COMMENTS BY THE STAFF
OF THE ILLINOIS COMMERCE COMMISSION
ON THE ILLINOIS POWER AGENCY'S
DRAFT POWER PROCUREMENT PLAN
FOR DELIVERY PERIODS BEGINNING JUNE 2014

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I. Introduction

On August 15, 2013, pursuant to the Illinois Public Utilities Act, 220 ILCS 5/1-101 *et seq*. ("PUA") and the Illinois Power Agency Act, 20 ILCS 3855/1-1 *et seq*. ("IPA Act"), the Illinois Power Agency ("IPA") made available to the public a "2014 Electricity Procurement Plan" ("the Draft Plan") and invited affected utilities and other interested parties to submit comments on the Draft Plan by September 16, 2013. In response, the Staff of the Illinois Commerce Commission ("Staff") hereby submits these comments to the IPA.

II. Overview

The Draft Plan constitutes a blueprint for procuring electric energy, renewable energy resources and/or renewable energy credits ("RECs"), energy efficiency program services, and various other related commodities and services needed to provide power to the dwindling number of "eligible retail customers" still purchasing power from Commonwealth Edison Company ("ComEd") and Ameren Illinois Company ("AIC" or "Ameren"). The Draft Plan lists the risks associated with such procurement. It presents a compelling analysis of some of these risks -- focusing on energy price and demand uncertainty -- and a modified strategy for mitigating these risks. On page 14 of the Draft Plan, the IPA recommends the following "Action Plan":

1. Approve the base case load forecasts of ComEd and Ameren as may be updated from time to time during the pendency of the approval docket
2. Require the utilities to provide an updated March 2014 forecast
3. Approve two procurements. The first in April 2014, the second conditionally in September 2014 subject to conditions pre-approved by the Commission

4. Require the utilities to expand the July 2014 forecast to include the November 2014 to May 2015 period

5. Approve continued procurement by ComEd and Ameren of capacity, network transmission service and ancillary services from their respective RTO for the 2014-2015 delivery year

6. Approve curtailment of ComEd and Ameren's Long-Term Power Purchase Agreements for renewable energy, subject to the updated Spring 2014 forecast

7. Approve the use of hourly ACP funds to buy curtailed RECs

8. Approve the Section 16-111.5B incremental energy efficiency programs submitted by the utilities

9. The ICC may also wish to consider the IPA's discussion of additional programs not included in the submittal for possible further inclusion either on a conditional basis, or on an additional basis

10. Approve and adopt the solutions to open Section 16-111.5B energy efficiency procurements issues recommended by the IPA, or as modified in response to stakeholder input. These recommendations include which programs the IPA must provide to the Commission and then which programs the Commission may or should not approve.

Staff generally supports the IPA's Action Plan, with the following exceptions:

First, Staff recommends modifying the Action Plan to describe or to explicitly reference the hedging strategy for mitigating risks associated with energy price and demand uncertainty.

Second, with regard to that strategy, Staff recommends changes to the prompt year hedging goal. The Draft Plan calls for a 6% adder to the target hedge ratio, as a means of accounting for what it calls "shaping risk." Staff recommends eliminating this adder for the present plan, and that the IPA perform additional analysis on the variability of "shaping risk" between delivery months and periods (on-peak versus off-peak).

Third, Staff recommends reducing the portion of the following year's contracts to be acquired in the April procurement event, with the portion eliminated from the April procurement acquired during the September procurement, instead.

Fourth, Staff recommends updating the summary and restatement of five energy efficiency "consensus items." Staff also recommends against setting a single standard for identifying "competing" and "duplicative" energy efficiency programs, especially if the standard is used to screen out programs before they reach the procurement plan. Instead, Staff recommends that, during procurement plan proceedings, the utilities and the IPA continue to provide to the Commission information that they believe pertinent to identifying "competing" and "duplicative" programs, on a case-by-case basis.

III. Demand Forecasts

A. Forecasting challenges identifies in the Draft Plan

More so than in any other previous IPA plan, the 2014 Draft Plan provides a critical analysis of the forecasting methods employed by ComEd and Ameren. Generally, Staff expresses no objections to the IPA's analysis and agrees with the recommendation that the Commission approve the base case load forecasts of ComEd and Ameren as may be updated from time to time during the pendency of the approval docket. However, the IPA's own analysis -- in Sections 3.4.5 and 3.4.6 of the Draft Plan ("Impact of Wholesale Pricing and Market Arrangements on Switching Behavior" and "Individual Switching") – points to shortcomings in the modeling of customer switching behavior. For instance, the Draft Plan states:

> Although it is not yet clear how governments running municipal aggregation programs and individual customers who may opt out or leave a program will act, it is likely that customers would return to utility service in periods of rising prices. [Footnote 64:] The necessary timeframe or magnitude of rising prices

> (or, more accurately, the spread between the bundled utility rate and the best price a municipal aggregation supplier will offer) for customers to engage in this behavior is unknown, and the IPA is interested in feedback from stakeholders as to expected quantitative or qualitative parameters.
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> ***
>
> Finally, independent of market pricing, there may be other market arrangements that motivate customers to switch from or return to utility service. … The IPA is interested in stakeholder feedback on the effect and magnitude of non-market price factors leading to government and individual decision-making.
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> ***
>
> Although the IPA recognizes that many ARES do focus on individual residential switching, the IPA is not aware of a way to model or predict how many customers will leave default service for a non-municipal aggregation ARES. In the absence of such a model, it is reasonable to assume that switching behavior by individual customers will not be a significant factor in the load forecast, except for transition to municipal aggregation, opt-out from municipal aggregation, and return from municipal aggregation.

(Draft Plan, p. 39) Staff recommends that, in preparation for the next IPA procurement plan, that the IPA direct its planning consultant to focus on these issues.

B. Allocation of PJM Peak Load Contributions

As noted above, IPA expressed an interest in receiving stakeholder feedback on the effect and magnitude of non-market price factors leading to government and individual decision-making. (Draft Plan, p. 39) The Draft Plan specifically asks about how the allocation of ComEd's PJM Peak Load Contribution ("PLC") may affect the cost of ARES service to residential customers and municipal aggregation and hence the marketing and pricing decisions of ARES. (*Id*.) While this is a legitimate line of inquiry, and while Staff believes that different ways of allocating PLC will have an impact on an ARES cost of service, such allocations are unlikely to have a significant impact on the accuracy of customer switching and demand forecasts. Note that Staff is not commenting on the propriety of ComEd's PLC allocation methodology.

The Draft Plan states that PLCs are allocated equally to all ComEd residential delivery customers, rather than proportionate to load, and that low-usage customers will find that they are disadvantaged by ARES or municipal aggregation service, relative to bundled service. Actually, ComEd's current practice uses four different PLCs – one for each of the four sub-classes of residential customers. Nevertheless, the IPA is correct that each of these constant PLCs is the same for all customers within the sub-class, regardless of other measures of the customer's "size." Other measures of customer "size" might be the customer's actual or estimated annual energy use or the customer's actual or estimated energy use over the calendar month within which the PJM system peak occurs (generally, some hour in July).

It is a reasonable theory that most individual customers' coincident or non-coincident peak usage is positively related to the customers' energy usage over longer periods of time. For instance, suppose that, for a sample of residential customers with hourly meters, 95% of the variability between customers in their peak July usage for any given year can be explained by their average energy usage during the month, through a relationship such as: peak usage = average usage x 1.61. That would mean that there would be a very good chance that a customer using twice as much electricity over the course of July would also use twice as much electricity during the peak hour and would be contributing more toward the ComEd Zone's peak usage, upon which load serving entities must pay a capacity charge to PJM. Hence, the existence of very large residential customers tending to use about 2500 kwhs in July would probably contribute to the Zone's total peak load by about 25 times very small residential customers using only 100 kwhs.

While ComEd allocates PLCs to residential customers without hourly meters in the manner described above, using a common PLC value for all customers within each of the four sub-classes, the utility nevertheless recovers its own capacity costs from such customers using a per kwh charge. It is unknown how ARESs attempt to recover these costs, but it in the case of municipal aggregation and advertised standard offers, it appears that they take a similar approach as ComEd to capacity cost recovery. To gauge the significance of this, consider that for 2014-2015, the PJM capacity charge will be approximately $0.126 per kw-day, which is applied each day of the year to the PLCs of customers being served by each load serving entity.

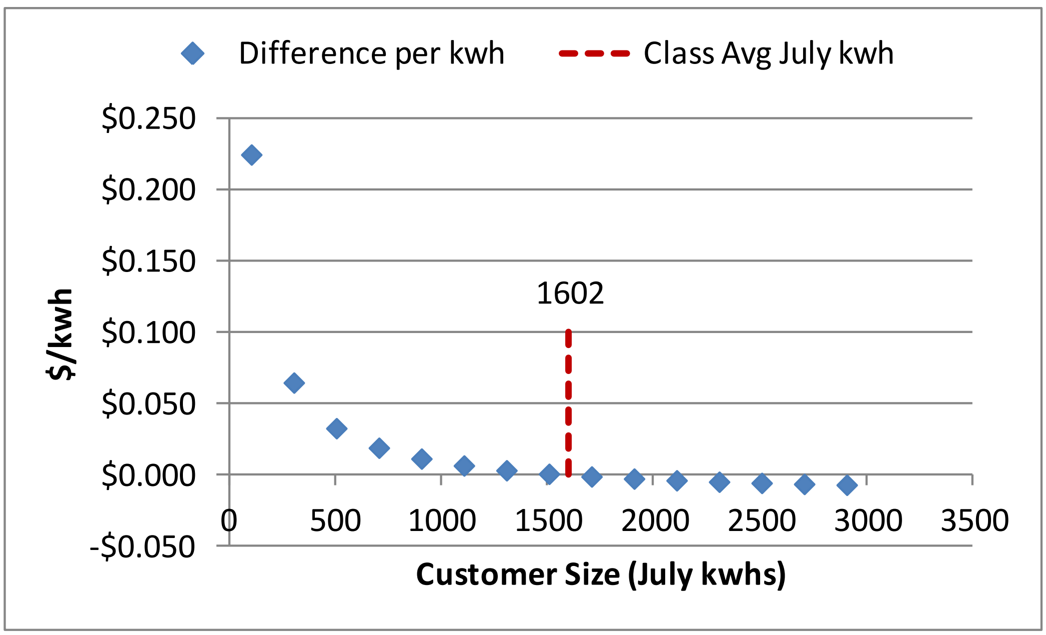
	PJM charge		PJM charge
peak kw / avg kw	$/kw-day	days	$/kw-year
1.61	**$0.126**	**365**	**$45.99**

To take a hypothetical example, if individual customer PLCs were determined proportional to usage (as is the practice of Ameren, for its customers without hourly metering), the large customer's load serving entity would be charged around $250 per year, while the small customer's load serving entity would be charged only around $10. However, if the class average July usage is around 1600 kwhs, and a class average PLC is assigned to each customer (as is the practice of ComEd, for its customers without hourly metering), then both customer's load serving entities might be charged around $160 (depending on how customer sizes are distributed across the service territory). If we further assume that everyone in the class shares an annual load factor of 35%, then the difference in the charge resulting from the class average PLC and the charges from the usage-proportionate PLCs amounts to approximately 22.5 cents per kwh for the small customer down to 0.5 cents per kwh for the large customer. Additional details behind this hypothetical example can be found in the table below. The bold-faced values shown at the bottom are class averages.

				Proportional allocation			Class avg allocation $/year	Proportional - class avg	
Customer concen-tration	Annual kwhs (assuming 35% LF)	July kwh	Avg July kw	Peak July kw	$/day	$/year		Difference per year	Difference per kwh
1%	663	100	0.1344	0.2164	$0.03	$9.95	$159.43	$149.48	$0.225
2%	1,990	300	0.4032	0.6492	$0.08	$29.86	$159.43	$129.58	$0.065
4%	3,317	500	0.6720	1.0820	$0.14	$49.76	$159.43	$109.67	$0.033
5%	4,644	700	0.9409	1.5148	$0.19	$69.66	$159.43	$89.77	$0.019
7%	5,971	900	1.2097	1.9476	$0.25	$89.57	$159.43	$69.86	$0.012
9%	7,298	1100	1.4785	2.3804	$0.30	$109.47	$159.43	$49.96	$0.007
10%	8,625	1300	1.7473	2.8132	$0.35	$129.38	$159.43	$30.06	$0.003
11%	9,952	1500	2.0161	3.2460	$0.41	$149.28	$159.43	$10.15	$0.001
12%	11,279	1700	2.2849	3.6788	$0.46	$169.19	$159.43	-$9.75	-$0.001
10%	12,606	1900	2.5538	4.1116	$0.52	$189.09	$159.43	-$29.66	-$0.002
9%	13,933	2100	2.8226	4.5444	$0.57	$208.99	$159.43	-$49.56	-$0.004
8%	15,260	2300	3.0914	4.9772	$0.63	$228.90	$159.43	-$69.47	-$0.005
6%	16,587	2500	3.3602	5.4099	$0.68	$248.80	$159.43	-$89.37	-$0.005
4%	17,914	2700	3.6290	5.8427	$0.74	$268.71	$159.43	-$109.27	-$0.006
2%	19,241	2900	3.8978	6.2755	$0.79	$288.61	$159.43	-$129.18	-$0.007
100%	**10,629**	**1602**	**2.1532**	**3.4667**	**$0.44**	**$159.43**	**$159.43**	**$0.00**	**$0.000**
				per kw-year		**$45.99**	**$45.99**		
				per kwh		**$0.0150**			

The above is a somewhat over-simplified analysis and depends on various assumptions. To further investigate this issue, one would need sample data showing individual energy usage, by hour, as well as billing statistics on the distribution of peak-month energy usage between customers. One would also want to observe the marketing and pricing behavior of ARES. Nevertheless, to the extent to which the above figures are not unrealistic, they provide some perspective on the magnitude of the cost differences that may be expected. The question is: Are such cost differences significant enough to induce ARES to actively avoid small customers in order to maintain a competitive rate to larger customers or to attain larger profits? As the table above and the graph below show, on a per unit basis, the cost is small among average-sized and large customers but progressively larger among smaller and smaller customers. On this basis, Staff believes it is reasonable to assume that only very small customers are likely to be avoided by ARES, if and where this is a feasible strategy. Thus, the impact on load forecasting for the IPA's plans should be minor.

Difference in Cost Incurred by a Load Serving Entity as a Function of Customer Size
(Class Average Allocation of PLC versus Allocation Based on Individual Customer Size)



C. Competitive Declaration

Staff also recommends that, in preparation for the next IPA procurement plan, the IPA take into account the possibility that, during the five-year planning horizon, the provision of power and energy to those classes of customers that are currently eligible to be "eligible retail customers" is declared to be a "competitive service." Since July 1, 2012, ComEd and Ameren have been permitted under the law to petition the Commission to declare as competitive the provision of power and energy to residential and small commercial customers. (220 ILCS 5/16-113(h)) Within 180 days of receiving such a petition, the Commission ”shall declare the class of tariffed service to be a competitive service within the electric utility's service area” if the petitioner “demonstrates that at least 33% of the customers in the electric utility's service area that are eligible to take the class of tariffed service instead take service from alternative retail electric suppliers, as defined in Section 16-102, and that at least 3 alternative retail electric suppliers provide service that is comparable to the class of tariffed service to those customers in the electric utility's service area that do not take service from the electric utility.” (220 ILCS 5/16-113(a)) Based on data that is regularly provided to Staff by Ameren and ComEd, there is little doubt that such a demonstration could be made (see table, below).

Illinois Electric Retail Market Structure as of May 2013

	Ameren			**ComEd**		
	% served by ARES		# of ARES	% served by ARES		# of ARES
	Customers	Usage		Customers	Usage	
Residential	53%	54%	17	68%	68%	43
Small Commercial	53%	60%	26	59%	63%	48

After a transition period, the declaration of power and energy service to ***most*** customer classes releases the utility from any obligation to provide power and energy service to those customers as a tariffed service:

> (e) The Commission shall not require an electric utility to offer any tariffed service other than the services required by this Section, and shall not require an electric utility to offer any competitive service.

(220 ILCS 5/16-103(e)) However, for residential and small commercial customers, the "transition period" is not finite:

> (c) Notwithstanding any other provision of this Article, each electric utility shall continue offering to all residential customers and to all small commercial retail customers in its service area, as a tariffed service, bundled electric power and energy delivered to the customer's premises consistent with the bundled utility service provided by the electric utility on the effective date of this amendatory Act of 1997. Upon declaration of the provision of electric power and energy as competitive, the electric utility shall continue to offer to such customers, as a tariffed service, bundled service options at rates which reflect recovery of all cost components for providing the service. For those components of the service which have been declared competitive, cost shall be the market based prices. Market based prices as referred to herein shall mean, for electric power and energy, either (i) those prices for electric power and energy determined as provided in Section 16-112, or (ii) the electric utility's cost of obtaining the electric power and energy at wholesale through a competitive bidding or other arms-length acquisition process.

(220 ILCS 5/16-103(c)) While the above excerpt from Section 16-103(c) indicates that the utility shall continue to offer to residential and small commercial customers power and energy as a bundled service option, Section 16-111.5(a) makes it clear that such customers would no longer be considered "eligible retail customers":

> "Eligible retail customers" for the purposes of this Section means those retail customers that purchase power and energy from the electric utility under fixed-price bundled service tariffs, other than those retail customers whose service is declared or deemed competitive under Section 16-113 and those other customer groups specified in this Section, including self-generating customers, customers electing hourly pricing, or those customers who are otherwise ineligible for fixed-price bundled tariff service.

(220 ILCS 5/16-111.5(a)) As such, the procurement of power and energy for such customers by the IPA would be optional for the utility:

> Those customers that are excluded from the definition of "eligible retail customers" shall not be included in the procurement plan load requirements, and the utility shall procure any supply requirements, including capacity, ancillary services, and hourly priced energy, in the applicable markets as needed to serve those customers, provided that the utility may include in its procurement plan load requirements for the load that is associated with those retail customers whose service has been declared or deemed competitive

> pursuant to Section 16-113 of this Act to the extent that those customers are purchasing power and energy during one of the transition periods identified in subsection (b) of Section 16-113 of this Act.

(*Id.*) Thus, with respect to providing power and energy service to residential and small commercial customers, after such service is declared competitive, it appears that the utility may choose to either: (a) continue utilizing the IPA (*Id*.); or (b) use a different "competitive bidding or other arms-length acquisition process" (220 ILCS 5/16-103(c)) Therefore, Staff believes it would be prudent for future procurement plans to take into account the possibility that, during the five-year planning horizon, the provision of power and energy to residential and small commercial classes is declared competitive.

IV. Energy Price Hedging

The Draft Plan includes a more extensive analysis of energy price and volume risk than in any previous IPA plan. While mentioning various alternative ways of managing such risk, the IPA's recommended approach remains unchanged: the "laddered" purchase of monthly on-peak and off-peak fixed-quantity forward contracts, with sought-after quantities tied to the current base-case load forecast. Previously approved plans called for annual procurement events, held in the spring, beginning two years and a couple of months prior to the start of the next three 12-month June-to-May delivery periods. However, the Draft Plan calls for a second annual procurement event to be held each September. Any procurement event (whether scheduled for spring or September) can be cancelled if the most recently-approved demand forecast and "target hedge ratios" render the event unnecessary.

The Draft Plan summarizes the IPA's recommended target hedge ratios for up to 72 different contacts[1] as follows:

Mid-April 2014 Procurement			Mid-Sept 2014 Procurement
June 2014-May 2015 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**November 2014-May 2015**
106% (June-Oct.) 75% (Nov.-May)	50%	25%	106%

The same target hedge ratios would be utilized for both on-peak and off-peak periods.

A. The Additional September Procurement

The primary rationale for the additional September procurement is the fluidity of the retail electric market. In brief, the difficulty predicting eligible retail customers' energy demand is exacerbated by the ability of customers to switch back and forth between bundled and unbundled service. While the additional September procurement event may facilitate a closer match between actual November 2014 – May 2015 energy demand and the quantities hedged for those five delivery months (thereby reducing the chance of over-hedging or under-hedging relative to the plan), it provides no protection for the manifestation of price volatility between spring and September. While the risk analysis performed by the IPA is still under review by Staff, it does not appear that this trade-off has been adequately evaluated. For instance, while Figures 6-6 and 6-7 on page 68 of the Draft Plan summarize the results of Monte Carlo simulations under four different hedging strategies for the prompt year, they fail to isolate the effect of adding the September procurement event. Comparing the last two hedging strategies shown in each of the figures comes closest to isolating the effect of adding the September procurement event. They show a hedge of **100**% completed in April next to a hedge of

[1] That is, 3 years times 12 months times 2 sub-periods (on-peak and off-peak).

75% partially completed in April converted into a hedge of **106**% completed in September. However, to isolate the effect of adding the September procurement event, more illuminating comparisons would have been:

(A) between a hedge of **100**% completed in April and a hedge of 75% partially completed in April converted into a hedge of **100**% completed in September; and

(B) between a hedge of **105**% completed in April and a hedge of 75% partially completed in April converted into a hedge of **105**% completed in September.

Using the IPA's model, comparison (A) may show less upward variability in the average price is obtained with the front-loaded hedge (100% in April) rather than the split hedge (75% in April and 100% in September). Similarly, comparison (B) may show less upward variability in the average price is obtained with the front-loaded hedge (105% in April) rather than the split hedge (75% in April and 105% in September). Such results have been obtained by Staff, albeit in simpler models than the one described in the IPA Draft Plan.

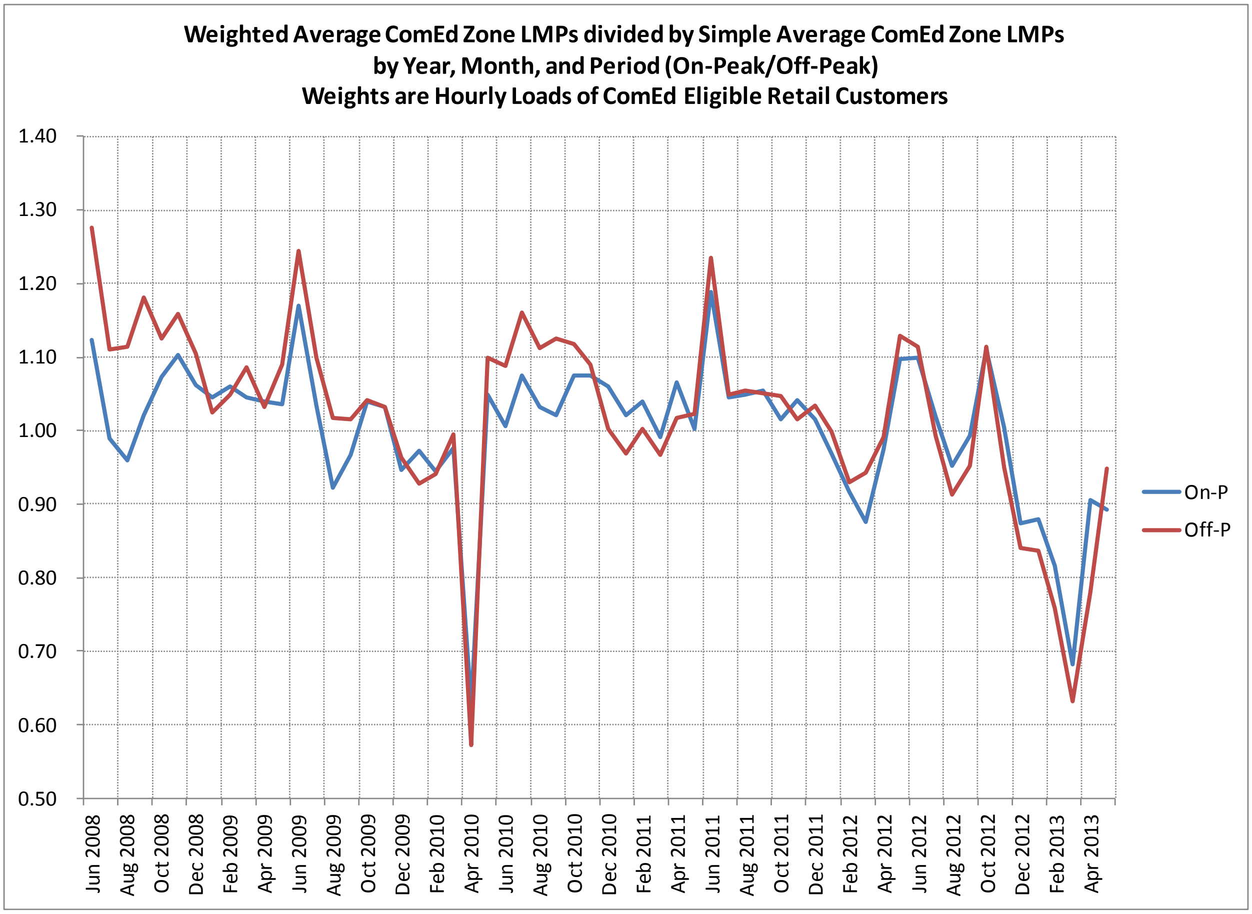
In any event, the validity of such comparisons is likely to depend on the validity of the assumed relationships in the Monte Carlo simulation between the energy demand of eligible retail customers and the simulation's price variables. Unfortunately, this aspect of the IPA's analysis is squarely within the realm of the modeling difficulties that the IPA cites in Sections 3.4.5 and 3.4.6 of the Draft Plan.

Given the modeling difficulties and uncertainty in predicting customer switching during the planning horizon, Staff supports the additional September procurement event. In fact, to better insure robust participation at ComEd's September procurement event, Staff recommends shifting some of the volumes to be procured from the April procurement. This is discussed in the next section.

B. The Hedge Ratios

1. Prompt year

For each month and period (on-peak and off-peak) of the prompt year (June 2014-May 2015), the Draft Plan adopts a target hedge ratio of 106% of the base-case demand forecast. The October through May period would not achieve the 106% hedge ratio until the September procurement event. Based on Staff's reading of the Draft Plan, the 106% target hedge ratio was obtained by first adopting a 100% hedge and then adding 6% to reflect "shaping risk," which appears to be the term used by the IPA for the expected difference between the load-weighted average of hourly locational marginal prices ("LMPs") and the simple average of those LMPs over all the hours of any given month and period (which is typically the settlement price of standard energy block swap contracts). Staff's review of the IPA's analysis is ongoing. However, based of Staff's review of hourly day-ahead and real-time LMPs and eligible retail customer loads, the shaping factor tends to differ between on-peak and off-peak periods, as well as between months, as shown in the two figures below.


Weighted Average ComEd Zone LMPs divided by Simple Average ComEd Zone LMPs
by Year, Month, and Period (On-Peak/Off-Peak)
Weights are Hourly Loads of ComEd Eligible Retail Customers
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
Jun 2008
Aug 2008
Oct 2008
Dec 2008
Feb 2009
Apr 2009
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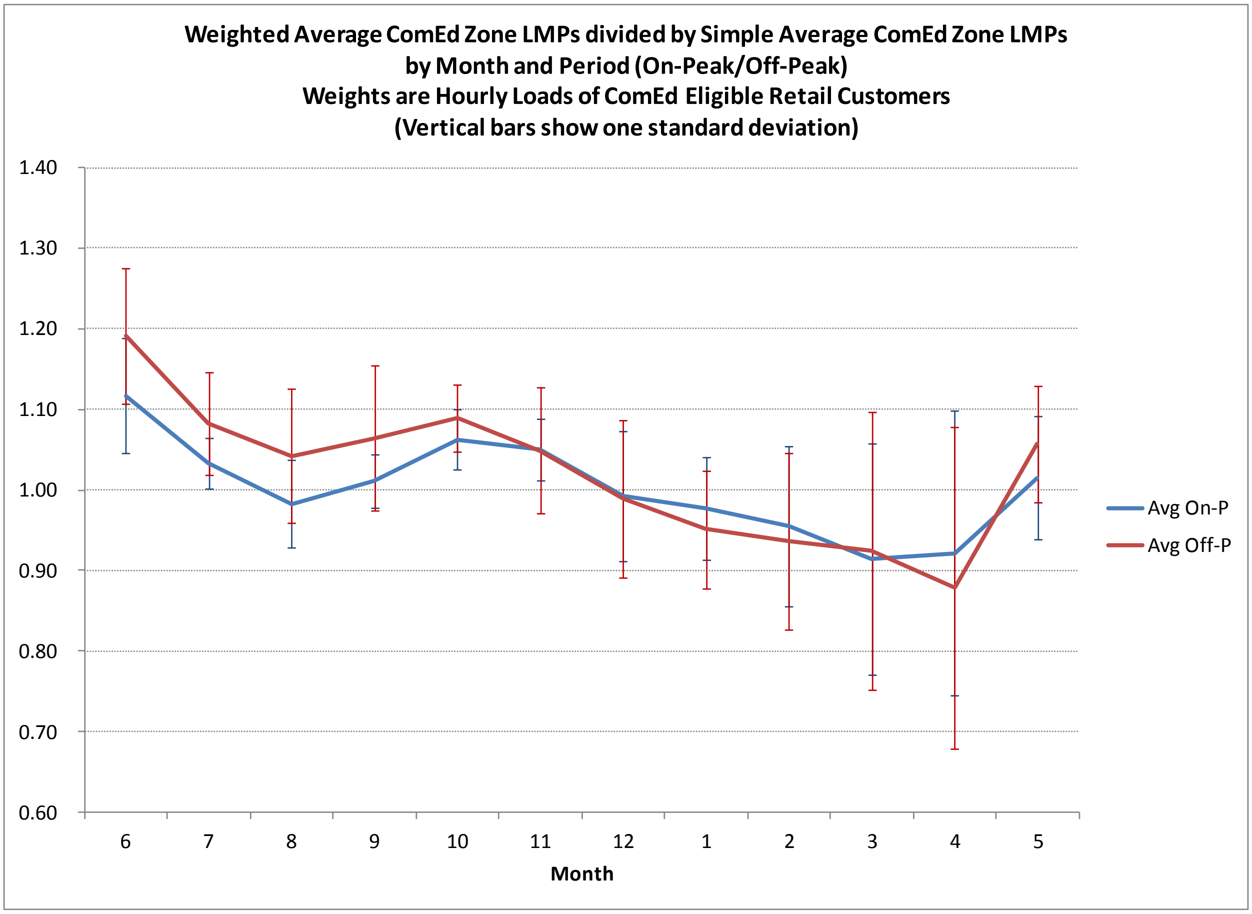

Based on these data, Staff does not believe there is a particularly stable or predictable relationship between load-weighted LMPs and simple average LMPs. Therefore, Staff recommends not incorporating a "shaping risk" factor into the hedge strategy. However, if one or more shaping factors are incorporated into the hedge strategy, Staff would recommend limiting their use to the summer-month contracts, where the shaping "premium" appears to peak. Staff recommends that the IPA continue to evaluate the utilization and calculation of shaping risk factors for future plans.

2. Out years

For the June 2015-May 2016 and June 2016-May 2017 contracts, the Draft Plan recommends accumulating hedge ratios of 50% and 25%, respectively, by the conclusion of the April 2014 procurement events. Staff has no objections to the hedging ratios. However, in ComEd's case, to better insure robust participation at the September procurement event, Staff recommends that the 50% hedging ratio for the June 2015-May 2016 be reduced to 25% for the April procurement and increased to 50% for the September procurement. Under the current base-case forecast, this increases the September procurement's goals from approximately one-quarter to one-third of the total MWHs to be hedged during the two procurement events.

C. Reverse RFP

In Section 6.3, entitled "Tools for Managing Surpluses and Portfolio Rebalancing," and in Section 7.2.3, entitled "Portfolio Rebalancing," the Draft Plan presents a list of reasons for and against the IPA conducting a reverse RFP to eliminate significantly "long" positions (i.e., the utility would sell forwards or forward energy swaps to the extent to which the utility has previously purchased such contacts in quantities that are in excess of expected demand). The Draft Plan recommends against holding such an RFP.

Staff finds most of the Draft Plan's list of reasons against the IPA conducting a ***reverse*** RFP to be inconsistent with the remainder of the Draft Plan. Each of these reasons could apply equally well as arguments against conducting ***procurement*** RFPs. For instance, the second reason given in the Draft Plan for retaining long positions is to avoid selling the contracts at a price lower than the mid-point (the mid-point between the bid and the ask price - market price), since "[b]uyers in any reverse RFP will seek purchases at below market price." Of course, it is equally true that sellers in any ***procurement*** RFP will seek to sell to the Illinois utilities at a price ***higher*** than the mid-point. The third reason given is to avoid the cost of administering a reverse RFP. Again, that same argument applies to administering procurement RFPs. The fourth reason given is that retaining a long position allows the utility's ratepayers to benefit from any subsequent increases in energy prices (through the MISO settlement process). Symmetrically, not entering into hedges through procurement RFPs allows the utility's ratepayers to benefit from any subsequent ***decreases*** in energy prices. The fifth reason provided in the Draft Plan for not holding a reverse RFP is that retaining a long position is a hedge in the event switching is lower than expected (or load returns to the utility) and load is consequently higher than expected. Again, symmetrically, not holding procurement RFPs provides, in the same sense, a hedge in case even more customers switch away from the utility at the same time that energy market prices are falling.

The first reason provided in the Draft Plan for holding a long position instead of conducting a reverse RFP is a little different and slightly more complicated to assess. The Draft Plan states,

> Avoid locking in a financial loss -- The 2014-2015 energy hedges are moderately "out of the money" (based on the ICE settlement curve as of July 31, 2013, the RSP hedges from September to May have an average unrealized loss of about $3.38/MWh, or 10.8%) and selling may result in locking in a loss."

If we are to take the current ICE settlement curve as a reasonably unbiased predictor of where these contracts will ultimately settle, then the fact that the contracts are currently out of the money is an indication that there is a greater than even chance that they will end out of the money. The expected loss of holding the long position to maturity was given by the same $3.38/MWh loss that could have been locked in through ICE trades on July 31, 2013. The difference is not in the ***expected*** loss, but in the ***uncertainty*** of the loss, which of course remains higher for a longer period of time while the long position is retained rather than eliminated. This is actually shown in the Draft Plan's Figure 6-8, where the "sales allowed" portion of the graph shows a reduction in the 90th percentile value of unit cost and a reduction in the range between the 90th and the 10th percentiles. Paradoxically, the same graph shows a reduction in the expected value of unit cost, as well. Staff recommends that the IPA provide an explanation to reconcile this result with the seemingly inconsistent observation that the net long position consists of contracts that were out of the money by an average of $3.38/MWh, presumably within the same time frame that the simulations were performed.

In conclusion, Staff does not believe that the reasons provided in the Draft Plan against conducting a reverse RFP to eliminate a long position are adequate. Generally, Staff recommends that the decision to conduct a reverse RFP should be parallel to the decision to conduct a procurement RFP. The decision to conduct procurement RFPs has always been based on the magnitude of short positions, relative to the target hedge ratios. Symmetrically, the decision to conduct reverse RFPs should be based on the magnitude of long positions. Consistent with the Draft Plan, the magnitude of long and short positions discussed below are relative to hedge ratios of 106%, 50%, 25%, 0%, and 0% for the five years of the planning horizon. However, as discussed below, there are some special considerations to take into account over the next several years (specifically, the fact that all of the long positions held by ComEd and Ameren are due to a statutorily mandated set of "Rate Stability" procurements that took place in 2012).

With the current base-case forecast, ComEd is long throughout the prompt year, and is long in some contracts and short in other contracts for June 2015-May 2016 delivery period. ComEd is long in all contracts for the June 2016-May 2017 period (totaling approximately 2.3 million MWHs) and the June 2017-December 2017 period (totaling approximately 3.3 million MWHs). Over the entire five-year planning horizon, ComEd is short by approximately 7 million MWHs, but is long by about 7 million MWHs. As a percentage of the base-case load forecast, ComEd is short by approximately 58% in the prompt year and 13% over the entire planning horizon, while ComEd is long by approximately 22% in the June 2016-May 2017 period, 31% in the June 2017-May 2018 period, and 13% over the entire five-year planning horizon. The long positions are primarily due to the contracts purchased in the 2012 “Rate Stability” procurement.

Under the Ameren base-case forecast, for the first half of the prompt year, Ameren is short in some months and periods and long in others. In the second half, Ameren is long in all months and periods. The long positions amount to 24% of the forecast in the prompt year, and 10% for the entire five-year planning horizon. Like ComEd, the long positions are primarily due to the contracts purchased in the 2012 “Rate Stability” procurement.

In Staff’s view, there are significant enough long positions being held by ComEd and Ameren to justify eliminating those positions with a reverse RFP. However, as previously noted, all of these long positions were the result primarily of the 2012 “Rate Stability” procurements, which were mandated by statute. Hence, Staff agrees with the Draft Plan’s conclusion to not conduct any reverse RFPs, but this concurrence only applies through the expiration of the 2012 Rate Stability contracts.

D. Options contracts

In sections 6.2 ("Tools for Managing Supply Risk") and 7.2.2 ("Other Products") the Draft Plan discusses the use of options contracts, such as call options, to manage price risk. The Draft Plan states,

> The Agency did not conduct a full analysis of the economic and regulatory implications of including options in the 2014 Procurement Plan; however, the IPA plans to investigate those implications in developing its 2015 Procurement Plan.

(Draft Plan, p. 90) Staff supports the IPA's plan to investigate the use of options. Staff further recommends that the IPA expand its investigation beyond simple call options, looking at the possibility of using more complex options, perhaps custom-designed, to deal with the type of quantity uncertainty that the IPA faces with its procurement plans.

E. Full-Requirements Contracts

The Draft Plan also contains an analysis of energy "full-requirements contracts." A hedging strategy centered on such contracts can be used to concentrate in the hands of suppliers, rather than eligible retail customers, the financial responsibility and risk of unanticipated customer switching, load-following, load uncertainty in general, and spot price volatility. Naturally, such a significant shift in risk would entail a "premium" relative to the prices of fixed quantity forward contracts. While Staff appreciates the IPA's efforts to examine this alternative strategy, Staff is skeptical of the model, assumptions, and analysis used by the IPA to compare full requirements contracts to the IPA's fixed quantity approach toward hedging. For example, the Draft Plan states:

> A full requirements supplier is assumed to charge a premium over the expected cost of its obligation. The premium is estimated as a "return on VAR". Effectively, it is assumed the hedge provider holds working capital equal to its VAR and has to pay a return on that capital. The VAR is the "95th percentile VAR", which equals the amount by the 95th percentile of the unit cost distribution

> exceeds the expected unit cost. As this is a preliminary estimate, used to inform the Agency and the ICC of the approximate cost of full requirements hedges, the return assumption for the third year of a three-year contract is 30% (about 10% per annum).

(Draft Plan, pp. 72-73) The pricing model and assumptions embedded in the above statement are not accompanied by any theoretical or empirical justification. Hence, Staff recommends that the IPA better justify the pricing model and assumptions used for its analysis of full-requirements contracts or, failing that, highlight that the pricing model and assumptions are merely illustrative.

Furthermore, the risk analysis that is summarized by Figure 6-12 (and others) appears to have assumed that, during the transition to a full requirements contracting strategy, the IPA would make no allowance for existing fixed quantity contracts. That is, while Ameren's existing portfolio of fixed-quantity contracts already provides an average hedge in the prompt year of 108% in the on-peak hours and 121% in the off-peak hours, from Figure 6-12, it appears that full requirements tranches were assumed to be purchased for 100% of actual demand. No wonder such a straw-man strategy is shown to increase both risk and expected cost. In effect, such an approach would lead to an extremely long position. Thus, Staff recommends that the IPA revise its analysis of full-requirements contracts to eliminate such an improper and ill-advised manner of implementing the strategy.

V. Capacity

While the Draft Plan could be clearer, it appears to include the recommendation that all resource adequacy requirements imposed upon Ameren by MISO be met through relatively passive participation in the RTO's Planning Resource Auction

(“PRA”). Presumably, this would entail Ameren offering into the PRA all Zonal Resource Credits (“ZRCs”) acquired by Ameren through previous IPA procurement events at a $0.00/MW-Day offer price (assuring that Ameren is paid the PRA auction clearing price for all of its ZRCs). It would also entail Ameren paying the same auction clearing price for its entire Planning Reserve Margin Requirement (“PRMR”), which is updated on a daily basis to take into account retail switching. There would be no additional purchases of ZRCs through IPA procurement events.

Similarly, for ComEd, it appears that the IPA recommends that the utility continue to meet its Daily Unforced Capacity Obligations vis-à-vis PJM through relatively passive participation in the PJM Reliability Pricing Model (“RPM”). This would entail ComEd paying the Final Zonal Capacity Price that arises from the Base Residual Auction (“BRA”) and the Incremental Auctions conducted by PJM. The Final Zonal Capacity Price is determined largely by the Base Residual Auction, which occurs three years and one month prior to the delivery period. There would be no attempt to create hedges against the results of the PJM auctions through even earlier IPA procurement events.

A significant difference between the MISO PRA and the PJM BRA is that the former occurs just a month prior to the delivery period, while the latter occurs three years and one month prior to the delivery period. Hence, one might argue that the IPA plan results in capacity price uncertainty lingering three years longer for Ameren than for ComEd. Notwithstanding this observation, Staff supports the IPA recommendations regarding “capacity,” although Staff recommends that the IPA utilize a more detailed description of the strategy.

VI. Transmission and Ancillary Services

Staff has no comments on this aspect of the Draft Plan

VII. Renewable Energy Resources

Staff has no substantive comments on this aspect of the Draft Plan. However, Staff notes that the "Current Contracted Supply" column of Table 7-4 (Ameren Procurement, Delivery Year 2014-2015) does not take into account the expected curtailment by Ameren of the 20-year renewable contract quantities (due to the budget constraint), while the same column of Table 7-8 (ComEd Procurement, Delivery Year 2014-2015) does take into account the expected curtailment by ComEd of the 20-year renewable contract quantities (due to the budget constraint). Staff recommends revising Table 7-4, accordingly.

Similarly, the "Expected Load" column of Table 7-8 does not take into account ComEd's additional Section 16-111.5A efficiency programs energy savings, while the same column of Table 7-4 does take into account Ameren's additional Section 16-111.5A efficiency programs energy savings. Staff recommends revising Table 7-8, accordingly.

VIII. Energy Efficiency

In Section 2.7, entitled "Energy Efficiency Resources," the Draft Plan presents a summary and restatement of five consensus items it believes to be directly related to the 2014 Procurement Plan and further requests that the Commission rule on those items in the procurement plan docket. For the sake of accuracy, Staff recommends certain revisions to these statements to reflect the consensus as shown below:

- Both new and expanded programs may be approved for more than one year.~~up to three-year increments (for expanded utility programs, to coincide with the 8-103 three year plans)~~
- DCEO may ~~and should~~ bid programs into the utility-run RFPs, although notwithstanding other exemptions DCEO programs should pass the TRC test as quoted above in order to be included.
- Any utility savings goals pursuant to Section 8-103 and contractor performance "goals" pursuant to Section 16-111.5B are separate and non-transferrable. Budgets should also be kept separate.
- Utilities should include bid reviews in their energy efficiency assessments and provide the IPA with all bids to the RFP (on a confidential basis) so the IPA may independently evaluate the bids.
- Parties should work collaboratively on contract principles for successful bidders, which may include pay-for-performance language~~ and grant the utility "flexibility" to reward successful programs while minimizing resources spent on unsuccessful programs~~.
- Section 16-111.5B(a)(3)(D) can be interpreted as the Utility Cost Test and should be calculated for each program.

(Draft Plan, p. 20)

In Section 7.1.3.4, entitled "Consideration of All Third-Party Bids," the Draft Plan recommends that the Commission set a standard for identifying "competing" and "duplicative" programs and "explicitly hold that 'competing' and 'duplicative' programs (however defined) are not to be approved pursuant to Section 16-111.5B(a)(3) or (5)." (Draft Plan, p. 82) Staff recommends against setting a single standard for identifying "competing" and "duplicative" programs, especially if the standard is used to screen out programs before they reach the procurement plan. Attempting to set such a standard for "competing" and "duplicative" programs would not be consistent with the statutory goal of capturing all achievable cost-effective savings (a concern expressed in the Draft Plan in Section 7.1.3.1, entitled "Feedback Mechanisms"). (Draft Plan, p. 80) Hence, Staff recommends that, during procurement plan proceedings, the utilities and the IPA continue to provide to the Commission information that they believe pertinent to identifying "competing" and "duplicative" programs, on a case-by-case basis. The Draft

Plan provides an example of such an approach, in its discussion of several bids received by ComEd for efficiency programs. (*see* Draft Plan, Sections 7.1.5.1 and 7.1.5.2, pp. 85-86)

IX. Corrections and Clarifications

A. Table 1-2

Staff notes that the Draft Plan adopts essentially the same strategy toward "capacity" for ComEd and Ameren, except for Ameren's offering of previously-acquired Zonal Resource Credits into the MISO capacity auction. However, Table 1-2 gives the impression that there is a difference between the ComEd and Ameren strategies. For instance, the portion of the table for Ameren shows expected MW values, while the ComEd portion does not. Staff recommends that the IPA amend the table to clarify its proposal.

B. Tables 4-5, 4-6, and 4-7

Tables 4-5, 4-6, and 4-7 do not appear to take into account contracts procured through the spring 2012 IPA procurement event (which followed the "rate stability procurement"). Staff recommends that the tables be revised accordingly.

X. Conclusion

Staff respectfully requests that the Illinois Power Agency revise its Draft Plan consistent with Staff's Comments.

Respectfully submitted,

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