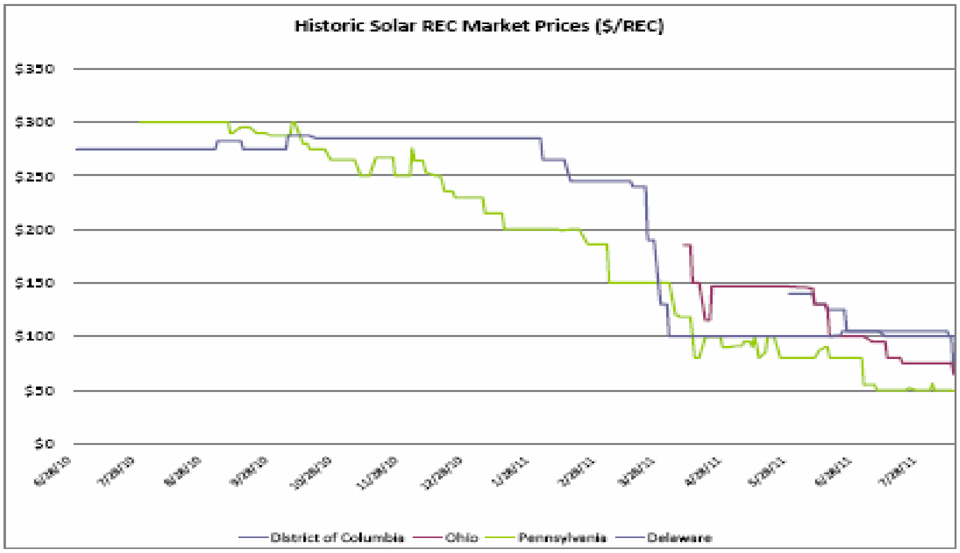
In prior years, the RPS obligation was met through the purchase of RECs only. This approach proved sufficient to meet RPS volume goals while observing the statutory budget constraints. In December 2010, a series of 20-year Long-Term Power Purchase Agreements (LTPPA) were entered. The LTPPAs specified a bundled purchase of energy plus RECs from renewable resources.

[142] 20 ILCS 3855/1-75(c)(1)
[143] 20 ILCS 3855/1-10.

Under these contracts, a single price was set for the bundled product (energy plus REC) with a 2% per annum cost escalator over the term of the contracts. The cost of the energy included in the product was to be paid as a standard index energy contract, with the unit price set at variable market index. The cost of the REC was to be paid out of the Renewable Resources Budget (RRB), with the unit price set at the contract cost minus the variable market index energy cost.

Lastly, the IPA Act requires that 75% of the RPS be met with wind resources and eventually 6% by solar resources. Recent solicitations for short term wind RECs within the region indicate that market prices for those assets range around $1/REC. Solar RECs are less plentiful and thus more expensive than wind RECs; however, the costs of solar RECs in other states appear to be dropping. Graph 6 presents historical price data for solar RECS dating back to June of 2010:

GRAPH 6: HISTORIC SOLAR REC COSTS



3.5.5 Evaluation. Meeting the RPS obligation is growing more complicated over time with volume requirements, budgets, and the costs of pre-existing contract obligations all operating in a variable manner. Additionally, because the forward cost curve governing the applied costs for RECs delivered under the LTPPAs is confidential, a final RRB for each utility cannot be presented in this Draft Plan.

The confidential forward price curve for energy is a critical component to establishing annual Renewable Resource Budgets developed by the IPA, Procurement Administrators, Commission Staff, and the Procurement Monitor to aid in establish which portion of the annual RRB is to be allocated to the LTPPA contract costs. Therefore, the cost of the long-term obligations is not a known variable and is subject to change over time.

For the purposes of this Draft Plan, the IPA observes that a comprehensive procurement system for renewable is necessary. The presence of the competing solar and wind carve-outs and their wide cost differences coupled with revenue variance increases the risk of the IPA portfolio not meeting its procurement goals in future years.

3.5.6 Recommendations. More than any other section of the Draft Plan, the IPA seeks inputs on the following recommendations from consumers, renewable asset developers, Utilities, and regulators.

The IPA recommends the following method to be used to meet the RPS obligations for the 2012-2013 compliance year and beyond:

- Establish a conservative Renewable Resources Budget for 20 years
  - Estimate the annual portfolio requirements for the next 20 years. Utilize current Utility Low Scenario projections to establish portfolio volumes for the first five year, then continue those projections trendlines over the next 15 years. The result will be a portfolio volume that represents the highest level of estimated consumer switching away from the IPA portfolio;
  - Consistent with the Act, apply the Rate Cap to the 20 year volumes to establish annual Renewable Resource Budgets (RRBs) for each year in the series;

  - Apply the confidential future price curve generated by the IPA and submitted to the ICC to back out Long Term Power Purchase Agreements (LTPPA) cost obligations from the RRB to yield a Net Renewable Resources Budget (NRRB) for each of the future years.
  - Factor each annual NRRB by 50% and solicit RECs bids for up to the 20 year horizon using the factored NRRB as a hard budget limit.
- Conduct procurements that yield carve-out consistent contracts for solar and wind
  - Invite bids for periods of up to 20 years from renewable generators (allow single year as well as multi-year bids for resources)
  - Select only those bids that fit beneath the NRBB
  - Sort bids according to price and source (solar, wind, etc.)
  - Select bids in a manner that yields at least the minimum carve out requirements are met when the LTPPA volume are added to the new REC volumes.

The proposed approach would facilitate offers from short term REC bidders seeking contracts for low price RECs who would be more likely to bid into the near years of the 20 year period. Longer term offers would be possible insofar as the costs of those bids coupled with existing LTPPAs do not over-obligate the RRB. In addition to the above, the IPA recommends the following:

Pricing Benchmark. The Procurement Administrators will be directed to continue to establish benchmark REC prices, 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. Because renewable energy resources are being procured for a period after June 1, 2011, the State of Illinois preference no longer applies.

Compliance Tracking. 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).

3.5.6.1 Ameren Illinois Utilities. 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 is 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 U 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.

TABLE U: 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
2012-2013	2010-2011	16,048,235	7.00%	1,123,376

Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables V and X below presents the Annual Renewable Energy Resource Budgets resulting from the application of the statute's standards to the Ameren portfolio for planning year 2012-2013.

TABLE V: ANNUAL AMEREN RRB CALCULATIONS – OPTION A

Option A (Incremental Increase from Prior Year)		
IPA Supply Portfolio Calculations (RRB)	**2012-2013**	
(A) Incremental amount per MWh paid in 2011	$	0.0580
(B) Planning Year Projected Total Delivery Volume		14,389,577
(C) Planning Year Option A Cost Cap [A * B]	$	834,595
HEP Supply Portfolio Calculations (RRB)		
(D) Compliance Year Budget	$	459,907
Total IPA RRB Calculations		
(E) Gross Budget [C + F]	**$**	**1,294,502**

TABLE W: ANNUAL AMEREN RRB CALCULATIONS – OPTION B

Option B (Percentage Increase on Base year)		
IPA Supply Portfolio Calculations (RRB)	**2012-2013**	
(A) Base year volume for eligible retail customers (MWH)		17,658,276
(B) Base year cost for eligible retail customers	$	1,582,184,107
(C) Base year Average Delivered Electricity Unit Cost - [B / A]	$	89.6001
(D) Planning Year Incremental RPS Cost Limit		2.015%
(E) Planning Year Maximum Unit Cost Increase [C * D]	$	1.8054
(F) Planning Year Projected Total Delivery Volume (MWH)		14,389,577
(G) Compliance Year Budget [E * F]	$	25,978,942
HEP Supply Portfolio Calculations (RRB)		
(H) Compliance Year Budget	$	459,907
Total IPA RRB Calculations		
(I) Gross Budget [G + H]	**$**	**26,438,849**

3.5.6.2 Commonwealth Edison. 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 X below cites the volume goals.

Table U below presents the Annual Volume Targets resulting from the application of the statute's standards to the ComEd portfolio for planning year 2012-2013.

TABLE X: 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
2012-2013	2010-2011	37,105,686	7.00%	2,597,398

Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables Y and Z below presents the Annual Renewable Energy Resource Budgets resulting from the application of the statute's standards to the ComEd portfolio for planning year 2012-2013.

TABLE Y: ANNUAL COMED RRB CALCULATIONS – OPTION A

Option A (Incremental Increase from Prior Year)	
IPA Supply Portfolio Calculations (RRB)	**2012-2013**
(A) Incremental amount per MWh paid in 2011	$ 0.0570
(B) Planning Year Projected Total Delivery Volume	26,796,137
(C) Planning Year Option A Cost Cap [A * B]	$ 1,527,380
HEP Supply Portfolio Calculations (RRB)	
(D) Compliance Year Budget	$ 1,462,037
Total IPA RRB Calculations	
(E) Gross Budget [C + D]	**$ 2,989,417**

TABLE Z: ANNUAL COMED RRB CALCULATIONS – OPTION B

Option B (Percentage Increase on Base year)	
IPA Supply Portfolio Calculations (RRB)	**2012-2013**
(A) Base year volume for eligible retail customers (MWH)	39,802,463
(B) Base year cost for eligible retail customers	$ 3,736,750,000
(C) Base year Average Delivered Electricity Unit Cost - [B / A]	$ 93.8824
(D) Planning Year Incremental RPS Cost Limit	2.015%
(E) Planning Year Maximum Unit Cost Increase [C * D]	$ 1.8917
(F) Planning Year Projected Total Delivery Volume (MWH)	26,796,137
(G) Compliance Year Budget [E * F]	$ 50,691,056
HEP Supply Portfolio Calculations (RRB)	

(H) Compliance Year Budget	$	1,462,037
Total IPA RRB Calculations		
(I) Gross Budget [G + H]	**$**	**52,153,093**

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

3.6 Transmission Resources.

3.6.1 Background. Ameren and ComEd acquire certain transmission-related products and services to effectuate delivery of power and energy to the applicable loads. These services may include Network Transmission Service and Ancillary Services. Further, Ameren may be allocated certain Financial Transmission/Auction Revenue Rights.

3.6.2 Evaluation. Ameren and ComEd are obligated by the MISO and PJM Tariffs to secure specific certain transmission service related products. As these are tariff mandated and governed transactions, the IPA procurement plan validates those obligations.

3.6.3 Recommendations. The IPA recommends the following measures with regard to Ameren and ComEd transmission arrangements:

3.6.3.1 Ameren Illinois Utilities. Network Transmission Service, and Ancillary Services as well as Financial Transmission/Auction Revenue Rights for Ameren should be managed as follows:

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 2011 ARR allocation process at MISO, Ameren received a set of ARR entitlements and were awarded ARRs for the 2011 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.

3.7.3.2 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.

4.0 Additional Issues

4.1 Clean Coal. Section 75 of the IPA Act includes a requirement that annual procurement plans include electricity generated by clean coal facilities. Moreover**,** it is the goal of the State that by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities. Consistent with the statute, and to further demonstrate the viability of coal and advance environmental protection goals, the Agency plans to seek proposals for both Utilities for up to 250 MW of electricity generated by advanced clean coal technologies that capture and sequester carbon dioxide emissions. The Agency will accept proposals from existing clean coal facilities, clean coal facilities that are under development, and qualifying coal-fired power plants previously owned by Illinois utilities that have been converted or will be converted into clean coal facilities. If a proposal is accepted and approved by the Commission, the project sponsor and both Utilities will enter into long-term (20 years or greater) sourcing agreements. The Agency will solicit proposals from entities that demonstrate that they have made significant progress to meeting a commercial in-service date of December 31, 2017 as measured by the following criteria prior to proposal submission.

TABLE AA: GENERALIZED SPECIFICATIONS FOR CLEAN COAL CANDIDATES

Item	Criteria
Clean Coal Facility Site Control	Executed option agreement(s) or ownership for all property rights necessary to construct the clean coal facility Note the additional requirements for CO_2 storage rights below.
CO_2 Storage Rights	Executed option agreement(s) or ownership of sufficient pore space in the Mount Simon deep saline geologic storage formation to support at least 20 years of CO_2 storage or for the duration of the proposed Power Purchase Agreement, whichever is greater.
Environmental Impact Statement (EIS)	If applicable, demonstrate that a draft EIS, final EIS or Record of Decision has been issued by the appropriate federal agency
PSD (Air) Permit	Demonstrate that a PSD (Air) Permit has either been issued, or an application has been filed with the Illinois EPA.

Class VI Underground Injection Control (UIC) Permit	Demonstrate that a the Class VI UIC Permit has been issued or an application has been filed with the United States EPA or other applicable agency
Transmission Capacity or Interconnection Agreement	Demonstrate available transmission capacity for the entire output of the facility or a completed Feasibility Study with Regional Transmission Operator or other agency as appropriate
Engineering Design	Demonstrate that a pre-Front End Engineering and Design (FEED) study for the clean coal facility has been completed.
Carbon Capture Rate	Consistent with the statute demonstrate a viable plan that provides for capturing and sequestering at least 50% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation before 2016, at least 70% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation during 2016 or 2017, and at least 90% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation after 2017.
Fuel Input	Constituent with the statute[1] >85% of thermal input must be coal, of which >50% shall have high value bituminous rank and greater than 1.7 pounds of sulfur per million Btu content
Electricity Output	>[85]% of thermal output must be electricity
Project Sponsor(s)	Demonstrate a viable plan for securing all of the necessary capital required to support the development, engineering, construction and startup and commissioning of the clean coal facility

4.2 Demand Response.

4.3 4.2.1 **Background.** Section 220 ILCS 5/16-111.5(b)(3)(ii).of the IPA Act requires the annual procurement 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.[144]

~~Past recommendations to include the procurement of Demand Response products where the cost of demand response is lower than procuring comparable capacity products have been rejected by the Commission.~~

4.2.2 Recommendations.

4.2.2.1 Commonwealth Edison. Demand response capacity procured from Eligible Retail Customers of ComEd would be procured through a separate, stand-alone procurement held in Spring of 2012. The RFP will ask for bids for three, five and ten year contracts. The product requested in the RFP will be capacity from residential and small commercial customers, for which the demand response provider, not the utilities, would be fully responsible for delivery when called by the utility or PJM. The procurement administrator, in conjunction with Illinois Commerce Commission Staff, IPA Staff and the procurement monitor, shall establish a market price benchmark for these bids pursuant to 220 ILCS 5/16-111.5(d)(3) in the following manner: the weighted average price of (a) the procurement administrator's projected average price of excess capacity credits in the PJM market for the first three years of the contract, and (b) the average price of capacity projected by the procurement administrator for years four through ten, as applicable.

4.2.2.2 Ameren Illinois Utilities. The RFPs for capacity resources will allow demand response capacity procured from Eligible Retail Customers of Ameren to bid and will be designed so that sufficient cost-effective demand response resources are acquired to reduce Ameren's peak demand for Eligible Retail Customers through demand response measures by 0.1% over the prior year.

This Draft Plan proposes that the IPA conduct a series of workshops prior to the Spring 2012 procurement events to discuss procurement issues in advance of the RFPs. ~~The workshops will seek to establish the following and report to the Commission the generalized findings:~~

- ~~The value of demand response assets in the Illinois market~~
- ~~The viability of soliciting demand response resources in the current market~~
- ~~The terms under which demand response providers would deliver demand response assets, and how those assets would be applied to the benefit of the IPA portfolio~~

[144] 220 ILCS 5/16-111.5(b)(3)(ii).