COMMENTS OF THE RETAIL ENERGY SUPPLY ASSOCIATION ON THE ILLINOIS POWER AGENCY'S DRAFT 2014 POWER PROCUREMENT PLAN

I. INTRODUCTION

The Retail Energy Supply Association ("RESA")[1] is a broad and diverse group of retail energy suppliers who share the common vision that competitive retail energy markets deliver a more efficient, customer-oriented outcome than a regulated utility structure. RESA is devoted to working with all stakeholders to promote vibrant and sustainable competitive retail energy markets for residential, commercial and industrial consumers. RESA has been an active participant in all of the proceedings before the Illinois Commerce Commission ("Commission") concerning approval of the annual procurement plans of the Illinois Power Agency ("IPA"), beginning with Ill. C. C. Docket 08-0519. RESA appreciates the opportunity to file comments on the IPA's Draft 2014 Power Procurement Plan, dated August 15, 2013 (the "2014 IPA Draft Plan").

In these Comments, RESA will address the following three issues: 1) the IPA's continued use of a three-year laddered approach for the procurement of energy supply, as opposed to multiple procurement events, 2) Alternative Compliance Payments ("ACPs"), and 3) the timing of the procurement process.

II. MULTIPLE PROCUREMENT EVENTS

[1] RESA's members include AEP Energy, Inc.; Champion Energy Services, LLC; ConEdison *Solutions*; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; Energetix, Inc.; GDF SUEZ Energy Resources NA, Inc.; Hess Corporation; Homefield Energy; IDT Energy, Inc.; Integrys Energy Services, Inc.; Just Energy; Liberty Power; MC Squared Energy Services, LLC; Mint Energy, LLC; NextEra Energy Services; Noble Americas Energy Solutions LLC; NRG, Inc.; PPL EnergyPlus, LLC; Stream Energy; TransCanada Power Marketing Ltd.; and TriEagle Energy, L.P.. The comments expressed in this filing represent the position of RESA as an organization but may not represent the views of any particular member of RESA.

The IPA recognized in its initial procurement plan (filed in Ill. C. C. Docket 08-0519) that a move toward multiple procurement events would mitigate risks inherent in a single annual procurement event. The IPA, in its Initial Plan, stated:

> A single annual procurement increases risk to the Portfolio because price risk is minimized by more frequent and smaller volume entries into the market. Additionally, single annual procurements increase the potential for bidders to exercise some level of market power depending on market conditions.
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> To mitigate these risks, the IPA recommends that procurement events occur more frequently than once per year. A likely method for managing such a schedule would be to migrate to multiple overlapping quarterly procurement cycles and eventually to implement a continuous procurement cycle. (IPA Initial Plan in Docket 08-0519, p. 15)

However, despite that recommendation, the IPA's Initial Plan utilized a three-year laddered procurement approach with 35% of the projected energy needs procured two years in advance of the year of delivery, 35% of the projected energy needs procured one year in advance of delivery, and 30% of the projected energy needs procured in the year of delivery. (*Id.*, pp. 22-23)

Moreover, the IPA continued to utilize the same three-year laddered approach in its next three annual procurement plans. (Ill. C. C. Dockets 09-0373, 10-0563, and 11-0660) However, the IPA's last procurement plan, the 2013 Procurement Plan (filed in Docket 12-0544), did not include any procurement of energy because the electric utilities were basically in a state of oversupply due to the IPA's previous procurements using its three-year laddered approach and the rapid migration from utility supply to Retail Electric Supplier ("RES") supply. Notwithstanding the fact that there was no energy procurement in the 2013 Plan, the IPA recognized the problems with its previous three-year laddered approach and indicated that it was considering modifying, as opposed to abandoning, its three-year laddered approach.

Specifically, instead of the 35%, 35%, and 30% approach, the IPA recommended the following approach: 75% for the plan year, 50% for the following year, and 25% for the year after that (basically an annual procurement of 25% for each of the three years). The IPA noted that "this recommendation was developed in a time frame characterized by declining market prices and accelerating customer switching. However, since no energy procurement is warranted in this Procurement Plan, next year's Procurement Plan will allow for additional analysis of this revised hedging strategy on volatility and expected cost." (IPA 2013 Procurement Plan filed in Ill. C. C. Docket 12-0544, p. 3)

The IPA proposes, in the 2014 IPA Draft Plan, a modified version of its three-year ladder approach discussed in its 2013 Procurement Plan: the IPA will procure 25% of the forecast energy need for the third year (June 2016 through May 2017), 50% for the second year (June 2015 through May 2016), and 75% for November to May of the first year (November 2014 through May 2015). However, the IPA will be fully hedged for June through October of the first year (June 2014 through October 2014). Actually, the IPA will procure 106% of the forecasted need. (2014 Draft Plan, p. 12)[2]

In support of its proposed procurement strategy, the IPA states that it believes that its continued use of a three-year laddered approach is "the most prudent and most likely to produce its statutorily mandated objective to 'develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability". (*Id*., pp. 11-12) Once again, the 2014 Draft Plan does not even mention, let alone recommend, multiple procurement events as a means to mitigate the risks inherent in its one-time procurement event approach. RESA

[2] The 2014 Draft Plan states that "If necessary, the IPA recommends the Commission pre-approve a supplemental September procurement which would bring the hedging level for the rest of the first delivery year to the 'fully hedged' level."

believes that this is a serious shortcoming of the 2014 Draft Plan which should be remedied when the IPA submits its final Plan to the Illinois Commerce Commission on September 30, 2013.

There are many methods that can be used to implement a multiple procurement structure, including having the current once-a-year approach broken down into four phases, with potential bidders electing at the first phase which of the four procurements in which to take part. This would prevent the IPA from having to conduct the same participant application and screening process four times, thus needlessly adding to the IPA's administrative burdens. Obviously, other additional steps can be taken to reduce the additional burden caused by multiple procurement events, and those too should be considered.

The IPA should move toward multiple procurement cycles for the following reasons. Generally, utility default service procurement should result in market reflective price signals. Continued progress toward a competitive electric market is the best way to help all consumers balance price risk and budget certainty while also providing innovative and customer-driven value-added services. Successful retail competition will produce downward pressure on price, offer a variety of product options for end use customers, increase conservation incentives, enhance customer service, improve environmental management and hasten the introduction of new, innovative products. Retail energy competition requires that default service pricing be properly structured; consumers must see a default price for electricity that reflects the actual market price of the electricity they consume.

RESA recognizes that in addition to more frequent procurement events, there are other mechanisms that can be considered to make current default service more market reflective. For example, the current weighting of the three-year blended contracts could be changed so that heavier weight is placed on the current energy year; or, rather than using three-year blended averages, shorter contract terms, such as 6, 12, and 18 month blended terms could be utilized.

Specifically, the failure of long-term procurement contracts to reflect current wholesale market prices creates inefficiencies in either direction. In the event that the company's procurement costs are higher than those available in the wholesale market, then customers are harmed by having to pay higher than market prices. In the event that wholesale market prices rise above the locked in utility costs, customers will receive incorrect price signals that distort the market and give rise to the following unintended harmful consequences: 1) a belief that energy is less expensive than it really is, leading to potential over-consumption; 2) discouraging energy efficiency investment by under-valuing avoided costs; and, 3) the risk of rate shock as those contracts end. In all of these instances, customers will be harmed.

The use of more frequent procurement events would enable the procurement of shorter-term contracts which could be procured closer in time to actual delivery of the supply. The use of shorter term contracts procured closer in time to the date of delivery will enable customers to see a default price that better reflects prevailing market prices and will minimize long term contract hedging premiums that are associated with longer term contracts procured far in advance of delivery. Better price signals will spur more thoughtful efficiency investments, wise energy usage, and spur development of the competitive market. Better accuracy reduces customer costs over the long term. A major benefit of having default prices reflect the market is that consumers who are on those default rates will be sent clearer price signals that, in turn, will cause more efficient energy usage.

Moreover, multiple procurement events will alleviate the problem of the inability to forecast shifts from utility supply to RES supply and *vice versa*. As the IPA acknowledges, it is concerned that there may be a shift back from RES supply as municipal aggregation programs expire, due to reductions in the electric utilities' default prices. (*Id*., p. 11)

Under the IPA's former three-year laddered approach and its modified three-year laddered approach, the time period between procurement and delivery of energy is too great, creating both price risk and volume risk. RESA's approach would provide multiple forecasts and multiple procurement events that would achieve the significant benefits described above.

III. ALTERNATIVE COMPLIANCE PAYMENTS

On page 102 of the 2014 IPA Draft Plan, the IPA notes the amount of Alternative Compliance Payments ("ACPs") which it received from RESs: approximately $7.1 million in 2010, approximately $5.6 million in 2011, and approximately $2.2 million in 2012. The IPA then notes that, in September 2013, it expects to receive approximately $40 million in ACPs for the June 2012 through May 2013 compliance period. The IPA attributes this tremendous increase in ACPs to being "a direct result of significant load switching from utility supply to RES supply in recent months, primarily driven by municipal aggregation activities". (2014 Draft Plan, p. 102)

Actually, the IPA's explanation is only partially accurate. Another cause was the increase in the ACP rate as a result of a changed assumption. The May 17, 2012 estimates of ACPs for the June 2012 through May 2013 compliance period were $0.6338/mWh for Ameren and $0.9085/mWh for ComEd. However, on May 13, 2013, the Commission published a Notice that it had revised its estimated ACPs as follows: $0.6687/mWh for Ameren and $0.9724/mWh for ComEd. The reason given for the revision was that the May 17, 2012 estimates assumed that ACP revenues collected by Ameren and ComEd from their hourly customers would be used to purchase RECs required for eligible retail customers' renewable energy credits portfolios, however this assumption was incorrect.[3] The Notice also indicated that actual ACP rates would be established by July 1, 2013. In fact, the actual ACP rates were identical to the May 13, 2013 estimates.

While the change in ACP rates, on a per mWh basis, may not seem large, the change is very significant when considering the total volumes of electricity sold by RESs. As another measure of this increase, the amount of that increase was greater than the entire previous year's Actual ACP rate for each utility--$0.0584/mWh for Ameren and $0.0568/mWh for ComEd.[4] Moreover, the timing of the notice of the changed assumption and the revised estimates—one year after the publication of the earlier estimate and 10 ½ months into the 12-month compliance period—made it impossible for RESs to accurately reflect these increased ACP costs in the products they provide to their customers. For 10 ½ months, the best information RESs had with which to anticipate ACP charges required by law to comprise 50% of their compliance, was the Estimated ACP published by the ICC in May 2012. The May 13, 2013 increase of this estimated number was a substantial change that made RES' reliance on the previous estimate inadequate for them to reflect the Actual ACP cost in their product pricing for customers during that 10 ½ month period. Competitive markets require predictability in order for suppliers to accurately forecast forward changes, but this change was unprecedented until 2013, so it was virtually unforecastable.

RESA requests that, in the future, if assumptions in the manner in which ACPs are calculated are changed, those changed assumptions should be made prospectively. For example,

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[3] Illinois Commerce Commission—Notice Concerning Alternative Compliance Payments ("ACPs") associated with the Public Utilities Act's Renewable portfolio standard for alternative retail electric suppliers and electric utilities operating outside their service territories dated May 13, 2013.

[4] Illinois Commerce Commission-Notice of Actual ACP Rates for Compliance Period June 2011 through May 2012, dated July 2, 2012.

if a changed assumption were reflected in the subsequent, rather than the current, compliance period, RESs would have some opportunity to adjust prices accordingly.

IV. TIMING OF PROCESS

Due to the fact that there were no procurement events held as a result of the 2013 Procurement Plan, there was obviously no problem with the publication of new rates sufficiently in advance of their effective dates, unlike the experience in previous years.

Delays in the release of utility tariffs and charges cause substantial confusion and competitive harm in the retail market. Future Commission orders approving the IPA Plans should establish schedules that permit calculation of new rates sufficiently in advance of their effective dates and require that utilities file and make available approved tariffs and charges no less than two weeks before the new rates would go into effect.

V. CONCLUSION

RESA appreciates the opportunity to submit these Comments on the 2014 IPA Draft Plan, which is generally well-thought out and carefully analyzed. However, three modifications should be made to that plan. First, provision should be made for consideration of multiple procurement events. Second, any change in assumptions which would impact the calculation of ACPs should be made prospectively. Third, there should be specific timetables in the plan that ensure that new rates will be available to RESs no less than two weeks before they would go into effect.

Respectfully submitted,

/S/ GERARD T. FOX
Gerard T. Fox

An Attorney for the Retail Energy Supply Association

Law Offices of Gerard T. Fox
Two Prudential Plaza
180 North Stetson, Suite 3500
Chicago, IL 60601
(312) 268-5674
gerardtfox@aol.com

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