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. <u>Thus, there is no need to procure block energy products for Ameren for this delivery year.</u>

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, <u>it is not recommended that any block energy purchases be made to secure supply for these years</u> 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. <u>Therefore, no energy procurement is required for this plan year</u>. 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 over-supply. 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. There is no need to conduct a 2013 procurement event for delivery during the 2015/2016 delivery year for standard block products.

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, the IPA recommends that Ameren participate in the FERC-approved MISO capacity auction to procure 290 MW of capacity resources for 2013/2014, 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

[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.

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[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.

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[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

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[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 ≥ 25 KW, ≤ 2 MW
Minimum Bid Size	1 MW aggregated nameplate capacity
Contract Term	5 years
Pricing Mechanism ≥ 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 ≥ 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**