2013

ILLINOIS
POWER AGENCY

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[ELECTRICITY PROCUREMENT PLAN]

Prepared in accordance with the Illinois Power Agency and Illinois Public Utilities Acts
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2013 Electricity Procurement Plan

1.0 Executive Summary

A Transition Year

This is the fifth electricity and renewable resource procurement plan (the "Plan", "2013 Procurement Plan") prepared by the Illinois Power Agency ("IPA" or "Agency") under the authority granted to it under the Illinois Power Agency Act ("IPA Act") and as further regulated by the Illinois Public Utilities Act ("PUA"). Section 2.0 of this plan describes the specific legislative authority and requirements to be included in any such plan. The Plan deals with the provision of electricity and renewable resource supply for the "eligible retail customers" of Ameren Illinois ("Ameren") and Commonwealth Edison ("ComEd"), generally residential and small commercial fixed price customers who have not chosen service from an alternate supplier, for a 5-year planning horizon that begins with the 2013-2014 delivery year and lasts through the 2017-2018 delivery year.

Despite the fact that several plans precede this one, this plan is not to be mistaken as a *pro forma* exercise in regulatory compliance. Illinois began its successful journey down the road of deregulated competitive markets for retail electricity supply in December 1997 with a competitive transition period that lasted through 2006. Since 2006, retail competitive markets have continued to flourish, with recent advances fostered by wide-spread municipal aggregation efforts. More recently, both ComEd and Ameren have experienced dramatic reductions in retail load serving obligations since the overwhelmingly successful March 2012 referenda authorizing opt-out aggregation of customers and the consequent opportunities for substantial savings on the supply portion of customers' bills. The utility load forecasts which underpin this supply procurement plan project significantly lower utility loads than did prior plans. These load forecasts are described in Section 3.0 of this Plan.

On the supply side, both Ameren and ComEd have a pre-existing portfolio of supply already procured and under contract. Section 4.0 of this Plan describes the nature of the pre-existing portfolio, which was designed to achieve low cost, reliable service and price stability over time. As this Section illustrates, however, the portfolio of pre-existing supply was procured without the benefit of witnessing the dramatic shift residential and small commercial customers have made to exploring competitive retail markets, at least as they exist today in Illinois. Therefore, particularly for the 2013-14 delivery year, there is significant apparent oversupply in the base case forecast.

Given the unprecedented (in Illinois) load shift, there is a need to recalibrate the supply and demand balance point for the retail electricity customers served by this Plan. The 2013-14 delivery year is the transition year in which the oversupply of current contracts winds down; and the utility supply portfolios can then start with a "clean slate" going forward. That is not to say that the IPA, stakeholders, or the Commission may assume that the utility load serving requirements are permanently altered to a lower level. Constant vigilance and analysis, and prudent risk management strategies must be maintained. The annual filing of IPA Procurement Plans allows for future adjustments to be made. Fortunately, Illinois retail electricity customers have the benefit of strong regional transmission organizations, PJM and MISO, which further assure supply reliability, transparent wholesale prices, and capacity, energy and ancillary service products designed to provide appropriate risk management tools. Section 5.0 of this Plan describes the MISO and PJM resource adequacy outlook and Section 6.0 discusses the current wholesale market outlook and risk management tools available to assure a responsible approach to portfolio management.

The Action Plan

The analysis of procurement options in this Plan, contained in Section 7.0, concludes that there is little in terms of electricity supply resources to be purchased in the 2013 Procurement Process. This holds true, as well, for renewable resources, which are discussed and analyzed in Section 8.0. A large part of the existing renewable resource portfolio for both utilities consists of pre-existing 20-year contracts executed in 2010. Payments under these contracts are forecasted to exceed the legislatively-mandated price caps for renewable resources for some or all of the delivery years in the planning horizon. Therefore, this Plan proposes to curtail purchases under those contracts in order to keep the purchase of renewables under the spending cap. The IPA is considering using its Renewable Energy Resources Fund, funded by alternate compliance payments made by the ARES to comply with at least 50% of the RPS requirements and administered by the IPA pursuant to Section 1-56 of the IPA Act to help mitigate payment risk for these contracts. In addition, the IPA proposes to use the ACP payments that have been collected by Ameren and ComEd from their respective hourly-priced service customers to be collectively used as necessary to supplement payment to the suppliers to the extent such payment would exceed the individual utility renewable resource budget caps in a given year. At the appropriate time, the IPA commits to work with Ameren, ComEd and the long-term renewable resource suppliers to effect a practical way to make this work within the confines of the existing PUA and IPA Act.

Again, the annual nature of Procurement Plan filing allows for a constant revisiting of actions to be prudently taken, so that each successive plan year allows for appropriately-timed and cost-effective response to actual market conditions. Furthermore, the strength of the PJM and MISO marketplace allows this to be done with a high level of confidence.

In order to deal with the risk associated largely with retail customer migration, the Illinois Power Agency recommends that its former hedging strategy for energy products, designed to result in a ladder of products and predicated on a philosophy of being 100% hedged for the first year in the planning horizon, 70% hedged for the second and 35% hedged for the third, be replaced with one suggested by Commission Staff and supported as a general matter by the Commission's Procurement Monitor:

Energy Hedging Plan: Staff Proposal 1

Fixed Price Hedge Quantities, as a % of *Expected* Average Hourly Load For Each of the 24 Periods of the Indicated Plan Year, to Have Established by June 1 of the Current Plan Year		
Current PY	*Current PY+1*	*Current PY+2*
75%	*50%*	*25%*

The IPA notes that this recommendation was developed in a time frame characterized by declining market prices and accelerating customer switching. However, since no energy procurement is warranted in this Procurement Plan, next year's Procurement Plan will allow for additional analysis of this revised hedging strategy on volatility and expected cost.

The IPA recommends retaining the 100%/70%/35% hedging strategy for purposes of Ameren's capacity requirements until such time as MISO demonstrates a robust FERC-approved capacity auction.

The table below summarizes the procurement recommendations contained in this Plan for both Ameren and ComEd. The IPA continues to recommend that ancillary services, load balancing services and transmission services (Network Integrated Transmission Service or NITS) be purchased, as they are now, by Ameren from the MISO marketplace and by ComEd from PJM. In addition, the IPA continues to recommend that each utility pursue Auction Revenue Rights (ARRs) in MISO or PJM. Ameren shall continue to actively participate in the MISO ARR nomination and allocation process as outlined and approved in prior Plans. ComEd shall similarly participate in the PJM nomination and allocation process as outlined and approved in prior Plans.

Summary of 2013 Illinois Power Agency Procurement Plan Recommendations						
	Ameren			ComEd		
Delivery Year	**Energy**	**Capacity**	**Renewable Resources**	**Energy**	**Capacity**	**Renewable Resources**
2013-14	No energy procurement required in 2013	Purchase remaining capacity resources requirement from the FERC-approved MISO capacity auction in 2013	Total volume targets already met < budget cap, no new resources required	No energy procurement required in 2013	Direct purchase from PJM capacity market	No new resources; supplement payment on long term contracts with ACP $ held by the IPA and utilities
2014-15	No energy procurement required in 2013	Already almost 70% hedged. Purchase remaining capacity resources requirement in 2014 using the MISO capacity auction.	Total volume targets already met < budget cap, no new resources required	No energy procurement required in 2013	Direct purchase from PJM capacity market	No new resources; supplement payment on long term contracts with ACP $ held by the IPA and utilities
2015-16	No energy procurement required in 2013	Defer procurement to 2014 Plan.	Total volume targets already met < budget cap, no new resources required	No energy procurement required in 2013	Direct purchase from PJM capacity market	No new resources; supplement payment on long term contracts with ACP $ held by the IPA and utilities
2016-17	No energy procurement required in 2013	TBD	No new resources; supplement payment on long term contracts with ACP $ held by the IPA	No energy procurement required in 2013	Direct purchase from PJM capacity market	No new resources; supplement payment on long term contracts with ACP $ held by the IPA and utilities
2017-18	No energy procurement required in 2013	TBD	No new resources; supplement payment on long term contracts with ACP $ held by the IPA	No energy procurement required in 2013	Direct purchase from PJM capacity market	No new resources; supplement payment on long term contracts with ACP $ held by the IPA and utilities

While there is little in terms of the purchase of traditional products, including renewable resource purchases, being recommended in this Plan, the Illinois Power Agency proposes the following Plan components in addition to the procurement action plan in the above table and requests the following Commission action:

1. Approve the ComEd and Ameren Load Forecasts;
2. Approve the curtailment of purchases of renewable resources under the long-term renewable resource contracts in order to keep the purchase of renewables under the statutory rate impact cap of 2.015%;
3. Approve the incremental energy efficiency programs as per the assessments by both Ameren and ComEd, as described and discussed in Section 7.1 of this Plan;
4. Approve the sourcing agreement between the FutureGen Alliance and the utilities and the ARES pursuant to Section 1-75(d)(5) of the Illinois Power Agency Act, as described

and discussed in Section 7.5 of this Plan, subject to any modifications made by the Commission;
5. Review the general parameters of a Distributed Generation program as described and discussed in Section 8.2 of this Plan, to be finalized in future utility DG offerings for eligible retail customers;
6. Reaffirm use of a blended imputed REC price contained within the bundled energy and REC prices associated with the long-term renewable contracts executed in 2010 as calculated and agreed upon by the Procurement Administrators, the IPA, Commission Staff and the Procurement Monitor, as being in the public interest and necessary to renewable resource procurement decisions in this and future Procurement Plans.

In addition, the IPA suggests that improvements be made to the Procurement Process as recommended in Section 9.0 of this Plan.

The Illinois Power Agency respectfully requests Commission approval of this Plan as contained herein and summarized above, and believes it to be compliant with all provisions of law and capable of the provision of adequate, reliable, affordable, efficient, and environmentally-sustainable electric service at the lowest, total cost over time, taking into account benefits of price stability.

2.0 Legislative/Regulatory Requirements of the Plan

This section of the 2013 Procurement Plan describes the legislative and regulatory requirements applicable to this Procurement Plan. A Regulatory Compliance Index, Appendix V, provides a complete cross index of regulatory/legislative requirements and the specific sections of this Plan that address each requirement identified.

IPA Authority

The IPA was established in 2007 by Public Act 95-0481 in order to ensure that customers, in particular customers in service classes that have not been declared competitive and who take service from the utility's bundled rate ("eligible retail customers"),[1] benefit from retail and wholesale competition, by improving the process to procure electricity for those customers.[2] In creating the IPA, the General Assembly found that Illinois citizens should be provided "adequate, reliable, affordable, efficient, and environmentally-sustainable electric service at the lowest, total cost over time, taking into account benefits of price stability."[3] The General Assembly also found that "investment in energy efficiency and demand-response measures, and to support development of clean coal technologies and renewable resources" furthered its stated goals.[4]

Each year, the Planning and Procurement Bureau of the IPA must develop a "power procurement plan" and conduct a competitive procurement process to procure supply resources as identified the final procurement plan, as approved pursuant to Section 16-111.5 of the Public Utilities Act ("PUA").[5] The purpose of the power procurement plan is to secure electricity commodity and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company ("ComEd") and Ameren Illinois Company

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

[2] 20 ILCS 3855/1-5(2); 3855 /1-5(3); 3855/1-5(4).

[3] 20 ILCS 3855/1-5(1).

[4] 20 ILCS 3855/1-5(4)

[5] 20 ILCS 3855/1-20(a)(2), 3855/1-75(a).

("Ameren" or "AIC").[6] The Illinois Power Agency Act ("IPA Act") requires that the procurement plan be developed, and the competitive procurement process shall be conducted, by experts or expert consulting firms (the "procurement planning consultant" and "Procurement Administrator", respectively).[7] The Illinois Commerce Commission ("Commission") is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[8]

Procurement Plan Development and Approval Process

Although the procurement planning process is ongoing and incorporates party input and lessons from past proceedings, the statutory deadlines for the 2013 Procurement Plan begin on July 15, 2012. On that date, each Illinois utility that procures electricity through the IPA must submit a range of load forecasts. These forecasts – which form the backbone of the Procurement Plan and which are covered in Chapter 3 in greater detail – must cover the five-year procurement planning period for the next procurement plan, and include hourly data representing a high-load, low-load and expected load-scenario for the load of the eligible retail customers.

Next, the IPA prepares a draft Procurement Plan by August 15 for public comment. During the thirty-day comment period, the IPA holds at least one public hearing within each utility's service area for the purpose of receiving public comment on the procurement plan; for the 2013 Procurement Plan, the hearing dates are September 17, 2012 in Chicago and September 20, 2012 in Springfield. Within fourteen days following the end of the 30-day review period, the IPA files a revised Procurement Plan with the Commission for approval. Objections must be filed with the Commission within five days after the filing of the Plan.[9] The Commission must enter an order confirming or modifying the Plan within 90 days after it is filed by the IPA.

The Commission approves the Plan, including the load forecast used in the procurement plan, if the Commission determines that it meets the requirements of the PUA.

Procurement Plan Requirements

At its core, the Procurement Plan consists of three pieces: (1) a forecast of how much energy (and in some cases capacity) is required by eligible retail customers, (2) the supply currently under contract, and (3) what type and how much supply must be procured to meet load requirements and all other legal requirements (such as renewable/clean coal purchase requirements or mandates from previous Commission Orders). To that end, the Procurement Plan must contain an hourly load analysis, which includes: multi-year historical analysis of hourly loads; switching trends and competitive retail market analysis; known or projected changes to future loads; and growth forecasts by customer class.[10] In addition, the Procurement Plan must analyze the impact of demand side and renewable energy initiatives, including the impact of demand response programs

[6] ICC Docket 11-0660, Final Order of December 21, 2011 at 1. Although the IPA must create a procurement plan for ComEd and Ameren, the IPA must also create a procurement plan for MidAmerican Energy Company ("MidAm") if MidAm elects to opt into the IPA procurement process. (*See* 20 ILCS 3855/1-20(a)(1).)

[7] 20 ILCS 3855/1-75(a)(1), 3855/1-75(a)(2).

[8] 220 ILCS 5/16-111.5(b), (c)(2)

[9] 220 ILCS 5/16-111.5(d)(3).

[10] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).

and energy efficiency programs, both current and projected.[11] Based on that hourly load analysis, the Procurement Plan must detail the IPA's plan for meeting the expected load requirements that will not be met through preexisting contracts,[12] and in doing so must:

- Define the different Illinois retail customer classes for which supply is being purchased, and include monthly forecasted system supply requirements, including expected minimum, maximum, and average values for the planning period.[13]
- Include the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year that, separately or in combination, will meet the portion of the load requirements not met through pre-existing contracts.[14] Such standard wholesale products include, but are 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.
- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[15]
- Assess the price risk, load uncertainty, and other factors associated with the proposed portfolio measures, including, to the extent possible, the following factors: contract terms, time frames for security products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment.[16] For those portfolio measures that are identified as having significant price risk, the Plan shall identify alternatives to those measures.
- For load requirements included in the Plan, the Plan should include the proposed procedures for balancing loads, including the process for hourly load balancing of supply and demand and the criteria for portfolio re-balancing in the event of significant shifts in load. [17]
- Include renewable resource and demand-response products, as discussed below.

Renewable Portfolio Standard

The General Assembly has acknowledged the importance of including cost-effective renewable resources in a diverse electricity portfolio.[18] "Renewable energy resources" is defined in the Illinois Power Agency Act, and means (1) energy and its associated renewable energy credit or (2) credits alone from qualifying sources such as wind, solar thermal energy, photovoltaic cells and

[11] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).

[12] 220 ILCS 5/16-111.5(b)(3).

[13] 220 ILCS 5/16-111.5(b)(i), 220 ILCS 5/16-111.5(b)(iii).

[14] 220 ILCS 5/16-111.5(b)(3)(iv).

[15] 220 ILCS 5/16-111.5(b)(3)(v).

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

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

[18] 20 ILCS 3855/1-5(5), 3855/1-5(6).

panels, biodiesel, and others as identified in the IPA Act.[19] A minimum percentage of each utility's total supply to serve the load of eligible retail customers shall be generated from cost-effective renewable energy resources; by June 1, 2013, at least 8% of each utility's total supply should be generated from renewable energy resources.[20] For the current (2013) Procurement Plan, to the extent cost-effective resources are available, at least 75% of the renewable energy resources used to meet those standards shall come from wind generation, 1.5% shall come from photovoltaics, and 0.5% shall come from distributed renewable energy generation devices.[21] Renewable energy resources procured from distributed generation devices to meet this requirement may also count towards the required percentages for wind and solar photovoltaics.[22]

The IPA Act defines "cost effective" in two ways: first, for different renewable resources the Procurement Administrator creates a "market benchmark" against which all bids are measured. Second, and in addition to the market benchmarks, the total cost of renewable energy resources procured for any single year shall be reduced by an amount necessary to limit the annual estimated average net increase due to the costs of these resources to no more than the greater of:

- 2.015% of the amount paid per kilowatthour by eligible retail customers during the year ending May 31, 2007; or
- The incremental amount per kilowatthour paid for these resources in 2011.[23]

In addition to the funds available from eligible retail customers, the IPA also has available the amounts collected by the utility from customers taking service under the utility's hourly pricing tariff or tariffs under the alternative compliance payment rate or rates in the prior year ending May 31.[24]

Finally, cost-effective renewable energy resources are subject to geographic restrictions: the IPA must first procure from resources located in Illinois or in states that adjoin Illinois.[25] If cost-effective renewable energy resources are not available in Illinois or adjoining states, the IPA must instead seek cost-effective renewable energy resources from elsewhere.[26]

Distributed Generation Resources Standard

Effective beginning in the 2013 Procurement Plan, a distributed generation resource requirement was added by the Legislature. Procurement of renewable energy resources from distributed renewable energy generation devices is to be conducted on an annual basis through multi-year contracts of no less than five years, and shall consist solely of renewable energy credits.[27]

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[19] 20 ILCS 3855/1-10.

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

[21] *Id.*

[22] 20 ILCS 3866/1-75(c)(1)

[23] 20 ILCS 3855/1-75(c)(2)(E).

[24] 20 ILCS 3855/1-75(c)(5).

[25] 20 ILCS 3855/1-75(c)(3).

[26] *Id.*

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

A generation source is considered a "distributed renewable energy generation device" under the IPA Act if it is:

- Powered by wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;
- Interconnected at the distribution system level of either an electric utility, alternative retail electric supplier, municipal utility, or a rural electric cooperative;
- Located on the customer side of the customer's electric meter and is primarily used to offset that customer's electricity load; and is
- Limited in nameplate capacity to no more than 2,000 kW.[28]

To the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25kW in nameplate capacity,[29]

In the ICC proceeding to approve the 2012 Electricity Procurement Plan, the Illinois Power Agency committed to holding workshops in the Spring of 2012 to assist with the development of a distributed generation renewable resource procurement plan.[30] Those workshops were held. The IPA discussed best practices for meeting the obligations of the distributed generation portfolio requirement with stakeholders on February 24th and April 2nd 2012. Meeting materials are available on the IPA website.[31] In Section 8.2 the Procurement Plan discusses in much more detail the process for procuring distributed energy resources.

Energy Efficiency Resources

Section 16-111.5B of the PUA, as amended by PA 97-0824 effective July 18, 2012, outlines the requirements for the consideration of energy efficiency in the Procurement Plan. The Procurement Plan must include the impact of energy efficiency building codes or appliance standards, both current and projected, and an assessment of opportunities to expand the programs promoting energy efficiency measures that have been offered by the utilities' ICC-approved energy efficiency plans or to implement additional cost-effective energy efficiency programs or measures. To assist in this effort, the utilities are required to provide, along with their load forecasts, an assessment of cost-effective energy efficiency programs or measures that could be included in the Procurement Plan. Both Ameren and ComEd have provided this information, which is included in the Appendices to this Procurement Plan along with their load forecast information. This information includes an analysis of new or expanded programs that demonstrates their cost-effectiveness as defined in the Act, and information sufficient to demonstrate the impacts of the assessed incremental programs on the overall cost to the utility of providing electric service, including how the cost of procuring these measures compares over the life of the measures to the prevailing costs of comparable supply, along with estimated supply quantity reductions should the IPA recommend to include them in the proposed resource portfolio.

The PUA requires the Agency to include in its Procurement Plan energy efficiency programs and measures that it determines are cost-effective and the associated energy savings shall be

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[28] 20 ILCS 3855/1-10.

[29] *Id.*

[30] Final Order in 11-0660 at 117.

[31] http://www2.illinois.gov/ipa/Pages/CurrentEvents.aspx.

factored into the resource solicitation process. If the Commission approves the procurement of this additional efficiency, it shall reduce the amount of power to be procured under the procurement plan and shall direct the utility to undertake the procurement of the efficiency resources. For purposes of meeting this statutory requirement, cost-effective means that the assessed measures pass the total resource cost test as defined in the IPA Act:

> *"Total resource cost test" or "TRC test" means a standard that is met if, for an investment in energy efficiency or demand-response measures, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the program to the net present value of the total costs as calculated over the lifetime of the measures. A total resource cost test compares the sum of avoided electric utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided natural gas utility costs, to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side program, to quantify the net savings obtained by substituting the demand-side program or supply resources. In calculating avoided costs of power and energy that an electric utility would otherwise have had to acquire, reasonable estimates shall be included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases.* [32]

Demand Response Products

The IPA may include cost-effective demand response products in its Procurement Plan. The Procurement Plan must include the particular "mix of cost-effective, demand-response products for which contracts will be executed during the next year, to meet the expected load requirements that will not be met through preexisting contracts."[33] Under the PUA, cost-effective, demand-response measures may be procured whenever the cost is lower than procuring comparable capacity products, if the product and company offering the product meet minimum standards.[34] Specifically:

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;
- The products must 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[35];
- The products must provide for customers' participation in the stream of benefits produced by the demand-response products;
- The provider must have a plan for the reimbursement of the utility for any costs incurred as a result of the failure of the provider to perform its obligations.[36]; and
- Demand-response measures included in the plan shall meet the same credit requirements as apply to suppliers of capacity in the applicable regional transmission organization market.[37]

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[32] 20 ILCS 3855/1-10

[33] 220 ILCS 5/16-111.5(b)(3)(ii).

[34] 220 ILCS 5/16-111.5(b)(3)(ii).

[35] 16-111.5(b)(3)(ii)(A); 16-111.5(b)(3)(ii)(B).

[36] *Id.* at 16-111.5(b)(3)(ii)(C); 16-111..5(b)(3)(ii)(D).

[37] *Id.* at 16-111.5(b)(3)(ii)(E).

Public Act 97-0616, the Energy Infrastructure Modernization Act (EIMA), requires ComEd and Ameren to file tariffs instituting an opt-in market-based peak time rebate (PTR) program with the Commission within 60 days after the Commission has approved the utility's AMI Plan.[38] These programs are discussed further in Section 7.4, where demand response resource choices are examined.

Clean Coal Portfolio Standard

The IPA Act contains an aspirational goal that cost-effective clean coal resources account for, 25% of the electricity used in Illinois by January 1, 2025.[39] To that end, the Plan must also include electricity generated from clean coal facilities.[40] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act[41], Section 1-75(d) describes two special cases:the "initial clean coal facility"[42] and "electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities ("retrofit clean coal facility").[43] Currently, there is no facility meeting the definition of an "initial clean coal facility" that the IPA is aware of that has announced plans to begin operations within the next five years. However, the IPA is aware of a retrofit clean coal facility that intends to begin operations within the next five years.

Retrofit Clean Coal Facilities

The IPA and the Commission are required to consider in a Procurement Plan any sourcing agreements presented by the owners of a retrofit facility to the utilities and alternate retail electric suppliers required to comply with the Clean Coal Portfolio Standard. In the case of sourcing agreements that are power purchase agreements, the contract price for electricity sales shall be established on a cost of service basis. In the case of sourcing agreements that are contracts for differences, the contract price from which the reference price is subtracted shall be established on a cost of service basis. The Agency and the Commission may approve any such utility sourcing agreements that do not exceed cost-based benchmarks developed by the procurement administrator, in consultation with the Commission staff, Agency staff and the procurement monitor, subject to Commission review and approval. Costs incurred under these provisions in the Power Agency Act or pursuant to a contract entered into under the relevant subsection of the Act shall be deemed prudently incurred and reasonable in amount and the electric utility shall be entitled to full cost recovery pursuant to the tariffs filed with the Commission.

By law, the total amount paid under sourcing agreements with clean coal facilities pursuant to the procurement plan for any given year shall be reduced by an amount necessary to limit the annual estimated average net increase in eligible retail customers' electric service bills to certain levels that are specified in the IPA Act by a set of formulas.[44] Because the IPA does not anticipate the operation of a clean coal facility until the 2017 delivery year, the maximum

[38] 220 ILCS 5-16-108.6(g)

[39] 20 ILCS 3855/1-75(d).

[40] 20 ILCS 3855/1-75(d)(1).

[41] 20 ILCS 3855/1-10

[42] *Id.*

[43] 20 ILCS 3855/1-75(d)(5)

[44] 20 ILCS 3855/1-75(d)(2).

allowable increases in rates allowed by those formulas are known today to be equal to 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009.[45] For Ameren, this amounts to 0.2169 cents per kwh, and for ComEd, it amounts to 0.2382 cents per kwh[46] this Procurement Plan will not address the impact of the cost cap at this time, except in a general sense.

3.0 Load Forecasts

The forecasts of Ameren and ComEd loads for "eligible retail customers" are key inputs to the IPA's Procurement Plan. While the 2013 Procurement Plan is the fifth such plan, it is the first impacted so heavily by the advancement of retail customer choice to the residential and small commercial customer classes. Both Ameren and ComEd are required by Section 16-111.5(d)(1) of the Public Utilities Act to provide 5-year planning forecasts, which is June 2013 – May 2018 for this 2013 Procurement Plan. These forecasts provided by Ameren and ComEd are summarized below, followed by an analysis of the major drivers of load forecast uncertainty in the Illinois retail electric marketplace. This Plan examines the impacts, many of which are unique to the Illinois retail electric marketplace, of customer migration, market price implications for making the choice to receive electric supply service under the utility default rates, efficiency programs and trends, demand response opportunities and emerging technology.

3.1 Ameren Illinois

Ameren Illinois's forecasts and analyses for the June 2013 – May 2018 planning period are included as Appendix I to this 2013 Procurement Plan. This Appendix contains the following information:

- A document titled *"Ameren Illinois Company ("AIC") Load Forecast for the Period June 1, 2013 – May 31, 2018"* that describes the forecast methodology.
- The Ameren Energy Forecast by Customer Class assuming the incremental energy efficiency programs are implemented, as discussed later in this Plan.
- The forecast of peak and off-peak total energy and average load.
- A projection of peak and off-peak contract volumes to procure.
- Ameren's capacity projections.
- Ameren's RPS calculations with certain explicit confidential price information redacted.
- Ameren's Electric Energy Efficiency Compliance Report Submitted in accordance with 220 ILCS 5/Sec. 16-111.5B.

There is a dramatic fall-off in Ameren's load serving responsibility associated with eligible retail customers. Customer switching, both individually and as part of municipal aggregation, is a key driver, followed by general economic assumptions and impacts of energy efficiency programs. A comparison of the Ameren Illinois Base Case average load forecast submitted for this plan is summarized below, as well as a comparison to the Base Case forecast from the 2012

[45] 20 ILCS 3855/1-75(d)(2)(E).
[46] Based on the amounts paid per kwh by those customers during the year ending May 31, 2009, as reported in the Procurement Plan filed by the IPA on September 30, 2009 in Docket 09-0373. Within that document see specifically Table Q on page 41, where the Ameren Reference Year Unit Cost for the Reference Year 2008-2009 is $107.66; and Table Y on page 55, where the analogous ComEd value is $118.23.

plan. Also shown is the March 2012 updated forecast used for the 2012 Spring procurements. This update was mandated by the Commission in its Final Order on the 2012 Procurement Plan, and provided for, in effect, a mid-course correction or informal portfolio rebalancing due to the known municipal aggregation measures on the March, 2012 ballot. This comparison is provided to illustrate the magnitude of the impacts of recent retail market developments on the load served by the IPA's procurement plans and processes.

Ameren Illinois Projected Average Demand for Eligible Retail Customers							
		Average Load (MW)					
		2013 Plan (Jul 2012 forecast)		**Spring 2012 Procurement (Mar 2012 forecast)**		**2012 Plan (Nov 2011 forecast)**	
		On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**
Year	**Month**						
2013	6	987	742	1591	1226	2018	1552
	7	1,150	923	1892	1500	2418	1916
	8	1,132	896	1914	1454	2449	1858
	9	859	724	1424	1193	1800	1511
	10	679	542	1173	994	1473	1251
	11	733	621	1262	1107	1594	1400
	12	861	760	1551	1406	1977	1797
2014	1	896	799	1620	1493	2071	1913
	2	832	747	1522	1369	1938	1746
	3	663	582	1263	1170	1604	1492
	4	567	468	1068	938	1351	1188
	5	545	451	1039	944	1321	1201
	6	777	610	1435	1198	1842	1528
	7	951	756	1800	1418	2330	1833
	8	944	743	1791	1423	2317	1840
	9	701	591	1323	1137	1693	1457
	10	546	444	1094	940	1391	1197
	11	603	517	1173	1063	1498	1361
	12	714	649	1477	1334	1903	1721
2015	1	765	693	1517	1430	1955	1845
	2	720	644	1428	1311	1832	1682
	3	571	511	1203	1108	1540	1419
	4	496	413	1024	895	1303	1137
	5	486	416	1024	923	1303	1176
	6	702	557			1808	1497
	7	878	686			2263	1807
	8	879	682			2223	1847
	9	653	542			1700	1397
	10	506	415			1376	1168
	11	561	479			1479	1309
	12	669	612			1872	1661
2016	1	718	665			1928	1839
	2	667	600			1806	1666
	3	538	491			1552	1379
	4	465	406			1295	1129
	5	469	394			1317	1138
	6	665	546			1771	1507
	7	849	681			2309	1798
	8	842	647			2218	1791
	9	621	527			1695	1378
	10	479	405			1388	1142
	11	529	464			1471	1282
	12	652	581			1863	1645

2017	1	692	633			1950	1778
	2	647	594			1804	1636
	3	514	471			1525	1366
	4	439	394			1287	1119
	5	452	370			1326	1103
	6	650	512				
	7	817	654				
	8	803	628				
	9	588	514				
	10	457	383				
	11	505	443				
	12	627	556				
2018	1	666	600				
	2	621	566				
	3	497	445				
	4	425	368				
	5	434	350				

3.2 <u>ComEd</u>

ComEd's forecasts and analyses for the June 2013 – May 2018 planning period are included as Appendix II to this 2013 Procurement Plan. This Appendix contains the following information:

- A document titled "Commonwealth Edison Load Forecast for Five-Year Planning Period", dated July 16, 2012, which includes ComEd's Appendices A, B, D and E. (Note that Appendix E contains information heretofore treated as confidential and which the IPA may need to release in order for the Commission to consider the IPA's proposal on whether to procure additional renewable resources in this and subsequent Procurement Plans.)
- ComEd Appendix C1: Assessment of Energy Efficiency and Load Management Potential (2011-2016) performed by the Cadmus Group, dated February 17, 2010
- ComEd Appendix -C2: Energy Efficiency Analysis Summary
- ComEd Appendix -C3: Energy Efficiency Monthly Savings Curves (by program)
- ComEd's Procurement Period Load Forecast for Total and Average Peak and Off-Peak Load.

As with the Ameren forecast, there is a dramatic fall-off in load serving responsibility associated with ComEd's eligible retail customers. Once again, individual customer switching and municipal aggregation are key drivers, followed by general economic assumptions and the impact of energy efficiency programs. A comparison of the ComEd Base Case average load forecast submitted for this plan is summarized below, as well as a comparison to the Base Case forecast from the 2012 plan. Also shown is the March 2012 updated forecast used for the 2012 Spring procurements. This update was mandated by the Commission in its Final Order on the 2012 Procurement Plan, and provided for, in effect, a mid-course correction or informal portfolio rebalancing due to the known municipal aggregation measures on the March, 2012 ballot. This comparison is provided to illustrate the magnitude of the impacts of recent retail market developments on the load served by the IPA's procurement plans and processes.

ComEd Projected Average Demand for Eligible Retail Customers							
		Average Load (MW)					
		2013 Plan (Jul 2012 forecast)		Spring 2012 Procurement (Mar 2012 forecast)		2012 Plan (Nov 2011 forecast)	
		On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Year	Month						
2013	6	1749	1406	2145	1751	2993	2465
	7	2042	1623	2511	2008	3651	2929
	8	1880	1499	2318	1871	3377	2740
	9	1406	1139	1730	1425	2477	2071
	10	1241	1016	1538	1282	2122	1794
	11	1364	1159	1739	1504	2338	2039
	12	1586	1372	2081	1825	2736	2407
2014	1	1594	1391	2129	1894	2733	2442
	2	1450	1277	1981	1783	2516	2272
	3	1284	1124	1733	1548	2226	2003
	4	1134	963	1495	1297	1989	1742
	5	1147	960	1458	1242	2013	1741
	6	1525	1236	1913	1568	2796	2309
	7	1827	1459	2287	1832	3447	2768
	8	1684	1359	2111	1722	3180	2603
	9	1267	1025	1589	1304	2343	1944
	10	1109	916	1399	1176	1992	1699
	11	1230	1058	1595	1398	2199	1942
	12	1461	1273	1952	1723	2621	2316
2015	1	1468	1292	1993	1789	2601	2342
	2	1341	1182	1866	1679	2408	2172
	3	1188	1043	1633	1462	2135	1922
	4	1039	893	1392	1221	1890	1672
	5	1048	891	1349	1167	1906	1675
	6	1417	1156			2704	2232
	7	1709	1369			3338	2669
	8	1575	1285			3073	2533
	9	1184	964			2251	1878
	10	1025	857			1900	1641
	11	1154	995			2125	1884
	12	1378	1200			2539	2245
2016	1	1389	1226			2517	2281
	2	1282	1129			2360	2122
	3	1133	998			2087	1880
	4	983	852			1826	1634
	5	1006	851			1875	1638
	6	1371	1103			2682	2177
	7	1650	1340			3289	2675
	8	1541	1231			3079	2466
	9	1135	942			2193	1870
	10	992	831			1858	1617
	11	1127	974			2101	1865
	12	1345	1176			2496	2225
2017	1	1360	1205			2491	2263
	2	1241	1102			2306	2095
	3	1102	978			2050	1864
	4	955	828			1788	1607
	5	985	830			1860	1616
	6	1346	1076			NA	NA
	7	1617	1315			NA	NA
	8	1504	1210			NA	NA

	9	1103	919			NA	NA
	10	970	810			NA	NA
	11	1102	947			NA	NA
	12	1309	1150			NA	N A
2018	1	1331	1181			NA	NA
	2	1208	1079			NA	NA
	3	1071	952			NA	NA
	4	934	806			NA	NA
	5	961	807			NA	NA

3.3 Load Forecast Uncertainty

Each of the utilities' load forecast analyses attached hereto as Appendices describe the drivers of uncertainty analyzed by ComEd and Ameren Illinois, respectively. The discussion below is a general overview from the IPA's perspective. The following key drivers of load forecast uncertainty are briefly defined and examined:

- Customer Migration
  - Individual Switching
  - Municipal Aggregation
  - Hourly Pricing
  - Market Price as It Affects the Choice Between ARES and Utility Supply
- Efficiency
  - Building Codes
  - Energy Efficiency Resource Standards
- Demand Response
- Emerging Technology

3.3.1 Customer Migration

The Procurement Plan includes the risk, in deciding how much electricity supply to purchase and at what price, that forecasts may be over- or under-estimating the likelihood that customers will leave utility fixed-price supply for competitive choices. Conversely, forecasts must consider the likelihood of customers who have migrated away from utility fixed-price supply returning in the future to such service. This risk comes from at least three sources: (1) Individual Customer Choice; (2) Municipal Aggregation; and (3) Hourly Pricing.

When restructured markets were phased-in in Illinois beginning in 1997, customer switching to ARES service was slow to take off in the residential and small commercial customer classes due, in part, to "transition charges" which the utilities applied to ARES service customers' bills, as well as the existence of frozen bundled service rates. By January 2007, those factors no longer existed but switching to ARES service remained slow due, in part, to the relatively high costs of customer acquisition and service for these smallest of utility customers. It was not until ComEd and Ameren began offering consolidated billing and purchase of receivables to ARES that residential and small commercial switching accelerated. ComEd and Ameren's tariffs implementing Utility Consolidated Billing ("UCB") and Purchase of Receivables ("POR") became effective in August of 2011 and August of 2009, respectively.[47] As an example of their positive marketplace impact, following the Commission's approval of ComEd's and Ameren's tariffs, the number of residential customers taking ARES service in ComEd territory increased from essentially zero in March 2011 to over 70,000 in June 2011.[48] From June 1, 2011 to August 12, 2011, residential enrollment with

[47] *See generally* ICC Docket No. 10-0138, Final Order dated Aug. 17, 2011; ICC Docket No. 08-0619, -0620, -0621 (cons.), Final Order dated Aug. 19, 2009).

[48] ICC Docket No. 11-0660, Final Order dated Dec. 21, 2011, at 56.

ARES in ComEd's service territory averaged 1,150 customers per day.[49] If that trend were to continue, ComEd projected last year that over a million residential customers could switch to ARES service by 2013-2014.[50]

For Ameren Illinois, residential switching began in earnest in July 2011, with the rate of switching steadily increasing ever since. Considering the recent success of municipal aggregation, Ameren Illinois now has in excess of 315,000 residential accounts that have switched to ARES with this quantity expected to increase further.

The Commission's Office of Retail Market Development reports the following increase in the numbers of residential suppliers over the last 12 months. [51]

Residential Suppliers		
	May 2011	May 2012
ComEd – ICC certified	22	40
ComEd - active	8	27
Ameren IL – ICC	16	26
Ameren IL - active	3	10

Whether as a result of municipal aggregation (discussed in further detail below) or as a result of individual consumer choice, migration of eligible retail customers indicates a greater penetration of ARES marketing efforts, a lowering of barriers to competition, and the natural market forces responding to market conditions in Illinois.

Municipal Aggregation

The impacts of municipal aggregation in Illinois have the potential to far outweigh any impacts associated with individual customer supply choice decisions, because of the potential to move large numbers of customers to or away from an individual supplier with a single decision. Public Act 96-0176 amended the IPA Act to allow municipal corporate authorities or county boards to adopt ordinances aggregating residential and small commercial retail electrical loads within their jurisdiction to enter into an electricity purchase agreement with a retail electric supplier.[52]

The Illinois Commerce Commission Office of Retail Market Development, in its June 2012 Annual report referenced above, has reported the dramatic increase in municipal aggregation activity in Illinois from 2011 to 2012. Buoyed by the savings success experienced by the programs instituted by ballot in 2011, and the continued downward trend in market-based electricity supply prices in Illinois, 306 communities placed an opt-out aggregation referendum on the March 20, 2012 ballot, with 245 of those referenda passing. Further illuminating statistics are tabulated below.[53]

[49] ICC Docket No. 11-0660, Final Order dated Dec. 21, 2011, at 56.

[50] ICC Docket No. 11-0660, Final Order dated Dec. 21, 2011, at 56.

[51] Office of Retail Market Development, Illinois Commerce Commission, 2012 Annual Report, June 2012

[52] Public Act 96-0176 (Aug. 2009).

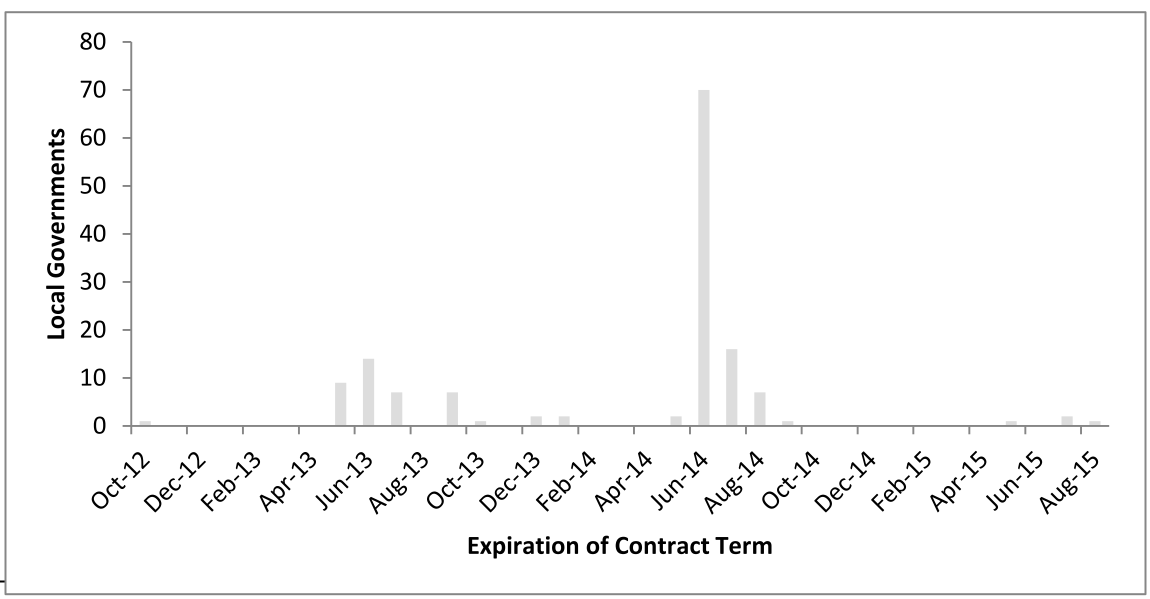
[53] Office of Retail Market Development, Illinois Commerce Commission, 2012 Annual Report, June 2012

Municipal Aggregation Statistics as of June 29, 2012		
	April 2011	March 2012
Referenda Passed	20	245
Aggregation Programs Announced or Implemented	19	200
# of "Winning" Suppliers - ComEd	4	7
# of "Winning" Suppliers – Ameren Illinois	N/A	7
Average Rate - ComEd	5.81	4.87
Average Rate – Ameren Illinois	N/A	4.10

Considering that the current typical average annual "price to beat" for ComEd is 7.77 cents/kWh and that Ameren Illinois' seasonal prices range from roughly 5.5 to 6.2 cents/kWh,[54] it is not surprising that municipal/county aggregation has become such an attractive alternative, with an opportunity to also dramatically reduce the load forecasts for Ameren and ComEd.

The chart below, however, shows that the above prices obtained through municipal aggregation are set for only a relatively short period of time. A majority of the known contracts expire during the Summer of 2014. As discussed below, the relative levels of market prices and the utilities' blended portfolio costs at the time these municipal aggregation prices expire will determine, in large part, the sustainability of the shift away from utility fixed-price supply service for the 2014-2015 delivery year and beyond.

Distribution of Municipal Aggregation Contract Terms



[54] http://www.pluginillinois.org/

The IPA concurs with the utilities' analyses that conclude there will likely still be some headroom between utility and ARES price offers in the 2014/2015 delivery year, and the IPA anticipates and expects that the policies supporting competitive electricity markets will continue. Eligible retail consumers currently served through the IPA portfolio will continue to migrate towards ARES options.[55] The IPA understands that the City of Chicago intends to place the opt-out aggregation question on the November 2012 ballot, as well as at least one county. An affirmative vote in Chicago could result in a massive migration away (estimated at roughly 9,000,000 mWh/year) from ComEd fixed-price service well before the beginning of June 2013-May 2014 delivery year, the first year of this Procurement Plan. The probability of this occurring is judged to be high based on the success of other aggregation programs, and this shift of Chicago load is included in the ComEd Base Case forecast. . For Ameren Illinois, at least eighty additional municipalities and counties will pursue November 2012, with the potential for another series of referenda in 2013. Under the expected forecast scenario submitted by Ameren Illinois, the outlook is that a majority of residential load could be switched by June 2013, and under the low forecast scenario (which includes high switching assumptions) a significant majority could be switched by June 2013.

Anticipating the possibility of load volatility due to shifts in customer load to ARES, Section 16-115.5(b)(4) of the PUA requires that the IPA determine criteria for rebalancing its portfolio in the event of significant shifts in load.

In the 2012 Procurement Plan, the IPA proposed that Ameren and ComEd should "true-up" their forecasted amount of customer switching expected due to municipal aggregation programs.[56] To do this, the IPA proposed that Ameren and ComEd survey the actual number and size of the municipalities that file with the relevant election authority to hold, or who have already passed referenda approving "opt out" aggregation.[57] Based on the results from these surveys, the IPA proposed that Ameren, ComEd, Staff of the ICC, and the Procurement Administrator and Monitor would rebalance the portfolio commensurate with the change in forecasted customer switching due to municipal aggregation programs.[58] In fact, the Commission provided an opportunity to rebalance the portfolio when it ordered that both utilities submit to the IPA updated forecasts prior to the Spring 2012 procurement. These forecasts, submitted to the IPA in March 2012, incorporated the knowledge that a significant number of referenda were going to be held that month. The regular Spring 2012 procurement events provided an opportunity to re-examine the gap between anticipated supply and demand and adjust purchases accordingly, mitigating the need for an explicit and separate supply rebalancing. The difference between the 2012 and 2013 Procurement Plan forecasts illustrates the power of competitive choices in a marketplace that facilitates an ease of making those choices.

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[55] ICC Docket No. 11-0660, Final Order dated December 21, 2011 at 5.

[56] *Id.* at 37.

[57] *Id.* at 37.

[58] *Id.* at 37.

Mitigating further the need for significant portfolio rebalancing going forward is the fact that sizeable contracts for energy and capacity products of 2007 vintage that are currently included in ComEd and Ameren's current supply mix and "price to compare" expire by May of 2013. Ameren's 1000 MW contract ends at the end of 2012, while ComEd's 3000 MW contract ends at the end of May 2013. For ComEd, in particular, this provides an opportunity to better accommodate a migration of City of Chicago customers out of the IPA portfolio; the IPA anticipates that Chicago and other potential November ballot municipal aggregation-related migration should be well settled before a Spring 2013 procurement is conducted.

Expiration of these relatively high priced portions of the supply portfolio should result in a reduction in the utility default service price, at which point some customers may find that the default supply option may be more economical than their current ARES offerings. Given the 20-year bundled REC and energy contracts entered into by Ameren Illinois and ComEd in late 2010, and the recovery of prior and current balancing costs (through the day-ahead market and captured through the PEA), it is likely that the utility default prices will still be above current ARES offers. This is especially true as those long-term contracts become a relatively larger part of the utility supply portfolio as the load denominator goes down due to customer migration.[59] See also the discussion below on market-price impacts on customer migration.

The amount of customer load forecasted to switch from the IPA portfolio to ARES-served load also affects the purchase of renewable resources and will be further discussed in that section of this Procurement Plan.

Hourly Pricing

Because customers who take electric supply pursuant to an hourly pricing tariff are not "eligible retail customers" under the PUA, the IPA is not obligated to purchase electrical supply on those customers' behalf.[60] Therefore, the amount and corresponding electrical load of customers who take service pursuant to an hourly pricing tariff affects the IPA's required procurement portfolio for the next five years. Based on historic trends, it is unlikely that the number or load of customers served by hourly pricing tariffs will significantly impact the IPA's procurement plan. However, recent developments in the Commission proceedings implementing Smart Grid infrastructure indicate that new tariff structures, in addition to the statutorily required Peak-Time Rebate, may be implemented by ComEd within the next calendar year or over the course of the planning horizon. The effect of these new tariffs on the obligations of the IPA is yet to be determined.

Market Price

Market price is discussed here because it may impact the level of customer migration. Section 6.1 more generally discusses market conditions, including market price, as they may affect the utility supply costs.

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[59] This disparity is mitigated somewhat to the extent that the Alternative Compliance Payment ("ACP") charged to ARES is based increasingly on the REC price from the long-term renewable contracts as the 20-year contracts take up a greater percentage of the renewable resource purchase.

[60] *See* 220 ILCS 5/16-111.5(a).

Well-informed customers and their suppliers will make rational economic decisions based on the relative costs of their electricity supply alternatives. This was vividly illustrated in the early years of the competitive transition in Illinois. The Electric Service Customer Choice and Rate Relief Law of 1997, which established Article XVI of the Public Utilities Act,[61] created a temporary retail supply option available to commercial and industrial customers known as the Power Purchase Option ("PPO"). This offer was based on an administratively-determined market price, which at times was lower than market-based supply offers of ARES. At other times, it was higher. Not only did customers choose the PPO option when it was lower-priced than ARES offers, but ARES themselves placed their customers on the PPO when it was economically advantageous to do so. In other words, ARES made the rational choice to use the PPO as their supply source in lieu of higher-priced market based resources. This raises the related question in the context of this Procurement Plan: could utility default service be used as an ARES supply option as was the PPO, increasing load volatility for the utility portfolio?

With an eye towards price stability and hedging short- and intermediate-term market price risk, the current IPA-arranged utility supply portfolio is based on a ladder of products which, over the long run, will tend to dampen utility price increases in a rising wholesale market and also dampen utility price decreases when wholesale market prices are falling. While protecting consumers against price volatility, as market prices have fallen in the last several years utility tariffed supply rates have not fallen as quickly, resulting in the current significant headroom between utility and ARES supply prices. Hence, the huge savings available through municipal aggregation – which an ARES can serve at current market prices without the burden of legacy contracts. This has significantly reduced utility load serving obligations. With market prices for electric energy projected to increase in the future, the potential exists for the utility portfolio to be priced lower than market if the current portfolio construct is maintained.[62] If ARES and customers once again return to utility supply in this situation, will Illinois experience the kind of mass customer swings experienced under the PPO?

The evidence suggests that this is less likely than earlier in Illinois' transition to competitive markets and care should be taken to not cause the utility to over-hedge today for this eventuality. If utilities are unhedged for this returning load and meet this returning load obligation through short term or day-ahead purchases, risk is mitigated somewhat because those purchases will be made at the same supply prices being faced by ARES. Furthermore, even though ARES maintained a relationship with the retail customers they placed on the PPO, it is not so easy (or necessarily possible) to do so under today's utility tariffs, where customers that return to utility bundled service are subject to a stay of 12 months if they do not choose another supplier within a 2-month window. An ARES is not likely to want to sever its customer relationships, as would occur if a customer is required to stay on utility supply for a full year. The loss of a customer relationship for a relatively long period of time is a significant factor risk factor for ARES that might be otherwise inclined to use utility service as a short-term supply option, and that differentiates current conditions from those of the PPO era.

At this juncture, the IPA recommends continued watchful analysis of retail and wholesale markets as they impact Illinois retail customer migration and retail default service costs. As noted above, the bundled utility rate is most likely to beat ARES offers in a situation of extended wholesale market price increases, which the IPA will monitor, along with the Commission and other interested stakeholders. However, it cannot recommend the purchase of supply to cover the risk of returning customers, especially in a spring 2013 procurement event, well before the majority of

[61] 220 ILCS 5/16

[62] As noted above, factors including load risk and long-term contracts may mitigate or overpower this effect.

municipal aggregation supplier agreements are scheduled to terminate. With respect to the possibility that the City of Chicago may not actually migrate to an ARES by June 2013, the IPA notes that ComEd is projected to be long on supply for the 2013/2014 delivery, so is already well-hedged for this possibility without making any new purchases.

3.3.2 Efficiency

Public Act 95-0481 also created a requirement for ComEd and Ameren to offer cost-effective energy efficiency and demand response measures to all customers.[63] Both Ameren and ComEd have incorporated the impacts of these statutory and spending-capped efficiency goals, as applied to eligible retail customers, as well as achieved and projected savings in the forecasts that are included with this Procurement Plan.

Building Codes

As noted by the utilities in their load forecast documentation, increasing energy efficiency of building stock and appliances is serving to dampen overall electric load growth and, in the face of customer switching, utility load serving obligations. A major driver of efficiency improvement is enhanced building codes and energy efficiency resource standards. These are described and examined below.

Energy Efficiency Building Act

Public Act 096-0778, which was signed into law on August 28, 2009, created a new statewide energy conservation code for residential and commercial buildings by amending the Energy Efficient Commercial Building Act,[64] renamed the Energy Efficient Building Act. The new requirements for residential buildings became effective on January 29, 2010. The efficiency gains of the 2009 code set a new baseline for International Energy Conservation Code-compliant homes and buildings, and while, there will be regional variability and uncertainty in the technology penetration, preliminary estimates from U.S. DOE suggest the 2009 IECC will be at least 18 percent and possibly even 22 percent more energy efficient than the 2006 IECC.

Chicago Energy Conservation Code

In November, 2008, the Chicago City Council passed an amendment to Chapter 18-13 putting into place the Chicago Energy Conservation Code for residential and commercial properties. The code includes requirements for residential properties to improve energy efficiency through the insulation of floors, roofs and walls as well as the installation of energy efficient windows and mechanical systems. Commercial buildings must meet the ASHRAE/IESNA 90.1-2004, Energy Standard for Buildings except Low-Rise Residential Buildings, Section 4.1 Compliance Requirements.

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[63] *See* P.A. 95-0481 (section originally codified as 220 ILCS 5/12-103).

[64] "Illinois Energy Conservation Code for Commercial and Residential Buildings." http://www.ildceo.net/dceo/Bureaus/Energy_Recycling/IECC.htm.

Building Industry Training and Education

Through the EEPS Illinois Energy Now program, DCEO has provided grants to various organizations providing training and education to trade allies and contractors performing work related to energy efficiency, building codes, and market transformation.[65]

Energy Efficiency Resource Standards

The American Council for an Energy Efficient Economy (ACEEE) reports the widespread adoption of "energy efficiency resource standards" ("EERS") and long-term energy savings targets. The most recent scorecard published by ACEEE in 2011 noted that 24 states have energy EERS (25 by the time the report was published). The widespread adoption of energy efficiency resource standards has put forth targets that, if met, will greatly reduce consumption and overall demand growth. However, this growth has put pressure on utility programs to increase customer participation, either in existing programs or through the development of new programs, including those reaching markets previously under-served or not served at all, and by implementing a more comprehensive set of measures than programs achieved earlier.

Appliance Standards and Energy Efficiency Savings

A joint report of the American Council for an Energy Efficient Economy ("ACEEE") and the Appliance Standards Awareness Project ("ASAP") examined the impact of appliance, equipment and lighting standards on electricity consumption.[66] Such standards, a cornerstone of U.S. energy policy since the 1980s, have significantly reduced U.S. energy consumption, providing large benefits for consumers and businesses. Taking into account products sold from the inception of each national standard through 2035, existing standards are estimated to net consumers and businesses more than $1.1 trillion in savings cumulatively.[67] By 2035, cumulative energy savings will reach more than 200 quads, an amount equal to about two years of total U.S. energy consumption.

Standards have had a particularly large effect on electricity use. On an annual basis, products meeting existing standards reduced U.S. electricity use in 2010 by about 280 terawatt-hours (TWh), a 7% reduction.[68] The electricity savings will grow to about 680 TWh in 2035, reducing U.S. electricity consumption by about 14% in each of those years.

For individual consumers, benefits have been very large, and are expected to grow as new and revised standards take effect. Based on a combination of existing and new standards, a typical household replacing its major appliances every 15 years could save over 180 MWh of electricity. Absent standards, this typical household's electricity use over this period would have been about 35% higher.

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[65] Illinois Energy Now DCEO 2011-2012 Report. June 26, 2012 at 18.

[66] "The Efficiency Boom: Cashing In on the Savings from Appliance Standards," ACEEE/ASAP (March 2012), Amanda Lowenberger, Joanna Mauer, Andrew deLaski, Marianne DiMascio, Jennifer Amann, and Steven Nadel (Report Number ASAP-8/ACEEE-A123).

[67] *Id.* at iii.

[68] *Id.*

3.3.3 Demand Response

As noted by the utilities in their load forecast documentation, demand response does not impact the weather-normalized load forecasts. As such, the IPA notes that they are more like supply resources. Section 7 of this Procurement Plan contains the IPA's discussion and recommendations for specific demand response resources to be included and approved in the 2013 Procurement Plan.

3.3.4 Emerging Technology and Load Forecast Uncertainty

A wide range of emerging supply side, demand side, and intermediating technologies will affect future load forecasts. These technologies are being developed and deployed at different rates and will affect load forecasting in different timeframes. Most of them depend on a common enabling infrastructure known as a "Smart Grid": a digital information network connecting all nodes of supply and demand and providing real time information to utilities, end-users, and authorized third parties. The smart grid, and in particular, the types of investments identified in the new Energy Infrastructure Modernization Act ("EIMA")[69], hold great potential benefits for Illinois electric customers, including:

- Improvements in operational efficiency and system reliability, including reduced metering costs through automated metering and improved asset life through improved information on maintenance issues in wires or in substations, before equipment failures or outages occur.
- Consumer benefits through improved usage information and ability to manage energy usage through energy efficiency, demand response and distributed generation investments, not only through expanded rate options that will give additional potential money saving opportunities from energy conservation and load shifting but through new technologies made practicable by smart grid investments.
- Environmental benefits through smarter long-term generation and transmission investments and more efficient resource utilization, avoided GHG emissions associated with peak energy usage and meter reading, and improved distributed and renewable resource interconnection.

If a utility chooses to have its delivery services rates set under the EIMA, that utility is obligated to make investments in transmission and distribution infrastructure improvements. Both ComEd and Ameren have elected to do so, and in turn are now obligated to invest $1,300,000,000 and $360,000,000, respectively in "Smart Grid electric system upgrades."[70]

Under the Energy Infrastructure and Modernization Act of 2011, full deployment of the Smart Grid may take a decade or more. But as sections of the grid are modernized and central office systems and software are modified to accommodate the new information flow, customers will be able to take advantage of new technologies in areas where Advanced Metering Infrastructure (AMI) is operational. Alternative suppliers of energy products can be expected to develop and market new products and services to residential and small commercial customers as deployment advances and utility tariffs may be set to accommodate AMI-enabled services and pricing options.

With only the 130,000 AMI meters installed in ComEd's 2010 pilot program presently in place and with most applications not yet functional, load forecasts for the 2013 Procurement Plan will not be affected, but the combined effect of emerging technologies will grow as AMI is deployed

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[69] Public Act 97-0616, as modified by Public Act 97-0646.

[70] 220 ILCS 5/16-108.5(b)(1)(B).

statewide. New demand-side technologies primarily are designed to shift load from peak periods to off-peak periods. Future energy management may be facilitated through the introduction of automatic controls and mobile smart phone applications. Although some emerging technologies will improve energy efficiency, others are part of an ongoing electrification trend that may increase overall kilowatt-hour usage by replacing fossil energy sources such as petroleum and natural gas.

Emerging technologies include the following:

- **Electric Vehicles (EV)** – A 2% penetration rate for electric vehicles in the ComEd and Ameren service territories represents more than 100,000 vehicles. Assuming electricity usage of 25kwh/100 mile, an EV would use about 3 MWh to drive 12,000 miles per year, and 100,000 vehicles would add 300,000 MWh to statewide annual energy needs. Forecasts for penetration rates of electric vehicles are widely variant and tied to anticipated comparative costs to own and operate fossil fueled vehicles. However, these vehicles could be expected to charge largely at night, and electric vehicles owners would likely opt for time-variant electric rates to take advantage of lower off-peak power prices.
    - Charging Station Regulation - House Bill 5071, passed in the spring of 2012, would amend the PUA to provide that "an entity that furnishes the service of charging electric vehicles does not and shall not be deemed to sell electricity and is not and shall not be deemed a public utility" or an "alternative retail electric supplier" unless the entity is otherwise deemed a utility or alternate supplier, or is otherwise subject to regulation under this Act.[71] This amendment may provide regulatory certainty to entities seeking to furnish electricity for the charging of PEVs who were uncertain about their designation under the PUA, thus potentially eliminating a barrier to market entry. The legislation also requires the ICC to initiate a rulemaking to establish certification requirements for individuals or entities that install, maintain, or repair electric vehicle charging stations. This statutory directive may impact ICC Docket 12-0212, an existing rulemaking to establish certification requirements for charging stations. The Commission opened this proceeding in response to a legislative directive in Public Act 97-0616, which added Sec. 16-128A to the PUA. The extent to which future regulations related to charging station installations require installers or customers to notify the utility of the installation will impact the accuracy of future utility load forecasts.
    - Ameren forecasts a PEV adoption rate of between 156,215 to 236,690 PEVs by 2020.[72]
    - ComEd forecasts between a few thousand to 20,000 PEVs in the utility's service territory by the end of 2013.[73] Using national forecasts, ComEd projects that the total cumulative number of PEVs on the road in the utility's service territory by 2020 could vary between 32,000 and 300,000.[74]
    - The Commission initiated a stakeholder process that led to the formation of five stakeholder-led workshops in the fall of 2011. These workshops culminated in the development of the ICC PEV Initiative Report and Recommendations. Of relevance to the IPA, stakeholders agreed that the existing RRTP programs provide "the correct price signals to PEV owners for their vehicle charging needs" and are

[71] 220 ILCS 5/3-105(c)and 220 ILCS 5/16-102.
[72] Ameren Illinois Initial Assessment of Plug-in Electric Vehicles at 9.
[73] Commonwealth Edison Company Initial Assessment of the Impact of the Introduction of Plug-in Electric Vehicles on the Distribution System at 6.
[74] Commonwealth Edison Company Initial Assessment of the Impact of the Introduction of Plug-in Electric Vehicles on the Distribution System at 17.

sufficient to meet the charging needs of PEV owners.[75] While no ARES currently offer a dynamic pricing option, the rates workshop found evidence from other states that ARES "will offer time-variant rates as smart meters become available."[76] The extent to which PEV owners switch out of the portfolio to participate in RRTP programs or take service from an ARES affects the size of the IPA's portfolio as well as the load shape of the customers served.

- **Electric Thermal Storage (ETS) Heating** -- Using a radiator filled with bricks as a heat sink, ETS heating effectively stores heat derived from off-peak electricity, needing only a small fan to radiate the heat during peak periods. Controllers anticipate the amount of stored heat to be needed based on outside temperature and individual settings. ETS can be expected to be installed primarily in new construction. Because more than 90% of residential heating in Illinois is fueled by natural gas, ETS heat would add to off-peak electricity loads.
- **Electric Thermal Storage Cooling** – Similar to ETS heating, ETS cooling uses off-peak electricity to make ice or a chilled chemical mixture, thus avoiding high cost peak power usage for compressors. Long available for larger cooling loads, this technology is under development for residential scale applications and can be expected to be commercialized as time variant electricity rates make it cost-effective.
- **Smart Appliances** – Connected through a Home Area Network (HAN), smart appliances "know" when to run and when not to run based on programmed instructions about price responsiveness, desired comfort levels and other settings. Projections based on experimental installations show significant load shifting opportunities.
- **Advanced Electricity Storage** – Cost-effective storage technology has the potential to reshape electricity load, thus improving capacity utilization of generation, transmission and distribution, and reducing overall energy costs due to lower peak electricity prices. Emerging electricity storage technologies include flow batteries, high temperature batteries, lithium ion batteries, flywheels, and compressed air storage. The modular nature of many of these technologies allows a variety of deployment options: by customers, by utilities at electricity substations, and by generators at wind farms. The relatively high costs of these technologies do not make for a compelling economic case in most applications at today's electricity market prices, however, intensive global R&D is producing rapid advancements that may soon lead to broader commercialization.
- **Central Direct Load Control** -- Programs such as those now offered by utilities to cycle air-conditioning usage during peak periods may be facilitated through AMI applications, offered by third party providers, and could be expanded to include other types of loads. The effect of greater direct load control would be reduced peak usage.
- **Distributed Generation** -- Emerging technologies may allow a much larger segment of customers to self-generate cost-effectively. Advancements in fuel cells and microturbines fueled by natural gas, as well as small-scale cogeneration of heat and power, are reducing costs to the point that these technologies may eventually become competitive with central station generation. PV solar costs also have plummeted in recent years. The pairing of distributed generation with net metering tariffs and/or new small-scale storage options may create a cost-effective option for a significant portion of small-volume electricity loads.

[75] ICC Initiative on Plug-In Electric Vehicles Executive Summary Report and Recommendations Page iii.
[76] ICC Initiative on Plug-In Electric Vehicles Executive Summary Report and Recommendations Page iii.

To spur development of this technology option, PA 97-0616 added a distributed generation component to the renewable portfolio requirements for utilities and ARES. See Section 8.4 of this Plan.

While all of these emerging technologies may at some point be subject to rapid and even simultaneous growth, they are unlikely to achieve market penetration so quickly as to provide short-term load forecasting uncertainty, such as in a single IPA procurement plan. However, the combined effect of emerging technologies could become a significant over time.

3.4 Recommended Planning Forecast Scenario

After consideration of all the risk and uncertainty factors discussed above, the IPA recommends the use of the Expected Load Forecasts provided by each of the utilities. These forecasts do not include the impacts of new or incremental efficiency programs identified by the utilities for IPA consideration. The IPA addresses these incremental programs in Section 7.0 of this Procurement Plan: Resource Choices for the 2013 Procurement Plan.

4.0 Existing Resource Portfolio and Supply Gap to Be Filled

The IPA has historically purchased supply in standard 50-MW peak/off-peak/around the clock blocks. Prior procurements have included a supply strategy designed to minimize price risk by procuring a “ladder” of standard energy products so that 100% of the first year in a 3-year procurement plan is fully hedged (meaning that existing contracts cover 100% of forecast load), 70% of the second year is hedged, and 35% of the third year is hedged. Because energy markets are only liquid and visible for a three-year horizon, the IPA has determined that, as a general matter, hedging for any part of the fourth and fifth years of the utility forecast period would introduce excessive and unnecessary price risk. The exception has been several longer term procurements mandated by the legislature, including a 20-year bundled REC and energy purchase, starting in June 2012, made by Ameren and ComEd in December 2010, and the February 2012 “Rate Stability” procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017. The discussion below explores in more detail the supply gap between the updated utility load projections described in more detail in Section 3.0 and the supply already under contract for the planning horizon. The IPA proposes to address the gaps (if any) in supply as described in Section 6.0 - Managing Supply Risks and Section 7.0 - Resource Choices for the 2013 Procurement Plan.

4.1 Ameren

The following illustrates the current gap in the Ameren supply portfolio for the June 2013-May 2018 planning period, using the Expected Load Forecast described in Section 3. Quantities shown are average peak and off-peak MW for both loads and historic purchases. Statistics are shown for the full 5-year forecast horizon, even though the IPA’s procurement plans have generally only prescribed purchases for a three-year forward horizon. This is being done so that when, later in this Plan we examine resource choices, we have a longer term scenario of expected load requirements. Nor do the tables below for both Ameren Illinois and ComEd represent the recommended amounts to be purchased in any future year. They are simply illustrative of the supply gap. How to fill that gap is the subject of Sections 6.0 and 7.0 of this Plan.

Ameren Illinois Expected Load and Current Hedge Position												
	Avg. Peak Contract Volumes						**Avg. Off-Peak Contract Volumes**					
Contract Month	**Expected Load MW**	**2011 MW**	**2012 MW**	**20-YR MW**	**SB 1652 MW**	**Residual MW**	**Expected Load MW**	**2011 MW**	**2012 MW**	**20-YR MW**	**SB 1652 MW**	**Residual MW**
Jun-13	987	750	0	47	650	(460)	742	550	0	48	650	(506)
Jul–13	1,150	850	0	28	650	(378)	923	700	0	40	650	(467)
Aug-13	1,132	900	0	30	650	(448)	896	700	0	50	650	(504)
Sep-13	859	650	0	44	650	(485)	724	600	0	48	650	(574)
Oct-13	679	550	0	71	650	(592)	542	500	0	86	650	(694)
Nov-13	733	550	0	89	650	(556)	621	500	0	93	650	(622)
Dec-13	861	700	0	74	650	(563)	760	650	0	69	650	(609)
Jan-14	896	750	0	78	650	(582)	799	700	0	86	650	(637)
Feb-14	832	700	0	72	650	(590)	747	650	0	79	650	(632)
Mar-14	663	600	0	83	650	(670)	582	550	0	92	650	(710)
Apr-14	567	500	0	90	650	(673)	468	450	0	98	650	(730)
May-14	545	550	0	70	650	(725)	451	450	0	77	650	(726)
Jun-14	777	0	0	45	650	82	610	0	0	50	650	(90)
Jul-14	951	0	0	28	650	273	756	0	0	40	650	66
Aug-14	944	0	0	32	650	262	743	0	0	48	650	45
Sep-14	701	0	0	42	650	9	591	0	0	50	650	(109)
Oct-14	546	0	0	71	650	(175)	444	0	0	86	650	(292)
Nov-14	603	0	0	93	650	(140)	517	0	0	89	650	(222)
Dec-14	714	0	0	70	650	(6)	649	0	0	72	650	(73)
Jan-15	765	0	0	82	650	33	693	0	0	82	650	(39)
Feb-15	720	0	0	72	650	(2)	644	0	0	79	650	(85)
Mar-15	571	0	0	79	650	(158)	511	0	0	96	650	(235)
Apr-15	496	0	0	90	650	(244)	413	0	0	98	650	(335)
May-15	486	0	0	73	650	(237)	416	0	0	74	650	(308)
Jun-15	702	0	0	43	200	459	557	0	0	53	200	304
Jul-15	878	0	0	27	200	651	686	0	0	41	200	445
Aug-15	879	0	0	32	200	647	682	0	0	48	200	434
Sep-15	653	0	0	42	200	411	542	0	0	50	200	292
Oct-15	506	0	0	74	200	232	415	0	0	82	200	133
Nov-15	561	0	0	89	200	272	479	0	0	93	200	186
Dec-15	669	0	0	70	200	399	612	0	0	72	200	340
Jan-16	718	0	0	86	200	432	665	0	0	79	200	386
Feb-16	667	0	0	69	200	398	600	0	0	78	200	322
Mar-16	538	0	0	76	200	262	491	0	0	100	200	191
Apr-16	465	0	0	94	200	171	406	0	0	94	200	112
May-16	469	0	0	70	200	199	394	0	0	77	200	117
Jun-16	665	0	0	43	0	622	546	0	0	53	0	493
Jul-16	849	0	0	31	0	818	681	0	0	37	0	644
Aug-16	842	0	0	29	0	813	647	0	0	52	0	595
Sep-16	621	0	0	42	0	579	527	0	0	50	0	477
Oct-16	479	0	0	78	0	401	405	0	0	79	0	326
Nov-16	529	0	0	85	0	444	464	0	0	97	0	367
Dec-16	652	0	0	74	0	578	581	0	0	69	0	512
Jan-17	692	0	0	82	0	610	633	0	0	82	0	551
Feb-17	647	0	0	72	0	575	594	0	0	79	0	515
Mar-17	514	0	0	76	0	438	471	0	0	100	0	371
Apr-17	439	0	0	99	0	340	394	0	0	90	0	304
May-17	452	0	0	66	0	386	370	0	0	80	0	290

Jun-17	650	0	0	43	0	607	512	0	0	53	0	459
Jul-17	817	0	0	31	0	786	654	0	0	37	0	617
Aug-17	803	0	0	29	0	774	628	0	0	52	0	576
Sep-17	588	0	0	44	0	544	514	0	0	48	0	466
Oct-17	457	0	0	74	0	383	383	0	0	82	0	301
Nov-17	505	0	0	85	0	420	443	0	0	97	0	346
Dec-17	627	0	0	77	0	550	556	0	0	67	0	489
Jan-18	666	0	0	82	0	584	600	0	0	82	0	518
Feb-18	621	0	0	72	0	549	566	0	0	79	0	487
Mar-18	497	0	0	76	0	421	445	0	0	100	0	345
Apr-18	425	0	0	99	0	326	368	0	0	90	0	278
May-18	434	0	0	66	0	368	350	0	0	80	0	270

The comparison of hedged supply and projected load shows that no purchases of energy are required for the 2013/2014 delivery year. In fact, depending on the month, supply is 400-700 MW over-hedged under this scenario, with the average being 550 MW during the peak period and 600 MW in the off-peak period.[77] For the 2014/2015 delivery year, Ameren is again generally over-hedged, with the exception of July and August. It is not until the 2015/2016 delivery year that Ameren Illinois is consistently short, driven largely by the fact that it was unable to purchase sufficient cost-effective[78] supply during the procurement mandated by Public Act 97-6016, falling 400 MW short. If a procurement event were to be held in the spring of 2013 to fill a 2015/2016 delivery year portfolio shortfall, there is a greater likelihood that any shortfall would be cost-effectively filled. Note that ComEd was able to purchase supply for the 2015/2016 supply year and through December 2017 because the legislature effectively prescribed they purchase a supply strip with a term of June 2013-Dec 2017 in order to effect a specified price construct applicable only to ComEd. Ameren products were specified as single delivery year products in order to increase the opportunities for lower bids in each individual year.

Regarding the excess hedged supply, the IPA considered two options: 1) allowing the energy to settle in the MISO markets or 2) a reverse RFP to sell excess through the bilateral market. The IPA recommends that the energy settle through the MISO markets since the benefits appear to outweigh the drawbacks as illustrated below. A similar set of drawbacks and benefits applies to ComEd's excess hedged supply. The IPA therefore recommends that no reverse RFP be undertaken for either utility in this Procurement Plan.

Benefits:

a) The 2013/14 energy hedges are moderately "out of the money" and selling may result in locking in a loss.
b) Buyers in any reverse RFP may seek purchases below market price.
c) The cost of administering a reverse RFP would be avoided.
d) A reverse RFP in spring would do nothing to mitigate price exposure between now and the RFP event.

[77] These values are rounded to the nearest 50MW, to reflect that the standard product currently purchased by the IPA is a 50 MW block.
[78] Where cost-effective means bids received are lower than the confidential price benchmarks approved by the Commission for the products being bid.

e) Any increase in energy prices during 2013/14 could prove beneficial through the MISO settlement process, whereas a reverse RFP could remove this benefit.
f) Any excess energy over that required to serve the expected load serves as a hedge in the event switching is lower than expected and load is consequently higher than expected.

Drawbacks:

a) Prices may continue to fall thus increasing the magnitude that 2013/14 hedges are "out of the money".
b) Switching to ARES may be higher than forecast, thus increasing the magnitude of the excess hedge position, which if coincident with falling prices would increase the magnitude of the "out of the money" position.

4.2 ComEd

A similar table is shown for ComEd below. The ComEd figures also show a significantly over-hedged position for the 2013/2014 delivery year based on expected load projections. However, unlike Ameren, subsequent delivery years are not comparably over-hedged.

ComEd Expected Load and Current Hedge Position												
	Avg. Peak Contract Volumes						Avg. Off-Peak Contract Volumes					
Contract Month	Expected Load MW	2011 MW	2012 MW	20-YR MW	SB 1652 MW	Residual MW	Expected Load MW	2011 MW	2012 MW	20-YR MW	SB 1652 MW	Residual MW
Jun-13	1749	1,800	0	99	450	(600)	1406	1,250	0	102	450	(396)
Jul–13	2042	2,250	0	59	450	(717)	1623	1,800	0	83	450	(710)
Aug-13	1880	2,100	0	63	450	(733)	1499	1,650	0	105	450	(706)
Sep-13	1406	1,300	0	92	450	(436)	1139	1,050	0	101	450	(462)
Oct-13	1241	1,350	0	150	450	(709)	1016	1,100	0	180	450	(714)
Nov-13	1364	1,450	0	187	450	(723)	1159	1,250	0	196	450	(737)
Dec-13	1586	1,750	0	155	450	(769)	1372	1,250	0	146	450	(474)
Jan-14	1594	1,500	0	164	450	(520)	1391	1,300	0	180	450	(539)
Feb-14	1450	1,600	0	152	450	(752)	1277	1,400	0	167	450	(740)
Mar-14	1284	1,400	0	174	450	(740)	1124	1,250	0	194	450	(770)
Apr-14	1134	1,300	0	188	450	(804)	963	1,100	0	205	450	(792)
May-14	1147	1,350	0	196	450	(849)	960	1,100	0	162	450	(752)
Jun-14	1525	0	150	94	450	831	1236	0	0	106	450	680
Jul-14	1827	0	300	59	450	1,018	1459	0	100	83	450	826
Aug-14	1684	0	200	66	450	968	1359	0	50	101	450	758
Sep-14	1267	0	0	87	450	730	1025	0	0	105	450	470
Oct-14	1109	0	0	150	450	509	916	0	0	180	450	286
Nov-14	1230	0	0	197	450	583	1058	0	0	188	450	420
Dec-14	1461	0	100	148	450	763	1273	0	0	152	450	671
Jan-15	1468	0	100	172	450	746	1292	0	0	173	450	669
Feb-15	1341	0	50	152	450	689	1182	0	0	167	450	565
Mar-15	1188	0	0	166	450	572	1043	0	0	202	450	391
Apr-15	1039	0	0	188	450	401	893	0	0	205	450	238
May-15	1048	0	0	206	450	392	891	0	0	156	450	285
Jun-15	1417	0	0	94	450	873	1156	0	0	106	450	600
Jul-15	1709	0	0	59	450	1,200	1369	0	0	83	450	836
Aug-15	1575	0	0	66	450	1,059	1285	0	0	101	450	734

Sep-15	1184	0	0	87	450	647	964	0	0	105	450	409
Oct-15	1025	0	0	150	450	425	857	0	0	180	450	227
Nov-15	1154	0	0	197	450	507	995	0	0	188	450	357
Dec-15	1378	0	0	148	450	780	1200	0	0	152	450	598
Jan-16	1389	0	0	172	450	767	1226	0	0	173	450	603
Feb-16	1282	0	0	152	450	680	1129	0	0	167	450	512
Mar-16	1133	0	0	166	450	517	998	0	0	202	450	346
Apr-16	983	0	0	188	450	345	852	0	0	205	450	197
May-16	1006	0	0	206	450	350	851	0	0	156	450	245
Jun-16	1371	0	0	94	450	827	1103	0	0	106	450	547
Jul-16	1650	0	0	59	450	1,141	1340	0	0	83	450	807
Aug-16	1541	0	0	66	450	1,025	1231	0	0	101	450	680
Sep-16	1135	0	0	87	450	598	942	0	0	105	450	387
Oct-16	992	0	0	150	450	392	831	0	0	180	450	201
Nov-16	1127	0	0	197	450	480	974	0	0	188	450	336
Dec-16	1345	0	0	148	450	747	1176	0	0	152	450	574
Jan-17	1360	0	0	172	450	738	1205	0	0	173	450	582
Feb-17	1241	0	0	152	450	639	1102	0	0	167	450	485
Mar-17	1102	0	0	166	450	486	978	0	0	202	450	326
Apr-17	955	0	0	188	450	317	828	0	0	205	450	173
May-17	985	0	0	206	450	329	830	0	0	156	450	224
Jun-17	1346	0	0	94	450	802	1076	0	0	106	450	520
Jul-17	1617	0	0	59	450	1,108	1315	0	0	83	450	782
Aug-17	1504	0	0	66	450	988	1210	0	0	101	450	659
Sep-17	1103	0	0	87	450	566	919	0	0	105	450	364
Oct-17	970	0	0	150	450	370	810	0	0	180	450	180
Nov-17	1102	0	0	197	450	455	947	0	0	188	450	309
Dec-17	1309	0	0	148	450	711	1150	0	0	152	450	548
Jan-18	1331	0	0	172	0	1,159	1181	0	0	173	0	1,008
Feb-18	1208	0	0	152	0	1,056	1079	0	0	167	0	912
Mar-18	1071	0	0	166	0	905	952	0	0	202	0	750
Apr-18	934	0	0	188	0	746	806	0	0	205	0	601
May-18	961	0	0	206	0	755	807	0	0	156	0	651

5.0 MISO and PJM Resource Adequacy Outlook and Uncertainty

From the perspective of the IPA Procurement Plan, resource adequacy should be viewed from two different angles. First, in contrast to the era in Illinois when fully-integrated utilities built and rate-based generation under full Commission oversight, the process of acquiring resources under the post-Restructuring Act paradigm could be considered simply a function of determining what level of resources to purchase from which markets over time. However, in order for these markets to properly function, the market must provide sufficient resources to satisfy the demand of all users, and there should be sufficient incentives for resources to be available or forthcoming over the planning horizon to support a competitive market. Without such fully functioning markets, the IPA could be in the position to augment the current resource markets by, for instance, seeking longer-term purchases or PPAs to incent development of generation. This section reviews the likely load/resource outcomes over the planning horizon to determine, if indeed, the current system is highly likely to provide the necessary resources such that customers will be served with adequate and reliable power.

In reviewing the load/resource outcomes over the planning horizon, this section analyzes several outside studies of resource adequacy that are publically available from different planning and reliability entities. These include:

- North American Electric Reliability Corporation ("NERC"), the entity certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards with the goal of ensuring the reliability of the American bulk power system.
- Midwest ISO ("MISO"), which operates the transmission grid in most of central and southern Illinois.
- PJM Interconnect ("PJM"), which operates the transmission grid in Northern Illinois.

From review of these entities' most recent documentation, it is clear that over the planning horizon both PJM and MISO will maintain adequate resources to meet the collective needs of customers in those regions. While uncertainties exist for the future, such as the implication of environmental standards, the best estimates at this time suggest it is highly probable that resources will be sufficient to meet the needs of Illinois customers without the need for the IPA to undertake any extraordinary actions. Regardless, the IPA will continue to actively monitor resource adequacy and future changes in electric markets that may require the IPA to reconsider its assessment.

5.1 North American Electric Reliably Corporation ("NERC") Reliability Assessments

NERC's most recent reliability assessments for MISO and PJM are reproduced in Table 5-1 and Table 5-2. For the IPA planning period (and well beyond), both MISO and PJM are projected to exceed the NERC planning reserve margin ("PRM") reference level.[79] While NERC uses a reference PRM of 15 percent, MISO calculates an even more conservative PRM. MISO's latest Loss of Load Expectation ("LOLE") studies imply a PRM that is slightly higher (17.4%).[80] Even so, MISO's anticipated PRM, shown on Table 5-5, far exceeds both the MISO and NERC reference PRM with the exception of summer 2018 through 2020, where MISO's anticipated PRM will meet or drop slightly below its own calculated reference PRM. The prospective and adjusted potential PRMs will continue to far exceed both the MISO reference level and the NERC reference PRM.[81] NERC also notes that there are no currently planned retirements in MISO that would significantly affect reliability and if, in the future, a retiring unit were to pose a reliability problem a "reliability mitigation plan" would be implemented until such time as alternatives become available.[82]

For PJM, NERC notes that PJM will meet its PRM for all of the planning periods with the exception of 2021 where it will be less than one percent deficient.[83] NERC notes that PJM has over 40,000 MW of nameplate generation in its interconnection queues. While PJM has identified 3,600 MW of generation retirements, as with MISO, if a retirement affects reliability a mitigation strategy will be put in place. PJM has identified no retirements significant to reliability as a result of recent environmental regulations.[84]

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[79] The PRM provides an estimate of the excess of resources over the expected demand or load for a given period.
[80] A LOLE study is used establish the necessary reserves such that load is disconnected, on an expected basis, at some frequency. For example, the current standard for PJM, based on First Reliability Corporation rules, is one day in ten years or 0.1 days per year.
[81] "2011 Long-Term Reliability Assessment" NERC, November 2011, pp. 223-235
[82] Id. p. 225.
[83] PJM's PRM is also slightly higher than the NERC reference level based on PJM's LOLE studies. Id. p. 375
[84] Id. p. 379.

From these data one can conclude that it is highly probable that both MISO and PJM will continue to meet resource adequacy standards over the planning period and beyond.

Table 5-1. MISO Demand, Resources, and Reserve Margins—Summer and following Winter

Period (Summer and following Winter)	Demand		Capacity Resources			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
2011	98,068	90,249	119,764	136,872	136,872	22.1%	39.6%	39.6%	15.0%
2011-2012	79, 052	71, 233	114, 870	131, 978	131, 978	45.3%	67.0%	67.0%	15.0%
2012	92,976	85,157	114,450	131,592	131,592	23.1%	41.5%	41.5%	15.0%
2012-2013	75,208	67,389	109,556	126,698	126,698	45.7%	68.5%	68.5%	15.0%
2013	94,834	87,015	114,509	131,651	131,651	20.7%	38.8%	38.8%	15.0%
2013-2014	77,410	69,591	109,615	126,757	126,757	41.6%	63.7%	63.7%	15.0%
2014	95,227	87,408	114,528	131,670	131,670	20.3%	38.3%	38.3%	15.0%
2014-2015	77,725	69,906	109,634	126,776	126,776	41.1%	63.1%	63.1%	15.0%
2015	95,947	88,128	114,551	131,693	131,693	19.4%	37.3%	37.3%	15.0%
2015-2016	78,574	70,755	109,657	126,799	126,799	39.6%	61.4%	61.4%	15.0%
2016	96,637	88,818	114,633	131,775	131,775	18.6%	36.4%	36.4%	15.0%
2016-2017	79,267	71,448	109,739	126,881	126,881	38.4%	60.1%	60.1%	15.0%
2017	97,332	89,513	114,633	131,775	131,775	17.8%	35.4%	35.4%	15.0%
2017-2018	79,992	72,173	109,739	126,881	126,881	37.2%	58.6%	58.6%	15.0%
2018	98,110	90,291	114,633	131,775	131,775	16.8%	34.3%	34.3%	15.0%
2018-2019	80,778	72,959	109,739	126,881	126,881	35.9%	57.1%	57.1%	15.0%
2019	99,010	91,191	116,196	133,338	133,338	17.4%	34.7%	34.7%	15.0%
2019-2020	81,577	73,758	111,302	128,444	128,444	36.4%	57.5%	57.5%	15.0%
2020	99,929	92,110	116,196	133,338	133,338	16.3%	33.4%	33.4%	15.0%
2020-2021	82,393	74,574	111,302	128,444	128,444	35.1%	55.9%	55.9%	15.0%
2021	143,485	135,199	200,308	200,308	200,308	39.6%	39.6%	39.6%	15.0%
2021-2022	83,217	75,398	111,302	128,444	128,444	33.7%	54.3%	54.3%	15.0%

Source:"2011 Long-Term Reliability Assessment" NERC, November 2011 Data from Tables 7 through 28

Table 5-2. PJM Demand, Resources, and Reserve Margins—Summer and following Winter

Period (Summer and following Winter)	Demand		Capacity Resources			Planning Reserve Margins			
	Total Internal (MW)	Net Internal (MW)	Anticipated (MW)	Prospective (MW)	Adjusted Potential (MW)	Anticipated (%)	Prospective (%)	Adjusted Potential (%)	NERC Reference Margin Level (%)
2011	148,941[(a)]	137,341	193,340	193,340	194,195	29.8%	29.8%	30.4%	15.0%
2011-2012	130,711	119,806	193,548	193,548	193,548	29.8%	29.8%	30.4%	15.0%
2012	158,603[(b)]	151,780	196,424	196,424	199,106	23.8%	23.8%	25.5%	15.0%
2012-2013	133,594	127,464	195,907	195,907	195,907	46.6%	46.6%	46.6%	15.0%
2013	162,489	153,510	200,244	200,244	203,310	23.2%	23.2%	25.1%	15.0%
2013-2014	135,529	127,243	199,712	199,712	199,712	47.4%	47.4%	47.4%	15.0%
2014	164,772	155,793	200,404	200,404	204,545	21.6%	21.6%	24.1%	15.0%
2014-2015	136,948	128,662	200,302	200,302	200,302	46.3%	46.3%	46.3%	15.0%
2015	166,506	157,527	200,990	200,990	206,142	20.7%	20.7%	23.8%	15.0%
2015-2016	137,985	129,699	200,308	200,308	200,308	45.2%	45.2%	45.2%	15.0%
2016	167,847	158,868	200,990	200,990	206,297	19.7%	19.7%	22.9%	15.0%
2016-2017	139,073	130,787	200,308	200,308	200,308	44.0%	44.0%	44.0%	15.0%
2017	169,443	160,464	200,990	200,990	206,522	18.6%	18.6%	21.9%	15.0%
2017-2018	140,040	131,754	200,308	200,308	200,308	43.0%	43.0%	43.0%	15.0%
2018	171,067	162,088	200,990	200,990	206,392	17.5%	17.5%	20.6%	15.0%
2018-2019	141,170	132,884	200,308	200,308	200,308	41.9%	41.9%	41.9%	15.0%
2019	172,780	163,801	200,990	200,990	206,723	16.3%	16.3%	19.6%	15.0%
2019-2020	81,577	73,758	111,302	128,444	128,444	36.4%	57.5%	57.5%	15.0%
2020	174,458	165,479	200,990	200,990	206,723	15.2%	15.2%	18.5%	15.0%
2020-2021	143,485	135,199	200,308	200,308	200,308	39.6%	39.6%	39.6%	15.0%
2021	176,060	167,081	200,990	200,090	206,723	14.2%	14.2%	17.4%	15.0%
2021-2022	144,621	136,335	200,308	200,308	200,308	38.5%	38.5%	38.5%	15.0%

Source: "2011 Long-Term Reliability Assessment" NERC, November 2011 Data from Tables 7 through 28
(a) Includes First Energy and Cleveland Public Power
(b) Includes Duke Ohio and Kentucky

5.2 MISO

While NERC uses data from MISO to conduct its assessment, MISO continues to update its analysis over time with its most recent long-term demand and capacity forecasts approved in December 2011. Total Internal Demand and Net Internal Demand are forecasted to grow to 100,926 MW and 96,717 MW by 2021. Net Internal Demand ranges from 88,765 MW in 2012 to 96,717 MW in 2021 with the reserve margin ranging from 24.5 percent to 16.1 percent over the same time period. The forecasted annual demand growth rate over the next ten years is approximately 1.0 percent, slightly increased from 2010. (Table 5-3)

Generator Interconnection Queue projects are expected to total approximately 7,000 MW of nameplate capacity by 2021, although only 2,549 MW is expected to be designated to serve MISO load by that time. Wind generators account for approximately 4,000 MW of nameplate capacity of the 7,000 MW amount. With the generator interconnection queue considered, Total Designated Capacity is projected to grow from 112,695 MW in 2012 to 114,749 MW in 2021. Internal Designated Capacity Resources are forecasted to be approximately 103,698 MW in 2012 and are assumed to be held constant through 2021. Behind-the-Meter Generation (3,608 MW in 2011) is treated as a capacity resource and not a load modifier, meaning it increases MISO's projected capacity rather than reducing its anticipated load. (Table 5-4) MISO's projection of PRMs is presented in Table 5-5 and is broadly consistent with the earlier NERC figures suggesting that MISO will maintain reliably throughout the planning horizon.

Table 5-3: MISO Load Projections 2012-2017

Demand (MW)	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***
Unrestricted Non-Coincident	97,206	99,149	99,560	100,313	101,034	101,701
Est. Diversity	4,230	4,315	4,333	4,366	4,397	4,429
Total Internal	92,976	94,834	95,227	95,947	96,637	97,332
Direct Control Load Management	1,118	1,118	1,118	1,118	1,118	1,118
Interruptible Load	3,093	3,093	3,093	3,093	3,093	3,093
Net Internal Demand	88,765	90,623	91,016	91,736	92,426	93,121

Source: MISO 2011 Long Term Resource Assessment Table 1-1

Table 5-4: MISO Forecast Capacity 2012-2017

Capacity (MW)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Internal Designated Capacity Resources	103,698	103,698	103,698	103,698	103,698	103,698
External Designated Capacity Resources	4,894	4,894	4,894	4,894	4,894	4,894
Behind-the-Meter Generation	3,608	3,608	3,608	3,608	3,608	3,608
Future Planned Resources	495	862	881	904	986	986
Total Designated Capacity	***112,695***	***113,062***	***113,081***	***113,104***	***113,186***	***113,186***

Source: MISO 2011 Long Term Resource Assessment Table 1-1

Table 5-5: MISO Projected Reserve Margins 2012 - 2017

Reserve Margin	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Reserve Margin (MW)	23,930	22,438	22,064	21,368	20,760	20,065
Reserve Margin (%)	27.0	24.8	24.2	23.3	22.5	21.5
Reserve Requirement (%)[7]	17.4	17.3	17.3	17.2	17.4	17.8

Source: MISO 2011 Long Term Resource Assessment Table 1-1

5.3 PJM

Summer peak load growth for the PJM RTO is projected to average 1.4% per year over the next ten years, and 1.3% over the next 15 years.[85] The PJM RTO summer peak is forecasted to be 176,420 MW in 2022, a 10-year increase of 22,638 MW. It reaches 185,294 MW in 2027, a 15-year increase of 31,512 MW.[86] Annualized 10-year growth rates for individual zones within PJM range from 0.9 to 1.9%.[87] Winter peak load for the PJM RTO is projected to average 1.2% per year over the next 10-year period, and 1.1% over the next 15 years.[88] The PJM RTO winter peak load in 2021/2022 is forecasted to be 144,836 MW, a 10-year increase of 15,996 MW, and reaches 150,901 MW in 2026/2027, a 15 year increase of 22,061 MW.[89] Annualized 10-year growth rates for individual zones within PJM range from 0.6% to 1.6%.[90]

PJM has a significant amount of generation waiting to be added for expected annual load increases. As of March, 2011, PJM had installed generating capacity of 166,292 MW. By the end of 2012, that will be 180,400 MW and by the end of 2013, 189,900 MW. By 2021, planned resources increase capacity by another 1,900 MW. PJM's generator interconnection queue has a total of 27,700 MW of on-peak conceptual capacity over the assessment period.

- Coal: 47.7% capacity
- Nuclear: 35.7% capacity
- Gas: 12% capacity
- 75,737 MW of capacity in generation request queues through 2018; of that, 37,579 MW is wind.

The PJM Reliability Pricing Model ("RPM") is built to encourage new investment to keep capacity reserves at roughly 15% for the PJM system. When existing generation retires, new generation should replace the lost capacity so that retirements should not create a threat to the overall PJM capacity reserves. The model determines capacity payments to generators; these are the payments for having excess capacity, not the price for energy actually being used by consumers. When there is more than 15% reserve capacity, the price of energy steadily lowers below PJM's calculation of the Cost of New Entry (NetCONE). When there is less than 15% reserve capacity the price increases, encouraging new investment up to 15%. There are price caps at 1.5x Net CONE, around 7% reserve capacity, meaning that when there is under 7% reserve capacity the price will not continue to increase.

The 2013/2014 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 152,743.3 MW of unforced capacity in PJM at a Resource Clearing Price of $27.73/MW-day.[91] This MW and price quantity pair on the RTO Variable Resource Requirement curve represents a 20.3% reserve margin; however when the Fixed Resource Requirement (FRR) load is considered the

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85 PJM Load Forecast Report, January 2012, PJM Resource Adequacy Planning Department

86 *Id.* at 1.

87 *Id.* at 2.

88 *Id.*

89 *Id.*

90 *Id.*

91 PJM "2013/2014 RPM Base Residual Auction Results," PJM DOCS #592585, at 1.

actual reserve margin for the entire RTO is 20.2%.[92] The $27.73/MW-day RTO resource clearing price represents an increase of $11.27/MW-day from the 2012/2013 BRA.[93]

A total of 4,831.9 MW of incrementally new capacity in PJM was available for the 2013/2014 Base Residual Auction.[94] This incrementally new capacity includes new generation capacity resources, capacity upgrades to existing generation capacity resources, new Demand Resources, upgrades to existing Demand Resources, and new Energy Efficiency Resources.[95] The increase is partially offset by generation capacity derations to existing generation capacity resources to yield a net increase of over 2,907.8 MW of installed capacity.[96]

The total quantity of Demand Resources offered into the 2013/2014 BRA was 12,952.7 MW (UCAP) which represents an increase of 3,105.1 MW (32%) over the Demand Resources that offered into the 2012/2013 BRA. Approximately 72% (9,281.9 MW) of these Demand Resources cleared in the auction. Part of this increase (1,384.8 MW) occurred in the new ATSI transmission zone that is participating for the first time in the Base Residual auction due to the ATSI integration. The remaining 1,720.3 MW increase was in the remaining zones of the market. The majority of the increased participation by demand response was driven by the forward capacity market incentives.

The total quantity of Energy Efficiency (EE) Resources offered into the 2013/2014 BRA was 756.8 MW (UCAP) which represents an increase of 33% over the EE Resources that offered into the 2012/2013 BRA. Approximately 90% (679.4 MW) of these EE Resources cleared in the auction.

Table 5-6 summarizes the offer and resultant data for each cleared Base Residual Auction from 2008/09 through the 2013/2014 Delivery Years, and includes all resources located in the RTO (including all LDAs within the RTO) and notes the capacity located outside the PJM footprint that was offered into the auction.[97]

Table 5-6: RPM Base Residual Auction Generation, Demand, and Energy Efficiency Resource Information

Auction Supply (all values in ICAP)	2008/2009	2009/2010	2010/2011	2011/2012**	2012/2013	2013/2014***
Internal PJM Capacity	166,037.9	167,026.3	168,457.3	169,241.6	179,791.2	195,633.4
Imports Offered	2,612.0	2,563.2	2,982.4	6,814.2	4,152.4	4,766.1
Total Eligible RPM Capacity	**168,649.9**	**169,589.5**	**171,439.7**	**176,055.8**	**183,943.6**	**200,399.5**
Exports / Delistings	4,205.8	2,240.9	3,378.2	3,389.2	2,783.9	2,624.5
FRR Commitments	24,953.5	25,316.2	26,305.7	25,921.2	26,302.1	25,793.1
Excused	722.0	1,121.9	1,290.7	1,580.0	1,732.2	1,825.7
Total Eligible RPM Capacity - Excused	**29,881.3**	**28,679.0**	**30,974.6**	**30,890.4**	**30,818.2**	**30,243.3**
Remaining Eligible RPM Capacity	***138,768.6***	***140,910.5***	***140,465.1***	***145,165.4***	***153,125.4***	***170,156.2***

[92] *Id.*

[93] *Id.*

[94] *Id.*

[95] *Id.*

[96] *Id.*

[97] *Id.* at 12.

Generation Offered	138,076.7	140,003.6	139,529.5	143,568.1	142,957.7	156,894.1
DR Offered	691.9	906.9	935.6	1,597.3	9,535.4	12,528.7
EE Offered	0.0	0.0	0.0	0.0	632.3	733.4
Total Eligible RPM Capacity Offered	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**
Total Eligible RPM Capacity Unoffered	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***

*RTO numbers include all LDAs.

**All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.

***2013/

The incremental effect of total capacity additions and reductions to date is summarized on the table below from the 2007/2008 to the 2013/2014 BRAs.[98] A total of 4,831.9 MW of incrementally new capacity in PJM was available for the 2013/2014 BRA, and this incrementally new capacity includes new generation capacity resources, capacity upgrades to existing generation capacity resources, new Demand Resources, upgrades to existing Demand Resources, and new Energy Efficiency Resources.[99] The increase is partially offset by generation capacity derations to existing generation capacity resources to yield a net increase of 2,907.8 MW of installed capacity.[100]

This table also illustrates the total amount of resource additions and reductions over seven Delivery Years since the implementation of the RPM construct. Over the period covering the first seven RPM Base Residual Auctions, 11,582 MW of new generation capacity was added which was partially offset by 7,184.7 MW of capacity derations or retirements over the same period.[101] Additionally, 12,966.5 MW of new Demand Resources were offered over these last seven auctions, and 733.4 MW of new Energy Efficiency resources were offered in the 2013/2014 auction.[102] The total net increase in installed capacity in PJM over the period of the last seven RPM auctions was 17,887.3 MW.

Table 5-7: Incremental Capacity Resource Additions and Reductions to Date

Capacity Changes (in ICAP)	2007 - 2008	2008 - 2009	2009 - 2010	2010 - 2011	2011 - 2012	2012 - 2013	2013 - 2014	Total
Increase in Generation Capacity	602.0	724.2	1,272.3	1,776.2	3,576.3	1,893.5	1,737.5	11,582.0
Decrease in Generation Capacity	-674.6	-375.4	-550.2	-301.8	-264.7	-3,093.9	-1,924.1	-7,184.7
Net Increase in Demand Resource Capacity**	555.0	574.7	215.0	28.7	661.7	7,938.1	2,993.3	12,966.5
Net Increase in Energy Efficiency Capacity**	0	0	0	0	0	632.3	101.1	733.4
Net Increase in Installed Capacity	**482.4**	**923.5**	**937.1**	**1,503.1**	**3,973.3**	**7,160.1**	**2,907.8**	**17,887.3**

* RTO numbers include all LDAs

** Values are with respect to the quantity offered in the previous year's Base Residual Auction. **Does not include Existing Generation located in ATSI Zone

[98] *Id.* at 14-15.

[99] *Id.* at 14.

[100] *Id.*

[101] *Id.*

[102] *Id.*

On May 18, 2012, PJM announced the results of its annual Reliability Pricing Model (RPM) for capacity three years forward, to meet the needs of the June 1, 2015 to May 31, 2016 delivery year. This auction procured a record amount of new generation in one year, 4900 MW. In addition, capacity imported from west of PJM increased about 8% to 4335 MW. Overall, the auction procured 164,561 MW of capacity resources at a base price of $136 per MW. This compares to PJM's all-time peak up to that time of 158,448 MW. In addition to new generation, most of it natural gas–fired, the capacity auction procured record amounts of demand response, energy efficiency and renewable generation. These results indicate that the PJM capacity market construct is providing the incentive for new generation and reliability, even in the face of coal retirements.[103]

The utilization of the capacity resources procured is dependent on the strength of the transmission system connecting the generators to the grid. As a complement to the RPM auction results, PJM announced on May 17, 2012 the approval of nearly $2 billion in electric transmission upgrades related to generation retirements, consisting of over 130 projects. The upgrades allow for safe and reliability flow of electricity from other sources to replace retiring generation.

5.4 Resource Adequacy Uncertainty and Environmental Regulation

While it appears from published material that resources are likely to remain adequate through the planning period, the uncertainty most likely to impact resource adequacy is new environmental regulation. New regulations requiring capital investments for some facilities such as the Cross State Pollution Rule and the National Emission Standards for Hazardous Air Pollutants have the potential to force a subset of those plants to retire, potentially degrading reliability and/or raising prices for capacity. NERC considers this to be the most significant resource adequacy risk in the coming one to five years.[104] Several entities have attempted to address the issue of environmental regulation-fueled facility retirements by looking at the likely retirement of plants as a result. For example, PJM recently examined the projected impacts of US EPA regulation on coal retirement.[105] Several conclusions are of importance include that:

- Some capital investment will be required with as much as thirty-seven percent of the total coal capacity in PJM requiring at least two retrofits.[106]
- Even with almost 7,000 MW less coal capacity clearing for the 2014/2015 delivery year, PJM estimates the RTO will carry a reserve margin of 19.6 percent for the delivery year.[107]
- Even with the potential retirement of coal capacity already there are also announced commitments to replace a portion of that capacity with new gas-fired capacity such that the PJM would still carry a reserve margin at or above of the target 15.3 percent installed reserve margin.

Add the potential for new entry from demand resources, as has been the trend in recent years, and resource adequacy does not appear to be threatened in PJM. Although no system-wide capacity problem is apparent in PJM, the report noted that localized reliability concerns could arise given the

[103] "PJM Capacity Auction Secures Record Amounts of New Generation, Demand Response, Energy Efficiency", PJM press release, May 18, 2012.
[104] 2011 Long-Term Reliability Assessment" NERC, November 2011, p. 72.
[105] "Coal Capacity at Risk: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants," PJM, August 26, 2011
[106] Id. p. i.
[107] Id. p. iv.

location of particular units and the unique locational services they provide such as congestion management of particular transmission facilities and voltage support for the transmission system. . In PJM's assessment, the key is whether replacement resources or transmission reinforcements can be timely added given the breadth of the potential retirements and the pressure on outside vendors to supply new turbines and related resources. PJM noted that as long as resource adequacy and local reliability are assured, the cycle of generation retirement and new resource entry are market-driven outcomes that can be reliability and efficiency enhancing. Newer, more efficient generation resources that replace retiring generation may have lower forced outage rates and thus, are more dependable than older generation resources that may be nearing the end of their useful lives. Additionally, new resources, whether it is new generation, demand response, or energy efficiency, may also provide lower cost alternatives to achieve resource adequacy.

MISO has undertaken its own study and determined that roughly 13,000 MW that could be at risk and -- under the most extreme scenario -- planning margins could fall below acceptable rates without additional resources added.[108]

However, decisions to retire generating plants hinge on a myriad of factors. For example, the sharp decline in natural gas prices, the rising cost of coal and reduced demand for electricity are all contributing to company decisions to retire some of the country's oldest power plants. As noted by Susan Tierney[109], in the 3/20/12 blog ***Politico***[110],

> "Most of the coal-fired power plants in line for retirement are, in fact, of typical retirement age. Many are between 50-60 years old; some are as old as 70. Many are "merchant" plants, whose financial performance is shaped by competitive markets. The bottom line comes down to economic fundamentals: Power companies just can't operate these older coal-fired plants and produce electricity at high enough prices to make money in today's conditions. The chief executive officer of American Electric Power, which owns a big fleet of coal-fired plants in Ohio, said as much recently when he explained a series of coal plant retirements to Wall Street analysts. He said that the coal plant closures involved "high cost plants," *which didn't run often anyway* (emphasis added), because it was more economical to use natural gas and other plants in the company's fleet. Shutting down the coal plants, he said, would mean costs savings."

Similarly, with respect to new coal construction,

> "Consumers Energy, for example, announced on Dec. 2 the cancellation of the 830-megawatt Bay City coal project. The Michigan utility said it was cancelling the project because of the same factors that led it to defer the project in May 2010. The factors are reduced customer demand for electricity due to the condition of the economy, surplus generating capacity in

[108] "EPA Impacts from the EPA Regulations on MISO," MISO, October 2011, p.

[109] *Susan Tierney is a managing principal at Analysis Group, a business strategy firm that consults on energy and other issues. She is a former assistant secretary for policy at the Energy Department and former secretary of environmental affairs of Massachusetts.*

[110] http://www.politico.com/news/stories/0312/74211.html

the Midwest and lower natural gas prices linked to expanded shale gas supplies. Lower natural gas prices make new coal-fired plants less economically attractive."[111]

NERC suggests that even in areas where retirements occur, there are options for mitigation that include advancing in-service dates of new generation, increases in transfers between regions, increased demand-side management, use of more gas-fired generation or re-powering coal units with combined cycle turbines, among other options.[112]

5.5 Overall Conclusions for Illinois

The RTO-based reliability assessments examined above are important measures of supply reliability in Illinois, because the Illinois electric grid operates within the control of the RTOs. The integration of Entergy into MISO this November will provide more generation to be dispatched and bid into the MISO markets, and the same can be said of the successful integration of Duke Energy Ohio and Duke Energy Kentucky into PJM. On a more local level, while the announced or actual retirement of several coal-fired units around the State were newsworthy events, including the Fisk and Crawford generating stations located in central Chicago, based on the IPA's familiarity with the in-state generating resources, Illinois appears to have an in-state generating portfolio that is better situated than most because of its early adoption of, and action to achieve, clean air targets, as well as the non-coal diversity of its generating stock, including nuclear and wind. Coupled with a relatively robust transmission system, overall, and proactive transmission planning in anticipation of coal plant retirements, the base case planning scenario for resource adequacy indicates sufficient reliable capacity to meet system reliability targets for the planning horizon. Given this conclusion, the IPA does not need to include any extraordinary measures in the 2013 Procurement Plan to assure reliability over the planning horizon.

6.0 Managing Supply Risks

The IPA Act lists the priorities applicable to the IPA's portfolio design, which 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…[113]

At the same time, the legislature recognized that achievement of these priorities requires a careful balancing of risks and costs, when it required that the IPA's Procurement Plan include:

> [A]n 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.[114]

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[111] A Path Forward for Coal, CARBON CAPTURE KEY, Published In: EnergyBiz Magazine. March/April 2012, Barry Cassell
[112] 2011 Long-Term Reliability Assessment" NERC, November 2011, p. 75-76
[113] 20 ILCS 3855/1-5(A)
[114] 220 ILCS 5/16-111.5(b)(3)(vi)

In other words, the challenge for the IPA in its procurement plans is to balance supply and demand in a given electric market environment, both wholesale and retail, with a goal towards achieving the lowest total cost over time, taking into account any benefits of price stability. The 2013 Procurement Plan, however, faces particular challenges as described below.

This is the IPA's fifth procurement plan. The prior four Plans appropriately assessed the various risk factors applicable to Ameren Illinois and ComEd supply for fixed price default service and resulted in a pre-existing portfolio consisting of laddered standard product supply contracts of varying short-term durations of from one month to one year, supplemented by longer term 20-year contracts from a December 2010 procurement for bundled RECS and energy, and a legislatively-mandated procurement conducted in February 2012 for a delivery period extending through December 2017. As shown in Section 3 of this 2013 Procurement Plan, these pre-existing contracts cover a majority of the supply requirements over the planning horizon. While the preponderance of supply needs have already been met (at least from the perspective of this Procurement Plan), there remain three key categories of risk at the forefront of impact on this specific procurement plan:

1. Market price uncertainty at the wholesale level
2. Supply volume uncertainty at the wholesale level
3. Demand volume uncertainty at the retail level

None of these categories operates without affecting the other categories of risks. As discussed in Sections 3 and 5, wholesale prices affect the quantity of wholesale supply, and both, in turn, affect retail prices and the retail demand for utility fixed price service relative to the demand for ARES retail service. Utilities in restructured markets such as Illinois are particularly burdened with demand volume risk, given the nature of their service obligations.[115] In contrast, an ARES can opt to control, to some degree, the demand volume uncertainty (and its wholesale market price risk) by locking in a portfolio of retail customers for a period of time with some certainty before locking in its supply resources and costs, or creating contractual protections against customers attempting to leave before parallel supply contracts end. Hence, an ARES is better able to control its supply and demand balance. That is one of the underlying factors why an ARES price offer under municipal aggregation is generally held open only for periods as short as a few hours. Neither Ameren Illinois nor ComEd have that luxury under the PUA. The utilities maintain an obligation to serve all default service customers and must be prepared to serve an uncertain range of load that may leave or return at will, subject to some restrictions. Hence, wholesale suppliers bidding to serve utility load are likely to include a volume premium in their price offers.[116] A standard energy block product was designed, in large part, to shift that risk back to the ratepayers, on the theory that the utilities (working in conjunction with the IPA and Commission) could address this risk with a lower premium than the competitive market.

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[115] *See*, *e.g.*, 220 ILCS 5/16-103(c) ("Notwithstanding any other provision of this Article, each electric utility shall continue offering to all residential customers and to all small commercial retail customers in its service area, as a tariffed service, bundled electric power and energy delivered to the customer's premises consistent with the bundled utility service provided by the electric utility on the effective date of this amendatory Act of 1997"); 220 ILCS 5/16-103(d) ("Any residential or small commercial retail customer which elects delivery services [*i.e.* leaves the IPA portfolio] is entitled to return to the electric utility's bundled utility tariffed service offering [*i.e.* return to the IPA portfolio] provided in accordance with subsection (c) of this Section upon payment of a reasonable administrative fee which shall be set forth in the tariff").

[116] Note that both utilities and ARES are subject to the same weather and economic risk. For purposes of this Procurement Plan, it is customer migration risk coupled with the obligation to serve that creates a differential risk between utility and ARES supply portfolios.

Beyond traditional customer-by-customer switching, migration risk due to municipal aggregation introduces an unprecedented potential for volume volatility for both the Ameren and ComEd supply portfolios. Historically, mismatches between the standard products purchased for the supply portfolio and the actual load serving responsibility at the time of delivery have been covered through utility transactions in the day-ahead and real-time balancing markets of MISO and PJM. However, it is necessary to examine the costs of this supply/demand balancing strategy against other solutions, given the current high potential volumes of mismatch. The costs of this strategy are paid by customers through a purchased electricity adjustment, rather than the base supply charge. This adds a level of volatility and unpredictability to supply charges, implicating one of the principles the legislature has articulated for the supply portfolio – price stability.

A number of procurement strategies have been proposed by parties in prior procurement plan approval proceedings at the Commission as means to mitigate certain perceived risks, such as the risk of rising market prices exacerbated by hypothesized resource scarcity. Below, this 2013 Procurement Plan examines the following portfolio risk management strategies in light of current and projected market conditions:

1. The role and risks of long-term contracts vs. short-term supply within the planning horizon.
2. Full-requirements supply as an alternative to reliance on the daily MISO and PJM balancing markets.
3. Demand response as a risk management tool.

In considering risk management strategies, there is no one portfolio strategy that is "optimal", although there can be a portfolio that has an optimal expected cost for a given set of risks. Therefore, the level of risk that each strategy optimally addresses must be understood.

6.1 Market Conditions

In order to understand the factors that create market price uncertainty and supply risks, the IPA conducted a set of modeling scenarios incorporating a range of assumptions with respect to system load, natural gas prices, demand response capability and carbon regulation compliance costs. A base case scenario covering the entire 5-year planning horizon was constructed, while high and low cases were examined over the typical 3-year procurement cycle. A key conclusion is that market prices in Illinois, as measured by Locational Marginal Prices (LMPs) are relatively insensitive to variability of the key inputs listed above. This conclusion means that portfolio strategy decisions can be made in an environment of a relatively well-defined bandwidth of market price projections. This is important because of the IPA's mandate to propose and conduct procurement strategies designed to foster low and stable prices over time.

Modeling of LMPs for Illinois was preformed utilizing a stochastic optimization program that simulates the operations of the electric system.[117] The modeling uses generator data, transmission data, and hourly load data to simulate the outcomes of system operation over the relevant planning horizon and over the entire Eastern Interconnect. As with any modeling of future outcomes, the choice and evolution of different variables can have significant effects on modeled outcomes. In order to obtain an understanding of how LMPs are likely to evolve over time in Illinois in the short term, the modeling results reported here reflect eight different possible

[117] Simulations completed using MarSi. For a more complete description of MarSi *see* "Annual Report: The Costs and Benefits of Renewable Procurement in Illinois under the Illinois Power Agency and Illinois Public Utilities Act," IPA, March 30, 2012, Appendix 3.

futures and one base case. While often this type of modeling is used to make inferences over a long planning horizon e.g., 20 years, in which future conditions are likely to change, given the relative short-term nature of the planning exercise undertaken here, the range of possible outcomes represented by the scenarios below are likely to represent the extremes of ranges of actual outcomes. Table 6.1 illustrates the changes in the key variables considered over possible futures.

Table 6.1: Scenarios for Modeling Illinois LMPs 2013-2017

	Load	**Gas Prices**	**Demand Response**	**Emissions Prices**
Scenario 0: Base Case	Base Case – Based on FERC estimates	NYMEX futures for 2013; escalated at 4%	Embedded in Forecast	CO_2 = $5/ton NOx = $10,000/ton
Scenario 1: Robust Economy	Base Case + 5% (energy growth)	Base Case	Base Case	Base Case
Scenario 2: Frail Economy	Base Case - 10% (energy growth)	Base Case	Base Case	Base Case
Scenario 3: High NG Prices	Base Case	Base Case +10%	Base Case	Base Case
Scenario 4: Low NG Prices	Base Case	Base Case -10%	Base Case	Base Case
Scenario 5: Demand Response I	Base Case	Base Case	Base Case -5% peak demand	Base Case
Scenario 6: Demand Response II	Base Case	Base Case	Base Case -10% peak demand	Base Case
Scenario 7: Carbon Constrained I	Base Case	Base Case	Base Case	CO_2 = $10/ton NOx = $10,000/ton
Scenario 8: Carbon Constrained II	Base Case	Base Case	Base Case	CO_2 = $20/ton NOx = $10,000/ton

One potential risk factor for the IPA portfolio is escalating short-term market prices in which the balancing of the IPA load is done. Using the above futures, the LMPs for the NI-Hub region (defined by 234 nodes in the ComEd territory) and the IL-Hub (defined by 150 nodes in the Ameren Illinois territory) were estimated for the Base Case and the eight scenarios for 2013-2015 and for the base case out to 2017.[118] In the short-term, both the IPA's planning model and PJM forecast LMPs for NI-Hub to increase, on average, modestly over the next three years as shown in Table 6.2.

Table 6.3 provides the same data for the IL Hub. The IL Hub LMPs in the Base Case appear to move even less than what is expected in NI Hub.

Table 6.2: NI-Hub Expected LMPs (2013-2017) - $/MWh

Year	Peak (Base Case)	Off-peak (Base Case)	Peak (Adica Forecast)[a]	Peak (NYMEX Futures) [a]
2013	41.62	35.16	39.09	35.69
2014	42.47	35.60	39.54	36.57
2015	43.61	36.35	39.99	37.31
2016	45.32	37.34		
2017	46.87	38.46		

(a) Source: Adica produced forecast based on hourly historical day-ahead LMP of PJM-NI-Hub

(b) Source: September 10. 2012, NYMEX Daily Settlements for PJM Northern Illinois Hub

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118 Note that Ameren and ComEd do not necessarily settle their MISO and PJM loads at NI-Hub or IL-HUB but this analysis serves as a useful proxy and comparison for LMP growth projections between the two utility service areas .

Table 6.3: IL-Hub Expected LMPs (2013-2017) - $/MWh

Year	Peak (Base Case)	Off-peak (Base Case)
2013	38.04	33.01
2014	38.85	33.61
2015	39.64	34.35
2016	41.22	35.29
2017	42.11	36.24

Note: MISO is in the process of preparing an Updated LMP Forecast

Figure 6.1 and Figure 6.2 present the results of the modeling in a slightly different manner. Here the ranges of the average monthly (peak) prices are shown for NI-Hub and IL-Hub respectively. The ranges are relatively tight over the three-year period. It is worth noting here that, one extreme Scenario (Carbon Constrained II) has been excluded for this comparison as representing an extremely unlikely outcome in the near term (although perhaps not in the long-term). [119]

[119] Many forecasters assume that carbon will not be priced until after 2017 in base and low case forecasts. In high forecasts carbon prices are likely to begin under $20/ton until at least 2017 (2010 USD). *See e.g.*, "2011 Carbon Dioxide Price Forecast," August 10, 2011 Synapse Energy Economics, Inc. (Table 3) This report also reviews assumptions used in utility planning exercises across the country. In nearly all plans filed before 2011 carbon prices were expected to exceed $20/ton by 2013-2015 (at least in high price scenarios). Those plans filed after 2010, however, typically assume carbon prices exceeding $20/ton only in high price scenarios during this time. It seems likely that carbon will not be priced until 2015 given the time needed to implement rules and the likelihood that the economic situation will not improve in the coming year.

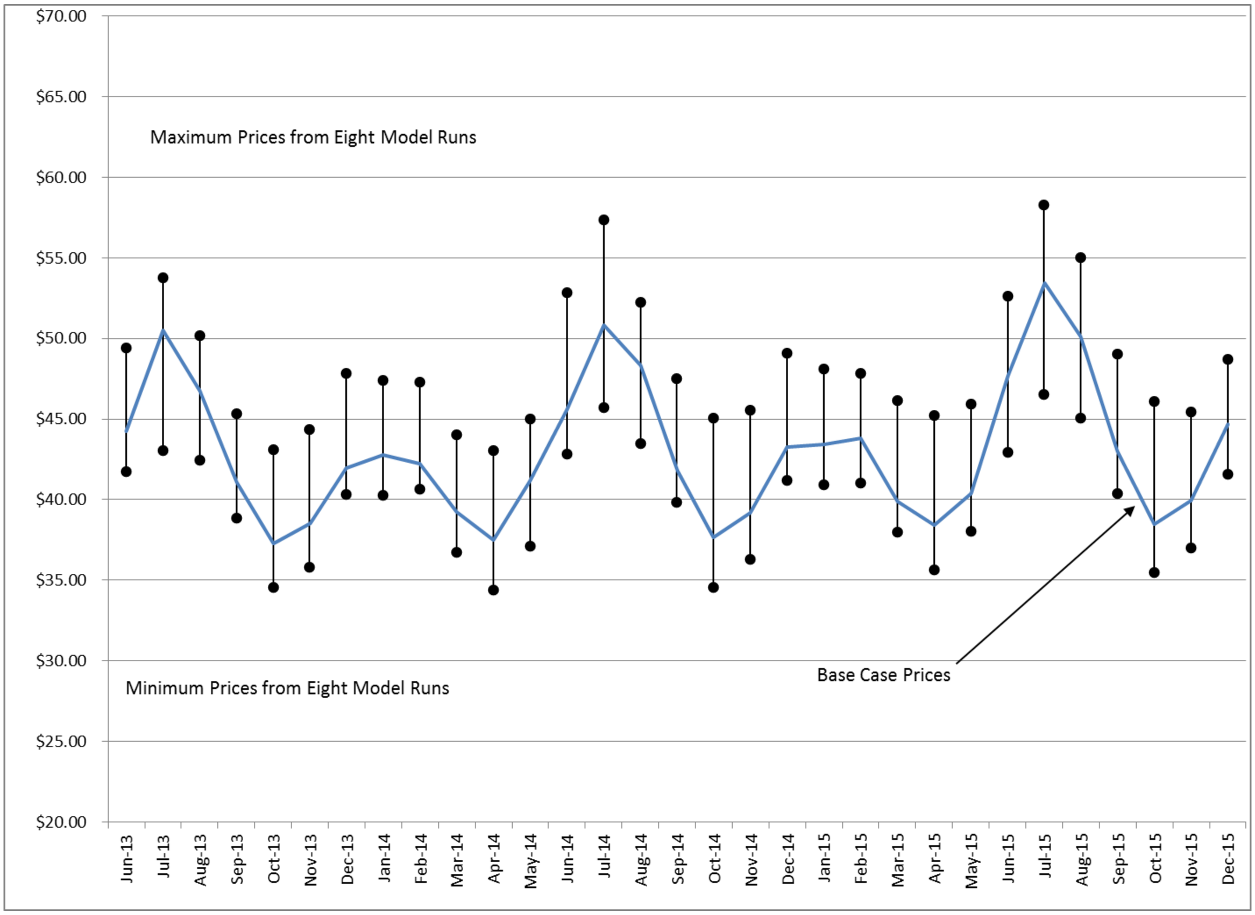

Figure 6.1: Range of Estimated Monthly Average Peak Prices in the Northern Illinois Hub during 2013-2015 ($/mWh)

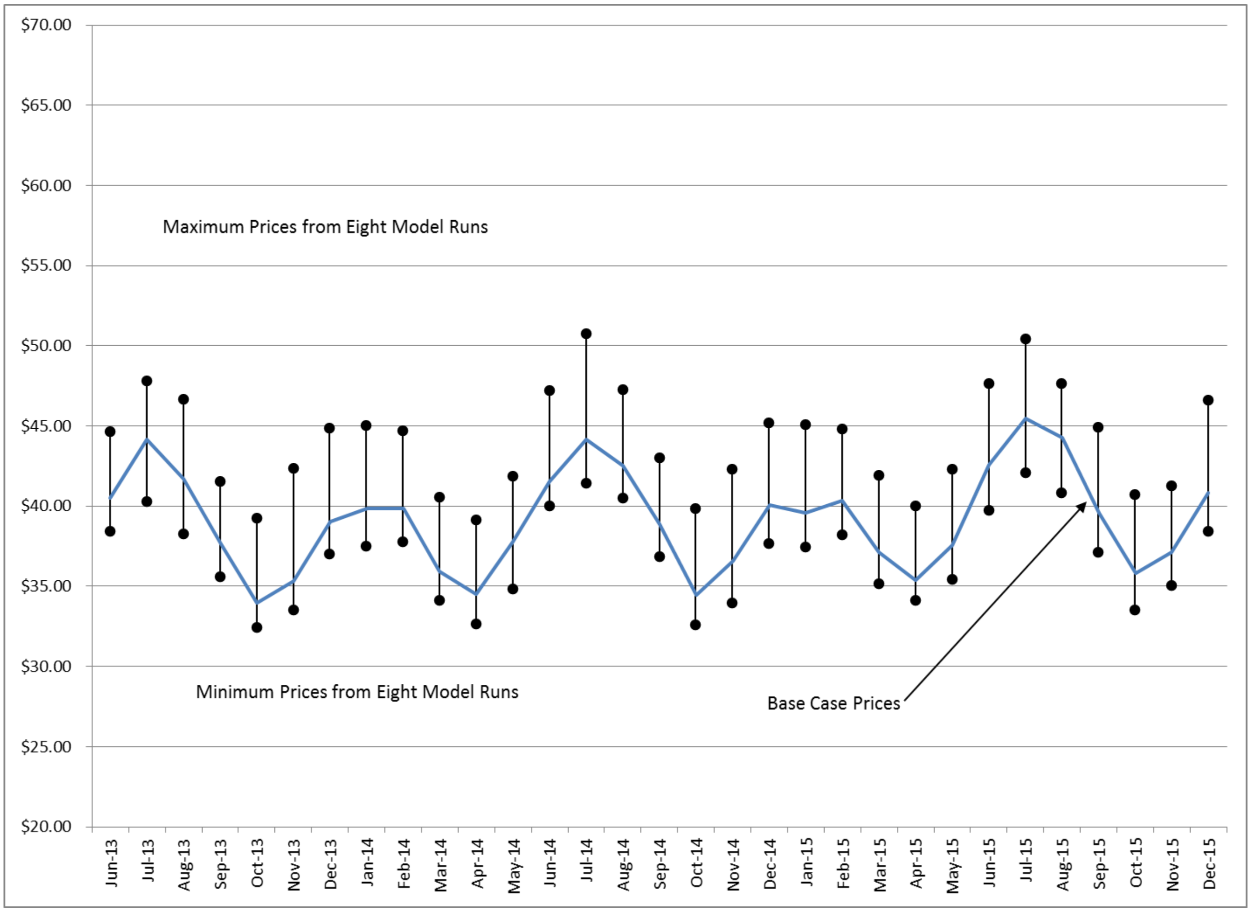

Figure 6.2: Range of Estimated Monthly Average Peak Prices in the Illinois Hub during 2013-2015 ($/mWh)

In the past, the IPA has been concerned about volatility issues that could affect the overall prices paid by customers. The current procurement portfolios already subject customers to some degree of market volatility due to the nature of existing standard block products, which require balancing in the day-ahead market. Additionally, other factors, such as uncertainty concerning utility load requirements suggest that the IPA refrain from recommending additional block energy purchases at this time. The magnitude of quantity risk can be illustrated by reviewing the utilities' compliance forecasts. For example, the ComEd load forecasts have become increasingly volatile largely due to the uncertainty associated with municipal aggregation and to a lesser extent other customer migration issues. For the past two compliance forecasts (2011 and 2012) the differences between the high and low forecast for the first year have expanded dramatically. In 2011 the difference was 85 percent (for 2012-2013). The current forecast shows a 103 percent difference between the high and the low forecast for the first year (2013-2014). For the out years the forecast variation is even wider. The same is true for Ameren. With this type of quantity risk, and the likelihood that market prices will remain soft for the immediate future, it could be prudent to reduce the use of fixed quantity products to hedge portfolio supply as Staff and others have suggested.

6.2 Role and Risks of Long-Term Contracts vs. Short-Term Supply Within the Planning Horizon

Long-term contracts have been characterized as a strategy to incentivize new build, ensure adequate supply, and lock in prices, thus providing reliability and price stability. Is the current IPA-procured portfolio strategy of relying largely on a ladder of short-term contracts appropriate in a future where there are projections of large-scale plant retirements due to promulgation of clean air rules? Section 5 of this Plan describes the PJM and MISO resource adequacy analyses, and concludes that over the 5-year planning horizon the risks of resource shortfalls that might jeopardize reliability are largely mitigated by actions taken by both RTOs, including transmission improvements as well as capacity market incentives. That being said, should the IPA propose a strategy of greater reliance on using long-term contracts as either a price hedge in the face of expected market-price increases or to incentivize new generation that would otherwise be incapable of being financed without a long term power purchase agreement? These arguments are often promulgated on behalf of renewable resources and other generation with economic development opportunities in Illinois. However, this procurement analysis must take place, not in the abstract, but in the context of the pre-existing supply portfolio and current retail and wholesale market conditions.

First, this Plan describes the means by which MISO and PJM operate to optimize additions to the generation supply in their respective market and reliability regions. Then an assessment of the role of additional long-term contracts in the Ameren and ComEd supply portfolios is provided.

6.2.1 Optimizing Timing of New Build for Economics, Reliability and Uncertainty

Building new generating capacity in either PJM or MISO is subject to many conditions and constraints—amount of existing capacity, coal retirements due to age and/or cost of air pollution control costs due to the Cross-State Air Pollution Rule (CSAPR), Mercury and Air Toxics Standard (MATS) and National Ambient Air Quality Standards (NAAQS), delivered fuel prices (coal and natural gas), and market rules for capacity additions. All of the factors are embedded in the bid price of capacity submitted in either the PJM or MISO auction market.

PJM

PJM relies on its Reliability Pricing Model - annual capacity auctions for capacity resources three years into the future plus residual auctions for resources needed one and two years out, calculations of the Cost of New Entry (CONE) and a price screen known as the Minimum Offer Price Rule (MOPR) designed to assure that generators bid on an equal footing - to secure cost-effective capacity resources and to incent new construction to bid into the auctions when it makes economic sense.

The basic premise of the capacity auction system in PJM is to have pricing interact with the targeted reserve margin level so that the closer the supply/demand intersection reaches the targeted reserve margin (15.4%) the more capacity prices will reflect the required economics for new generators. In theory, capacity prices at the target reserve margin level of the supply/demand curve would reach sufficient levels to incentivize new peaker construction, calculated as the Net Cost of New Entry (Net CONE). It is important to recognize the auction itself is structurally designed with a view towards constructing gas-fired peakers; decisions regarding baseload generation remain tied to the underlying energy price outlook, as their high load factors dictate that this is where the bulk of the their revenues and margin is achieved.

The calculations of MOPR and CONE are detailed and complex. In fact, CONE is calculated separately for each of 5 CONE Zones. ComEd is in CONE Area 3, along with AEP, APS, ATSI, Dayton, DEOK, and Duquesne. These calculations serve much like the benchmarks used to screen bids in the IPA-administered procurement process rather than setting minimum and maximum bids. It appears that within PJM, natural gas-fired capacity (either combustion turbines or combined cycle) is currently economically viable, and is being/will be bid into regional markets if the capacity is required and/or it is lower cost on the margin than existing capacity.

PJM has a system to procure capacity resources designed to provide appropriate price signals that will reach the level necessary to bring new resources to the marketplace when it is economically the optimum time to do so. While the capacity market only looks three years into the future, in theory robust capacity, energy and ancillary services markets will, in a mature marketplace, provide a steady stream of revenues over the useful life of the generating asset, thus allowing the asset to be financed and built. In practice, project developers still desire the certainty that long term power purchase agreements provide in terms of revenue streams sufficient to support the total carrying costs of a project. However, in a retail choice state such as Illinois, finding a wholesale customer with a 20-year portfolio horizon is difficult due to the uncertain outlook for the level of steady-state retail load to be served by the wholesale purchase. For a utility in such a volatile load position, care must be taken so that the supply portfolio is not over-burdened with strandable long-term contract costs. Fortunately for generators, the Illinois generation marketplace has access to both the MISO and PJM markets, providing a wealth of opportunity for sales to electricity counterparties other than ComEd and Ameren, including traditional vertically integrated utilities that retain an obligation to serve all customers in their service area and, therefore, more certain load serving obligations. The interconnected system is indifferent to the financial transactions of generators and their customers, only that sufficient supply and demand balance exists electrically at all times. It should not matter who the customer is – the lights will still stay on.

MISO

The MISO capacity market is much less developed than is PJM's and still subject to significant evolution over the next several years. MISO is slated to host its inaugural annual capacity auction in late March 2013, for the 2013/2014 planning year. It is a voluntary auction, unlike PJM's mandatory auction, and the preponderance of MISO members are vertically integrated utilities. Further, the MISO capacity markets construct places much of its emphasis on motivating vertically-integrated utilities to "opt-out" of participation via filing fixed resource adequacy plans (FRAPs). This design orientation is a result of a FERC order (to MISO) to remove its proposed MOPR provisions from its tariff. The signals to incent new build and compensate generator developers in the MISO marketplace come less from the MISO capacity construct and more from the vertically-integrated utilities that predominate the MISO region and that can rate base new assets over their economically useful lives.

For these reasons, liquidity in the inaugural MISO capacity auctions is expected to be low and they are not likely to result in useful price signals to generators to add or bid in new capacity. With the removal of the MOPR, which essentially acts as a price floor for auction bids, industry analysts expect that capacity compensation will be extremely low in the MISO marketplace.

Clearly this is a complex marketplace in transitory times – low prices that benefit ratepayers but that leave generators short of the compensation necessary to finance new projects, newly applicable clean air rules, newly developed capacity constructs in MISO and evolving mechanisms in PJM, reduced expectations for Ameren and ComEd eligible customer retail load, and existing supply portfolios that are over-hedged for at least the first year of the planning horizon.

Ideally, the IPA would like to see the MISO marketplace evolve to at least the point where Ameren can rely on it (rather than IPA-administered procurement events), as ComEd procures all its capacity through the PJM auctions. It does not appear to be at that point and may not be for several years. Ameren has been making capacity purchases via IPA administered procurement events. As a result of the April 5, 2012 IPA procurement, Ameren currently holds capacity in the amount of 1,660 MW of Zonal Resource Credits (ZRCs)for the 2013/2014 plan year and 1,110 MW of ZRCs for the 2014/2015 plan year. Section 7.6 of this Plan discusses the IPAs recommendation for additional Ameren capacity purchases for the planning horizon.

6.2.2 Long Term Standard Product and Unit-Specific Contracts

While PJM and, to a much lesser extent, MISO attempt to send proper economic signals and compensation for generation, including when it is the optimal time to build that generation, the IPA must still assess whether it is in the interests of the electricity consumers of the State of Illinois for it to include additional long-term contracts designed to compensate new generator development in its procurement plan. These contracts can take one of two forms: contracts for standard products for periods of longer than 3 years; and power purchase agreements tied to the output of specific generating units for extended periods of time.

Arguing against adding long-term contracts of either form to the supply portfolio is the dramatic decline in the Ameren Illinois and ComEd fixed-price default service load forecasts; so that the existing long-term contracts in these utilities' supply portfolios constitute a significant portion of the current supply portfolios. This issue was discussed in Section 4, which contained a comparison of base case load forecasts and existing supply contracts and shows that existing commitments from longer-term procurement events constitute the preponderant current committed supply in many months. Adding even more supply tied to long-term delivery commitments runs several risks, including: (1) the possibility of stranded costs should retail load continue to fall; (2) a disconnect in supply and demand due to outdated pricing in future years between utility prices and ARES prices that will further distort the supplier switching dynamics; and (3) further price risk borne by remaining retail customers should the utilities find it necessary to sell excess supply to the marketplace at a loss. Furthermore, unit-specific or unit-contingent contracts with generators in which the utility takes generation as it is produced add load balancing costs greater than those experienced with standard products. Given that neither Ameren Illinois nor ComEd require purchases for the 2013/2014 delivery year, and the continued uncertainty surrounding the ultimate impact of municipal aggregation on utility retail load, the IPA recommends that any decision on whether to add additional long-term supply contracts to the supply portfolio (either for standard products or output tied to specific generators) be deferred until at least the 2014 Procurement Plan, when more will be known about the sustainability of municipal aggregation, overall switching to ARES, the impacts of clean air rules on available resources, the MISO capacity market and general market price levels.

The IPA makes two exceptions to this recommendation. The first is the proposal for the Commission to approve the power purchase agreement between the retrofit clean coal facility known as "FutureGen 2.0" and which is discussed in Section 7.3 of this Plan. Secondly, the IPA also requests Commission approval of a Distributed Generation Renewable Resource program design (although not its immediate implementation), as described in Section 8.4.

6.3 Load Balancing Market Risks

The supply portfolios of both Ameren and ComEd beginning with the 2013 delivery year consist of either standard 50 MW block products or the metered output of the renewable resources purchased in December 2010 under long-term 20-year contracts. On a real-time basis, however, the output of these contracts will be either less than or more than the actual load on the respective utility systems (as described in this Procurement Plan, it is almost universally more than actual load in the 2013/2014 delivery year). In order to ensure a match between supply and demand, ComEd transacts in the PJM day-ahead and real-time spot markets, while Ameren does the same within the MISO markets. The functioning of these processes is well-documented in prior procurement plans for both physically and financially-settled supply contracts. Due to the significant shifts in load away from both utilities due to municipal aggregation and individual customer choice, the mismatch between supply and demand has become significantly more pronounced. The utilities are in the position of potentially selling large quantities back to their RTOs at prices that are below the original purchase price (because market prices have fallen since the products were procured). This potential is particularly pronounced when it comes to the 2007-vintage large-volume energy contracts mentioned in subsection 3.3.1. For the most part, projected electricity supply costs are recovered from eligible retail customers through a set of utility charges that are updated relatively infrequently (such as annually). However, unanticipated imbalances between costs and revenues are tracked and form the basis for monthly credits or surcharges to customers' bills, as governed by the "Purchased Electricity Adjustment" ("PEA") factor.

In prior procurement plan proceedings it has been suggested that the price risk borne by retail customers using the balancing procedure above could be better handled through the use of full-requirements contracts, which monetize the balancing risks up front when bidders include a balancing risk premium in their fixed price bids. While rejected in the past for inclusion in the supply portfolios and procurement plans under the purview of the IPA, full requirements contracts are briefly discussed here for completeness of discussion. The subsections below examine the historic volatility of the PEA, describe the nature of a full requirements contract, and then assess the ability to include a full-requirements contract in the future utility supply portfolios. Finally, a hedging proposal recommended by both ICC Staff and Boston Pacific (the Procurement Monitor) is assessed for applicability in this Plan.

6.3.1 Magnitude and Volatility of the Purchased Electricity Adjustment

The Purchased Electricity Adjustment (PEA) functions as a balancing mechanism to assure that electricity supply charges match supply costs over time. The balance is reviewed monthly and the charge rate is adjusted accordingly. The PEA can be a debit or credit to address the difference between the revenue collected from customers and the cost of electricity supplied to these same customers in a given period. The supply costs are tracked (and the PEA adjusted) for each customer group.

The table below displays the PEA ($/MWh) for ComEd and Ameren since 2010. The ComEd value does not change significantly month-to-month because ComEd has imposed a voluntary, self-imposed cap on the PEA of 0.5 cents/kWh. The ComEd PEA is expected to remain at this level through at least May 2013.

	Ameren/Reg I[(a)] ($/MWh)	Ameren/Reg II[(a)] ($/MWh)	Ameren/Reg III[(a)] ($/MWh)	ComEd[(b)] ($/MWh)
01/2010	0.74	(1.92)	(1.07)	2.28
02/2010	1.33	(1.44)	(1.55)	5.00
03/2010	(1.22)	(2.21)	(1.30)	5.00
04/2010	(2.00)	(2.69)	(1.99)	1.69
05/2010	(1.92)	(2.48)	(0.75)	2.88
06/2010	(2.22)	(2.23)	(0.24)	2.49
07/2010	(2.36)	(2.57)	(0.89)	5.00
08/2010	(2.37)	(2.81)	(1.17)	5.00
09/2010	(2.94)	(3.08)	(1.71)	5.00
10/2010	(2.85)	(3.27)	(1.93)	(5.00)
11/2010	(2.02)	(2.70)	1.82	(5.00)
12/2010	2.26	(1.94)	2.32	(6.50)
01/2011	2.42	(0.99)	1.86	(6.50)
02/2011	1.34	(1.02)	1.42	0.67
03/2011	(1.63)	(6.13)	(1.24)	5.00
04/2011	(2.35)	(7.01)	(2.17)	3.11
05/2011	(2.29)	(6.98)	(2.45)	(0.26)
06/2011	(2.26)	(6.33)	(2.55)	3.24
07/2011	(2.28)	(6.38)	(2.91)	5.00
08/2011	(3.41)	(6.29)	(3.63)	5.00
09/2011	(3.62)	(6.30)	(3.94)	5.00
10/2011	(2.65)	(6.15)	(2.75)	5.00
11/2011	(2.28)	(5.19)	(2.09)	1.80
12/2011	(2.08)	(4.57)	(1.49)	(1.51)
01/2012	(2.17)	(4.44)	(1.11)	4.70
02/2012	(2.07)	(4.64)	(1.08)	5.00
03/2012	(3.28)	(6.07)	(2.34)	5.00
04/2012	(2.74)	(4.99)	(1.61)	5.00
05/2012	(2.97)	(4.66)	(1.48)	5.00
06/2012	(2.81)	(4.62)	(1.25)	5.00
07/2012	(3.26)	(5.03)	(1.60)	5.00

(a) Source: http://www.ameren.com/sites/aiu/Rates/Documents/
(b) Source: Figures provided by Regulatory Affairs Department at ComEd and are on file with the author.

The combined effect of customer migration and falling market prices has had and continues to have a significant impact on the utilities' electric supply charges, including but not limited to the PEAs. In particular, utility rates have increased relative to market prices and even higher than the prices that were locked in place years ago through long-term hedge contracts, as the utility customer base shrinks relative to the power supply procured under those long-term contracts. In February 2012 it appeared that ComEd's PEA could more than double in March (from 0.5 to 1.0 cents/kWh), which would have resulted in a 4% increase in overall household electric rates (to 13 cents per kWh).[120] While the increase in PEA was voluntarily capped, the problem remains: how

[120] ComEd Mulls Power Hike to Offset Loss of Suburban Customers (Crain's Chicago Business, February 18, 2012).

to cover previously committed power procurement costs with a shrinking customer base. The converse can also occur: if customers return to the utility because market prices are rising compared to the price of the utility portfolio, the utility will need to procure additional supply in a rising cost market.

Given that a portion of the supply portfolio has already been procured, the challenge faced by ComEd (and Ameren) is two-fold: 1) forecast customer demand as accurately as possible, including the effect of customer switching to minimize PEA volatility, and 2) increase the PEA in the near-term to ensure that departing customers pay for at least some of the power purchased on their behalf. However, increasing the PEA today could accelerate the rate of customer migration to competitive suppliers, compounding the supply cost-customer revenue imbalance problem.

6.3.2 Full Requirements Service/Contracts

A solution that has been proposed by some parties has been to employ full-requirements supply rather than standard block products as part of the portfolio. Several other jurisdictions use full requirements as a way to shift price risk to the supplier and to monetize in a predictable way the costs of that risk. The IPA notes, however, that the degree of switching volatility currently being experienced in Illinois may not be operative in these other jurisdictions. The Constellation and Boston Pacific July 13, 2011, process comments (at http://www.icc.illinois.gov/downloads/public/Boston%20Pacific%20Reply%20Comments%20on%20the%202011%20RFPs.pdf) describe an analysis that could be undertaken to quantify the difference between full requirements benchmark prices and the actual costs incurred through the use of block purchases plus the daily PJM/MISO balancing markets.

Full requirements service (FRS) is typically a standardized product and generally includes energy, capacity, ancillary services and other electricity services needed by basic service customers regardless of the season/time of day or number of customers. In FRS procurements, potential bidders offer to provide "all electricity services" for a standardized block of customer load for a fixed time period and price.

The design of FRS procurement has implications for the distribution of financial risks associated with the electricity supply bid. One risk is portfolio risk, which is addressed by the mix of short-, medium- and long-term financial and physical arrangements the supplier engages in to service the FRS contract. Another type of risk is volumetric risk, which arises from uncertainty about the customer load. This risk has increased in importance and is sensitive to the migration of customers to/from the utility service territory.

However, stable prices can have undesirable consequences: for example, (1) they prevent customers from seeing true cost of power and thus make uneconomic load/technology decisions, and (2) thus they slow the development of competitive power options—both supply and demand, and on both sides of the meter.

While stable prices are desirable—by both customers and suppliers—there are a number of risks that are currently difficult to quantify (monetize) given their interdependencies and market/regulatory uncertainties. For example, on the supply side:

- Cost of compliance with the Cross-State Air Pollution Rule (CSAPR) and the Mercury Air Toxics Standard (MATS). Some utility plants have already been targeted for shutdown since their cost of compliance exceeds the current market clearing price for power. However, some utility plants are likely to get special conditions (from EPA and/or FERC)—for example, power plants owned by municipals/cooperatives where the power generated is the only source of income to the entity.

- Natural gas is currently trading at very low prices due to available (and expected) supply. However, while prices are currently low (and have been declining) gas is not generally being sold under long term contract. Thus, there may be some potential for risk related to gas prices in the very long term.

There are also risks on the demand side whenever there are shifts in pricing methodology so care must be taken to not make casual changes back and forth between methodologies. If a shift to full requirements supply provides the consumer higher per-unit prices because all the costs are monetized in a predictable way, the new prices may induce conservation/efficiency investments potentially resulting in these investments becoming "stranded" if there is a shift from a stable (but high) price back to a more volatile price environment. These demand side impacts of pricing make it important that consumers be aware of the entire costs included in either utility default or ARES service. The utilities do provide full requirements service, but it takes the addition of all the charges related to supply including transmission service and PEA to determine the full utility FR price.

There will always likely be a risk differential between the utility and ARES provision of FR service. The ARES can better manage their load risk than can the utilities by choosing the customers and the number of customers they wish to serve. The volume risk of the utilities still exceeds that of the ARES and so the price premium for the utility full requirements service may exceed that for the ARES, depending on perceptions of that volume risk. The current method of using the day-ahead markets for load balancing may well be least cost, even though it introduces price volatility. If one puts a permissible bandwidth around the PEA as ComEd has done, even that volatility can be mitigated.

At this point in the evolution of the retail electric marketplace in Illinois, customer migration risk is extremely large and attempts to incorporate a full requirements product into the current pre-existing portfolio may be difficult without paying a large risk premium for the product. Furthermore, while it was possible to maintain a portfolio of both full requirements and standard block products when the post-2006 full requirements portfolio acquired during a reverse auction in 2006 was being phased out and replaced with the IPA's procurement of standard block products, adding full requirements supply to a portfolio built up with standard blocks and various odd gaps in the supply hedge over the next 5 years seems to be a tricky proposition. Given that no energy procurement events are being recommended in this Plan, the IPA and stakeholders have an opportunity to further consider this in the 2014 Plan.

The specific concern over high PEAs should be mitigated somewhat once the 3000 MW swap for ComEd expires at the end of May 2013. The Ameren swap expires at the end of 2012. As will be discussed in Section 7, the 2013/2014 delivery year presents a challenge, but subsequent delivery years can allow for a clean slate approach to the supply portfolio, so long as the procurement portfolio is not burdened with a supply strategy that creates more risk than it resolves. At this time, the IPA does not recommend the addition of any full requirements products to the utility supply portfolio during the planning horizon.

6.3.3 Managing Risk Through Increased Reliance on Spot Markets

The Illinois Commerce Commission Staff and the Commission's Procurement Monitor, Boston Pacific Company, have each provided complementary thoughts on a way to deal with portfolio risk in an era of tremendous retail load uncertainty for Ameren and ComEd.

We see three ways in which the risk of over- or under- procuring may be mitigated. First, the Commission could order the utilities to submit an updated load forecast in March that would be used to update the quantities to be procured (which would have originally been based on a load forecast that was developed during the previous Fall). Such an update was required by the Commission this year and, as indicated above, resulted in a substantial decrease in the quantities to be procured. Second, the IPA could procure less by lowering the targets to be hedged over the next three service years. As indicated above, the IPA attempts to procure 100% of the first year's need, 70% of the second year's need, and 35% of the third year's need. Third, RFPs could be held more frequently. For example, procurements could be held twice during the year, once each half-year period. The risk of over or under-procuring would decrease because there would be more frequent load projections from which to derive the quantities to be procured. We view the third option as one that will not likely be implemented because of the added complexity of introducing additional RFPs each year.[121]

The ICC Staff provides the following insight:

To address the above-described situation, Staff recommends that the IPA modify its planning process as follows. First, to the extent possible, the IPA should incorporate into its risk modeling differences between the utility's purchased electricity charges and current market prices, and the impact of such differences on eligible retail customer load. Second, the IPA should consider reducing the degree to which it relies upon fixed-quantity fixed-price forward contracts for meeting the expected (but unknown) future demands of eligible retail customers, especially for periods beyond the first year included within each plan. For example, Staff offers the following alternative proposals for the IPA to analyze:

Energy Hedging Plan: Staff Proposal 1

Fixed Price Hedge Quantities, as a % of *Expected* Average Hourly Load For Each of the 24 Periods of the Indicated Plan Year, to Have Established by June 1 of the Current Plan Year		
Current PY	*Current PY+1*	*Current PY+2*
75%	*50%*	*25%*

Energy Hedging Plan: Staff Proposal 2

Fixed Price Hedge Quantities, as a % of *Low Load Forecast* Average Hourly Load For Each of the 24 Periods of the Indicated Plan Year, to Have Established by June 1 of the Current Plan Year		
Current PY	*Current PY+1*	*Current PY+2*
90% to 100%	60% to 70%	30% to 40%

Either of the above two hedging proposals would or could have the following benefits:

1. The utility's remaining eligible retail customers would suffer lower financial losses from the utility holding "out-of-the-money" forward contracts.

2. Customers would oscillate less between utility supply and ARES supply, due to transitory differences in cost structures.

[121] Comments On The 2012 Procurement Process Pursuant To Section 16-111.5(O) Of The Public Utilities Act Presented To The Illinois Commerce Commission By Boston Pacific Company, Inc. As The Commission's Procurement Monitor Boston Pacific Company, Inc., June 14, 2012

3. Retail rates may better reflect the marginal cost of supply, which may lead to more economically efficient levels of consumption.[122]

The IPA concurs with the three numbered recommendations above and proposes the following:

1. Require updated load forecasts from ComEd and Ameren in November after the results of the municipal aggregation referenda on the November ballot are known, followed by an update in March and after any referenda results are known, to be reviewed before any procurement event occurs by the IPA, the utilities, Commission Staff, the Procurement Administrators and the Procurement Monitor. This group shall concur on any final product quantities to be procured.
2. Adopt Staff Energy Hedging Plan: Staff Proposal 1 for purposes of determining the amount of supply to purchase, if any, in the 2013/2014, 2014/2015 and 2015/2016 planning years. This hedging plan is based on a projection of expected average hourly load and a specified % of that load. It is more straightforward than Staff Proposal 2, which provides for a range of hedge percentages as a function of low load, both of which would require further judgmental decisions, possibly inducing additional risk exposure.
3. No additional procurement events are recommended at this time, except as may be necessary upon concurrence of the utilities, the IPA, the ICC Staff, the Procurement Administrators and the Procurement Monitor in the event of a need to rebalance the portfolio in the event of significant shifts in load, supplier default, insufficient supplier participation, Commission rejection of procurement results, or any other cause.

6.4 Demand Response as a Risk Management Tool

The discussion above has been focused on traditional energy and capacity supply products. As described more fully in Appendix II – which describes the ComEd load forecast – demand response programs operated by ComEd are not used to offset the capacity that would otherwise need to be purchased to serve the weather-normalized expected case peak load. Rather, because ComEd's demand response measures are called on days when the weather is hotter than normal, they are a risk management tool available to help assure that sufficient energy and capacity resources are available under extreme conditions. PJM has a functional capacity market that includes dispatchable demand response as a resource.

MISO also provides the ability for demand response measures to contribute to reducing supply risk. Over the past five years MISO has been working with stakeholders through the Demand Response Working Group to incorporate Demand Response Resources into its markets. The Midwest ISO employs demand response as a risk management tool to:

- reduce loads whose values to end use customers are less than the costs of serving those loads (i.e., *Economic Demand Response*)
- provide Regulating or Contingency Reserves (i.e., *Operating Reserves Demand Response*)
- reduce demand during system Emergencies (i.e., *Emergency Demand Response*), and

[122] Initial Comments By The Staff Of The Illinois Commerce Commission, In the matter of the Public Notice of Informal Hearing (Request for Comments) Concerning the 2012 Electric Procurement Events Which Were Held on Behalf of Commonwealth Edison Company and Ameren Illinois Company Pursuant to 220 ILCS 5/16-111.5(o), June 14, 2012

- substitute for generating capacity (i.e., *Planning Resources Demand Response*)[123]

Section 7 of this plan, wherein the resource choices for the 2013 procurement plan cycle are presented, provides the detail for the assumed demand response resources to include for both ComEd and Ameren.

7.0 Resource Choices for the 2013 Procurement Plan

This section of the 2013 Procurement Plan sets out recommendations for the resources to procure for the forecast horizon covered by this plan. These include: (1) incremental energy efficiency; (2) a consideration of standard market block products; (3) full requirements/balancing market recommendations; (3) demand response and energy efficiency; and (4) Clean Coal sourcing agreement approval. Procurement of additional Renewable Resources, including wind, solar and distributed generation is considered separately in Section 8.

7.1 Incremental Energy Efficiency

The legislature has required that the IPA consider energy efficiency proposals from the utilities that are incremental to the Commission-approved efficiency programs already being conducted and that are already reflected in the load forecasts submitted to the IPA for purposes of this Plan. These incremental programs, if approved within the context of this Plan, could provide the basis to reduce the energy forecasts for which a resource procurement plan is being proposed. Therefore, before making any other recommendation on resource choices, the incremental programs assessed by Ameren and ComEd are the initial focus of this Section of the plan.

The Energy Infrastructure Modernization Act[124] requires ComEd and Ameren to submit in annual load forecasts an assessment of "opportunities to expand the programs promoting energy efficiency measures" beyond the EEPS programs already approved by the Commission for implementation.[125] By July 15 of each year as part of their respective Load Forecast, the utilities must submit an assessment that includes the following components:

- A comprehensive energy efficiency potential study for the utility's service territory that was completed within the past 3 years.
- Beginning in 2014, the most recent three year plan analysis submitted to and approved by the Commission as required by the PUA.
- Identification of new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in the EEPS plans, and that would be offered to eligible retail customers.
- Analysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service.

[123] Draft Demand Response Business Practices Manual found on the MISO web site at https://www.midwestiso.org/Library/Repository/Tariff/BPM%20Drafts/Draft%20Demand%20Response%20BPM.pdf

[124] Public Acts 97-0616 and 97-0646.

[125] 220 ILCS 5/16-111.5B(a).

- Analysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply.
- An energy savings goal, expressed in megawatt-hours, for the year in which the measures will be implemented.
- The impact of energy efficiency building codes or appliance standards, both current and projected.[126]

To prepare for the assessments, utilities are required to conduct an annual solicitation process to request proposals from third-party vendors, and submit the results to the IPA as part of the assessment, including documentation of all bids received.[127] Once presented with the utilities' assessments, including results of the Total Resource Cost ("TRC") test, the IPA in turn is required to "include" for Commission approval all energy efficiency programs with a TRC score above 1.[128]

Both Ameren and ComEd have submitted all the required information and analyses. The following are the Ameren and ComEd assessments for incremental energy efficiency programs and the IPA's recommendations regarding their implementation, along with the revised load forecasts that reflect their impacts.

7.1.1 Ameren

Ameren's submission to the IPA prepared in compliance with Sections 16-111.5 and 16-111.5B of the PUA is included in Appendix I of this Plan. Note that two of the Appendices (5 and 6) in Ameren's submittal contain confidential data, and are redacted. In addition, Appendices 3 and 4 are rather large and may be found on the IPA web site posting of the 2013 Procurement Plan at www.illinois.gov/ipa.

Ameren's assessment includes eight expanded or new energy efficiency offerings in this Procurement Plan.[129]. All of these programs passed the TRC test at the time of assessment. These reprograms are:

- Expansion of Current Programs
  - Residential Multi-Family
  - Residential ENERGY STAR New Homes
  - Residential Lighting
  - Small Business Prescriptive
- New Programs
  - Residential Efficiency Kits
  - All-Electric Homes
  - CFL Distribution
  - Small Business Direct Install

These programs, described in more detail in the Appendix, are presently offered to all eligible customers, regardless of their choice of retail electricity supplier. The programs, if approved and implemented in a manner consistent with Ameren's assessment, are expected to provide incremental net energy savings of 70,834 MWh for the June 2013-May 2014 program year.

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[126] 220 ILCS 5/16-111.5B(a)(3)

[127] *Id.*

[128] *See* 220 ILCS 5/16-111.5B(a)(4) (requiring inclusion of "cost-effective" energy efficiency); 220 ILCS 5/16-111.5B(b) (defining "cost-effective" in reference to 220 ILCS 5/8-103(a)); 220 ILCS 5/8-103(a) (defining "cost-effective" as a TRC score of above 1); *see also* 20 ILCS 3855/1-10 (defining T

[129] Subsequent to Ameren's issuance of its assessment, on July 18, 2012 Senate Bill 3811 became Public Act 97-0824. Although Ameren provided analysis assuming SB3811 became law, it also included analysis for if SB3811 failed to become law.

This value constitutes the estimated savings goal for the program package. After considering the impacts of projected customer switching, the anticipated reduction to the energy required for the IPA-procured portfolio is 25,409 MWh for the June 2013-May 2014 delivery year. The IPA notes that these savings values are based on *a priori* calculations and that it is appropriate for Ameren (and also for ComEd with respect to its proposed programs) to exercise some flexibility in its administration of these programs in order to achieve the savings goals. As noted by Ameren at page 15 of its submittal, the Commission has previously recognized the importance of providing and preserving flexibility as needed to respond to market changes.

Ameren makes three additional requests which the IPA recognizes are for the Commission to decide. The requests are presented below to highlight them as issues for Commission consideration. They are:

1. To the extent any new or expanded energy efficiency programs are recommended by the IPA for inclusion in the Procurement Plan, Ameren expects that any resulting savings from such programs count towards its 8-103(f) savings goals; and
2. To maximize efficiencies, any additional funds needed to acquire the approved additional MWh savings in Section 16-111.5B will be allowed to operate on a functional level as a single budget; and
3. To minimize ratepayers costs, the independent evaluators who assess the achieved savings have the option to perform a single assessment of the combined programs.

The table below illustrates the impact of the incremental energy efficiency programs on the unhedged portion of the Ameren supply portfolio over the forecast horizon. During the peak period, the unhedged peak period average MW is reduced by no more than 4 MW each month. For all practical purposes, this reduction does not reduce the quantity of standard peak period block energy required. Nevertheless, for purposes of examining the energy hedge strategy alternatives and ultimate recommendation, the unhedged volumes for the peak period assuming the incremental energy efficiency programs are implemented for the remainder of this Plan. Similar results apply to the off-peak period. Negative values mean that Ameren has more than enough supply procured for the relevant period, and efficiency programs increase that over-supply.

Impact of Recommended Incremental EE on Ameren's Unhedged Portfolio Volumes (Expected Forecast)				
Contract Month	Peak Avg. MW		Off-Peak Avg. MW	
	w/o EE	w/EE	w/o EE	w/EE
Jun-13	(460)	(464)	(506)	(509)
Jul-13	(378)	(381)	(467)	(469)
Aug-13	(448)	(451)	(504)	(507)
Sep-13	(485)	(488)	(574)	(576)
Oct-13	(592)	(595)	(694)	(697)
Nov-13	(556)	(559)	(622)	(624)
Dec-13	(563)	(566)	(609)	(611)
Jan-14	(582)	(586)	(637)	(640)
Feb-14	(590)	(594)	(632)	(634)
Mar-14	(670)	(673)	(710)	(712)
Apr-14	(673)	(676)	(730)	(732)
May-14	(725)	(728)	(726)	(728)
Jun-14	82	79	(90)	(92)
Jul-14	273	271	66	64
Aug-14	262	260	45	43

Sep-14	9	6	(109)	(111)
Oct-14	(175)	(178)	(292)	(294)
Nov-14	(140)	(143)	(222)	(224)
Dec-14	(6)	(9)	(73)	(75)
Jan-15	33	30	(39)	(42)
Feb-15	(2)	(5)	(85)	(87)
Mar-15	(158)	(161)	(235)	(238)
Apr-15	(244)	(246)	(335)	(337)
May-15	(237)	(240)	(308)	(310)
Jun-15	459	456	304	302
Jul-15	651	649	445	443
Aug-15	647	645	434	432
Sep-15	411	409	292	290
Oct-15	232	229	133	130
Nov-15	272	270	186	183
Dec-15	399	396	340	338
Jan-16	432	429	386	383
Feb-16	398	395	322	320
Mar-16	262	260	191	188
Apr-16	171	169	112	110
May-16	199	197	117	115
Jun-16	622	620	493	491
Jul-16	818	816	644	642
Aug-16	813	811	595	593
Sep-16	579	577	477	475
Oct-16	401	398	326	324
Nov-16	444	441	367	365
Dec-16	578	575	512	510
Jan-17	610	607	551	549
Feb-17	575	573	515	513
Mar-17	438	435	371	369
Apr-17	340	338	304	302
May-17	386	384	290	288
Jun-17	607	605	459	458
Jul-17	786	784	617	615
Aug-17	774	772	576	574
Sep-17	544	542	466	464
Oct-17	383	381	301	300
Nov-17	420	417	346	344
Dec-17	550	547	489	487
Jan-18	584	581	518	515
Feb-18	549	546	487	485
Mar-18	421	419	345	343
Apr-18	326	324	278	276
May-18	368	366	270	268

As a final footnote, although the requirement has been removed from Section 111.5B(b) of the PUA by Public Act 97-0824, Ameren also calculated the Utility Cost Test ("UCT"), which compares the total costs to save energy through an efficiency program to the cost of procuring a similar amount of energy. The IPA notes that Ameren concluded that all but one of the assessed programs pass the UCT test; the IPA recommends that the Commission take the favorable UCT results into account and approve the programs.

7.1.2 ComEd

ComEd's submission to the IPA prepared in compliance with Sections 16-111.5 and 16-111.5B of the PUA is included in Appendix II of this Plan. Note that the document entitled "ComEd Third Party Efficiency Program Summary of Vendor Scoring Process June 22, 2012" contains confidential data and is redacted from this Plan.

ComEd proposes eight new or expanded programs as detailed in Appendix C-2 of their submission. These include five residential and three small commercial programs as follows:

- Residential
    - Energy Efficient Lighting
    - Fridge and Freezer Recycle Rewards
    - All-Electric Single Family Retrofit Program
    - Low-Income CFL Distribution
    - Faith Based Behavioral Program
- Small Commercial
    - Multi-family Common Area Lighting
    - Small Business Direct Install
    - School Direct Install and Education

These programs, in total, are estimated to provide an annualized savings goal of 173,753 MWh at the busbar to the total population of retail customers to which they will be offered. (See ComEd Appendix C-2.) ComEd Appendix C-3 shows the monthly savings goals by program both for all customers and for those not switching to an ARES and, hence, subject to IPA-procured supply. The annual savings estimates for customers served by the IPA-procured portfolio range from 22,574 MWh for the 2013-14 delivery year to 39,688 MWh for 2014-15. Savings diminish somewhat for the remaining three years of the forecast horizon due to continued customer switching.

ComEd performed its TRC and UCT calculation correctly anticipating that what became Public Act 97-0824 would become law. The IPA notes that, in addition to passing the TRC test, ComEd concluded that all of the proposed programs pass the UCT test; the IPA recommends that the Commission take the favorable UCT results into account and approve the programs.

Impact of Recommended Incremental EE on ComEd's Unhedged Portfolio Volumes (Expected Forecast)

Contract Month	Peak Avg. MW		Off-Peak Avg. MW	
	w/o EE	w/EE	w/o EE	w/EE
Jun-13	1,749	1,749	1,406	1,406
Jul-13	2,042	2,042	1,623	1,623
Aug-13	1,880	1,879	1,499	1,499
Sep-13	1,406	1,404	1,139	1,138
Oct-13	1,241	1,239	1,016	1,014
Nov-13	1,364	1,361	1,159	1,156
Dec-13	1,586	1,582	1,372	1,369
Jan-14	1,594	1,590	1,391	1,387
Feb-14	1,450	1,445	1,277	1,273
Mar-14	1,284	1,280	1,124	1,120
Apr-14	1,134	1,128	963	959
May-14	1,147	1,141	960	956
Jun-14	1,525	1,521	1,236	1,233
Jul-14	1,827	1,823	1,459	1,455
Aug-14	1,684	1,680	1,359	1,355
Sep-14	1,267	1,262	1,025	1,021
Oct-14	1,109	1,103	916	912
Nov-14	1,230	1,224	1,058	1,053
Dec-14	1,461	1,455	1,273	1,268
Jan-15	1,468	1,462	1,292	1,287
Feb-15	1,341	1,335	1,182	1,178
Mar-15	1,188	1,183	1,043	1,039
Apr-15	1,039	1,034	893	889
May-15	1,048	1,044	891	888

Jun-15	1,417	1,413	1,156	1,153
Jul-15	1,709	1,705	1,369	1,366
Aug-15	1,575	1,571	1,285	1,282
Sep-15	1,184	1,179	964	960
Oct-15	1,025	1,020	857	853
Nov-15	1,154	1,148	995	991
Dec-15	1,378	1,372	1,200	1,195
Jan-16	1,389	1,384	1,226	1,221
Feb-16	1,282	1,278	1,129	1,125
Mar-16	1,133	1,128	998	994
Apr-16	983	979	852	849
May-16	1,006	1,003	851	848
Jun-16	1,371	1,368	1,103	1,101
Jul-16	1,650	1,646	1,340	1,338
Aug-16	1,541	1,537	1,231	1,228
Sep-16	1,135	1,130	942	939
Oct-16	992	987	831	828
Nov-16	1,127	1,122	974	970
Dec-16	1,345	1,340	1,176	1,172
Jan-17	1,360	1,355	1,205	1,200
Feb-17	1,241	1,237	1,102	1,098
Mar-17	1,102	1,098	978	975
Apr-17	955	951	828	825
May-17	985	982	830	827
Jun-17	1,346	1,343	1,076	1,073
Jul-17	1,617	1,614	1,315	1,312
Aug-17	1,504	1,501	1,210	1,207
Sep-17	1,103	1,099	919	916
Oct-17	970	965	810	807
Nov-17	1,102	1,097	947	943
Dec-17	1,309	1,304	1,150	1,146
Jan-18	1,331	1,326	1,181	1,177
Feb-18	1,208	1,203	1,079	1,075
Mar-18	1,071	1,067	952	948
Apr-18	934	930	806	803
May-18	961	957	807	805

7.2 Full Requirements Supply/Balancing Markets

As the IPA concludes in Section 6 of this Procurement Plan, it does not recommend the use of full requirements products as a component of the supply portfolio at this time. That does not mean that such products will never have a place in the utility supply portfolio in the future, but that until the level and direction of retail switching and its impacts on the utilities' load serving requirements are more predictable, the level of risk premium in such a product may be high due to volume volatility. A full requirements supply price may actually exacerbate the switch away from the utility default service if it is higher than ARES' costs to procure full requirements supply. Rather, continued use of the spot markets for balancing makes sense at this time. As shown in the analysis of ComEd's PEA earlier in this Plan, this has been an expensive option due largely to the existence of the very large and high-priced legacy swap contracts entered into several years ago; but, as both the Ameren and ComEd legacy swap contracts will have expired by the time this Procurement Plan's supply becomes effective in June 2013, the financial impacts of relying on the spot markets becomes less costly. Furthermore, the expiration of these swaps allows for a recalibration of the supply portfolio to better match customer demand going forward.

The IPA will continue to evaluate the costs and benefits of full requirements in future years to determine whether a full requirements product would be prudent given relevant market and hedging factors.

Instead of full requirements supply purchases, both the Commission Staff and the Procurement Monitor offer an alternative in which the utility load is less fully hedged than in its current strategy (100% hedged in the current year, 70% hedged in the next, and 35% hedged in the following year), and in Section 6 of this Plan the IPA recommends adoption of Staff Proposal 1. Therefore, the remainder of this Plan will be based on the following:

Energy Hedging Plan: Staff Proposal 1

Fixed Price Hedge Quantities, as a % of *Expected* Average Hourly Load For Each of the 24 Periods of the Indicated Plan Year, to Have Established by June 1 of the Current Plan Year		
Current PY	*Current PY+1*	*Current PY+2*
75%	*50%*	*25%*

The amounts to be procured through this Procurement Plan using this strategy are calculated in the year-by-year discussion of Standard Market Products below.

7.3 Standard Market Products

7.3.1 Ameren

Current Plan Year

(2013/2014)

Ameren's current supply portfolio is significantly over-hedged for this supply year, whether or not the incremental/new efficiency programs are offered. Therefore, no block energy procurement is required for this plan year. Given the amount of switching/municipal aggregation uncertainty, it is useful to examine the difference between the high and the expected Ameren forecast for this year as compared to the amount of apparent over-supply. This provides an indication of the risk exposure in the event that switching is less than anticipated. For simplicity, the average peak period demand values are examined below and compared to the expected case hedge position with incremental energy efficiency program impacts. A negative hedge position means that there is excess supply in the portfolio for the expected load scenario.

Comparison of Ameren Expected and High Peak Period Load Forecasts with Projected Expected Case Excess Supply				
Delivery Month	**(a)** **High Load Forecast (MW)**	**(b)** **Expected Load Forecast (MW)**	**(a)-(b)** **Difference**	**Hedge Position w/EE**
Jun-13	1,657	987	670	(464)
Jul-13	1,957	1,150	807	(381)
Aug-13	1,955	1,132	823	(451)
Sep-13	1,510	859	651	(488)

Oct-13	1,218	679	539	(595)
Nov-13	1,333	733	600	(559)
Dec-13	1,584	861	723	(566)
Jan-14	1,683	896	787	(586)
Feb-14	1,607	832	775	(594)
Mar-14	1,327	663	664	(673)
Apr-14	1,181	567	614	(676)
May-14	1,121	545	576	(728)

While there are more factors to explain the difference between the expected and high load forecasts beyond retail switching/municipal aggregation assumptions, there is sufficient excess supply in the expected load scenario to cover a preponderance of the risk of the high load scenario.

Plan Year + 1

(2014/2015)

For the 2014/2015 delivery year, if the goal is to have only 50% of the expected load hedged for this delivery year, there are no required purchases of block energy for Ameren. The current contracted supply of 650 MW of block energy procured during the 2012 Rate Stability Procurement plus the long-term energy plus REC renewables contracts entered into in December 2010 are more than enough to satisfy this hedging strategy. In fact, supply exceeds 100% of the expected peak period demand for 7 months of this delivery year.

If the Commission approves a hedge strategy other than the one proposed and if it requires energy block purchases for this delivery year, the IPA recommends deferring any purchases for the 2014/2015 delivery year to the 2014 Procurement Plan. Next year, the 2014 Procurement Plan would treat the 2014/2015 delivery year as the current delivery year and any required purchases would be made during the Spring of 2014. This is advantageous because supply in MISO is projected to be more than adequate for this delivery year and the forward price premium to cover market price risk is likely to be lower for products that are for prompt delivery relative to the price premium for purchase in Spring of 2013. In addition, the IPA anticipates based on the load forecasts that there will be greater load certainty.

Analysis of Ameren Required Energy Purchases for 2014/2015 Using Staff Energy Hedging Proposal 1								
Delivery Month	Expected Load w/EE MW		50% of Expected Load w/EE MW		Current Contracted Supply MW		Required Purchases MW	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Jun-14	774	608	387	304	695	700	0	0
Jul-14	949	754	475	377	678	690	0	0
Aug-14	942	741	471	371	682	698	0	0
Sep-14	698	589	349	295	692	700	0	0
Oct-14	543	442	272	221	721	736	0	0
Nov-14	600	515	300	258	743	739	0	0
Dec-14	711	647	356	324	720	722	0	0
Jan-15	762	690	381	345	732	732	0	0
Feb-15	717	642	359	321	722	729	0	0
Mar-15	568	508	284	254	729	746	0	0
Apr-15	494	411	247	206	740	748	0	0
May-15	483	414	242	207	723	724	0	0

Plan Year + 2

(2015/2016)

Once again adopting Commission Staff's Hedging Proposal 1, only a 25% hedge is required for the 2015/2016 delivery year. As the chart below illustrates, currently contracted supplies are more than sufficient to meet this hedging goal. Thus, there is no need to procure block energy products for Ameren for this delivery year.

Analysis of Ameren Required Energy Purchases for 2015/2016 Using Staff Energy Hedging Proposal 1								
Delivery Month	Expected Load w/EE MW		25% of Expected Load w/EE MW		Current Contracted Supply MW		Required Purchases MW	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Jun-15	699	555	175	139	243	253	0	0
Jul-15	876	684	219	171	227	241	0	0
Aug-15	877	680	219	170	232	248	0	0
Sep-15	651	540	163	135	242	250	0	0
Oct-15	503	412	126	103	274	282	0	0
Nov-15	559	476	140	119	289	293	0	0
Dec-15	666	610	167	153	270	272	0	0
Jan-16	715	662	179	166	286	279	0	0
Feb-16	664	598	166	150	269	278	0	0
Mar-16	536	488	134	122	276	300	0	0
Apr-16	463	404	116	101	294	294	0	0
May-16	467	392	117	98	270	277	0	0

Plan Year + 3 and Plan Year +4

(2016/2017 and 2017/2018)

Given the absence of visible and liquid block energy markets four and five years out, it is not recommended that any block energy purchases be made to secure supply for these years in this Procurement Plan's planning horizon.

7.3.2 ComEd

Current Plan Year

(2013/2014)

As with Ameren, ComEd's current supply portfolio is significantly over-hedged for this supply year. Therefore, no energy procurement is required for this plan year. Given the amount of switching/municipal aggregation uncertainty, it is useful to examine the difference between the high and the expected ComEd forecast for this year as compared to the amount of apparent oversupply. For simplicity, the average peak period demand values are examined below and compared to the expected case hedge position with incremental energy efficiency program impacts included.

Comparison of ComEd Expected and High Peak Period Load Forecasts with Projected Expected Case Excess Supply				
Delivery Month	**(a) High Load Forecast (MW)**	**(b) Expected Load Forecast w/EE (MW)**	**(a)-(b) Difference**	**Hedge Position w/EE**
Jun-13	2976	1749	1227	(600)
Jul-13	3575	2042	1533	(717)
Aug-13	3826	1879	1947	(734
Sep-13	2211	1404	807	(438)
Oct-13	1966	1239	727	(711)
Nov-13	2319	1361	958	(726)
Dec-13	2602	1582	1020	(773)
Jan-14	2576	1590	986	(524)
Feb-14	2476	1445	1031	(757)
Mar-14	2084	1280	804	(744)
Apr-14	1910	1128	782	(810)
May-14	1802	1141	661	(855)

One of the key load switching/municipal aggregation risks between the two cases for ComEd is whether the City of Chicago passes its opt-out program referendum in November and its aggregated residential and small commercial customer load leaves ComEd supply before the 2013/2014 delivery year begins. While there are more factors to explain the difference between the expected and high load forecasts than retail switching/municipal aggregation assumptions, the amount of oversupply roughly matches with the high load forecast risk for a number of months. Although it falls short of covering the high case risk in all months, the over-hedged position serves to mitigate the risk that Chicago does not move its supply needs to an ARES.

The IPA believes that no extraordinary action need be taken to reduce the over-supply for the 2013/2014 delivery year. The IPA views the 2013/2014 delivery year as an important transition year for the ComEd and Ameren portfolios, and recommends that ComEd and Ameren maintain a cautious and flexible approach for this year, which the use of RTO day ahead and real time balancing markets allows. Beginning in the 2014/2015 delivery year there is an opportunity to recalibrate the supply to the demand on a going-forward basis, as excess supplies dwindle in size and customer switching behavior becomes more certain.

In the event the Commission determines that more certain impacts on consumer prices and a more proactive approach to managing any oversupply for the 2013-14 delivery year is desirable, the IPA recommends that at the time the utilities submit updated load forecasts in March 2013, the utilities, the IPA, the Procurement Administrators, the Procurement Monitor and ICC Staff reach consensus on the amount of any over-supply forecast for each utility for the delivery year at that time, determine a quantity of peak and off-peak block energy products each utility could reasonably put back to the market, and assess any advantage to be gained by selling back to the market either monthly or annual peak and off-peak energy products.

Plan Year + 1

(2014/2015)

For this plan year, if the goal is to have only 50% of the expected load hedged for this delivery year, there are minimal required purchases of block energy for ComEd. The current contracted supply of 450 MW of block energy procured during the 2012 Rate Stability Procurement, plus the blocks purchased in the Spring 2012 procurement, plus the long-term energy plus REC renewables contracts entered into in December 2010 are more than enough to satisfy this hedging strategy for the majority of the monthly periods.

Analysis of ComEd Required Energy Purchases for 2014/2015 Using Staff Energy Hedging Proposal 1								
Delivery Month	Expected Load w/EE MW		50% of Expected Load w/EE MW		Current Contracted Supply MW		Required Purchases MW	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Jun-14	1,521	1,233	761	617	694	556	50	50
Jul-14	1,823	1,455	912	728	809	633	100	100
Aug-14	1,680	1,355	840	678	716	601	100	100
Sep-14	1,262	1,021	631	511	537	555	100	0
Oct-14	1,103	912	552	456	600	630	0	0
Nov-14	1,224	1,053	612	527	647	638	0	0
Dec-14	1,455	1,268	728	634	698	602	50	50
Jan-15	1,462	1,287	731	644	722	623	0	0
Feb-15	1,335	1,178	668	589	652	617	0	0
Mar-15	1,183	1,039	592	520	616	652	0	0
Apr-15	1,034	889	517	445	638	655	0	0
May-15	1,044	888	522	444	656	606	0	0

Required purchases shown in this chart are rounded to the nearest multiple of 50 MW to reflect the fact that energy is purchased in 50 MW peak and off-peak blocks. Only 9 monthly peak or off-peak products are required for this delivery year, out of a possible total of 24. Four of the products are for a single 50 MW block, while the remaining five are for only two 50 MW blocks.

Given these minimal purchases and the costs of conducting a competitive procurement, which are largely fixed, the IPA recommends that there be no Spring 2013 procurement event for ComEd for the 2014/2015 delivery year. Next year, the 2014 Procurement Plan can treat this delivery year as the current delivery year and any required purchases can be made during the spring of 2014. This is advantageous because supply in PJM is projected to be more than adequate for this delivery year and the forward market price premium should be lower for products that would be for prompt delivery. In addition, there will be greater load certainty a year from now. Finally, a low volume of products being bid reduces bidder interest in a procurement event, as pointed out by NERA in its reply comments on the 2012 procurement process, submitted pursuant to Section 16-111.5(o) of the PUA, dated June 28, 2012. All this means that there is no advantage or compelling reason to conduct the procurement for the 2014/2015 delivery year in the Spring of 2013.

Plan Year + 2

(2015/2016)

Once again adopting Commission Staff's Hedging Proposal 1, only a 25% hedge is required for the 2015/2016 delivery year. As the chart below illustrates, currently contracted supplies are more than sufficient to meet this hedging goal. Thus, there is no need to procure block energy products for ComEd for this delivery year.

Analysis of ComEd Required Energy Purchases for 2015/2016 Using Staff Energy Hedging Proposal 1								
Delivery Month	Expected Load w/EE MW		25% of Expected Load w/EE MW		Current Contracted Supply MW		Required Purchases MW	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Jun-15	1,413	1,153	353	288	544	556	0	0
Jul-15	1,705	1,366	426	342	509	533	0	0
Aug-15	1,571	1,282	393	321	516	551	0	0
Sep-15	1,179	960	295	240	537	555	0	0
Oct-15	1,020	853	255	213	600	630	0	0
Nov-15	1,148	991	287	248	647	638	0	0
Dec-15	1,372	1,195	343	299	598	602	0	0
Jan-16	1,384	1,221	346	305	622	623	0	0
Feb-16	1,278	1,125	320	281	602	617	0	0
Mar-16	1,128	994	282	249	616	652	0	0
Apr-16	979	849	245	212	638	655	0	0
May-16	1,003	848	251	212	656	606	0	0

ComEd is closer to being 50% hedged for the 2015/2016 delivery year, rather than the target 25% hedge. <u>There is no need to conduct a 2013 procurement event for delivery during the 2015/2016 delivery year for standard block products.</u>

Plan Year + 3 and Plan Year +4

(2016/2017 and 2017/2018)

Given the absence of visible and liquid block energy markets four and five years out, it is not recommended that any block energy purchases be made to secure supply for these years in this Procurement Plan's planning horizon.

7.4 Ancillary Services and Capacity Purchases

7.4.1 Ancillary Services

Both Ameren and ComEd have been purchasing their ancillary services from their respective RTOs : MISO and PJM. The IPA is not aware of any justification or reason to alter this practice.

7.4.2 Capacity

ComEd has the benefit of a well-developed forward capacity market in PJM, in which capacity is purchased in a three-year ahead forward market through mandatory capacity rules. The PJM capacity market and the implications for ComEd are further discussed in Section 5 of this Procurement Plan. ComEd should continue to purchase its capacity in this manner.

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.

On the other hand, the MISO capacity marketplace applicable to Ameren is still under development, with its first FERC-approved annual voluntary capacity auction scheduled to take place in the spring of 2013 for capacity for the 2013/2014 delivery year. See Section 5 of this Procurement Plan for further discussion of this aspect of MISO's marketplace. As a result of this less developed RTO-based method of assuring sufficient capacity, the IPA has overseen competitive procurement for Ameren for capacity and has secured a portfolio of capacity supply, summarized below:

Ameren Estimated Capacity Requirements Expected Case Forecast				
Delivery Year	**Peak Load + Losses + Reserves**	**Capacity Required**	**2012 Purchase**	**Required 2013 Purchase**
6/13-5/14	1944	1950	1660	290
6/14-5/15	1648	1160 @ 70% hedge	1110	50
6/15-5/16	1537	540@ 35% hedge	0	540
6/16-5/17	1483	0	0	0
6/17-5/18	1425	0	0	0

The "Capacity Required" column of the table above is based on the IPA's traditional 100%/70%/35%/0/0 hedge structure for Ameren capacity. Because of the importance of capacity resources to assure system reliability and the difference between capacity risks and daily energy risks, the IPA recommends retaining this risk ladder strategy for capacity portfolio management even if the Commission approves the IPA's proposed energy hedging strategy. For that reason, <u>the IPA recommends that Ameren participate in the FERC-approved MISO capacity auction to procure 290 MW of capacity resources for 2013/2014,</u> with such quantities subject to revision based on Ameren updated forecasts that are mutually agreed upon by Ameren, IPA, ICC Staff, Procurement Administrator and Procurement Monitor, and MISO's resource adequacy requirement as discussed below.

While all indications are that MISO will implement its annual capacity construct in 2013/14, the mechanics and business practice manuals are still being finalized and this leaves some operational uncertainty. Ameren expects that the initial resource adequacy requirements for each market participant in the Ameren Illinois control area will be based on a yet to be developed forecast provided by Ameren's local balancing authority (a separate organization from Ameren Illinois). The 2013/14 Ameren Illinois capacity requirement may be based on a forecast different from the forecast used in this Procurement Plan. It is also expected that the MISO capacity market will include a settlement provision which calculates each market participant's actual resource adequacy requirement on an after the fact basis. In order to address this uncertainty, the IPA proposes that Ameren Illinois purchase any *remaining* 2013/14 capacity in the MISO auction so as to satisfy the initial MISO resource adequacy requirement, with any balancing of capacity requirements to be achieved as required by MISO.

For subsequent years, the IPA has the choice of waiting until the prompt year auctions for those years, or conducting a competitive procurement for Zonal Resource Credits (ZRCs) for Plan Year+1 and Plan Year+2. While supportive of the prompt year auctions, the relative immaturity of the MISO process suggests that leaving future years completely unhedged and dependent on the future MISO capacity auctions is a somewhat risky strategy at this time. This is particularly the case for 2015/2016, which is currently completely unhedged, but less of a concern for 2014/2015, which is currently 67% hedged (for all practical purposes at the 70% hedge position). The IPA might have recommended that the it conduct a bilateral capacity procurement on Ameren's behalf for 540 MW of Zonal Resource Credits for 2015/2016, with such quantities subject to revision based on Ameren updated forecasts that are mutually agreed upon by Ameren, IPA, ICC Staff, Procurement Administrator and Procurement Monitor. However, given the administrative costs of conducting such a bi-lateral capacity procurement in the absence of any energy or renewable resource procurements, the IPA recommends that no bi-lateral procurement for capacity products be conducted in the 2013 Procurement Plan. The 2014 Procurement Plan will provide ample opportunity to assess the progress of the development of the MISO capacity construct and its market and to make further recommendations at that time.

Ultimately, the IPA encourages the development of MISO's capacity markets in order to provide transparent and robust capacity prices and price signals to incentivize appropriate levels of capacity resources for reliability purposes. The IPA looks forward to working with other stakeholders to ensure the market rules produce maximally efficient results.

7.4.3 Demand Response Products

Section 8-103(c) of the PUA establishes a goal to implement demand response measures, providing that:

> (*c) Electric utilities shall implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Section 16-111.5 of this Act, 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.*

According to the information supplied by ComEd in Appendix II, the following are the estimated annual MWs of demand response measures that will need to be implemented over the five-year forecast period to meet the goals set forth in the PUA:

ComEd
Estimated Annual Level of Demand Response Measures

Planning Year	Peak Load at Meter Prior Year	Annual Goal	Cumulative Goal
2012	8,795 MW	10.7 MW	54.0 MW
2013	3,193	10.8	64.8
2014	2,834	2.8	67.6
2015	2,675	2.7	70.3
2016	2,603	2.6	72.9
2017	2,563	2.6	75.5

ComEd states that it assumes it will meet its statutory goals over the Procurement Plan's forecast horizon.

Ameren finds itself in a different position with respect to demand response goals. In the 2011 Integrated Electric and Natural Gas Energy Efficiency Plan, the Commission recognized the lack of cost effective demand response available to Ameren at that time. The Commission approved a Voltage Optimization Pilot Program and found that at that time it was not necessary for the IPA to acquire demand response for Ameren (Final Order Docket #10-0568 at page 28).

Ameren Demand Response Programs

Currently Ameren has no demand response program that qualifies as a MISO demand response asset, so that none of its current programs offer an opportunity to offset capacity purchases.

ComEd Demand Response Programs

For purposes of the IPA's Procurement Plan, ComEd's demand response measures do not impact ComEd's load forecasts and, therefore, the procurement planning scenarios. A key value to ComEd's demand response portfolio lies in its ability to serve as a risk management tool in the event of hotter than normal weather, as well actively engaging customers in understanding the impacts of consumer decisions on market prices.

The 2012 portfolio of ComEd programs includes the following:

- **Direct Load Control ("DLC"):** ComEd's residential central air conditioning cycling program is a DLC program with over 73,000 customers with a load reduction potential of 112 MW (ComEd Rider AC).
- **Voluntary Load Reduction ("VLR") Program:** VLR is an energy-based demand response program, providing compensation based on the value of energy as determined by the real-time hourly market run by PJM. This program also provides for transmission and distribution ("T&D") compensation, based on the local conditions of the T&D network. This portion of the portfolio has roughly 1,225 MW of potential load reduction (ComEd Rider VLR).
- **Capacity-based Load Response (Rider CLR) – Suspended June 2012:** As a result of PJM terminating the Interruptible Load for Reliability (ILR) program, which is the basis of ComEd's Capacity-based Load Response (CLR) Program, ComEd will not be offering the Capacity-based Load Response Program to its business customers during the 2012/13 delivery year which begins June 1, 2012 and extends through May 31, 2013.
- **Residential Real-Time Pricing (RRTP) Program:** All of ComEd's residential customers have an option to elect an hourly, wholesale market-based rate. The program uses ComEd's Rate BESH to determine the monthly electricity bills for each RRTP participant. This program has roughly 5 MW of price response potential.

Peak Time Rebate Programs

Public Act 97-0616, the Energy Infrastructure Modernization Act (EIMA), requires ComEd and Ameren to file tariffs instituting an opt-in market-based peak time rebate (PTR) program with the Commission within 60 days after the Commission has approved the utility's AMI Plan.[130] The PTR program must be available to all residential retail customers with smart meters.

On June 19 and July 19, 2012, ComEd invited stakeholders to workshops to discuss the proposed tariff the utility must file with the Commission around August 21, 2012. As explained by ComEd, the first season will begin on June 1, 2014, with customers able to enroll as soon as the PTR tariff has been approved, which is expected to be October of 2013, and the customer has a smart

[130] 220 ILCS 5-16-108.6(g). Currently, ComEd had an AMI Plan approved in ICC Docket No. 12-0298 (which is currently on rehearing to clarify certain issues), but Ameren had yet to receive AMI Plan approval in ICC Docket No. 12-0089.

meter installed. ComEd is still evaluating into which PJM DR product to bid the PTR program, and additional details that will be clarified in ComEd's filing.

It is important to note that ComEd's PTR Program peak load reductions are anticipated to be calculated into the load forecasts, and thus are not anticipated to be procured as a separate resource or otherwise impact IPA procurements.

Because Ameren does not have a Commission-approved AMI Plan yet, it does not have a statutory obligation to file a PTR tariff at this time. However, in its AMI Plan docket, Ameren proposed to meet the statutory requirements for the program and provide rebates based on the amount of compensation "obtained through markets or programs at MISO."[131]

7.5 Clean Coal

Section 1-75(d) of the Illinois Power Agency Act contains the legislative requirement that procurement plans shall include electricity generated using clean coal, as that term is defined in the IPA Act.[132] It further sets out targets for the proportion of each utility's portfolio to be sourced from clean coal facilities, and describes two specific types of facilities to be included in the clean coal supply portfolio. These are (1) the "initial clean coal facility"; and (2) repowered/retrofitted coal-fired power plants previously owned by Illinois utilities. Because there is not currently an "initial clean coal facility" for the IPA to consider, this Procurement Plan will focus on the repowered/retrofitted clean coal facility to be considered by the IPA, popularly known as "FutureGen 2.0".

Appendix III describes the FutureGen 2.0 project, as presented by the FutureGen Alliance at the Illinois Commerce Commission's March 6, 2012, Electric Policy Committee meeting. FutureGen 2.0 consists of the proposed repowering of one unit at the Ameren Energy Resources Meredosia Plant in Morgan County near Jacksonville. FutureGen 2.0 is to be developed as 166 MWe (gross) of near-zero emissions coal-fueled generation, with a targeted commercial operation date in 2017, and a 30-year life. It is anticipated to operate as a base-load plant to be dispatched by MISO in the coal stack of the dispatch order. An interconnection request has been submitted to MISO, with no significant issues identified in its initial system study. The air and water permitting process has begun with the Illinois EPA.

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131 *Id* at 60.

132 "Clean coal facility" means an electric generating facility that uses primarily coal as a feedstock and that captures and sequesters carbon dioxide emissions at the following levels: at least 50% of the total carbon dioxide 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 dioxide 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 dioxide emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation after 2017. The power block of the clean coal facility shall not exceed allowable emission rates for sulfur dioxide, nitrogen oxides, carbon monoxide, particulates and mercury for a natural gas-fired combined-cycle facility the same size as and in the same location as the clean coal facility at the time the clean coal facility obtains an approved air permit. All coal used by a clean coal facility shall have high volatile bituminous rank and greater than 1.7 pounds of sulfur per million btu content, unless the clean coal facility does not use gasification technology and was operating as a conventional coal-fired electric generating facility on June 1, 2009 (the effective date of Public Act 95-1027).

The purposes and anticipated benefits of this project include the potential to validate the cost and performance of commercial-scale, near zero emissions oxy-combustion coal-fueled power generation with carbon capture and sequestration, and to advance the technology necessary to cleanly convert Illinois basin coal. In addition, the plant is in the process of receiving $1 billion in federal stimulus funds and additional state-level grant funding. These funding sources, coupled with the non-profit status of the FutureGen Alliance, significantly improve the economics of the project.

The first year of commercial operation for the FutureGen 2.0 facility is anticipated to be 2017. This is the fifth year in the planning horizon considered by this 2013 Procurement Plan. While the Procurement Plan has historically focused on a ladder of resources for a 3-year future (in this case 2013/14, 2014/15 and 2015/16), inclusion of the FutureGen sourcing agreement in this year's procurement plan is appropriate so that financing for the unfunded portion of the project can be secured and to allow pre-commercial operation date work on the project to proceed.

The retrofit provision of the IPA Act states in whole:

> *(5) Re-powering and retrofitting coal-fired power plants previously owned by Illinois utilities to qualify as clean coal facilities. During the 2009 procurement planning process and thereafter, the Agency and the Commission shall consider sourcing agreements covering electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities, as defined by Section 1-10 of this Act. Pursuant to such procurement planning process, the owners of such facilities may propose to the Agency sourcing agreements with utilities and alternative retail electric suppliers required to comply with subsection (d) of this Section and item (5) of subsection (d) of Section 16-115 of the Public Utilities Act, covering electricity generated by such facilities. In the case of sourcing agreements that are power purchase agreements, the contract price for electricity sales shall be established on a cost of service basis. In the case of sourcing agreements that are contracts for differences, the contract price from which the reference price is subtracted shall be established on a cost of service basis. The Agency and the Commission may approve any such utility sourcing agreements that do not exceed cost-based benchmarks developed by the procurement administrator, in consultation with the Commission staff, Agency staff and the procurement monitor, subject to Commission review and approval. The Commission shall have authority to inspect all books and records associated with these clean coal facilities during the term of any such contract.* (20 ILCS 3855/1-75(d)(5) (Public Act 97-0658).)

The IPA is unaware of any dispute that FutureGen 2.0 is a facility that has been previously owned by an Illinois utility and that will be converted into a clean coal facility, and that this plan is after the 2009 procurement planning process. In addition, FutureGen 2.0 has proposed to the IPA a sourcing agreement intended for "utilities and alternative retail electric suppliers." (*See Appendix IV to this Plan.)* The sourcing agreement is drafted as a contract for differences, and anticipates a market-based reference price be subtracted from cost-based benchmarks (netting any additional income). Thus, the section is operative.

The IPA wishes to clarify its role in the process associated with "approving" or considering a sourcing agreement proposed by a retrofitted clean coal facility. by distinguishing the IPA's role herein from the approval process of other "sourcing agreements." Procedures under Sections 9-

220(h) and 9-220(h-1) of the Public Utilities Act required the IPA to act in a quasi-judicial capacity and arbitrate disputed decisions in a sourcing agreement between utilities and clean coal facilities. These quasi-judicial actions were final Agency decisions, and explicitly subjected to the Administrative Review Law in one case. (*See, e.g.*, 220 ILCS 9-220(h-3)(7).) In both instances, the Commission was explicitly given a more limited role. On the other hand, Section (d)(5) above does not restrict the Commission's review of the proposed sourcing agreement; the permissive "may approve" allows the Commission the latitude to review the provisions of the proposed sourcing agreement for compliance with Illinois law and Commission Orders and policy.

As a corollary to the Commission's wide-ranging review powers over the sourcing agreement, the IPA believes the Commission has the authority to determine whether it should require that the facility's output be divided amongst utilities and ARES in a competitively neutral manner.That outcome would be consistent with long-standing Commission policies supporting competition, which the Commission has specifically applied to consideration of clean coal sourcing agreements. (*See, e.g.*, ICC Docket No. 11-0710, Final Order on Rehearing dated July 11, 2012 at 30 (applying cost-causation principles to clean coal sourcing agreement).) If, based on the arguments of interested parties or the Commission's own determination, the Commission identifies modifications that would make the FutureGen 2.0 sourcing agreement competitively neutral, the IPA believes that Section 1-75(d)(5) of the IPA Act would allow the Commission to order such changes.

In addition, the IPA assumes that the Commission does have the authority to bind non-utility counterparties, based on Section 16-115(d)(5) of the Public Utilities Act.[133] As the ultimate approving authority, the IPA believes the Commission must determine 1) which of ComEd and Ameren's customers must purchase the output from FutureGen 2.0, 2) the allocation of FutureGen 2.0's output among the entities required to purchase; and 3) a mechanism to obligate current and future non-utilities to purchase any share of the output from FutureGen 2.0 . The IPA requests that the Commission approve a sourcing agreement for bundled service customers and ARES customers, and hourly load customers in a competitively neutral manner, utilizing either a rulemaking or (in cooperation with stakeholders) utility tariffs to ensure current and future customers are bound while minimizing administrative burden on all parties.

FutureGen 2.0 has proposed a sourcing agreement between itself, Ameren and ComEd, and Alternate Retail Electric Suppliers (ARES) subject to Section 16-115(d) of the Public Utilities Act. The IPA's Procurement Administrator Levitan is developing the "cost-based benchmark" for review by the Commission. By submitting the sourcing agreement to the Commission, the Agency "approves" the agreement for review and determination of approval by the Commission contingent on the cost benchmark coming in lower than the cost cap.

The IPA recommends that the Commission approve a sourcing agreement. To the extent that there are unresolved issues with respect to the operation or applicability of the sourcing agreement to current and future ARES, the IPA suggests that the Commission initiate a rulemaking to clarify and resolve any such issues.

To facilitate the Commission's approval, attached as Appendix IV is the sourcing agreement proposed by the FutureGen Industrial Alliance, Inc. for use with the FutureGen 2.0 project. This

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[133] For instance, as a condition of certification, ARES: "will source electricity from clean coal facilities, as defined in Section 1-10 of the Illinois Power Agency Act, in amounts at least equal to the percentages set forth in subsections (c) and (d) of Section 1-75 of the Illinois Power Agency Act." The IPA notes that this requirement is not restricted to the "initial clean coal facility."

proposal, according to the FutureGen Alliance, captures results, as of the date of filing of this Plan, of on-going discussions between the FutureGen Alliance and various potentially affected parties.[134] The discussions were instrumental in redesigning a sourcing agreement that was initially drafted as a conventional unit contingent contract for physical delivery of a specific generator's output to specific counterparties with stable market shares. In its current form, the sourcing agreement is based on physical delivery into MISO and financial settlement with counterparties, with a mechanism that recognizes a constantly shifting share of retail load among utilities and ARES and that is intended to provide a high degree of competitive neutrality.

One key component of the restructured sourcing agreement is a rate adjustment mechanism to assure each buyer that the FutureGen cost-based revenue requirement is appropriately allocated among all the ARES and utility buyers, regardless of load share in the marketplace . As presented in the sourcing agreement, this approach is forward-looking using actual retail load data, while incorporating an initial and final settlement similar to the manner in which MISO and PJM settle wholesale energy transactions. Each buyer's net payment to the FutureGen Alliance is calculated on a per MWh basis as the difference between the cost of service for the project and the revenue from sales into MISO at the nodal energy price, divided by the total retail load served in the Ameren and ComEd service areas. This structure (i.e. a per MWh flat charge, subject to settlement) is significantly less complex for all parties than, for instance, requiring buyers to schedule the FutureGen plant's energy through MISO on a continual basis with fluctuating load requirements. Payments are simply made based on initial and final settlements using the appropriate project costs, total energy sales and retail loads. Therefore, buyers will not require the Alliance to deliver energy specifically to them via MISO schedules. The approach is loosely modeled on the concept of a renewable energy credit, which similarly calculates the difference between the operating cost (plus any developer margin) minus the revenue from selling energy into the hourly or bilateral market, divided by the total output of the facility. The Alliance has represented to the IPA that it has been in contact with both ComEd and Ameren Illinois regarding their ability to provide the necessary load data in their roles as Meter Data Management Agents for the ARES in their zones and has received favorable responses from both entities.

The IPA believes that, in the interest of competitive neutrality, as noted above, the total retail load used to ascertain the ComEd and Ameren load ratio share should include the load of non-eligible retail customers (i.e. hourly priced service customers). The IPA therefore recommends that the Commission approve cost recovery for the utilities for costs associated with the FutureGen clean coal purchases by the utilities from their non-eligible retail customers, as well as their eligible retail customers, and direct the utilities to revise their tariffs accordingly in order to do so.

Because this proposed agreement is structured as a financial transaction arrangement rather than physical delivery, there have been concerns among those in the energy-trading industry that such arrangements may be subject to onerous financial regulation for certain financial products. Recently, the Commodity Futures Trading Commission (CFTC) has issued a rule dealing with the definition of "swaps" and exclusions from swap regulation under the Dodd-Frank Act. In addition, there are petitions pending at the CFTC to further clarify the applicability of certain Dodd-Frank Act provisions to various types of electricity transactions. While we believe these issues will be favorably clarified by the CFTC, the proposed sourcing agreement includes a savings clause that allows the parties to make amendments to the sourcing agreement, if necessary, to minimize the potential for application of the Dodd-Frank Act.

[134] During the stakeholder meetings, the parties reserved their respective right to contest whether they may be bound by a Commission-approved sourcing agreement. The IPA defers to the Commission and interested parties as to the most appropriate proceeding for this question – if raised – to be litigated.

In order to approve this sourcing agreement and this specific resource in this Procurement Plan, the Commission must ensure the proposed resource is priced at or below a confidential price benchmark.[135] The IPA has engaged one of its Procurement Administrators, Levitan and Associates, to create a confidential benchmark for FutureGen 2.0. Levitan has been the procurement administrator for the prior Ameren procurements and has prepared the confidential benchmarks that the Commission has subsequently approved for those procurement events. The IPA proposes that after the initiation of the 2013 Procurement Plan Docket, the Procurement Administrator will submit a confidential benchmark report for the FutureGen 2.0 project to the ICC Staff and the Procurement Monitor for review and subsequently to the Commission under confidential seal for approval.[136]

In addition, the FutureGen Alliance has submitted to the IPA information sufficient for the Commission to assess the prices buyers will see for the output of this project, which it then can compare to the confidential benchmark and other relevant information. That information is included in Appendix IV of this Plan. It will also allow the Commission to assess whether the prices under the agreement will not result in an annual estimated average net cost increase for retail customers that would exceed the statutory rate impact cap.

The IPA notes that one risk to the ability to accept deliveries under the FutureGen sourcing agreement is the possibility that purchases from an "initial clean coal facility", if one is proposed, will be required during the FutureGen 2.0 project life and the cost of the two projects combined exceeds the rate impact cap specified in the law. To the extent that the legislature considers expanding clean coal purchase requirements under the current cost cap, the IPA urges the legislature to consider the following question: If these additional purchases cause the utility clean coal expenditures to exceed the cost caps mandated by law for such purchases, which contract will prevail?

Given the size of the plant and the allocation of its output to Ameren and ComEd and the ARES in proportion to their market share, it is anticipated that the Ameren and ComEd combined market share of the output could be on the order of a 50 MW block of energy, with the remainder shared among the ARES. Given the large unhedged positions of Ameren and ComEd in 2017 and beyond, this purchase does not appear to introduce an appreciable amount of portfolio risk, while maintaining competitive neutrality with ARES.

While Appendix IV contains an agreement reflective of discussions up to the time of submitting this Plan to the Commission, the IPA understands that not all potential parties are currently in agreement regarding the terms of the sourcing agreement and that it may change somewhat over the course of the Commission's docketed proceeding. The IPA requests Commission approval of the final proposed sourcing agreement once agreed upon by all affected parties and inclusion of this resource within the context of approving the 2013 Procurement Plan. Additionally, it requests the Commission approve the justness, reasonableness and prudence of the prices or changes in prices under the agreement.

[135] *E.g.*, 20 ILCS 3855/1-75(d)(5) (providing for approval of sourcing agreements "that do not exceed cost-based benchmarks developed by the procurement administrator, in consultation with the Commission staff, Agency staff and the procurement monitor, subject to Commission review and approval.")

[136] The IPA defers to the Commission as to whether the Commission would prefer to approve the benchmark as part of the Procurement Plan approval proceeding, in a separate docket, or as a non-docketed matter similar to approval of other benchmarks.

8.0 Renewable Resources Availability and Procurement Analysis

Renewable resource procurement on behalf of eligible retail customers is done under the auspices of the IPA's Commission-approved procurement plan. Procurement on behalf of eligible retail customers is subject to targets for purchase volumes and upper limits on customer bill impacts, which (based on the load forecast) creates a cap on the available budget.[137] As the 2013 Procurement Plan is the fifth such IPA plan in which renewable resources are procured and the first plan since long-term renewable resource contracts began delivery, the Plan must assess the pre-existing portfolio and its underlying costs against the future delivery year requirements for renewable resources. At the same time, the customer base over which those resources and costs may be applied and recovered is anticipated to shrink rapidly due to successful retail customer switching to alternate suppliers, either individually or through municipal aggregation. Finally, while the renewable portfolio percentage targets for renewable resources increase over time, they are applied to a potentially shrinking volume of load. Based on switching results from previous forecasts, stakeholders might have reasonably expected additional renewable resource purchases in 2013. However, due to the factors above, meeting this expectation depends on the key threshold issue of calculating of the price caps and dollar budget available for the 2013 renewable resource procurement.

8.1 Renewable Resource Budgets

As the analyses below show, Ameren and ComEd each find themselves in potentially different circumstances with respect to an ability to make additional renewable resource purchases within the planning horizon of this Plan, leading to different sets of available procurement options. As a preliminary matter, the IPA notes that the following analysis requires the use of the heretofor confidential imputed REC prices associated with the purchase of bundled REC and energy products in the December 2010 20-year procurement of such resources for both Ameren and ComEd. These REC prices are developed in accordance with the ICC's Order in Docket 09-0373 which approved the long-term procurement and the terms of "Appendix K" to the 2010 Procurement Plan, which specified a fixed forward price curve to be used for the full life of the contracts to determine imputed fixed REC prices for the full life of the contracts for purposes of the Renewable Resource Budgets (RRB). Given the analytical results and the recommendations that follow, upon Commission concurrence with these recommendations, the IPA will release the blended average unit prices of the total wind and non-wind portfolio of purchases for each utility, i.e. the imputed average REC prices, to better allow all parties to consider the IPA's proposals on whether to procure additional renewable resources in this and subsequent Procurement Plans. The IPA notes that the information is stale at this point in time and its being made known will not influence future bidder behavior nor reveal information likely to harm any bidder.

8.1.1 Ameren

The Ameren calculations required to assess renewable resource volume and dollar budgets available for use in this 2013 Procurement Plan were submitted to the IPA and are contained in Appendix I. They are summarized below. The quantity targets for future years in the 2013 Procurement Plan's planning horizon have been more than met by prior long-term purchases. The dollar targets are projected to be exceeded for the last two years of the planning horizon,

[137] 20 ILCS 3855/1-75(c)(1)-(2).

suggesting fairly certain rate cap risk for purchases longer than 3-years forward. However, it is noteworthy that the Ameren low forecast scenario, which includes higher switching assumptions relative to the expected scenario, suggests the budget could be exceeded as early as the first year of the planning horizon (2013-2014).

Ameren Summary of Renewable Resource Budgets, Previous Commitments and Available 2013 Spend						
Delivery Year	**RPS Target RECs**	**Previously Purchased RECS**	**Remainder to be Purchased in a 2013 Procurement**	**RPS Budget $**	**Previously Committed RPS $**	**Available RPS $ for a 2013 Procurement**
2013-14	1,107,877	1,136,020	0	11,627,681	9,654,861	1,972,820
2014-15	844,744	1,025,366	0	10,287,942	9,167,145	1,120,797
2015-16	644,050	1,008,810	0	9,695,547	9,183,529	512,018
2016-17	655,319	1,029,245	0	9,331,091	10,403,861	(1,072,770)
2017-18	698,140	854,396	0	8,970,536	9,412,155	(441,619)

On a total portfolio basis, there is no compelling reason to purchase additional renewable resources during the planning horizon, even though there may be dollars "left over" to spend. In addition, the IPA does not intend to sell any "excess" RECs through a reverse RFP mechanism, nor does it recommend that Ameren do so.

Within the portfolio, however, there are quantity sub-targets for specific resource types: wind, solar PV and distributed generation (DG). Analysis of the sub-targets shows that additional quantities of photovoltaic and distributed resources are still needed to meet the sub-goals.

Ameren Remaining Target and Net Budget						
Remaining REC Target	**Purchased RECs**	**% Hedged**	**Remaining Wind Target**	**Remaining PV Target**	**Remaining DG Target**	**Remaining Budget**
(28,143)	1,136,020	103%	(181,318)	24	5,539	$1,972,820
(180,622)	1,025,366	121%	(316,114)	16,648	6,336	$1,120,797
(364,760)	1,008,810	157%	(496,878)	29,749	6,441	$512,018
(373,926)	1,029,245	157%	(485,362)	26,925	6,553	($1,072,770)
(156,256)	854,396	122%	(324,733)	35,830	6,981	($441,619)

Because the volume targets represent target quantities rather than maximum allowable quantities, purchases of additional resources to meet volume sub-targets appear to be permissible under the law, even if total RPS percentage targets are exceeded, subject to rate caps. The policy decision for the Commission to make is – do we halt all purchases of renewable resources for Ameren because the overall RPS volume targets have been met, or should additional costs to be recovered from retail customers be incurred to further the acquisition of PV and DG resources? This question is further complicated by the uncertain levels of switching over the foreseeable future. Given a scenario of higher than anticipated switching, any projected remaining budget could quickly disappear when Ameren updates its forecasts in November 2012 and again in 2013.

Related to the policy question is a related technical question: Is it realistically possible to purchase the desired target quantities of PV and DG resources with the remaining dollars? There are at least two ways to examine this second question.

(1) Assuming the Commission approves a plan to meet the statutory PV and DG volume targets, then comparing remaining dollar budgets with remaining volume targets

provides a useful way to determine the maximum price possible that would pass the price cap screen. If we further assume for this calculation that our goal is to meet the separate PV and DG volume targets, we can add the two volume targets and divide them into the remaining dollars. The following are the results:

Ameren Maximum REC Price for Additional Solar/DG			
Delivery Year	**(a) Remaining $ Budget**	**(b) Combined Solar/DG Volume Target**	**(a/b) Max. REC Price $/REC[138]**
2013-14	$1,972,820	5,563	354
2014-15	$1,120,797	22,984	49
2015-16	$512,018	36,190	14
2016-17	($1,072,770)	33,478	0
2017-18	($441,619)	42,811	0

A recent market-based price for solar RECs can be found in the Ameren purchase of 2,188 solar PV RECs for delivery in the 2012/13 delivery year for $80 per REC. In the February 2012 Rate Stability REC procurement, Ameren's purchase price for annual PV RECs for delivery over the 2013-2017 period ranged from about $85-100 per REC. The maximum prices Ameren could pay fall well below the price for the 2014-15 and 2015-16 delivery years, casting doubt on the ability to achieve the solar and DG volume targets for those years.

This analysis suggests that a solar/DG procurement may only be cost-effectively conducted for 2013-14 delivery. The costs of conducting a procurement event for a relatively small number of RECs may not justify doing so, however. The volume is exceptionally low compared to past procurements and bidder interest is likely to be low, given the costs of participating in a procurement event.

(2) If, instead, we recognize that DG is often PV, and that the DG targets count as PV targets, then the divisor consists solely of the solar PV volume targets.

Ameren Maximum REC Price for Additional Solar/DG			
Delivery Year	**(a) Remaining $ Budget**	**(b) Solar PV Volume Target**	**(a/b) Max. REC Price $/REC**
2013-14	$1,972,820	24	82,201
2014-15	$1,120,797	16,648	67
2015-16	$512,018	29,749	17
2016-17	($1,072,770)	26,925	0
2017-18	($441,619)	35,830	0

Again, it appears that a cost-effective solar PV procurement, which could include DG solar, may only be conducted for 2013-14 delivery, using prior procurements as a reference point.

Arguing against conducting a 2013-14 procurement event is the fact that the volume to be procured probably does not justify the expense of conducting the procurement, particularly because overall RPS targets are met already. If overall RPS target levels are already met with the

[138] Any procurement by the IPA would be subject to a market-based benchmark; thus, the maximum REC price is for illustrative purposes.

current renewable portfolio, should consumers pay more to adjust the portfolio to meet aspirational sub-targets? Although the IPA recognizes that the Commission will decide this question with input from all interested stakeholders, the IPA notes that it finds no compelling legal mandate to increase consumer bills in this manner, especially given the risks of exceeding the Renewable Resource Budget in the event of higher updated switching impacts on the load forecasts.

There are some unused dollars already collected from retail customers, however, that are available to fund a limited Ameren renewable procurement for 2013-14 delivery. Ameren has $563,692[139] available to it, consisting of Alternate Compliance Payments (ACP) collected by Ameren from its hourly-priced service customers but not previously used to purchase RECs. In response to request for comments on ways to improve the procurement process, both Commission Staff and its procurement monitor Boston Pacific, along with the Environmental Law and Policy Center (ELPC) discuss this issue in their June 14, 2012 comments (Staff and Boston Pacific) and June 28, 2012 reply comments (ELPC). The IPA agrees with the assessment that a clear direction is required for how these funds should be used. Going forward, the IPA intends to use ACP funds collected from hourly-priced service customers during the prior plan year to actually purchase RECs for the next plan year, rather than simply increasing the dollar budget but not necessarily being spent. Staff provided in its comments the following process chart:

Timeline for Collecting ACPs from Hourly Supply Customers and Subsequently Spending those Funds on Renewable Energy Resources					
June - May Period:					
Cycle	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
1	collect	plan	spend		
2		collect	plan	spend	
3			collect	plan	spend

The IPA proposes two alternative plans for using the accumulated hourly-customer ACP balances for the Commission to consider:

(1)The IPA respectfully requests that the Commission approve a continued accumulation of hourly ACP balances by Ameren in an account to be used in future years to offset any inability to take full delivery under the long-term 2010 bundled REC and energy contracts due to rate cap limits in the Ameren service territory. This is expected to occur for Ameren in the 2016/2017 delivery year, but could occur as early as 2013/2014 depending on customer switching over the next 12 months.

(2)As an alternative, the IPA considered that the Commission could allow Ameren to conduct a solar PV renewable resource REC procurement for 2013-14 delivery,[140] funded by the accumulated unspent hourly ACPs collected during Cycles 1 and 2 as shown in the above chart. But after considering the possibility that switching could be higher than anticipated, thus eliminating

[139] Of this amount, $424,440 was collected during the 2010 Plan Year (June 2010-May 2011) and $139,252 was collected during the 2011 Plan Year (June 2011-May 2012).

[140] Under Section 1-56(b), procurement from distributed renewable resources "shall consist solely of renewable energy credits." 20 ILCS 3855/1-56(b).

any remaining budget currently forecast for 2013/14, the IPA recommends this alternative not be pursued.

8.1.2 ComEd

ComEd has provided the requisite calculations as Appendix E attached to their forecast documentation and found in Appendix II to the IPA's 2013 Procurement Plan. They are further summarized below for purposes of understanding a 2013 -2018 renewable resource procurement strategy for ComEd. While there is a small shortage in the quantity of RECs required in the first delivery year, the budget has clearly already been exceeded for every delivery year. The IPA further notes that the calculations below do not include the impacts of the purchase of the additional energy efficiency measures that are assessed and proposed in this plan. The approval of those purchases by the Commission will result in the REC budgets for each delivery year shown below to be exceeded by even greater amounts.

ComEd Summary of Renewable Resource Budgets, Previous Commitments and Available 2013 Spend						
Delivery Year	**RPS Target RECs**	**Previously Purchased RECS**	**Remainder to be Purchased in a 2013 Procurement**	**RPS Budget $**	**Previously Committed RPS $**	**Available RPS $ for a 2013 Procurement**
2013-14	2,602,940	2,601,634	1306	20,884,088	24,080,269	(3,196,181)
2014-15	1,707,474	1,885,302	0	18,986650	24,214,969	(5,228,320)
2015-16	1,103,985	1,464,204	0	17,972,057	23,103,678	(5,131,622)
2016-17	1,154,234	1,561,397	0	17,419,445	23,427,324	(6,007,880)
2017-18	1,235,062	1,533,198	0	17,012,491	23,720,034	(6,707,542)

The previously purchased RECs consist of a mix of one-year RECs purchased in the February 2012 Rate Stability Procurement and the December 2010 20-year energy and REC procurement. While the Rate Stability purchases are firm, the long-term purchases made in 2010 contain contract terms that allow for curtailed purchases sufficient to assure that the rate caps (budget limits) are not exceeded. If the entire value of the dollar shortfall shown in the last column above is used to adjust deliveries from the long-term contracts to meet the budget cap, then suppliers under those contracts will see sales curtailed by those dollar amounts, with percentage reductions in quantity ranging from 14.3% in 2013/2014 to 29.0% in 2017/2018. Stated another way, any additional purchases of renewable resources by ComEd in the 2013 Procurement Plan will violate the legislative rate cap constraints put in place to protect consumers.

ComEd also has accumulated hourly ACP payments that have not been used to purchase RECs. Rather than proposing that ComEd use the accumulated hourly ACP payments to conduct an additional REC procurement, the accumulated funds should be used to mitigate any reductions in delivery of RECs under the long term contracts due to the operation of the rate cap. ComEd holds $1,499,113 in hourly ACP funds collected during the 2010/11 delivery year that should have been earmarked for spending in the 2012 procurement but were not. An additional $284,847 was collected during the 2011/12 delivery year and should be used for this same purpose.

8.1.3 Conclusions for 2013 Renewable Resource Procurement

The IPA concludes that, based on the utility expected case load forecasts, there should be no new renewable resource procurements or sales, and the accumulated ACP payments from hourly-service customers should continue to be held by Ameren to be used to mitigate rate cap limits on taking delivery under the existing long-term contracts. The IPA further concludes that there should be no new ComEd REC procurement event included the 2013 Procurement Plan.

In addition, Section 1-75(c)(2) of the IPA Act requires the IPA to reduce the amount of renewable energy resources to be procured for any particular year in order to keep the "estimated" net increase in charges to eligible retail customers below the statutory cap. Therefore, the purchases under the long term renewable contracts may need to be reduced. An estimate of the overall amount is shown in this Plan for both Ameren and ComEd, however the exact amount is uncertain at this time. Both utilities will be submitting updated forecasts in November 2012 and in March 2013. In addition, it is unclear how much of the additional energy efficiency measures will be approved by the Commission. Once the Commission has approved this Plan, including the updated November forecasts and the incremental energy efficiency program amounts, and the utilities have submitted further updated forecasts in March 2013 to reflect municipal aggregation activity and any Commission-approved energy efficiency programs, each utility should calculate both the overall amount of the necessary reduction to keep the purchases under the statutory cap, and determine the amount that each long term renewable contract will need to be reduced. This calculation should only be made for the 2013/14 delivery year. Future procurement plans will address the need, if any, for additional reductions. This information should be submitted to both the IPA and the Commission Staff for their review and acceptance. Once the utilities have received written acceptance from both the IPA and the Commission Staff, they may then notify the suppliers under the long-term renewable contracts of the amounts of the reductions. The suppliers will then make the election allowed them under the agreements. Since the reductions under the IPA Act are to be made on the basis of the "estimated" net increase in charges to Eligible Retail Customers, no further reductions in purchases of renewable under the long-term contracts for delivery year 2013/14 will be made based on the actual increases in charges experienced by Eligible Retail Customers during the 2013/14 delivery year. This will serve to promote certainty and materially assist the suppliers in the election they will need to make.

The IPA's accumulated hourly ACP funds should also be used to mitigate delivery reductions under the long-term contracts due to operation of the rate cap mechanism.

The long-term bundled REC and energy purchases made in 2010, before there was a practical appreciation of how quickly and successfully customers would choose alternate electricity suppliers, could be considered the new generation of stranded costs, in this new incarnation to be borne by competitive generators rather than regulated utilities and their customers. In order to further mitigate concerns by the sellers of the 2010 long-term energy and REC products, that reduced revenue streams from the utilities will damage the continued financial viability of the underlying generating assets, the IPA is considering to also use the Renewable Energy Resource Fund (RERF) under its control. Although Section 1-56 of the IPA Act does not require Commission approval for this use of the renewable funds, the IPA recognizes that the utility contracts have specific language which under certain circumstances involves Commission action. The IPA is raising this possibility to inform the stakeholders of its options. The IPA believes its proposal is within its charter and is consistent with the requirements of the Renewable Portfolio Standard. This fund receives its dollars from ARES as explained below, and represents a logical source of funds to partially and temporarily support sellers under the long-term 2010 contracts.

Use of the Alternate Compliance Payments by ARES to Supplement Utility RPS Budgets for Purposes of Performance Under the 2010 Long-Term Bundled Energy and REC Contracts

The renewable energy obligation for ARES is measured as a percentage of the actual amount of metered electricity (megawatt-hours) supplied by the ARES in the compliance year. ARES must meet at least 50% of their renewable energy resource obligations through the Alternate Compliance Payment (ACP) mechanism.[141] The remaining 50% of the obligation may be met with additional ACP payments, by procuring renewable energy, or by procuring RECs sufficient to comply with the RPS. ACPs are remitted by ARES directly to the ICC, and the ICC forwards that money to the Renewable Energy Resources Fund administered by the IPA for use in purchasing RECs. The IPA is directed to purchase renewable resources at a price not to exceed the winning bid prices for like resources under the IPA's procurements for electric utilities.[142] The ACP rate, which is essentially the average price of RECs purchased for the utilities, fluctuates from year to year based on the results of IPA procurement events. Nevertheless, because the ACP is tied to the average prices for renewable resources purchased by the utilities, the mechanism allows for competitive neutrality with respect to RPS compliance costs passed through to all retail electric customers.

The IPA does not believe it requires Commission approval to spend the RERF in any fashion, either within or outside of a Commission-approved procurement plan. The IPA presents this proposal in the context of this Plan, however, because this Plan has uncovered the potential shortfall in the utility ability to compensate the long-term REC sellers and some discussion is necessary to answer the inevitable questions of both the generators under contract and the renewable resource investment community. The IPA is not a party to the contracts between the utilities and the generators under these contracts, nor does it wish to be. The IPA’s sole obligation is to purchase RECs through competitive procurements that are similar in price and qualities to those procured by the utilities, and to then retire those RECs.

It makes sense that if the Ameren and ComEd long-term REC procurements have the potential to become "stranded" (from the point of view of the generators), in large part because of customer load shifts to ARES, that the ARES RPS compliance payments made through the ACP mechanism be used to make up for the subsequent shortfalls in the utility RPS budgets caused by those load shifts. On the other hand, the IPA has to consider that the ACP money is intended to aid RPS compliance on behalf of ARES customers, meaning that every dollar spent on prior purchases of renewable resources on behalf of eligible retail customers is a dollar not spent on procuring *additional* renewable resources on behalf of ARES customers. The IPA will make a decision with regard to this balancing outside of the context of the Procurement Plan.

Currently, the balance in the IPA’s Renewable Energy Resource Fund (RERF) is $14.9 million. In the past, the State has borrowed a portion of the funds in the RERF but has subsequently repaid it. The IPA has successfully been granted a legislative appropriation to spend $8 million in the 2013 fiscal year, which ends June 30, 2013. This amount of dollars equals, in round numbers, one year’s ARES’ past deposits into the RERF and was also the balance in the fund as of April 1, near the time the appropriations requests were being drafted. While the 2013 fiscal year ends just when the 2013/14 delivery year begins, any use of the RERF to purchase RECs for the delivery year would be contractually committed to before June 1, 2013.

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141 220 ILCS 5/16-115D(a)(2) and (d)(3).

142 *See* 20 ILCS 3855/1-56(d) and (e)

The IPA proposes that, upon receipt of updated load forecasts from the utilities in March 2013 and the establishment of the Renewable Resource Budget for the 2013 delivery year, and a determination and notification by either utility that it will be unable to fully recover its costs of accepting delivery under the contracts due to the operation of the RRB price caps, the IPA will enter into discussions with the utilities and the counter-parties to the 2010 long-term energy and REC contracts to sort out a mechanism wherein a shortfall in the ability of the utility to purchase the REC portion of the output is made up for by the IPA's RERF. The IPA would set up any required accounts and processes at PJM and M-RETS that would facilitate the documented retirement of RECs.

The actual degree to which the ARES-supplied and the hourly-customer supplied ACP funds will be required to supplement the payments to the long-term renewable resource suppliers is mostly a function of customer migration. To the extent all available ACP dollars are not used for this purpose in any one year, they should be allowed to roll-over for use in subsequent years. In addition to filing its annual procurement plans, the IPA is also required to issue an annual report to the Legislature and the Commission on the collection and use of the ACP funds. Both these filings provide ample opportunity to monitor and report on the state and sustainability of this method of ensuring that renewable resources are appropriately funded.

It cannot be presumed that the ACP funds will always be sufficient to fully mitigate against the impacts of customer migration. First, there is legislative uncertainty that the form of the ACP may be altered or eliminated in favor of another mechanism, a "wires charge" being one of those proposed. Second, there are other longer term requirements that may arise in the future such as the Distributed Generation carve-out described below that may place additional demands on the ACP funds.

8.2 Other Renewable Resources - Distributed Generation

A Distributed Generation component of the Illinois electricity RPS is mandated for deliveries beginning June 1, 2013, meaning that of the renewable energy resources procured pursuant to the RPS, at least the following percentages shall come from distributed renewable energy generation devices: 0.5% by June 1, 2013, 0.75% by June 1, 2014, and 1% by June 1, 2015 and thereafter.[143] The law defines distributed generation as a device that is powered by a renewable resource; connected at the distribution system level of an electric utility, ARES, municipal utility or rural electric cooperative; located on the customer side of the customer's meter; used primarily to offset that customer's electricity load and limited in nameplate capacity to no more than 2,000 kilowatts. The new standard also requires that, to the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25 kilowatts in nameplate capacity. Essentially, the IPA has been tasked with developing a DG procurement structure. The analysis in this Section of the Plan makes clear that there is a great deal of risk associated with the utilities' ability to purchase long-term DG RECs through 5 year or longer contracts and still meet the budget caps, due to prior obligations and general uncertainty as to the availability of ARES ACP funds as an alternative funding source. Given the uncertainty around the projections and the availability of ACP funds to supplement the budgets, it is not clear when it may be economically feasible to actually begin a Distributed Generation program due to the potential effects on the requisite 5 (or more) year contracts. Rather than wait to approve all the details of such a program until it becomes crystal clear that the utilities can afford to include one in their portfolios, the IPA wishes to propose a program design for Commission review and comment in the 2013 Procurement Plan, for implementation at such time as the RPS budgets and available ACP

[143] 20 ILCS 3855/1-56.

funds allow. The IPA is doing this at this time because it believes that consistency between any utility and ACP-funded IPA programs will ensure better consumer understanding and success of both endeavors.

To prepare a proposed DG program, the IPA conducted a set of well-attended workshops and discussions with DG stakeholders, and also performed a survey of DG programs in other states to identify program features that may be used in an Illinois DG program. The workshops held on February 24 and April 2, 2012, examined the factors required to define a successful distributed generation program in Illinois. The following points summarize the discussion.

1. General parameters for the Illinois DG program are laid out in PA 97-0616.
2. No desire to regulate or certify aggregators, as the ICC does with agents, brokers or consultants (ABCs), so long as they meet the financial/credit worthiness/technical qualifications of the REC procurement process.
3. A ten-year term seems preferable from a project developer/aggregator/end use customer standpoint. A five-year term is economically viable but requires higher payments over the shorter time frame in order to ensure projects will be economically viable.
4. Electric commodity value is realized through net metering, where the generator is essentially paid retail rates, as opposed to wholesale market value, for generation.
5. The procurement should be conducted as a category of the normal REC procurement process run by the Procurement Administrators.
6. The program requires a separate set of DG benchmarks in addition to the wind, solar and other benchmarks to fairly include all categories of RECs.
7. Use the Alternate Compliance Payment Fund, to the extent it is available, or its successors, to mitigate migration risk, given the long term nature of the contracts.
8. Keep transactions costs low.
    - a. Self-certification of REC output, subject to audit and verification, seems preferable to GATS, M-RETS or NARR registries. However, there are questions on how the ICC or utilities can reliably obtain verification.
    - b. Parties agreed that it was permissible to measure REC output at the inverter rather than a utility-grade meter.
    - c. If (a) and (b) are accepted, there would be no need for aggregator to assume Meter Data Management Agent (MDMA) responsibility with the RTO.
    - d. An entity like SREC Trade (a commercial company) that requires a homeowner data report each month may facilitate a transparent market.
    - e. Structure the arrangement to permit the use of a simple, straightforward and standard contract between the homeowner/business and the aggregator. Include condition that a homeowner/business may only sell a REC, or a portion of a REC, once.
    - f. Allow for some flexibility in delivery to minimize need for collateral.
    - g. Base 1 MW minimum on aggregation group on nameplate for simplicity.
9. Keep the process and procurement program transparent.
    - a. Require aggregators to register with the IPA. IPA to list approved aggregators on the IPA website, much like ARES are listed on the ICC website. Will help system owners to find an aggregator. No IPA endorsement of any particular aggregator.
    - b. Participants suggested that the IPA post standard customer/aggregator contract forms on the IPA website.
10. There is a distinction in costs between the <25 kW segment and the 25 kW-2 MW segment, as well as distinct procurement targets, so that two separate procurement categories may be appropriate.

11. Allow the under 25 kW systems to be price takers based on adjusted results for competitive bids from larger systems.
    a. This would permit homeowners to know the price upfront.
    b. Getting the scalar or multiplier right is key.
12. Experience with project financing by developers in other states suggests that while leasing equipment to a homeowner rather than selling it to him/her may make more sense, a PPA model that accomplishes the same cash flow is preferable from a tax standpoint. Developers do not want to become an ARES. This may require revisiting ARES rules, or creating an exception for PPAs associated with DG financing structures.
13. Clarify the legal responsibilities associated with an aggregator. Provide that the utilities execute contracts with aggregators and the aggregators execute contracts with homeowners/businesses. It is unclear whether an aggregator is a broker (in a common usage sense, rather than an ABC regulated pursuant to Section 16-115D of the Public Utilities Act).
14. The length of the contract between the homeowner and the aggregator may not match up to the contract between the aggregator and the utility.
15. Solicit interest from a wide range of third party organizations to be aggregators. May require aggressive outreach.

Based on the input received, the IPA has gathered that the key points for a program such as this, where one is dealing in many cases with homeowner and small business installations, are: (1) keep it simple, (2) keep transactions costs low, (3) ensure performance of the aggregate bid and not necessarily individual underlying small generators, but (4) ensure that individual generator performance is reasonably verifiable.

Because the IPA is creating a new DG program, a survey of programs from other states provides additional insight. Many of the workshop attendees conduct business in other states that have DG programs, and brought their insight and experience to the table. It is appropriate to survey and summarize these other programs. Appendix V contains a survey of DG programs, focusing on those that bear some similarity to the program parameters specified in the Illinois legislation. These include programs in Colorado, Connecticut, Delaware, Florida, Maine, Missouri, New Mexico, New Jersey, North Carolina (Duke), Ohio (AEP), and South Carolina (Duke).

Based on the workshop discussions and the survey of other states' programs, as well as comments regarding Distributed Generation procurement design submitted to the Commission in its post-procurement informal comment process held in June 2012, the Agency presents for review and comment the following distributed generation program, to be finalized and executed at such time as sufficiently allowed by the ratepayer impact limits associated with overall renewable resource procurement, or the Commission orders it to be executed. The IPA is not proposing specific contract language at this time, because the mandated rate caps and projected renewable resource budgets preclude actual implementation of a DG procurement during the forecast horizon. However, if ordered to begin a utility-based program now, the IPA will work with stakeholders to develop contract language in a manner consistent with any Commission Order.

Because of the uncertainty associated with the ability to sustainably fund a multi-year program, the contract term is proposed to be 5 years, the legislatively mandated minimum. This also makes it less problematic to bid in a fixed price for the entire 5-year strip of RECs, similar to a multi-year strip of standard product energy blocks. A fixed price for an extended term will bring income certainty to the project for the retail customer hosting the generator and facilitates the administration of customer additions to the portfolio in the case of a standard offer aggregation, and, on the other hand, customer replacements in case an original aggregation member ceases to perform or drops out.

A key feature of the program proposal is the method of pricing renewable resource procurement from the larger (greater than 25 kW but less than 2 MW) and the smaller generators. It is proposed that the larger generators participate in a competitive procurement and that the smaller generators be offered a "standard offer" price, based on the results of the competitive procurement that are adjusted by a "scalar". The purpose of the scalar is to recognize that smaller generators may be more expensive to install on a dollars per kwh basis, and that their bid prices would reflect the difference. Anticipating that the scalar might be different for the Ameren and ComEd service areas due to differences in construction costs, the IPA asked NERA and Levitan, the respective Procurement Administrators for ComEd and Ameren, to each provide an assessment of an appropriate scalar to use. Their analyses are included in Appendix V. In fact, the independent analysis conducted by each Procurement Administrator concludes that an appropriate scalar to use for either the Ameren or ComEd DG programs is 1.25. The IPA concurs. The IPA also concurs with workshop participants who expressed the opinion that the scalar may be appropriately reduced over time in order to maintain the 50/50 mix of smaller and larger-sized installations.

Proposed Ameren and ComEd Distributed Renewable Resource Generation Program (all resources must meet the requirements of PA 97-0616)	
Product Categories	Two products: Individual Generators < 25 KW Individual Generators $\geq$ 25 KW, $\leq$ 2 MW
Minimum Bid Size	1 MW aggregated nameplate capacity
Contract Term	5 years
Pricing Mechanism $\geq$ 25 KW	Pay as bid competitive procurement, fixed price for 5-year term.
Pricing Mechanism < 25 KW	Standard offer based on competitive procurement adjusted by a scalar to be separately determined for the Ameren and ComEd service areas to account for cost differences in the service areas.
Ameren Scalar	1.25 (based on Procurement Administrator calculations)[144]
ComEd Scalar	1.25 (based on Procurement Administrator calculations)[145]
Delivery Term Start Date	Offer bidders a choice of June 1, October 1, January 1, or March 1 in the initial delivery year to facilitate new build schedules or initial aggregation efforts. Contract extends for 5 years from the Start Date.
Bid Information Required for $\geq$ 25 KW generator portfolio	Total MWh quantity of RECs offered for the Contract Term (same value each year for 5 years)
	Fixed price for the 5-year strip of RECs
	Type of generator (wind, PV, etc.) For purposes of being able to cleanly compare

[144] See Appendix V.
[145] *Id.*

	competing bids, each bid must be for an aggregation of same type generators
	Expected generator device sizes in the aggregation (nameplate capacity in kW-AC and kW-DC)
	Status of the generation underlying the aggregated portfolio as of the application date: in-service, under construction, speculative
	Certification that each eligible DG device will be interconnected behind a retail customer meter and generating RECs by the delivery term start date. (Need not provide specific generator information at the time of bid, but must provide specific detail on the individual aggregated generators by the delivery term start date)
	Certification that generator installers comply with any applicable ICC Rules.
	Pay a non-Refundable Application fee of $5/kW of nameplate capacity on the aggregated bid.
Bid Process	• Initial application submitted without price bids by a given Application Date. Reviewed for completeness and compliance with the RFP. • Application Fee due by the Application Date. • Price bids accepted by a specific Bid Date. • Select winners from among those bids that do not exceed confidential benchmarks approved by the ICC prior to the Bid Date. • Execute contracts. Winning bidders pay performance guarantees as appropriate.
Contract Process	• Aggregator aggregates DG generators into minimum of 1 MW aggregated nameplate capacity and enters into contracts with each generator. • Aggregators enter into contracts with utilities to supply RECS from a minimum of 1 MW aggregated nameplate capacity pursuant to standard contracts developed by procurement administrator for the program.
Performance guarantees	• No later than the Delivery Term Start Date, assess a Performance Assurance Deposit for 1% of the value of RECs over the lifetime of the contract. May be cash, bond or letter of credit. Reduce the amount of Performance Assurance held by the contracting utility every two years, in proportion to the remaining length of the contract. • If the aggregator fails to supply at least 90% of contracted RECs over a 3-year rolling

	average during the contract term, the utility may terminate the contract and require the applicant to forfeit the remaining Performance Assurance.
Certification of underlying RECs	• 90 days before the Delivery Term Start Date provide a firm list of underlying generators/projects to supply the winning bid, including retail customer name, service address, utility account number, type of DG system, DG nameplate capacity. • Certification by the project owner that the aggregator is authorized to sell that project's RECs into the DG program on its behalf. • Unless self-certified and subject to periodic audit by an entity to be determined, aggregator must choose to track RECs through PJM-EIS , M-RETS or a commercial REC trading entity such as SREC Trade. • Aggregator may substitute Illinois DG RECs of same type obtained through PJM-EIS, M-RETS or other commercial trading entity for RECs generated within the aggregation if doing so will allow the aggregation to avoid performance default, upon approval of the contracting utility
Standard Offer Process	• Price will be published based on the competitive procurement results and the approved utility scalar. Will only be offered to aggregated groups of at least 1 MW nameplate capacity. • Aggregator of <25 kw units must register with the IPA, which will maintain list of registered suppliers on its web site. • IPA to conduct an aggregator registration rulemaking to determine registration and REC formulaic determination. • Amount of RECs determined based on formulaic determination. • Aggregators of generators that are <25 kw will be allowed to avail themselves of the standard offer on a first come-first served basis until such time as the budget or rate cap limits prevent additional participation.
Registration of Aggregators	• Winning Aggregators Register with IPA, so that they may be listed on the IPA web site. • Registration requirements to be developed in an IPA Aggregator Registration process to be determined.

The IPA looks forward to the implementation of a Distributed Generation program and welcomes the Commission's comments on the general parameters as outlined above or as modified in this or any subsequent proceeding. The IPA acknowledges that the law regarding distributed generation program implementation leaves us in a quandary as it specifies details to such a degree that it may make actual program administration difficult. For example, some industry commenters opined that individual projects should be paid based on individual project economics, yet the law clearly requires that bidding entities be aggregations of projects totaling no less than 1 MW per entity. In addition it may be necessary that the utilities propose and receive approval for required tariffs with respect to standard offer contracts[146], much like the PURPA avoided costs tariffs had been structured. Finally, mandated rate caps and projected renewable resource budgets may simply not allow for 5-year terms. The IPA will continue to explore the issues surrounding a Distributed Generation program. Its own implementation of a Distributed Generation program will be highly dependent on the degree to which its ACP funds are used for other purposes, including supplementing payment to the long-term renewable resource contracts or as a result of legislative action.

8.3 Load Forecast Impacts on Renewable Resource Procurement Recommendations

The conclusions herein with respect to renewable resource procurement have been predicated on the use of the expected case load forecasts for both Ameren and ComEd. To the extent that differences in customer migration or other influences change the actual loads to be served, different conclusions could be reasonably reached. As with its energy procurement recommendations, the IPA recommends that utilities submit updated load forecasts in November, after the next municipal aggregation voter referenda are held, and again in March, before the traditional Spring procurements have normally been held.

9.0 Procurement Process Design

The procedural requirements for the procurement process are detailed in the Illinois Public Utilities Act at Section 16-111.5. The procurement administrators, retained by the Agency in accordance with 20 ILCS 3855/1-75(a)(2), conduct the competitive procurement events on behalf of the IPA. The costs of the procurement administrators incurred by the Illinois Power Agency are recovered from the bidders and suppliers that participate in the competitive solicitations, through both Bid Participation Fees and Supplier Fees assessed by the IPA. As a practical matter, the utility "eligible retail customers" ultimately incur these costs as it is assumed that suppliers' bid prices reflect a recovery of these fees. As required by the PUA and in order to operate in the best interests of consumers, the Agency and the procurement administrators have reviewed the process for potential improvements.

Per the Public Utilities Act, the procurement process must include the following components:

(1) Solicitation, pre-qualification, and registration of bidders.

[146] While Ameren and ComEd may find it practical to handle certain contract terms through a standard offer tariff, the IPA notes that eligible Distributed Generation installations are not restricted to being located only in the purchasing utility's service area, although they must be located in Illinois.

The procurement administrator shall disseminate information to potential bidders to promote a procurement event, notify potential bidders that the procurement administrator may enter into a post-bid price negotiation with bidders that meet the applicable benchmarks, provide supply requirements, and otherwise explain the competitive procurement process. In addition to such other publication as the procurement administrator determines is appropriate, this information shall be posted on the Illinois Power Agency's and the Commission's websites. The procurement administrator shall also administer the prequalification process, including evaluation of credit worthiness, compliance with procurement rules, and agreement to the standard form contract developed pursuant to paragraph (2) of this subsection (e). The procurement administrator shall then identify and register bidders to participate in the procurement event.

(2) Standard contract forms and credit terms and instruments.

The procurement administrator, in consultation with the utilities, the Commission, and other interested parties and subject to Commission oversight, shall develop and provide standard contract forms for the supplier contracts that meet generally accepted industry practices. Standard credit terms and instruments that meet generally accepted industry practices shall be similarly developed. The procurement administrator shall make available to the Commission all written comments it receives on the contract forms, credit terms, or instruments. If the procurement administrator cannot reach agreement with the applicable electric utility as to the contract terms and conditions, the procurement administrator must notify the Commission of any disputed terms and the Commission shall resolve the dispute. The terms of the contracts shall not be subject to negotiation by winning bidders, and the bidders must agree to the terms of the contract in advance so that winning bids are selected solely on the basis of price.

(3) Establishment of a market-based price benchmark.

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

(4) Request for proposals competitive procurement process.

The procurement administrator shall design and issue a request for proposals to supply electricity in accordance with each utility's procurement plan, as approved by the Commission. The request for proposals shall set forth a procedure for sealed, binding commitment bidding with pay-as-bid settlement, and provision for selection of bids on the basis of price.

(5) A plan for implementing contingencies

in the event of supplier default or failure of the procurement process to fully meet the expected load requirements due to insufficient supplier participation, commission rejection of results, or any other cause.

Of these five process components, the area with the greatest potential for efficiency improvements resulting in lower costs passed along to ratepayers is item (2): development of standard contract forms and credit terms and instruments. The IPA believes that the forms can be further standardized while remaining acceptable to future potential bidders, thus reducing procurement administrator time and billable hours, while shortening the critical path time needed to conduct a procurement event. This is because the forms, terms and instruments have become relatively stable, with fewer comments being received from potential bidders requesting revision or optional terms for each succeeding procurement event.

Any procurement process to be conducted under the auspices of the 2013 Procurement Plan would be the seventh iteration of IPA-run procurements, when including the February 2012 Rate Stability procurements and the December 2010 long-term REC and energy procurement. In each of the prior iterations, potential bidders have had an opportunity to comment on documents and those comments have been, where appropriate, incorporated into the documents or provided as acceptable alternative language. In the two procurements conducted in 2012 (the Rate Stability Procurement and the standard Spring Procurement) comments have been few, with virtually no new modifications being accepted or made (in part because some comments made by new participants have been handled in prior procurements). The documents used for the 2012 IPA-run procurements illustrate both the breadth and depth of bidder input to the current state of the documents and the maturity of the documents themselves.

Section 16-111.5(o) of the PUA states,

> *On or before June 1 of each year, the Commission shall hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change.*

In fulfillment of this requirement for the 2012 procurements, the Commission instituted an informal process of written comments and opportunities for reply, so that it could hear from all interested parties their comments relating to the procurement process. Initial comments, submitted by five parties were due June 14, 2012, while replies were due June 28. Seven parties submitted replies, one of which is the IPA. Both initial comments and replies are available of the Commission's web site.

The IPA's reply comments addressed process improvement suggestions contained in the initial comments. Those suggestions and the IPA's reply are summarized below. In some instances, the IPA has had the benefit of further review of party replies and additional insight gained in the development of the 2013 Procurement Plan. That additional insight is reflected below.

1. Boston Pacific, the Commission-selected Procurement Monitor, suggests that the IPA clarify in its next Procurement Plan whether the quantity of RECs to be purchased on behalf of a utility should be increased so that the Alternate Compliance Payments (ACP) by hourly customers are properly utilized. The IPA has made such a clarification in Section 8.0 of this Plan and recommends that the ACP payments from hourly customers and held by utilities be actually spent on the purchase of renewable resources.

2. Boston Pacific recommends a further harmonization of the ComEd and Ameren pre-bid letters of credit and recommends that the parties pursue a mutually agreeable single pre-bid letter of credit form. This would greatly simplify the process for

bidders that participate in both the ComEd and Ameren RFP's. The IPA concurs. While the IPA initially also concurred with the initial comments of NERA (the ComEd Procurement Administrator)- that this be taken one step further, so that a common pre-bid letter of credit is executed between the bidders and the IPA rather than the individual utilities- the IPA has been persuaded by the reply comments of ICC Staff that the utilities should remain the beneficiaries of the pre-bid letters of credit.

3. The IPA supports the suggestion by Boston Pacific that Ameren and ComEd pursue a mutually agreeable form of the post-bid letters of credit.

4. Exelon Generation submitted comments with respect to the timing of the procurement events and the prompt notification of winning bidders of their winning status. The IPA concurs with these comments, but like Commission Staff, notes that there are practical and statutory (such as the selection process for the Procurement Administrators) considerations with implementing the timelines contained in the statutorily mandated process. The IPA commits to as expeditious a process as the Act will allow.

5. NERA suggested that having ComEd prepare (or populate) the contract documents rather than NERA would be more cost-effective. The IPA concurs, especially in light of the fact that Ameren populates its own contracts. The IPA has informal confirmation from ComEd that it concurs with this suggestion.

6. Staff offers suggestions for improving the procedures for approving "Other Alternative Sources of Environmentally Preferable Energy". The IPA's web site has been redesigned with direct links to the M-RETS and PJM web sites to be a better resource in this regard. Also, the REC RFPs used in 2012 better articulated the nature of resources that would be acceptable for utility RPS compliance. Staff's suggestions offer further potential for improvement; the IPA acknowledges these additional recommendations. The IPA is preparing to begin several rulemakings and has taken Staff's suggestions under advisement as to whether rulemaking or some other mechanism can accomplish what Staff and the IPA aim to achieve.

7. NERA has suggested that the contract comment process be streamlined or rationalized, and Commission Staff generally concurs. Despite the development of "standard contract forms" over the past four procurement plans, considerable time and effort are still being expended in the solicitation and review of comments for each procurement, some of which deal with issues that have already been resolved in previous procurements. Furthermore, although the EEI Master Agreement is used as the framework for the supplier contract for energy for ComEd, the process followed up until now requires suppliers to sign a new Edison Electric Institute (EEI) Master Purchase and Sale Agreement for each procurement, in addition to the Confirmation Sheet, Collateral Annex and other documents related to the specific transaction. Renegotiating and signing a new EEI Master Agreement each transaction somewhat defeats the purpose and removes the efficiencies of having a standard contract document. In general practice, a supplier would sign an EEI Master Agreement with ComEd, and then simply execute a Confirmation Sheet and related documents for each procurement transaction subsequently entered into. Similarly for Ameren, a separate stand-alone long form agreement for energy and

capacity, based on EEI language, has been signed for each procurement event. The long form agreement should ideally function in a manner similar to the EEI Master Agreement. Given that there are limited procurement events associated with this Procurement Plan, the IPA recommends that the utilities work with the IPA, the Procurement Administrators, ICC Staff and the Procurement Monitor to seek future streamlining opportunities.

Appendices

I. Ameren Load Forecast

II. ComEd Load Forecast

III. Retrofit/Repowered Clean Coal Facility Description

IV. Clean Coal Sourcing Agreement and Cost Analysis

V. Distributed Generation Survey and Scalar Analysis

VI. Legislative Compliance Index