STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	**:**	
	:	
Petition for Approval of Initial Procurement Plan.	**:** **:**	**09-0373**

ORDER

DATED: December 28, 2009

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By the Commission:

I. BACKGROUND

As set forth more specifically therein, Section 16-111.5(d)(2) of the Public Utilities Act ("PUA"), 220 ILCS 5/16-111.5, requires the Illinois Power Agency ("IPA" or "Agency") to "prepare" a procurement plan ("prepared plan"), which is to be "posted" on the IPA and Illinois Commerce Commission ("Commission") websites. Section 16-111.5(d)(2) does not require that the prepared plan be "filed" with or docketed by the Commission. Similarly, comments on the prepared plan are to be submitted "to the [Illinois Power] Agency," for review by the IPA, and posted.

Nevertheless, in order to facilitate the Section 16-111.5(d)(2) process by providing a practical procedural mechanism for use by the IPA in posting the prepared plan, and by "interested entities" in submitting and posting comments on the prepared plan, the Commission docketed the IPA's prepared plan on the Commission's e-Docket system and it was assigned Docket No. 09-0373.

Pursuant to Section 16-111.5(d)(2), the IPA is required to make revisions as necessary based on the comments submitted to it, and then to "file" the plan as revised with the Commission. As such, the only plan the IPA is required to formally "file" with the Commission, and the one that is actually before the Commission for its review in this proceeding, is the one containing the IPA's post-comment revisions; the Commission's role prior to that filing is limited.

Section 16-111.5(d)(3) of the Public Utilities Act, 220 ILCS 5/16-111.5, provides, in part, "Within 5 days after the filing of the procurement plan, any person objecting to the procurement plan shall file an objection with the Commission."

Under Section 16-111.5(d)(3), "The Commission shall enter an order confirming or modifying the plan within 90 days after the filing of the plan . . . ." The Plan was filed on September 30, 2009; thus, the deadline is December 29, 2009.

Under Section 16-111.5(d)(4), "The Commission shall approve the procurement plan, including expressly the forecast used in the procurement plan, if the Commission determines that it will 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."

Section 16-111.5(e) specifies the major components to be included in the procurement process. Section 16-111.5(e)(4) provides that the procurement administrator shall design and issue a request for proposals ("RFPs") to supply electricity in accordance with each utility's procurement plan, as approved by the Commission. The RFPs "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."

Section 16-111.5(f) provides in part:

> Within 2 business days after opening the sealed bids, the procurement administrator shall submit a confidential report to the Commission. The report shall contain the results of the bidding for each of the products along with the procurement administrator's recommendation for the acceptance and rejection of bids based on the price benchmark criteria and other factors observed in the process. The procurement monitor also shall submit a confidential report to the Commission within 2 business days after opening the sealed bids. The report shall contain the procurement monitor's assessment of bidder behavior in the process as well as an assessment of the procurement administrator's compliance with the procurement process and rules.

It further provides, "The Commission shall review the confidential reports submitted by the procurement administrator and procurement monitor, and shall accept or reject the recommendations of the procurement administrator within 2 business days after receipt of the reports."

II. PROCEDURAL HISTORY

On September 30, 2009, pursuant to Section 16-111.5(d)(2) of the Public Utilities Act, the IPA, after reviewing the comments received, filed with the Commission, for approval, its procurement plan ("IPA Plan, "Plan" or "filed Plan") with regard to securing electricity commodity and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company ("ComEd"), Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP, (the three Ameren utilities are sometimes jointly referred to hereinafter as the "Ameren Illinois Utilities," "AIU" or "Ameren").

Petitions for leave to intervene in this proceeding were filed by ComEd, AIU, Ameren Energy Marketing Company, the Citizens Utility Board ("CUB"), Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. ("Constellation"), the People of the State of Illinois (the "AG" or “the People”), the Illinois Wind Energy Association ("IWEA"), Wind on the Wires ("WOW"), the Environmental Law & Policy Center ("ELPC" and jointly with WOW, "WOW/ELPC"), Iberdrola Renewables, Inc. ("Iberdrola"), Exelon Generation Company, LLC ("ExGen"), the Retail Energy Supplier Association ("RESA"), WM Illinois Renewable Energy, L.L.C. (“WMILRE”) and WM Renewable Energy L.L.C. ("MWRE") (jointly, "WMRE/WMILRE"), Illinois Competitive Energy Association ("ICEA"), and Invenergy Wind LLC ("Invenergy"). Dynegy Inc. filed an appearance in this proceeding.

Pursuant to Section 16-111.5(d)(3) of the PUA, which allows five days for objections to the Plan, objections to the IPA's procurement Plan were filed by ComEd, AIU, the Staff of the Commission ("Staff"), ExGen, and Constellation.

On November 3, 2009 the Commission determined pursuant to Section 16-111.5(d)(3) of the PUA that no hearing in this matter was necessary in this proceeding.

By ruling, parties were given leave to file responses to objections by October 16, 2009. Responses to the various Objections were filed by a number of parties, including the AG, RESA, ComEd, Staff, WOW/ELPC, ICEA, Invenergy, ExGen, IWEA, and the IPA.

Parties were also given leave to file replies to responses on October 26, 2009. Replies to Responses to Objections were filed by various parties, including the AG, Iberdrola, WOW, ICEA, IWEA, ExGen, AIU, ComEd, Staff, WMILRE and the IPA.

On October 28, 2009, APX, Inc. ("APX") filed a petition to intervene. Also on October 28, 2009, APX comments on the Draft Power Procurement Plan filed by the IPA with the Commission on August 17, 2009; however, the comments from APX were submitted well after the statutory deadline, and could not be considered by the IPA in the preparation of its filed Plan.

On October 30, 2009, Tenaska Taylorville, LLC ("Tenaska") filed a petition to intervene and a "Response to the Illinois Power Agency's Procurement Plan filed September 30, 2009." It is observed, however, that the statutory deadline for filing objections or responses to the filed Plan was October 5, 2009. Tenaska's Response to the filed Plan was not filed in compliance with the statutory deadline, or for that matter with any other applicable schedule, and was not accompanied by a motion for leave to file late or out of time. The substantive findings in this order will not be based on that Tenaska filing; to do so would be unfair to other parties adversely affected by it.

On November 2, 2009, the parties were notified that certain question were posed by Commissioner Elliott and that they were allowed until November 6, 2009 to provide responses to the those questions. Responses were filed by several parties.

On November 9, 2009, the IPA filed a Motion to File Supplemental Recommendations for the Procurement Plan that were attached to the motion as

Appendix K. Parties were given leave to file responses on November 13, 2009 to the IPA's filing, as well as replies to responses. The motion, as well as the supplemental recommendations, was supported in responses filed by the AG, ComEd, AIU, and ExGen. Staff did object to the motion or supplemental recommendations, but did express certain concerns. WOW, ICEA, IWEA and APX filed responses describing concerns with the motion or the substance of the IPA's supplemental recommendations. Replies to responses were filed by the AG, ComEd, the IPA, WOW and ExGen. The parties' positions regarding this issue are discussed in detail later in this Order.

A proposed order was issued by the Administrative Law Judge. Briefs on exceptions ("BOEs") were filed by the IPA, AIU, ComEd, the AG, WOW, ICEA and Staff.

III. OVERVIEW OF THE IPA'S PROPOSED PROCUREMENT PLAN

This section of the order describes the IPA's Plan as filed on September 30, 2009, after receipt by the IPA of comments from others. Proposed modifications to the Plan are described later in this order.

According to the IPA, the purpose of the Plan is to detail a procurement approach that will secure electricity commodity and associated transmission services, plus required renewable energy assets, to meet the supply needs of eligible retail customers served by ComEd and AIU. The Plan outlines a procurement strategy for the period of June 2010 through May 2015 based on detailed 5-year demand forecasts. Because existing contracts are in place for a significant portion of the load needed to meet consumers' electricity needs over the next several years, the IPA states that procurement under its auspices will initially be limited to meeting residual consumer demand not covered by existing contracts. The IPA provides a table, reproduced below, which illustrates the annual percentages of bundled service loads that are anticipated to be procured pursuant to IPA plans over a 60-month horizon. IPA Plan at 1.

Procurement Period	ComEd	AIU
2010 - 2011	26.87%	26.82%
2011 - 2012	33.14%	49.11%
2012 - 2013	33.86%	69.50%
2013 - 2014	100.00%	100.00%
2014 - 2015	100.00%	100.00%

The IPA believes that what it describes as a "laddered approach" to procurement using a Request for Proposals ("RFP") bid process will provide the highest probability of cost stability and "at-the-market prices" for electricity. According to the IPA, the lowest price risk scenario is achieved when the portfolio is procured relatively evenly over three years, the current period for which the IPA says there is sufficient liquidity in wholesale energy markets. The IPA asserts that procurement distributions ranging between 20% and 40% continue to deliver a sufficient propensity to mitigate price risk for consumers. According to the IPA, because future market conditions cannot be known, it proposes loads to be procured in each of the three years prior to the delivery month. Within this range, the IPA says modeling determined that the following three-year laddered procurement strategy has the highest probability of yielding the lowest and most stable prices, based on current market conditions:

- 35% of projected energy needs procured two years in advance of the year of delivery;
- 35% of projected energy needs procured one year in advance of delivery;
- 30% of projected energy needs procured in the year in which power is to be delivered.

In a change from the last procurement cycle, the IPA proposes to consolidate the procurement of renewable energy resources for ComEd and AIU under a single procurement event. Another change proposed by the IPA is to conduct formal solicitations for capacity in the both the ComEd and AIU service regions, and to open those solicitations to qualified demand response providers, which the IPA says is consistent with Section 16-111.5(b)(3)(ii) of the PUA. *Id.* at 2.

For the upcoming procurement cycle, the IPA proposes to conduct a separate capacity procurement event to be limited to demand response providers only in the event that no demand response providers participate in the standard capacity procurement described above, which the IPA says is changed from last year. The IPA indicates that the purpose of the separate capacity procurement will be to develop contract terms and conditions that will provide incentives for the development of demand response programs that meet the stated requirements of Section 16-111.5(b)(3)(ii) of the PUA.

In a final change from last year, the IPA proposes to conduct solicitations for long-term supply contracts from renewable energy providers that are cost-of-generation based, and take full advantage of federal and state incentives that are available in the near term. *Id.*

The IPA asserts that its greatest challenge is to achieve low and stable prices when acquiring electricity in a market where prices change constantly and sometimes dramatically, particularly when the load to be served is also subject to constant flux. The IPA states that designing the portfolio requires understanding the variables that drive price and load fluctuation, and assessing how those variables affect price risk. After completing its portfolio design exercise and examining the 2008 and 2009 procurement plans approved for ComEd and AIU, the IPA proposes a series of standard electricity products to be acquired to meet the needs of eligible customers that would be augmented by market purchases if and when necessary. *Id*.

The IPA points out that Section 16-113 of the PUA provides for generation services to be declared competitive for classes of customers when the Commission finds sufficient evidence of competition to meet legal standards and that certain classes have been declared competitive as a matter of law under Section 16-113. The IPA states that all ComEd commercial and industrial ("C&I") customer classes with demand greater than 100 kilowatts ("kW") are deemed competitive, as are AIU customers with demand of at least 400 kW. According to the IPA, the statute allows ComEd customers with demand below 400 kW, and AIU customers with demand between 400 kW and 1 megawatt ("MW"), to continue to purchase power and energy from the utility through May 31, 2010, provided that no customer in a class that has been declared competitive is allowed to return to bundled utility service after having switched to an alternative provider. The IPA states that after that date, ComEd and AIU will procure power for a customer in a class deemed competitive only by purchasing electricity in the hourly spot market and passing through those variable market prices to customers. *Id.* at 5.

The IPA says its procurement Plan will be designed to accommodate the electricity needs of all customers who continue buying bundled service electricity from ComEd and AIU. The IPA states that for the months of April 2009 and May 2009, 44% of the combined total electricity usage of ComEd and AIU customers was supplied through fixed price bundled utility service. This is the load that will be served through IPA procurement planning. The IPA states that according to reports filed by ComEd and AIU with the Commission, 99.8% of ComEd and 99.5% of AIU residential customers remain on bundled rates. *Id*.

The IPA indicates that it must submit a Plan each year identifying projected loads for "eligible retail customers," and a plan for fulfilling those load requirements. Section 16-111.5 of the PUA, defines "eligible retail customers" as:

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

IV. LOAD FORECASTS

The IPA states that pursuant to Section 16-111.5(d)(1) of the PUA, on July 15, 2009, ComEd and AIU prepared and submitted to the IPA separate load forecasts. The IPA adds that it requested, and ComEd and AIU also provided, detailed descriptions of the statistical methods and assumptions underlying the projections. The IPA indicates that it has not independently validated the load forecast models and results provided by ComEd and AIU. Copies of ComEd's and AIU's load forecast submittals are included in Attachment A and C to the IPA's Plan. IPA Plan at 10.

The IPA says it relied on load forecasts from the ComEd and AIU as best estimates for future consumption factored for the largely unknown variable of retail switching. According to the IPA, the creation of the Office of Retail Market Competition within the Commission, and the passage of legislation to facilitate retail competition, indicate the potential for significant changes in retail switching among eligible retail customers. Since ComEd's and AIU's data projections are updated annually, the IPA states that it will readjust load projections should retail switching exceed ComEd and AIU's projections. The IPA says that for the purpose of this load projection readjustment, a difference will be deemed to be significant if the adjustment would result in a 200 MW or larger change in the supply quantity. The IPA says this readjustment will be based on the impact of retail switching among eligible retail customers based on Commission generated reports.

According to the IPA, the ultimate goal of the forecasts is not to identify the combined load of all customers of ComEd and AIU; rather, it is to identify the load requirements of the “eligible retail customers” for ComEd and AIU. *Id*.

A. ComEd's Load Forecast

According to the IPA, the ComEd customer classes declared competitive by the PUA include those customers with demand greater than 100 kW. Customers with demand of greater than 100 kW are no longer eligible for bundled service and are not included in the load forecasts. IPA Plan at 12.

The IPA indicates that ComEd utilizes a forecasting process based on econometric models that produce monthly sales forecasts for primary customer classes including: Residential, Small C&I and Large C&I. The IPA states that those base monthly forecasts are normalized for primary load variables (weather, economic growth, population, etc.) and combined with the hourly models to obtain on-peak and off-peak quantities for each month and each delivery service class. The IPA indicates that ComEd's statistical models are measured for accuracy against past period consumption volumes for each customer class. According to the IPA, comparisons between predicted and actual consumption volumes are highly correlated and are the best models available for forecasting loads for the eligible retail customers. *Id.* at 13.

The IPA states that forecasted portfolio volumes are generated by altering model variables within expected ranges and examining model outputs. According to the IPA, resulting High, Expected, and Low volume scenarios are generated, and it has selected the Expected Load Model as the basis of the procurement Plan for the ComEd portfolio. *Id*.

Section 8-103(c) (referred to by the IPA by its old number, Section 12-103) of the PUA establishes specific requirements for utility company Demand Response Programs. Section 16-111.5(b) of the PUA requires that the procurement Plan shall include an analysis of the impact of demand side initiatives established by Section 8-103(c) of the PUA. The IPA states that those demand side initiatives include the impact of demand response programs (both current and projected) and the impact of energy efficiency programs (both current and projected). *Id.* at 12, 13.

For the purpose of projecting loads for this year's Plan, the IPA assumes that each utility intends to implement demand response programs sufficient to achieve their targeted peak reductions. Based on ComEd's analysis, the IPA says the effective aggregated reduction in ComEd's maximum system load requirements for eligible retail customers due to demand response programs is projected to be 32.8 MW in 2010, 43.3 MW in 2011, 53.9 MW in 2012, 64.8 MW in 2013, and 75.7 MW in 2014. As stated previously, Section 8-103(b) of the PUA also establishes specific requirements for energy efficiency programs that reduce energy consumption of delivery services customers by 0.2% in 2008 planning year and by an additional 0.2% each year through 2012, growing to a total decrease in energy consumption of 1.8% in 2013. The IPA indicates that the annual aggregate reductions in ComEd's supply requirements to be acquired through the RFP process (net of customer switching) is projected to be: 347.4 gigawatt-hours ("GWh") in 2010, 600.3 GWh in 2011, 933 GWh in 2012, 1,309.5 GWh in 2013, and 1,687.2 GWh in 2014. *Id.* at 13-14.

According to the IPA, an analysis of the accuracy of the usage projections generated by ComEd for the 2008-2009 planning period indicates that, adjusted for weather, the ComEd load forecasting methodology was accurate within -5.5% of actual recorded consumption by the portfolio.

B. Ameren Illinois Utilities' Load Forecast

The IPA states that AIU's five-year hourly load forecast identifies load projections for eligible retail customers. As noted above, eligible retail customers include residential and other customers who are entitled to purchase electricity from AIU under fixed-price bundled service tariffs.

AIU, the IPA says, utilizes a statistically adjusted end-use model as the basis of its load forecasting process. The IPA adds that after adjusting consumption data for weather, seasonal variables and economic conditions, a detailed core consumption model was developed. According to the IPA, AIU's statistical models are measured for accuracy against past period consumption volumes for each customer class. The IPA says comparisons between predicted and actual consumption volumes are highly correlated and are the best models available for forecasting loads for the eligible retail customers. IPA Plan at 11-12.

Forecasted portfolio volumes, the IPA adds, are generated by altering model variables within expected ranges and examining model outputs. The IPA indicates that the resulting High, Expected, and Low volume scenarios are generated. The IPA selected the Expected load model as the basis of the procurement Plan for the AIU portfolio. The IPA states that because the PUA declares retail customers with peak demand of 1000 kW and above to be competitive as of May 2008, the Plan does not include those volumes.

As previously noted, the PUA also declares electricity supply to all AIU customers with demand above 400 kW to be competitive. As a result, customers above

400 kW taking service from an alternative retail electric supplier ("ARES") as of or who subsequently switch to an ARES, are no longer eligible to take bundled service under tariffs offered by AIU. Further, those customers above 400 kW who continue to receive bundled utility service will be placed on the AIU tariff Rider HSS (Hourly Supply Service) if they do not choose to take service from an ARES by June 1, 2010. The IPA's plan, therefore, does not include these volumes. *Id.* at 12.

For the purpose of projecting loads for this year's Plan, the IPA indicates it has included the impacts of demand response programs based on the AIU's analysis of the current and projected programs. Based on AIU's analysis, the IPA says the effective reduction in AIU's maximum system load requirements for eligible retail customers due to demand response programs is projected to be: 4 MW in 2010, 13 MW in 2011, 17 MW in 2012, 21 MW in 2013, and 24 MW in 2014.

The IPA has also included the impacts of AIU's energy efficiency programs based on its analysis of the current and projected programs. The annual incremental reductions in AIU's supply requirements to be acquired through the RFP process (net of customer switching) is projected to be: 103.9 GWh in 2010, 132.3 GWh in 2011, 161.53 GWh in 2012, 220.5 GWh in 2013, and 274.6 GWh in 2014. *Id.* at 12.

The IPA reports that an analysis of the accuracy of the usage projections generated by AIU for the 2008-2009 planning period indicates that, adjusted for weather, the AIU load forecasting methodology was accurate within 0.235% of actual recorded consumption by the portfolio. *Id.* at 13.

V. PORTFOLIO DESIGN

The IPA is responsible for developing and implementing a plan to secure electricity supplies for eligible retail customers for ComEd and AIU. Citing Section 16.111(d)(4) of the PUA, the IPA contends its priorities for the portfolio design are: " . . . to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."

The IPA indicates it must arrange purchases of electricity from the wholesale market in a manner that accommodates both changing prices and load requirements. The IPA claims that designing the portfolio requires an understanding of the variables that drive price and load fluctuation, and the extent to which those variables can affect price. The IPA says one such factor is risk. For the purposes of the IPA's analysis and planning, risk is defined as any market condition or internal and external processes that have the potential of raising prices or increasing their volatility. IPA Plan at 16.

A. Risk Assessment

According to the IPA, Section 16-111.5 of the PUA identifies the primary categories of risk exposure to the portfolio when it requires the IPA to include in the Plan the following:

> "an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the following factors: contract terms, time frames for securing products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment; the proposed procurement plan shall also identify alternatives for those portfolio measures that are identified as having significant price risk."

The IPA asserts that the Portfolio is exposed to price risk on two levels: (1) long-term cost trend risk, and (2) short-term clearing risk. The IPA says the average upward movement of electricity prices is due to rising costs for multiple elements in the electricity sector: fuel costs, capacity costs, transmission costs, and the cost of plant additions and construction all put upward pressure on future prices for electricity. The IPA states that the ability to enter the market with some flexibility as to timing enhances the dollar-cost averaging approach to procurement and can slow the long-term upward price trend.

Short-term clearing risk, the IPA avers, occurs when excess electricity purchased on behalf of the Portfolio is not used and is sold back to the market at a loss, or when electricity above the projected volumes is required, and additional volumes must be purchased from the market at spot prices that might be high relative to the average price of electricity already secured for the Portfolio. In the IPA's view, short-term risks can be mitigated by arranging procurement events as close to the expected load volumes as possible. Additionally, the IPA recommends some oversubscription of electricity for the peak periods of July and August. The IPA asserts that historically, July and August have the highest potential to generate instances of forced buying in high spot markets. (IPA Plan at 16-17)

According to the IPA, the Portfolio is exposed to load uncertainty risk due to inelasticity of demand among many portfolio participants, and the unknown pace of migration of eligible customers to ARES over time. The IPA states that consumption by bundled service customers is relative inelastic, meaning that usage of electricity does not diminish significantly when prices are high, in part because customers are not directly exposed to these prices. The IPA says inelasticity of demand represents risk insofar as portfolio participants who do continue to use large volumes of electricity when prices are high (e.g., running air conditioning units during hot summer afternoons) do not carry the full direct cost of their usage. Instead, the IPA says the cost of their consumption during high cost periods is averaged across the entire portfolio. The IPA believes it does not presently have tools with which to address this issue. The IPA suggests this could be addressed, in part, by changing utility rate structures so that individual ratepayers are exposed to the real costs of consumption during peak cost periods, or conversely, are rewarded for reducing demand during system peaks. The IPA further suggests that implementation of demand response programs and the advent of "Smart Grid" systems may provide effective tools to address the need to reshape loads. *Id.* at 17.

The IPA also asserts that unpredicted migration to ARES presents some level of risk to the Portfolio insofar as migration can cause cost spiraling under certain conditions. The IPA posits a scenario where a high percentage of anticipated long-term load requirements for the IPA portfolio were secured with fixed volume contracts and market prices decreased in the future. In such a situation, the IPA claims higher-than-market bundled rates would motivate switching by those customers who could be profitably served by ARES at the relatively lower market prices. The IPA states that as the number of bundled service customers eroded, those remaining on bundled rates would effectively be paying not only for the cost of their consumption, but also the costs of disposing of the volumes secured for customers who have switched to other suppliers. The IPA claims that over time, bundled-rate customers could see high rate volatility, as well as, potential inverse market price signals (bundled rates would be rising while market prices were falling). For this reason, the IPA believes that laddering-in purchases over time enables the IPA to minimize risk for consumers by allowing the IPA to adjust procurement volumes in response to changing customer needs and market conditions.

According to the IPA, contract terms present risk to the portfolio to the extent that the underlying credit requirements for the bidders and the utility may increase costs that are ultimately borne by the end-use customer. The IPA says contracts entered into as a result of the procurement process will be through either an International Swaps and Derivatives Association ("ISDA") agreement for financial instruments such as fixed/floating rate swaps or an Edison Electric Institute ("EEI") agreement for physical products such as energy or capacity. Individual transactions will be memorialized utilizing standard transaction specification sheets, such that, to the extent practicable, purchasing decisions will be made on the basis of price, rather than non-price factors. *Id.* at 17.

Time frames for securing products and services, the IPA avers, present risk to the portfolio insofar as the underlying volatility in electricity markets places a premium on time. The IPA asserts that particular risks in this area are the annual planning cycle, time between procurement events, and time between bid and contract execution. According to the IPA, the present schedule yields a procurement event that occurs as many as nine months after load projections are made and eight months after the initial Plan is developed. The IPA states that changes in loads due to retail switching and other factors, and changes in market conditions during that extended period, could limit the value of the forecasts and expose customers to risk. *Id.* at 17-18.

The IPA indicates that the PUA allows a period of four business days for review of the bids submitted during the procurement event (two business days for the Procurement Administrators and Procurement Monitors to submit reports, and two business days for the Commission to review and consider the reports). The IPA says the time lag between the submission of wholesale electricity bids and their acceptance creates risk for bidders, which translates into higher costs for consumers. In order to lay off the potential liability in the event that market prices rise between the time a bidder submits a bid and the contract is executed, the IPA says bidders may purchase five-day option contracts to guarantee the price they submit to the IPA. According to the IPA, the insurance has a premium, and that premium is embedded in the bid price of the electricity. *Id.* at 18.

The IPA states that a five-day option premium is estimated to cost between $1.40 and $1.60/megawatt-hour ("MWh"). If underlying volatility increases in the market (e.g. loss of baseload generating units), or if market prices increase generally (e.g. carbon tax costs are levied), then the IPA claims premium costs will increase. As the volumes of electricity purchased through the IPA process increase over time due to the expiration of legacy supply contracts, the IPA asserts that the total cost premiums built into wholesale bids increase. Over the next three procurement cycles, the IPA estimates the total cost of the embedded premiums to exceed $166 million.

To mitigate this risk, the IPA recommends that review processes be abbreviated and automated to an extent that allows for approval of bids to occur on the same day they are submitted. The IPA recommends that the Commission, its procurement monitor, and the procurement administrator work together to devise a timely process to address this risk while maintaining appropriate oversight functions, and detail any revisions in the process to bidders in the relevant RFPs. *Id*.

Fuel costs, the IPA states, present risk to the portfolio insofar as fuel costs are the primary drivers of generation costs. Even more important, in the IPA's view, is the effect on market prices of rising fuel costs when they occur in a market such as the PJM Interconnection ("PJM") or Midwest Independent Transmission System Operator ("MISO"), in which market clearing prices are set by the marginal producer. The IPA states that natural gas fueled plants are the marginal producers during the summer months in both the PJM and MISO regions, while coal fueled plants are the marginal producers for the majority of hours in PJM and MISO. The IPA avers that electricity market prices incorporate fuel price risk. According to the IPA, mitigation options outside of the proposed portfolio design would have limited utility as the Portfolio Design is geared towards mitigating general electricity price risk. However, the IPA suggests that renewable energy resources that have zero fuel costs, such as wind power, can be cost-effective hedges against rising fuel costs for conventional resources. *Id.* at 19.

The IPA asserts that weather patterns present risk to the portfolio because weather-related changes in demand and supply correlate with spot prices. Particular risks, the IPA states, include the possibility of having to sell electricity contracted for at relatively high fixed prices at a time of low spot market prices, or in the opposite case, having to purchase extra volumes at high spot prices. The IPA avers that electricity consumption is highly correlated to weather (e.g. hot summer temperatures drive up summer cooling load). If mild summer weather were to reduce regional cooling loads, the IPA indicates spot prices for electricity would drop. With mild weather effectively reducing demand for electricity, the IPA says consumption would drop below projections based on average temperatures. The IPA suggests that excess energy procured through block contracts would have to be sold back into the market, likely at a price lower than what was originally paid and the resulting financial losses would be applied against the portfolio.

If warm summer weather were to increase regional cooling loads, the IPA says spot prices for electricity would rise. With warmer weather effectively increasing demand for electricity within the portfolio, the IPA suggests consumption would increase above projections that were based on an assumption of marginally lower average temperatures. The IPA states that excess energy would need to be procured from the spot market to meet portfolio requirements, likely at a price higher than what was paid for fixed price purchases executed through the standard procurement process and the resulting increased costs would be applied against the portfolio.

According to the IPA, oversubscription for peak hours in the July and August delivery periods has been used to mitigate weather risk in the last two procurement plans. However, the IPA claims that analysis of the results of this approach over the past two years indicates that the strategy has cost consumers more than what it has saved. Therefore, the IPA proposes to procure at the 100% subscription level for all months in this Plan. (IPA Plan at 19) On this issue, the Commission observes that the IPA subsequently clarified its position; its current intent is to hedge at the 110% subscription level for the July and August delivery periods, as discussed below.

The IPA observes that AIU operates in the MISO, while ComEd operates in PJM. According to the IPA, risks associated with these markets are new transmission asset related costs, and higher integration costs associated with wind energy developments. The IPA states that recent projections indicate plans for billions of dollars in transmission investments in the MISO and PJM regions. The IPA avers that some of the transmission system upgrades propose to extend transmission between wind generating regions in the western spans of the MISO region and larger population centers in the eastern reaches of MISO as well as PJM. According to the IPA, existing and future transmission costs are already being borne by MISO and PJM participants via tariff. *Id.* at 19.

The IPA also suggests that the rapid development of wind-based renewable electricity generation in the PJM and MISO regions will likely cause upward pressure on transmission costs because wind facilities tend to be in remote locations that may not have adequate existing transmission to bring power to load centers. In addition, the IPA says system operators will need to alter system operations to accommodate the intermittent nature of wind energy. According to the IPA, estimates of costs relative to integrating wind assets into regional transmission portfolios range from as low as

$2.11/MWh for 15% wind penetration within the portfolio to $4.41/MWh for a penetration level of 25%. The IPA says some of these costs may be offset by contributions of wind assets towards system reliability and other ancillary services. The IPA believes it is limited in its ability to mitigate these risks outside of factoring them into cost modeling over the longer range horizon and seeking offsetting cost avoidance elsewhere within the portfolio. The IPA observes, however, that transmission cost allocation is a subject of federal regulation and any changes in transmission costs will likely be borne by all customers regardless of supplier. *Id.* at 19-20.

The IPA states that market conditions generally relate to the drivers of market prices, customer usage, and customer switching levels. The IPA claims these variables are included in the statistical modeling conducted by the IPA relative to the portfolio design.

The IPA believes its analysis provides a reasonable representation of the significant risks associated with the June 2010 – May 2011 horizon, and that its Plan provides reasonable protection for customers from likely risk factors. As a result, given the guidance provided under the PUA, the IPA does not recommend an alternative to its recommended portfolio. *Id.* at 20.

According to the IPA, the advent of federal legislation that proposes to apply a comprehensive national “Cap and Trade” system for the regulation of greenhouse gas emissions represents a new price risk for the IPA portfolio. While estimates vary, the IPA says a recent report to the National Association of Regulatory Utility Commissioners ("NARUC") by Synapse Energy Economics Inc. projects a ratepayer cost impact range of between $0.94 and $13.12/MWH with the variance explained by uncertainty as to how credit allocations are applied in the final regulatory scheme. *Id.* at 20.

To mitigate this risk to consumers, the IPA proposes to include energy from renewable energy resource providers into the portfolio as a hedge against the higher market costs expected as a result of greenhouse gas regulatory structures. The IPA states that renewable energy generation assets typically generate power at costs higher than those available in the market today, and are generally developed only when supported by longer term power purchase agreements. The IPA recommends soliciting proposals from renewable energy providers under longer term contracts with ComEd and AIU. *Id.* at 20.

The IPA also suggests that substantial federal and state assistance in the form of various subsidies are available to offset a portion of the premiums associated with such providers. The IPA recommends taking advantage of the current financial climate to issue solicitations for longer term renewable energy supply contracts. Assuming bid prices are acceptable when compared to a market benchmark developed by the IPA in consultation with the Commission, the IPA says deliveries of energy would likely begin sometime during the 2011-2012 planning year. According to the IPA, target volumes for AIU would range around 600,000 MWh per year and 140,000,000 MWh per year for

ComEd, representing approximately 3.5% of annualized load volumes for each utility. *Id.* at 20.

The IPA says that as some renewable assets are variable in their output (wind, hydro, and solar), the IPA recommends that the laddered volumes of traditionally sourced energy contracts specified in this Plan noted as "Short term portfolios" be maintained, and that future procurement plans be adjusted to reflect the output realities of the renewable assets selected (if any) in the 2010 renewable energy solicitations. *Id.* at 20.

B. Modeling Approach

According to the IPA, the options for electric energy products fall into two general categories: fixed price and variable price products. The IPA states that fixed price products allow the purchase of known volumes of electricity to be delivered at some time in the future at a set price. Forward purchases, futures contracts, swaps, and options are examples of fixed price products. The IPA adds that fixed price products offer price certainty, but may turn out to be relatively costly if the market price drops prior to delivery, or if too much power is purchased and the excess must be sold back to the market at a loss. (IPA Plan at 21)

The IPA states that variable price products allow the purchase of electricity at prices set by supply and demand for electricity at the time of consumption. The IPA says locational marginal prices (“LMP”) provided through regional transmission organizations (“RTO”) are the basis of variable price products in organized wholesale markets. Variable price products, the IPA states, offer the ability to buy only the amount of electricity needed at any moment, but may turn out to be relatively costly if high market prices exist at the time of usage. *Id.* at 21.

The IPA asserts that in order to manage procurement for a variable population with uncertain loads in an unpredictable market, its Plan utilizes methods similar to those used by investors to manage market portfolio risks. According to the IPA, the Plan begins by first defining the portfolio and potential risks; then identifying measures that will mitigate those risks; and finally, measuring the relative effectiveness of the risk management measures. The IPA says the risk profile of its proposed portfolio changes over time. Accordingly, the IPA indicates it will be making process improvements that allow for continuous monitoring and annual adjustments to the portfolio strategy as each Plan is developed. *Id*.

Next, the IPA discusses the premises upon which it constructed its portfolio and risk management approach, beginning with physical and financial product parity. According to the IPA, a physical product is one in which the contract requires furnishing of a specified volume of electricity under the terms and conditions of the contract. A financial product, the IPA says, is an agreement to guarantee the price for a specified volume of electricity. The IPA views prices for physical electricity products to be equivalent to financially based electricity products, insofar as suppliers of physical products price offers based on forward price curves determined in futures markets.

The IPA views existing forward markets as providing sufficient liquidity to assure price competition for up to three years. The IPA believes that trading volume in the periods greater than three years into the future are presently insufficient to assure that observed prices are available, reliable, and representative. According to the IPA, past market performance with regard to price volatility, trending, and correlations is the basis of the assumptions incorporated into IPA modeling and evaluations. *Id.* at 21.

The IPA indicates that it used three metrics to identify price risk:

- Metric A: Year-over-Year Price Variance – the extent to which prices change from one year to the next,

- Metric B: Mark-to-Market Price Variance – the extent to which prices agreed to in prior years vary from index prices in the current market, and

- Metric C: Longitudinal Variance – the extent to which prices in the latter years of a plan vary from current futures market prices.

To establish a model Portfolio for ComEd and AIU, the IPA indicates that a Monte Carlo model using Excel® and Crystal Ball® was developed and applied to each utility's respective load projections to illustrate the trade-offs between risks and benefits associated with different procurement approaches and ratios of Forward and Index purchases. The IPA asserts that with efficient market prices, all portfolios should have the same expected value; however, price stability (measured as standard deviation) can vary. The IPA says that to evaluate the price stability of the different portfolios, volatility in the three price metrics was measured and combined to generate a composite risk metric for use in the evaluation. The composite metric that the IPA created is the square root of the average of the average (A) Year-over-Year Price Variance, (B) Mark-to-Market Price Variance, and (C) Longitudinal Variance. *Id.* at 21-22.

According to the IPA, a set of potential portfolios was evaluated with model runs of 5,000 iterations against the risk metric defined above. There are three main sections to the model, the first of which is the price section. In the price section, the IPA indicates that the model uses monthly forward peak and off-peak New York Mercantile Exchange ("NYMEX") pricing through 2013 as of August 10, 2009. The IPA views NYMEX as an appropriate indicator of future prices in the nearer term where market liquidity is sufficient to generate pricing competition. For periods after 2012, the IPA says the monthly prices indicated on the NYMEX for those periods were escalated at 2% per year to account for market unknowns.

To test how each portfolio will perform under various market conditions, the IPA says forward price curves are assumed to vary over time. According to the IPA, prices for forward energy products are highly volatile, meaning that the price observed today for a product may be quite different than the price of that same product when observed at some point in the future. The IPA asserts that analyses of the historical movements in prices of the front end of the forward energy curve reveal annualized volatilities of 24% and 18% for peak and wrap contracts, respectively. The IPA claims these volatilities include changes in prices due to all factors, including fuel price movements. The IPA says market price volatility was selected as the appropriate representative of market price risk as ComEd and AIU do not own generation and therefore cannot control significant variables such as fuel expense. *Id.* at 22.

The IPA says price movements in delivery periods beyond the first year of the forward curve were modeled to move proportionately to movements of the first year but with somewhat lower volatility. According to the IPA, the magnitude of these proportional movements is based on an historical analysis of how prices in years 2-6 of the forward curve moved relative to the magnitude in movements in the price of the first year of the forward curve. Consequently, the IPA says the forward prices in the analysis move together but with a muted effect as one goes out in time.

In the IPA's view, the process captures how the forward curve moves between annual procurement processes that are assumed to occur each March. The IPA says the model then uses the same annual volatility estimates to estimate potential price movements from the March procurement date until the future delivery month. Once forward prices are estimated for each month as of the beginning of the month (i.e. the close of the forward product), the IPA indicates that monthly spot prices are then developed based on the historical volatility observed between the price of the forward at the beginning of the month and the realized average spot price observed for each month. *Id.* at 22.

The second main section of the model relates to estimated load requirements. The IPA avers that as market prices are uncertain and will deviate from estimates, so too will the actual supply required by eligible customers deviate from even the best forecast. To capture this risk, the IPA indicates that the model starts with the base load estimates for eligible retail customers supplied by ComEd and AIU on July 15, 2009 and then allows the Monte Carlo simulation to vary the loads based on both weather and non-weather (economy and retail switching) factors. The IPA says the model assumes a triangular distribution for the loads based on the high/low load forecasts supplied by ComEd and AIU. *Id.* at 22.

According to the IPA, for each month for both peak and non-peak (wrap) periods, the model takes the included load for the scenario and estimates the net open requirements by subtracting (1) the load previously awarded through the auction process and (2) the amount hedged through the swap arrangements. In addition, the IPA says the model does allow for the adjustment of the amount purchased for summer (July and August) and non-summer periods to investigate whether procuring more or less than 100% of net open requirements would reduce a model portfolio's risk. *Id.* at 23.

The IPA indicates that the last major section of the model estimates the average cost to serve the included customers. For each iteration, the model sets a random load and price based on the distributions and correlations. According to the IPA, the model then estimates the effective cost associated with the swap contracts (price and quantity fixed), the cost of any RFP purchases, transmission costs for ancillary services and capacity and finally, the cost associated with any spot purchases or sales to balance the procured quantities with those actually required. A blended portfolio price is calculated for each iteration and at the end of the run a distribution of potential outcomes is presented.

According to the IPA, a key factor in the analysis is the cost associated with the load shape that results from customers using relatively more energy when prices are high and relatively less energy when prices are low. The IPA says this relationship between expected prices and expected demand generally has the effect of raising the cost to serve load above the level of the straight average price during a delivery period. Since the procurement Plan is using monthly block products that provide the same amount of energy every hour (i.e. not sculpted to match expected customer demand), the cost difference between supply provided by these block products and actual customer load profile is picked up through a price/load gross-up factor. *Id.* at 23.

The IPA provides a simple example of a price/load gross-up factor in which it assumes a world with three hours where the customer loads were typically 10, 20 and 30 MW and the corresponding prices $50, $100, and $150/MWh. The average load is 20 MW and the average price is $100/MWh. According to the IPA, since the price is highest when loads are highest, the actual average cost to serve the load is $116.7/MWh ((10*50+20*100+30*150)/60 or $116.7/MWh).

The IPA says that in this example, the load/price gross-up factor is 16.7% ($116.7/$100 – 1). Based on an analysis of historical monthly spot prices and loads, average monthly gross-up factors were estimated for both the peak and the wrap periods. For the peak period, the IPA says gross-up factors were approximately 10% in summer and 3% in other months. For the wrap period, the IPA says gross up factors were approximately 14% in summer and 6% in other months. The IPA states that the same historical analysis also shows these gross-up factors are highly variable over time. *Id.* at 23.

According to the IPA, the level of gross-up variability, and how strongly those variations are correlated to movements in price and load, can play an important role in determining the desirability of one model portfolio versus another. The IPA suggests that if the correlation is very strong (i.e. when changes in monthly spot prices are high the change in the gross-up factors are also high), the analysis would show that risk-minimizing hedge ratios would be higher than if the correlation were weak or non-existent. The IPA says a historical analysis of monthly gross-up factors, spot prices and loads suggests that any relationships between gross-ups and price, or between gross-ups and load, may be relatively weak. In the IPA's view, while this result may not be intuitive, on a daily basis, the correlation between prices and gross-up factors is fairly strong, but when gross-ups and price/loads are measured over monthly intervals, the strength of the relationship appears to diminish. *Id.* at 23.

C. Proposed Portfolio Design

The IPA claims the model was designed to help identify whether some portfolios may be superior to other portfolios when looking at specific risk metrics. For conceptual ease, the IPA separated portfolio characteristics into two categories: 1) the composition of the portfolio (i.e. what mix of products) and 2) the scale of the procurement (i.e. the volume purchased relative to the expected future load requirement). (IPA Plan at 23-24)

The IPA says several portfolio structures were tested in the model to help identify whether one was of relatively lower risk than the others when evaluated using the composite risk metric. The portfolio structures analyzed by the IPA ranged from all requirements being purchased in the RFP just prior to the beginning of the delivery period to all requirements being purchased three years in advance (the extent of assumed market price liquidity). The IPA says each of these portfolios was scaled to provide 100% of the expected load requirement so that scale effects could be disassociated from composition effects. (IPA Plan at 24)

For the portfolio structure analysis, the IPA indicates it focused on the 2012-2013 period. The IPA says it chose to look out this far to get past legacy contracts including the swaps which tend to distort near-term results in an attempt to illustrate the level of risk each portfolio would produce in a "Steady State."

According to the IPA, the lowest price risk scenario is achieved when the portfolio is procured relatively evenly over three years, the current period for which there is sufficient liquidity in wholesale energy markets. The IPA says that procurement distributions ranging between 20% and 40% per procurement cycle were determined to be relatively comparable in their capacity to mitigate risk. Because it believes future market conditions are unknown, the IPA proposes to employ a portfolio distribution schedule that allows between 20% and 40% of projected loads to be procured in each of the three years prior to the delivery month.

Within this range, the IPA asserts that acquiring 35% of projected energy needs procured two years in advance of the year of delivery; 35% of projected energy needs procured one year in advance of delivery; and 30% of projected energy needs procured in the year in which power is to be delivered would yield the lowest and most stable prices, based on current market conditions. The IPA describes this acquisition structure as a laddered procurement strategy. In the IPA's view, such a ladder provides a reasonable hedge while allowing sufficient flexibility in future procurement cycles to incorporate longer-term contracts for certain products should the planning process find that they are appropriate elements of the portfolio. *Id.* at 24-25.

The IPA contends that its analysis supports a recommendation of fixing the price of 30% of requirements in the procurement immediately prior to the delivery period, 35% one year earlier, and 35% two years earlier. The IPA suggests this 30/35/35 model portfolio is analogous to dollar cost averaging in investing. The IPA says this laddering of energy supply contracts does not apply to the purchase of renewable energy credits.

Given the high-level nature of its analysis, the IPA states that the 30/35/35 recommendation can be thought of as representative of a range of procurement portfolios that may have very similar risk profiles. The IPA believes that leaving 5-10% of the procurement uncovered (i.e., taking it to spot) does not significantly increase risk exposure to customers based on model results. However, because buying wholesale block products to meet the customer load shape already subjects ComEd and AIU to a significant amount of load balancing transactions in the spot market, the IPA does not recommend additional exposure to the spot market at this time. *Id.* at 25.

VI. APPLICATION OF PROPOSED PORTFOLIO DESIGN

The IPA explains how the power and energy will be procured for delivery from June 1, 2010, through May 31, 2013, for ComEd’s and AIU's eligible retail customers. (IPA Plan at 26, 43)

The IPA states that generally, the portfolio includes residential, commercial and industrial customers that have a peak demand less than 100 kW. For ComEd specifically, this includes customers from the following supply groups as defined in ComEd’s currently effective General Terms and Conditions:

- Residential Customer Group: the customer supply group applicable to any retail customer in the residential sector and using electric service for residential purposes.
- Watt-Hour Customer Group: the customer supply group applicable to any retail customer in the nonresidential sector, using electric service for nonresidential purposes, and for which no metering equipment or only watt-hour metering equipment is installed at the retail customer’s premises. Generally, a retail customer in this customer supply group uses less than 2,000 kilowatt-hours ("kWh") during a monthly billing period.
- Demand Customer Group: Beginning with 2008 monthly billing period, Demand Customer Group means the customer supply group applicable to any retail customer in the nonresidential sector, using electric serves for nonresidential purposes, and for which (a) the Self-Generating Customer Group is not applicable, (b) the Competitively Declared Customer Group is not applicable, and (c) demand metering is installed at the retail customer’s premises.
- Dusk to Dawn Lighting Customer Group: the customer supply group applicable to (a) any retail customer in the lighting sector and using electric service for a street lighting system that operates on a dusk to dawn basis, or (b) the portion of electric service provided to a retail

customer in the residential sector or nonresidential sector, located outside the City of Chicago, and using such portion for private, outdoor, fixture-included, dusk to dawn lighting purposes, provided that the Competitively Declared Customer Group is not applicable to the retail customer described in item (a) or (b).

- General Lighting Customer Group: the customer supply group applicable to any retail customer (a) in the lighting sector, (b) using electric service for a lighting system other than a lighting system that operates on a dusk to dawn basis, and (c) to which the Competitively Declared Customer Group is not applicable.

Id. at 43.

For AIU, the IPA says the portfolio includes residential, commercial and industrial customers that have a peak demand less than 400 kW. Specifically, the IPA indicates this includes customers from the following supply groups as defined in AIU's currently effective General Terms and Conditions:

- Residential (DS-1)
- Non Residential less than 150 kW (DS-2)
- Non Residential from 150 kW up to 400 kW (DS-3A)
- Lighting Service (DS-5)

Id. at 26.

The IPA's Plan provides that AIU will procure power under a single Procurement Plan, for the combined needs of its Illinois utilities. To the extent permitted by the applicable legal and regulatory authorities, the IPA states that AIU will jointly pool such resources for their mutual benefit, and that of their eligible retail customers. The IPA indicates that AIU will further allocate capacity and energy and cost responsibility therefore among themselves in proportion to their actual requirements. For purposes of determining such requirements, the IPA states that AIU will use either kilowatt-hours or kilowatts, as appropriate, to determine the ratio of the individual AUI utility's requirement to the total requirement. *Id.* at 39-40.

A. Supply Requirements

The IPA provides two tables, reproduced below, which includes the forecasted monthly supply requirements of ComEd and AIU for the period June 1, 2010 through May 31, 2011. The IPA says this forecast includes anticipated normal weather, the effect of competitive declarations, energy efficiency and demand response programs, and the impact of forecasted customer switching.

ComEd Supply Requirements

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June 2010	1,896,921	1,624,045	5,389	4,413
July 2010	2,231,242	2,197,192	6,641	5,385
August 2010	2,169,255	1,969,226	6,163	5,024
September 2010	1,588,361	1,512,634	4,727	3,939
October 2010	1,357,368	1,415,482	4,040	3,469
November 2010	1,501,640	1,500,691	4,469	3,908
December 2010	1,916,427	1,695,654	5,208	4,510
January 2011	1,752,398	1,886,938	5,215	4,625
February 2011	1,557,990	1,522,786	4,869	4,326
March 2011	1,599,912	1,451,093	4,348	3,859
April 2011	1,301,326	1,311,732	3,873	3,416
May 2011	1,330,118	1,399,860	3,959	3,431

(IPA Plan at 44)

AIU Supply Requirements

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June 2010	779,952	680,221	2,216	1,848
July 2010	962,074	923,346	2,863	2,263
August 2010	972,635	891,295	2,763	2,274
September 2010	742,449	684,079	2,210	1,781
October 2010	616,307	631,933	1,834	1,549
November 2010	636,263	643,953	1,894	1,677
December 2010	854,143	774,962	2,321	2,061
January 2011	817,614	925,975	2,433	2,270
February 2011	721,585	744,639	2,255	2,115
March 2011	713,785	647,218	1,940	1,721
April 2011	554,568	563,412	1,651	1,467
May 2011	558,272	596,638	1,662	1,462

Id. at 26.

According to the IPA, ComEd will procure the capacity and ancillary services required by the "eligible retail customers" directly from PJM-administered markets. The IPA states that under the Reliability Pricing Model ("RPM") program approved by the Federal Energy Regulatory Commission ("FERC") and administered by PJM, ComEd is able to purchase capacity directly from PJM-administered markets. *Id.* at 44.

The RPM capacity prices for the June 2010 - May 2013 period have already been determined through a competitive bid process, so the IPA views direct procurement from PJM results as a reasonable approach to procuring capacity for these customers. Furthermore, the IPA indicates that the PJM-administered markets for ancillary services are the most visible and easily accessible markets for these services, so direct procurement from these markets is a reasonable approach for providing these services to customers. *Id.* at 44.

A detailed summary of MISO's resource adequacy requirements are contained below in the further description of the IPA's proposed Plan.

The planning reserve margin beginning June 2010 has yet to be established; therefore, the IPA recommends that the 5.35% that has been effective for the period June 2009 through May 2010 be used for this Plan, with the caveat that future adjustments can be made once reserve margins are reset by MISO at a later date. *Id.* at 27.

The load forecast presented in the tables above is a forecast of the expected full energy requirements of the Eligible Retail Customers. The IPA notes however, that ComEd and AIU will not need to procure that amount of energy in order to serve that load due to pre-existing contracts for supply. The IPA observes that pursuant to Section 16-111.5(k) of the PUA, ComEd entered into a five-year swap contract with Exelon Generation ("ExGen"). The IPA says this agreement will provide price certainty for 3,000 MW of Around-The-Clock (“ATC”) energy that ComEd will procure through the PJM spot markets for the period June 1, 2010 through May 31, 2013. *Id.* at 44.

Similarly, the IPA indicates AIU entered into a five-year swap contract with Ameren Energy Marketing. AIU's contract will provide price certainty for 1,000 MW of ATC energy that AIU will procure through the MISO spot markets for the period June 1, 2010 through December 31, 2012. *Id.* at 30.

The IPA notes that additional fixed price contracts for the June 2010 through May 2011 period were secured as a result of the 2009 Procurement Cycle.

The IPA provides tables, reproduced in part below, which identify the Monthly Residual Load volumes for ComEd and AIU over the Procurement Period. (see also AIU BOE at 1-2) The IPA indicates that the Monthly Residual Load Volumes are derived by subtracting pre-existing contract volumes from projected load volumes.

ComEd Residual Supply Requirements

Contract Month	Residual Volumes (MW) On-Peak	Residual Volumes (MW) Off-Peak
June 2010	1,639	1,213
July 2010	2,306	1,535
August 2010	2,130	1,424
September 2010	1,428	938
October 2010	1,040	469
November 2010	1,270	908
December 2010	1,508	1,260
January 2011	1,415	1,225
February 2011	1,318	1,126
March 2011	1,148	859
April 2011	872	417
May 2011	960	430

Id. at 45.

AIU Residual Supply Requirements

Contract Month	Residual Volumes (MW) On-Peak	Residual Volumes (MW) Off-Peak
June 2010	466	548
July 2010	1100	613
August 2010	1039	724
September 2010	560	381
October 2010	384	399
November 2010	444	377
December 2010	671	661
January 2011	683	770
February 2011	655	665
March 2011	490	471
April 2011	351	367
May 2011	362	362

Id. at 27-28.

B. Energy

In order to meet the requirements of the Eligible Retail Customers, the IPA indicates that certain wholesale supply products must be procured. These include energy, capacity, and ancillary services. The IPA says the determination of the appropriate portfolio (i.e., form, term-lengths, and mix) of these products is guided by the specific goals for this Procurement Plan as defined in Section 16-111.5(j)(ii) of the PUA:

> The Commission shall approve the procurement plan if the Commission determines that it will 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.

(IPA Plan at 46)

The IPA recommends a two-part method for meeting the energy requirements of ComEd's and AIU's eligible customers: a short term portfolio and a long term portfolio. The IPA says the short term portfolio will center on the application of the laddered volume approach discussed above. According to the IPA, the long term portfolio will center on securing as much as 1,400,000 MWh for ComEd and 600,000 MWh for AIU, of annual energy supply from renewable energy resources with a first delivery date expected to occur during the 2011-2012 plan year. *Id.* at 29, 46.

Under the IPA's Plan, the short term energy required by **ComEd's** Eligible Retail Customers comes from four sources. First, the swap contract with ExGen provides a financial hedge on 3,000 MW of ATC energy during the June 2010 – May 2013 period. Second, certain fixed price physical supply contracts were secured through the 2009 Procurement Process. Third, the IPA will solicit standard wholesale products through a sealed-bid RFP per its proposed Plan. Finally, balancing energy will be procured from the PJM-administered day-ahead and real-time energy markets. *Id.* at 46.

The IPA states that short term energy required by **AIU's** Eligible Retail Customers comes from three sources. First, the swap contract with Ameren Energy Marketing provides a financial hedge on 1,000 MW of ATC energy during the June 2010 – December 2012 period. Second, various fixed price swap contracts were secured through the 2009 procurement cycle that will be in effect during the June 2010 through May 2011 period. Third, under the IPA’s Plan, AIU will meet its combined physical load requirements via the MISO day ahead and real-time energy markets, and will enter into financial swap contracts to hedge price exposure for Residual Volumes. The IPA indicates it will solicit standard wholesale products through a sealed-bid RFP under its proposed Plan. *Id.* at 29.

According to the IPA, a financial swap is a commercial transaction between two parties involving the exchange (swap) of risk. The IPA states that in this instance, AIU desires to pay a fixed price, and will settle all loads with the MISO at LMP. Under a swap transaction, the IPA says AIU will pay a fixed price to its supplier in exchange for receiving a floating price (MISO LMPs) from the supplier. As such, the LMP paid by AIU to the MISO is offset by the LMP received from the supplier, leaving AIU only paying the fixed price. In the IPA's view, financial swaps provide the same level of hedging as physical transactions. According to the IPA, the use of financial swaps will not adversely affect reliability as AIU will contract for sufficient capacity to meet the load obligations, and as such the contracts for such capacity shall obligate the seller to offer such capacity into the MISO markets. *Id*.

In determining the granularity of the standard wholesale products to be procured through the RFP, the IPA says it recognized that if the products are defined in a way such that the megawatt amount contracted in each given hour is equal to the actual customer load in that hour, then the wholesale products will effectively provide price stability for customers because the fluctuations in the cost to supply the load will effectively be hedged. The IPA states however, that standard products traded in the wholesale market do not involve delivery quantities that vary within the 24 monthly on-peak/off-peak periods throughout the year, so the quantities of energy procured in the form of standard wholesale products cannot approximate customer load shapes on a more granular basis than a monthly on-peak/off-peak basis. *Id.* at 30, 46-47.

Given these facts, the IPA plans to issue solicitations for monthly on-peak and off-peak standard wholesale block energy products (or their equivalent volumes in seasonal or varietal strips) for delivery during the June 2010-May 2013 period. The IPA says the target procurement quantities are determined by multiplying ComEd's and AIU's average forecasted load obligation in each monthly on-peak/off-peak period by the targeted hedge position after the procurement event is completed (i.e. 35% for requirements two years out, 70% for requirements one year out, and 100% for requirements in the year in which power is delivered).

Next, megawatts covered by the previous RFPs and ExGen and Ameren Energy Marketing swaps are subtracted from the target requirements. To the extent the calculated procurement quantity for a period is less than zero, the IPA says no energy will be procured for that period and existing positions will be maintained. The IPA also notes that calculations in the model are rounded to the nearest 50 MW. The IPA believes that by procuring a portfolio of the most granular standard wholesale products available and in quantities reflective of forecasted loads, the forecasted net amount of energy transacted in the volatile spot market will be minimized. *Id.* at 30, 47.

According to the IPA, bidders will be provided an opportunity to bundle their bids for various products. By providing some flexibility for bundled bids, the IPA claims bidders will be better able to bid on the products for which they can offer the most competitive prices. The IPA says the procurement administrator will accept the bids that together represent the lowest cost portfolio of products that provide the desired monthly on-peak and off-peak quantities being solicited through the RFP. *Id.* at 30, 47.

Based on the current load forecast, the quantities of standard wholesale energy products to be procured through the sealed-bid RFP by the IPA in the 2010 procurement cycle, rounded to the nearest 50 MW, are shown in the tables below.

ComEd Peak Load Volumes to be Secured in 2010 Procurement Cycle by the IPA

Month	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)
June	2010	1650	2011	700	2012	0
July	2010	2300	2011	2000	2012	0
August	2010	2150	2011	1650	2012	0
September	2010	1450	2011	200	2012	0
October	2010	1050	2011	0	2012	0
November	2010	1250	2011	100	2012	0
December	2010	1500	2011	600	2012	0
January	2011	1400	2012	650	2013	0
February	2011	1300	2012	350	2013	0
March	2011	1150	2012	50	2013	0
April	2011	850	2012	0	2013	0
May	2011	950	2012	0	2013	0

ComEd Off Peak Load Volumes to be Secured in 2010 Procurement Cycle by the IPA

Month	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)
June	2010	1200	2011	0	2012	0
July	2010	1550	2011	700	2012	0
August	2010	1400	2011	450	2012	0
September	2010	950	2011	0	2012	0
October	2010	450	2011	0	2012	0
November	2010	900	2011	0	2012	0
December	2010	1250	2011	200	2012	0
January	2011	1200	2012	250	2013	0
February	2011	1150	2012	50	2013	0
March	2011	850	2012	0	2013	0
April	2011	400	2012	0	2013	0
May	2011	450	2012	0	2013	0

Id. at 47-49.

AIU Peak Load Volumes to be Secured in 2010 Procurement Cycle by the IPA

Month	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)
June	2010	450	2011	550	2012	0
July	2010	1100	2011	1150	2012	0
August	2010	1050	2011	1100	2012	0
September	2010	550	2011	500	2012	0
October	2010	400	2011	250	2012	0
November	2010	450	2011	300	2012	0
December	2010	650	2011	600	2012	0
January	2011	700	2012	700	2013	800
February	2011	650	2012	500	2013	750
March	2011	500	2012	300	2013	650
April	2011	350	2012	100	2013	550
May	2011	350	2012	150	2013	550

AIU Off Peak Load Volumes to be Secured in 2010 Procurement Cycle by the IPA

Month	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)
June	2010	550	2011	250	2012	0
July	2010	600	2011	600	2012	0
August	2010	700	2011	550	2012	0
September	2010	400	2011	200	2012	0
October	2010	400	2011	50	2012	0
November	2010	400	2011	150	2012	0
December	2010	650	2011	400	2012	0
January	2011	750	2012	550	2013	750
February	2011	650	2012	400	2013	700
March	2011	450	2012	200	2013	600
April	2011	350	2012	0	2013	500
May	2011	350	2012	0	2013	500

Id. at 30-32; see also AIU BOE at 1-2.

According to the IPA, the PUA provides that it is the duty of the Procurement Administrator, in consultation with the Commission Staff, ComEd and AIU, and other interested parties, to develop the standard contract form that will be used for the standard wholesale products to be procured through the RFP. The IPA states that standard wholesale products to be procured through the RFP could be settled physically or financially. In both cases, the IPA indicates that ComEd and AIU would contract to purchase or hedge specific quantities of energy at fixed prices.

In the case of financial settlement, the IPA says ComEd or AIU would procure energy in the day-ahead or real-time markets, and debit or credit a dollar amount to the seller based on the difference between the agreed-upon fixed contract price and an index price, whereby the index price would be specified in the contract to be either the day-ahead or real-time energy price. The IPA claims financial contracts are generally referred to as “contracts for differences” ("CFD"). The swap contracts with ExGen and Ameren Energy Marketing, the IPA avers, are examples of a financially-settled contract. *Id.* at 32, 50.

In the case of physical settlement, the IPA indicates that contracting parties would transact through PJM or MISO. In this case, the IPA says both parties must be PJM or MISO members in good standing. The IPA states that ComEd or AIU and the seller would execute an agreement, under which the seller transfers energy to ComEd via a PJM e-Schedule or to AIU via a MISO process. According to the IPA, ComEd or AIU would then directly pay the seller the agreed-upon fixed contract price for the specified amount of energy. *Id*.

The IPA believes that the choice between settling physically and financially does not affect service reliability. According to the IPA, whether the products settle physically or financially, PJM and MISO will still dispatch the system in such a way to ensure that customers’ requirements are met. The IPA asserts that the decision to settle physically or financially affects the logistics regarding cash flows, the administrative tasks that are required of the various parties involved, the non-performance risks and the standard of legal review. *Id*.

The IPA recommends that the contracts to be procured through the RFP be settled physically for ComEd volumes. According to the IPA, physical contracts are lower risk in the event of supplier default. The IPA says exposure of a supplier under a CFD is limited only by the PJM energy price cap of $999 per MWh. While it would be very rare for prices for a sustained period to be at or near the energy price cap, the IPA states that a primary value of a hedge is to protect against such occurrences. In the IPA's view, it is not inconceivable that a supplier may in fact be unable to pay the difference between spot and contract prices if there is a sustained price spike. If the contract is physical, the IPA says the supplier will be liable to PJM, and until the supplier’s PJM market privileges are revoked, ComEd will receive the energy at the contract price. The IPA adds that any default costs would be spread over PJM. *Id.* at 51.

In the event of a default under a CFD, the IPA indicates that ComEd would owe PJM the high spot prices and would bear the cost of the supplier being unable to pay the difference. While increased collateral may reduce this risk, the IPA claims it is not clear that there are adequate credit provisions to equalize this risk; therefore the IPA believes the physical contract is of lower risk for customers.

According to the IPA, physical contracts also reduce ComEd credit requirements and overall credit costs. Under a financial contract, the IPA says ComEd would be considered by PJM to be buying all load in the spot market and would have to provide credit for all volumes. Under a physical contract, the IPA indicates that the supplier is responsible to provide credit for all volumes. While the credit cost is not eliminated, the IPA believes it may be reduced as some suppliers may have lower financing costs, especially in the event that the supplier is maintaining offsetting long positions within PJM. *Id.* at 51.

In contrast, the IPA recommends that the contracts to be procured through the RFP be settled financially for AIU volumes. The IPA states that the MISO market rules do not maintain the same credit requirements found in the PJM market; therefore, financial swaps are a standard method used by multiple entities within the MISO market for securing fixed cost pricing for loads. With the ability to settle prices financially without added premium, the IPA believes that a larger, more diverse, and competitive bidder pool will be interested in bidding on AIU requirements. *Id.* at 33.

The IPA indicates that it anticipates securing load for ComEd's and AIU's eligible customers by laddering in purchases so that no one month or season is purchased all at one time. By dollar-cost averaging in this manner, the IPA hopes to mitigate risk to ComEd's and AIU's eligible customers. *Id.* at 33.

With regard to what it describes as the long term portfolio, the IPA recommends issuing solicitations for longer term power purchase agreements ("PPAs") with renewable energy providers. The IPA asserts that long term PPAs can serve as a hedge against potential cap and trade legislation that would serve as an additional tax on fossil fuel costs. Further, the IPA claims that grants, loans and credit enhancement available currently from US Department of Energy, Department of Commerce and Economic Opportunity and the Illinois Finance Authority will result in lower cost renewable energy projects that are developed now through the end of 2012 due to the public grants and financing. *Id.* at 34, 51.

Given these factors, the IPA believes it is prudent to solicit proposals from renewable energy providers to capitalize on available funding and secure a modest level of renewable energy under longer term PPAs if deemed cost effective. The IPA states that as neither the cost liabilities nor the availability of other hedging options associated with cap and trade are unknown, the IPA seeks to limit their use in the ComEd portfolio to 1,400,000 MWh per year and in AIU portfolio to 600,000 MWh per year, starting as early as the 2011-2012 planning year. The IPA contends that the use of a MWh goal for these contracts is due to the variable output nature of some renewable assets that may be selected through the solicitation process (i.e. hydro, wind, and solar). *Id*.

The IPA recommends that bids be evaluated through a process similar to that used to evaluate bids in the short term portfolio: standard terms and conditions regarding performance guarantees and penalties are agreed to by bidders prior to solicitation, bidders must pre-qualify to be allowed into the bidder pool, application of a cost benchmark to reject above market value bids, and scoring of submitted bids according to a methodology that considers and ranks proposals on the basis of output, capacity value, financing costs, transmission and capital costs, fixed cost vs. escalators offers, return on equity and other normalizing factors. *Id*.

C. Capacity, Ancillary Services, Transmission Services

According to the IPA, **ComEd** will procure the capacity and ancillary services required by the Eligible Retail Customers directly from PJM-administered markets. The IPA states that under the RPM program approved by the FERC and administered by PJM, ComEd is able to purchase capacity directly from PJM-administered markets. The IPA indicates that the RPM capacity prices for the June 2010 - May 2013 period have already been determined through a competitive bid process administered by PJM, so direct procurement from PJM results in a reasonable approach to procuring capacity for these customers. Furthermore, the IPA asserts that the PJM-administered markets for ancillary services are the most visible and easily accessible markets for these services so direct procurement from these markets is a reasonable approach for providing these services to customers. IPA Plan at 52.

The IPA states that while it recognizes that PJM procures demand-response measures in the RPM auction for capacity resources, the IPA believes it necessary to certify that additional sources of demand response sources capacity are not available at less than the current RPM forward price curve. *Id.*

The IPA states that Module E of MISO's Open Access Transmission and Energy Markets Tariff addresses resource adequacy. Under Module E, the IPA says MISO will develop a Planning Reserve Margin ("PRM") for each Load Serving Entity ("LSE"). If higher or lower PRMs are mandated by a state regulatory authority, then MISO shall recognize and incorporate such PRMs for any affected LSE(s). The IPA states that nothing in Module E affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. At present, the State of Illinois has not mandated a PRM different than the one developed by MISO. The IPA says that Module E, along with the associated business practice manual, also requires AIU to provide an annual forecast of monthly loads adjusted for transmission losses and subsequently confirm on a month-ahead basis that AIU has enough capacity to meet or exceed its monthly peak load forecast plus its planning reserve margin. *Id.* at 35.

For demonstration purposes, the IPA utilized the reserve margin of 5.35% that has been effective for the period June 2009 through May 2010. The IPA reports that the planning reserve margin beginning June 2010 has yet to be established and therefore the IPA recommends that the Commission authorize the IPA's procurement administrator, in consultation with the IPA, the Commission Staff, the procurement monitor, and AIU, to adjust the quantities of capacity to acquire in order to comply with the applicable planning reserve requirements. Furthermore, to the extent to which it is impractical or impossible for the procurement administrator to modify its capacity RFP to fully account for all applicable capacity requirements the applicable planning reserve requirements, the IPA recommends that the Commission authorize AIU to make up the difference through one or more supplemental procurement processes. *Id.* at 35.

The IPA proposes for 70% of AIU's monthly capacity requirements to be acquired for the second planning year, June 2011 through May 2012. The IPA also proposes that 35% of AIU's monthly capacity requirements be acquired for the third planning year, June 2012 through May 2013, and that 0% of the monthly capacity requirements be acquired for the fourth and fifth planning years, June 2013 through May 2015. *Id.* at 36-37.

For both ComEd and AIU, the IPA recommends that the initial solicitation of demand response as an alternative to standard capacity be conducted in the 2010 Procurement Cycle. Specifically, the IPA recommends that Demand Response Procurement be specified as a bid alternate in the spring 2010 solicitation for capacity. In the event that Demand Response providers do not exist or do not participate in the spring solicitation, the IPA proposes that a secondary solicitation will be conducted in the fall of 2010 that will seek to establish capacity contracts that will incent the development of demand response programs within the AIU and ComEd service territory. *Id.* at 38, 52.

Citing Section 16-111.5(b)(3)9ii) of the PUA, the IPA states that qualified demand response bids submitted in the spring procurement that are of lesser cost than comparable capacity sources will be selected as winning bidders. The IPA recommends that if the secondary solicitation described above is necessary, then the total volume of capacity to be awarded not exceed a maximum contract volume basis of 500 megawatts in any given month. *Id.*

The IPA recommends that demand response providers participating in the spring capacity solicitation be allowed to bid on all months and volumes under the same terms and conditions as other traditional suppliers. If the secondary solicitation is necessary, the IPA suggests that offers from bidders that extend over a five year period from the time of first contract obligation or delivery will be considered. *Id*.

In addition to the acquisition of power and energy-related products, the IPA indicates that AIU is obligated by the MISO Tariff to acquire certain transmission service related products and services to effectuate delivery of power and energy to the applicable loads. The IPA says these services include Network Transmission Service and Ancillary Services. *Id.* at 38.

The IPA says Network Integrated Transmission Service (“NITS”) is described in Section III of Module B to the MISO Tariff. The IPA indicates that AIU utilizes such NITS to reliably deliver capacity and energy from its Network Resources to its Network Loads, namely its Native Load obligations. According to the IPA, the MISO tariff requires each NITS customer to complete an application for service, complete any applicable technical arrangements in conjunction with the Transmission Provider and Transmission Owner and execute both a Service Agreement and a Network Operating Agreement. The IPA claims AIU has acquired the necessary NITS in accordance with the tariff and the cost for this service is that established in the applicable MISO tariff schedules. *Id.* at 38.

The IPA states that ancillary services are services that are necessary to support capacity and the transmission of energy from resources to loads while maintaining reliable operation of the transmission system. According to the IPA, effective January 2009, MISO implemented an Ancillary Services market to provide regulation service and operating reserve service (both spinning and supplemental) reserves. The IPA recommends that AIU procure these required services through the MISO Ancillary Services market. *Id.* at 38.

D. Auction Revenue Rights

The IPA states that while Auction Revenue Rights ("ARRs") are not a power and energy resource, the nomination and subsequent allocation of such rights to ComEd and AIU generally serves to reduce the cost of congestion borne by ComEd and AIU and, thus, ultimately by their customers. As part of the 2009 ARR allocation process at PJM and MISO, the IPA says ComEd and AIU received sets of ARR entitlements and was awarded ARRs for the 2009 planning year. *Id.* at 38-39, 53.

For future planning years, the IPA indicates that ComEd and AIU should continue to actively participate in the PJM and MISO ARR nomination and allocation process, and should seek to nominate those ARRs with an expected positive value, recognizing that ComEd and AIU may be required to accept certain ARRs which do not have an expected positive value and further that though nominated, ComEd and AIU ultimately may not be allocated all of the ARRs requested. *Id.* at 39.

The IPA believes ComEd and AIU should retain the allocated ARRs and receive associated credits for their customers. The IPA suggests that all proceeds and costs of such sales, including costs incurred by ComEd to evaluate and execute such a strategy, should be passed to customers through ComEd's Rider PE. The IPA also believes AIU should make no further changes except to the extent that, should the delivery point for one or more of the energy resources be other than within the Ameren Transmission-Illinois ("AMIL") balancing authority, AIU may attempt to reallocate the applicable ARRs from their historical resource points to those which align more closely with the designated energy resource delivery point. *Id.* at 39, 53.

E. Load Balancing Procedures

Under the IPA's Plan, **ComEd** will utilize the PJM-administered day-ahead and real-time energy markets to balance its loads. On a daily basis, the IPA indicates that ComEd will report to PJM its estimate of its total load requirements for the following day.

ComEd will then submit its day-after estimate to PJM via a daily load responsibility schedule and the estimate will in turn be settled by PJM based on the real time market prices. The IPA states that if the delivered physical power exceeds the day-ahead estimate, PJM will credit the difference to ComEd at the day-ahead price; if the delivered physical power is less than the day-ahead estimate, PJM will charge ComEd the difference at the day-ahead price. *Id.* at 53.

When ComEd submits its day-after estimate to PJM, the IPA says that PJM will perform a similar settlement function in the PJM real-time market. The IPA states that to the extent the day-ahead estimate reported by ComEd is less than the day-after estimate, PJM will charge ComEd the difference at the real-time price. To the extent that the day-ahead estimate reported by ComEd is greater than the day-after estimate, PJM will credit ComEd with the difference at the real-time price. *Id*.

According to the IPA, upon Commission approval of its Plan, **AIU** will be entering into financial swap transactions to hedge the energy price risk of the portfolio. The IPA says 100% of the energy required to supply the load included in the Plan will be purchased in the MISO energy markets. The IPA indicates that AIU will forecast respective load requirements for each delivery day in accordance with industry standards and practices for each delivery day. The IPA expects that these forecasts will be utilized to submit a day-ahead demand bid to the MISO market, which will be settled with the MISO at a price equal to the MISO day-ahead LMP for each hour. The IPA explains that hourly balancing will be performed through the MISO real time energy market, with deviations from the day-ahead demand bid settling at a price equal to the MISO real-time LMP. The IPA says MISO charges, including Revenue Neutrality Uplift and Revenue Sufficiency Guarantee payments, will also apply. *Id.* at 39.

F. Portfolio Rebalancing

The IPA says the PUA requires it to provide the criteria for portfolio rebalancing in the event of “significant shifts in load.” The IPA states that in the event that ComEd's or AIU’s annual forecast increases above the High Forecast or decreases below the Low Forecast during the active delivery year of an approved Procurement Plan, ComEd and AIU are required to promptly notify the IPA. The IPA indicates it will subsequently convene a meeting with ComEd or AIU, the Commission Staff, and Procurement Administrator to determine whether it is appropriate to rebalance the portfolio, and if so, to what extent and how such a rebalancing can be achieved.

The IPA claims that over the term of its Plan, the most significant driver of load shifting levels is customer switching. If customer switching levels are significantly different from forecasted levels, the IPA believes a re-balancing of the portfolio may be warranted. *Id.* at 39, 53.

G. Renewable Portfolio

The IPA observes that Section 1-75(c) of the Illinois Power Agency Act ("IPA Act") establishes that:

> The procurement plans shall include cost-effective renewable energy resources. A minimum percentage of each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act. (20 ILCS 3855/1-75(c)(1))

The statute defines renewable energy resources as:

> "Renewable energy resources" includes energy and its associated renewable energy credit or renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, trees and tree trimmings, hydropower that does not involve new construction or significant expansion of hydropower dams, and other alternative sources of environmentally preferable energy. For purposes of this Act, landfill gas produced in the State is considered a renewable energy resource. (20 ILCS 3855/1-10)

The IPA indicates that the statute also establishes a methodology for calculating annual volumetric goals for the portfolio as well as establishing a Renewable Energy Resource Budget ("RRB") that serves as a maximum cost cap for meeting those goals. In the event that the cost cap is met, purchases of renewable energy resources are to be curtailed, leaving the annual volumetric goal unmet. *Id.* at 40, 54.

According to the IPA, for the 2010-2011 delivery period, the annual volume goal is 5% of June 1, 2008 through May 31, 2009 eligible retail customer load. The IPA also indicates that the maximum cost standard on renewables in the statute for that delivery period is the greater of an additional 0.5% of the amount paid per kilowatt-hour by those customers during the year ending May 31, 2009 or 1.5% of the amount paid per kilowatt-hour by those customers during the year ending May 31, 2007. *Id.* at 41, 55.

As noted above, the statute requires the higher of two separate calculations to establish each planning year's RRB. The IPA states that annual RRBs resulting from the application of the statute's standards to the ComEd portfolio for planning years 2010-2011 are $58,247,099 and $51,324,076, respectively. The corresponding values for AIU are $24,394,776 and $21,556,601, respectively. *Id.* at 41, 55.

The table below was derived from information contained in the IPA's Plan and summarizes the Renewable Portfolio Standard ("RPS") metrics and targets for the 2010-2011 planning period for ComEd and AIU.

Renewable Portfolio Standard Metrics and Targets for 2010-2011

	ComEd	AIU
RPS Volume Target (MWh)	1,887,014	860,860
Renewable Energy Resource Budget (RRB)	58,247,099	24,394,776
Average Price per Renewable Unit ($/MWh)	$30.87	$28.34
Estimated Consumers Covered by RRB	3,746,747	1,190,808
Estimated Annual RPS Cost/Consumer	$15.55	$20.49

Id. at 41, 54.

The IPA states that ComEd and AIU will meet the renewable energy resource portfolio standard for the Plan year through the acquisition of qualifying renewable energy credits ("REC's") as defined in Section 1-10 of the IPA Act. The acquisition of REC's for this period, according to the IPA, meets the requirements of the IPA Act and is preferable to the direct acquisition of energy from qualifying renewable resources at this time. *Id.* at 42, 56.

According to the IPA, the RPS can be met only by procuring either RPS Option A - Energy (from a qualified resource) and its associated renewable energy credit; or RPS Option B - Renewable Energy Credits ("RECs"). Based on the Volume goals and RRB, the average unit price that can be paid for each renewable energy resource is $30.87/MWh for ComEd and $28.34/MWh for AIU. The IPA asserts that the available funds under the RPS are not sufficient to meet the RPS volume requirements through RPS Option A. *Id.* at 42, 56.

Under the IPA's Plan, sufficient RECs to comply with the quantities established by Section 1-75(c)(1) of the IPA Act will be acquired on the basis of (1) the requirements established in Section 1-75(c)(3) of the IPA Act and (2) price, as determined by comparing qualifying bids meeting approved benchmarks. The IPA states that acquisitions of renewable energy credits will be memorialized with a Master Renewable Energy Certificate Purchase and Sale Agreement. *Id.* at 42, 56.

The IPA indicates that the Procurement Administrator will be directed to continue to establish benchmark REC prices (as was done in 2009), and to reject bids priced above the benchmarks. The IPA notes that the revision to Section 1-75(c)(1) of the IPA Act, by Public Act 095-1027, now requires the development of benchmarks. According to the IPA, the benchmarks will be set at levels that consider relevant market prices and the economic development benefits of in-state resources. The IPA adds that the benchmark prices will be confidential, but will be provided to, and will be subject to, Commission review and approval prior to solicitations of REC bids. *Id.* at 42, 56.

The IPA states that Section 1-75(c)(3) of the IPA Act requires that until June 1, 2011, cost-effective renewable energy resources be procured first from facilities in the State of Illinois, then from facilities located in states adjacent to Illinois, then from facilities located elsewhere. Additionally, the IPA says that prior to June 1, 2015, at least 75% of the renewable energy resources procured must be sourced from wind assets and 25% from other qualified assets. *Id.* at 42.

In the IPA's view, the acquisition of RECs in amounts equal to the statutory requirement ensures compliance. The IPA states that PJM Environmental Information System's ("EIS") Generation Attribute Tracking System ("GATS") and the Midwest Renewable Energy Tracking System ("M-RETS") will be utilized to independently verify the location of generation, resource type and month and year of generation. The IPA says GATS tracks generation attributes and the ownerships of the attributes as they are traded or used to meet renewable portfolio standards and other programs, typically for generators whose energy is settled in the PJM market or whose facility is located in the PJM footprint. The IPA says that M-RETS tracks renewable energy generation and assists in verifying compliance with individual state/provincial RPS requirements or voluntary programs, typically for generators located in the MISO footprint and other RTOs outside of PJM. *Id.* at 41-42, 56-57.

Under the IPA's Plan, each agreement for the acquisition of a REC will have a specified term. The IPA says that all RECs used by ComEd and AIU to comply with the statutory requirements shall be retired in compliance with Section 1-75(c)(4) of the IPA Act. *Id.* at 42, 57.

H. Contingencies

The IPA has developed a Plan to procure power and energy for ComEd's "Eligible Retail Customer" load should all or any part of that load not be met due to the advent of: 1) supplier default; 2) insufficient supplier participation; 3) Commission rejection of procurement results; or 4) any other cause. The IPA says the proposed Plan is substantially based on the contingency plan as specified in the IPA Act and Section 16-111.5(e)(5)(i) of the PUA. *Id.* at 57.

In the event of a supplier default that results in contract termination where the amount of load provided by that supplier is 200 MW or greater and there are more than 60 calendar days remaining on the defaulted contract term, the IPA proposes for ComEd to immediately notify the IPA, Commission Staff, and the Procurement Administrator that another procurement event will be administered. The IPA proposes for the Procurement Administrator to execute a procurement event to replace the same products and amounts as that initially approved by the Commission in this Plan. The IPA proposes for the Commission Staff and its monitor to oversee the event.

The replacement plan will, to the maximum degree possible, seek to replace the defaulted products with the same or similar products to those that were defaulted on. Under the IPA's proposal, this replacement plan would continue to seek energy for only standard block products. The IPA says all ancillary services, capacity and load balancing requirements would continue to be procured through the PJM administered markets. During the interim time period beginning at time of default and continuing through the contingency procurement process, the IPA plans for all electric power and energy to be procured by ComEd through PJM-administered markets. The IPA adds, however, that if a particular required product is not available through PJM, it will be purchased in the wholesale market. *Id.* at 57.

In the event of a supplier default that results in contract termination where the amount of load provided by that supplier is less than 200 MW, or there are less than 60 calendar days remaining on the defaulted contract term, the IPA proposes for ComEd to procure the required power and energy directly from the PJM administered markets. The IPA says this procurement would include day ahead and/or real time energy, capacity, and ancillary services. Should a required product not be available directly through the PJM administered markets, the IPA says it will be procured through the wholesale markets. *Id*.

In the event that the Commission rejects the results of the initial procurement event or the initial procurement event results in under subscription, the IPA proposes a meeting of the Procurement Administrator, the Procurement Monitor, and the Commission Staff to occur within 10 calendar days to assess the potential causes and to consider what remedies, if any, could be put in place to either address the Commission's concerns or would result in full subscription to the load. The IPA says that if revisions to the procurement event are identified that would likely either address the Commission's concerns or enhance the possibility of having a fully subscribed load, the Procurement Administrator will implement those changes and run a procurement event predicated on a schedule established within the aforementioned meeting. The IPA proposes for the new procurement event to be executed by the Procurement Administrator within 90 calendar days of the date that the initial procurement process is deemed to have failed. *Id*.

Should a procurement event be required subsequent to the initial event, the IPA proposes for the Procurement Administrator and the Procurement Monitor to separately submit a confidential report to the Commission within two business days after opening the sealed bids. The IPA proposes that the Procurement Administrator's report will put forth a recommendation for acceptance or rejection of bids based on the established benchmarks as well as other observed factors to include any modifications necessary to run a subsequent procurement event if necessary. *Id.* at 57-58.

In all cases where the factors are such, either for an interim period or otherwise, that there would be insufficient power and energy to serve the required load, the IPA proposes for ComEd to procure the required power and energy requirements for the eligible load through the PJM-administered markets. The IPA says direct procurement activities would include day-ahead and/or real-time energy, along with the normal direct procurement of capacity and ancillary services. Also, in the case that a particular required product is not available through PJM, the IPA says ComEd will purchase that product through the wholesale market. *Id.* at 58.

According to the IPA, AIU's Rider PER (Purchased Energy Recovery) (Electric Service Schedule Ill.CC. No. 18) will serve as the basis of AIU's Contingency Procurement Plan. *Id.* at 43.

VII. OBJECTIONS, RESPONSES AND REPLIES; COMMISSION CONCLUSIONS

A. Long-Term Renewable Resources

By far the most contentious issue in this proceeding was the IPA's proposal to acquire long-term renewable resources. That is, for the upcoming procurement, the IPA proposes to issue solicitations for long-term power purchase agreements with renewable energy providers. *Id.* at 34, 51. As explained below, that proposal, as contained in the filed Plan, drew numerous objections. The IPA attempted to clarify and explain its proposal in its response to the objections. Thereafter, parties filed replies to the IPA's responses.

Thereafter, on November 9, 2009, the IPA filed a Motion to File Supplemental Recommendations for the Procurement Plan. In this Motion and Attachment K thereto, the IPA further explained its proposal to acquire long-term renewable resources, and proposed certain modifications to that proposal. The IPA's motion indicates that Appendix K supplements and modifies the IPA's prior proposal in a way that is intended to address and resolve the concerns identified by Commission Staff, ComEd, AIU and the AG. In responses to the motion, ComEd, Ameren Illinois Utilities and the AG all support approval of those recommendations in Appendix, and Staff does not object to them. Some of the other parties disagree with the terms of Appendix K, as set forth in responses filed November 13, 2009. Replies to responses were filed by some parties on November 16, 2009.

Subsection A.1 below summarizes the parties' positions as set forth in their objections to the filed Plan, responses to objections, and replies to those responses.

Subsection A.2 below summarizes the IPA's supplemental recommendations filed November 9, other parties' responses to those supplemental recommendations, and parties' replies to those responses.

Subsection A.3 contains the Commission's analysis and conclusions regarding the procurement of long-term renewable resources.

1. Objections to Filed Plan; Responses; Replies

To facilitate an understanding of the issues, an effort has been made to categorize the arguments as those relating primarily to statutory issues and those that are not related primarily to statutory issues. In some instances it was difficult to distinguish or categorize certain arguments.

While the objections of ComEd, AIU, Staff and ExGen are summarized below, it is noted that those objections applied to the proposal contained in the IPA's filed Plan. These parties do not object to the IPA's current proposal for long-term renewable as filed on November 9; nor does the AG.

a. Statutory Issues

Section 1-75(c) of the IPA Act lays out the Renewable Portfolio Standard as follows:

> (c) Renewable Portfolio Standard.
>
> (1) The procurement plans shall include cost-effective renewable energy resources. A minimum percentage of each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act, procured for each of the following years shall be generated from cost-effective renewable energy resources: at least 2% by June 1, 2008; at least 4% by June 1, 2009; at least 5% by June 1, 2010; at least 6% by June 1, 2011; at least 7% by June 1, 2012; at least 8% by June 1, 2013; at least 9% by June 1, 2014; at least 10% by June 1, 2015; and increasing by at least 1.5% each year thereafter to at least 25% by June 1, 2025. To the extent that it is available, at least 75% of the renewable energy resources used to meet these standards shall come from wind generation and, beginning on June 1, 2015, at least 6% of the renewable energy resources used to meet these standards shall come from photovoltaics. For purposes of this subsection (c), "cost-effective" means that the costs of procuring renewable energy resources do not cause the limit stated in paragraph (2) of this subsection (c) to be exceeded and do not exceed benchmarks based on market prices for renewable energy resources in the region, which shall be developed by the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor and shall be subject to Commission review and approval.
>
> (2) For purposes of this subsection (c), the required procurement of cost-effective renewable energy resources for a particular year shall be measured as a percentage of the actual amount of electricity (megawatt-hours) supplied by the electric utility to eligible retail customers in the planning year ending immediately prior to the procurement. For purposes of this subsection (c), the amount paid per kilowatt hour means the total amount paid for electric service expressed on a per kilowatt hour basis. For purposes of this subsection (c), the total amount paid for electric service includes without limitation amounts paid for supply, transmission, distribution, surcharges, and add-on taxes.

Notwithstanding the requirements of this subsection (c), the total of renewable energy resources procured pursuant to the procurement plan for any single year shall be reduced by an amount necessary to limit the annual estimated average net increase due to the costs of these resources included in the amounts paid by eligible retail customers in connection with electric service to:

(A) in 2008, no more than 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007;

(B) in 2009, the greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2008 or 1% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007;

(C) in 2010, the greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2009 or 1.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007;

(D) in 2011, the greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2010 or 2% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007; and

(E) thereafter, the amount of renewable energy resources procured pursuant to the procurement plan for any single year shall be reduced by an amount necessary to limit the estimated average net increase due to the cost of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011.

No later than June 30, 2011, the Commission shall review the limitation on the amount of renewable energy resources procured pursuant to this subsection (c) and report to the General Assembly its findings as to whether that limitation unduly constrains the procurement of cost-effective renewable energy resources.

(3) Through June 1, 2011, renewable energy resources shall be counted for the purpose of meeting the renewable energy standards set forth in paragraph (1) of this subsection (c) only if they are generated from facilities located in the State, provided that cost-effective renewable energy resources are available from those facilities. If those cost-effective resources are not available in Illinois, they shall be procured in states that

adjoin Illinois and may be counted towards compliance. If those cost-effective resources are not available in Illinois or in states that adjoin Illinois, they shall be purchased elsewhere and shall be counted towards compliance. After June 1, 2011, cost‑effective renewable energy resources located in Illinois and in states that adjoin Illinois may be counted towards compliance with the standards set forth in paragraph (1) of this subsection (c). If those cost‑effective resources are not available in Illinois or in states that adjoin Illinois, they shall be purchased elsewhere and shall be counted towards compliance.

(4) The electric utility shall retire all renewable energy credits used to comply with the standard.

(5) Beginning with the year commencing June 1, 2010, an electric utility subject to this subsection (c) shall apply the lesser of the maximum alternative compliance payment rate or the most recent estimated alternative compliance payment rate for its service territory for the corresponding compliance period, established pursuant to subsection (d) of Section 16‑115D of the Public Utilities Act to its retail customers that take service pursuant to the electric utility's hourly pricing tariff or tariffs. The electric utility shall retain all amounts collected as a result of the application of the alternative compliance payment rate or rates to such customers, and, beginning in 2011, the utility shall include in the information provided under item (1) of subsection (d) of Section 16‑111.5 of the Public Utilities Act the amounts collected under the alternative compliance payment rate or rates for the prior year ending May 31. Notwithstanding any limitation on the procurement of renewable energy resources imposed by item (2) of this subsection (c), the Agency shall increase its spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year by an amount equal to the amounts collected by the utility under the alternative compliance payment rate or rates in the prior year ending May 31.

Section 16-111.5(b) of the PUA states in part, "The plan shall specifically identify the wholesale products to be procured following plan approval, and shall follow all the requirements set forth in the Public Utilities Act and all applicable State and Federal laws, statutes, rules, or regulations, as well as Commission orders. Nothing in this Section precludes consideration of contracts longer than 5 years and related forecast data. Unless specified otherwise in this Section, in the procurement Plan or in the implementing tariff, any procurement occurring in accordance with this Plan shall be competitively bid through a request for proposals process."

The PUA goes on to state that:

> (iv) the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year, separately or in combination, to meet that portion of its load requirements not met through pre-existing contracts, including but not limited to monthly 5 x 16 peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity obligations, capacity purchase plan, and ancillary services;

The definition of renewable energy resources is contained in the IPA Act,

> "Renewable energy resources" includes energy and its associated renewable energy credit or renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, trees and tree trimmings, hydropower that does not involve new construction or significant expansion of hydropower dams, and other alternative sources of environmentally preferable energy. For purposes of this Act, landfill gas produced in the State is considered a renewable energy resource. "Renewable energy resources" does not include the incineration or burning of tires, garbage, general household, institutional, and commercial waste, industrial lunchroom or office waste, landscape waste other than trees and tree trimmings, railroad crossties, utility poles, or construction or demolition debris, other than untreated and unadulterated waste wood.

As explained more fully below, the **IPA** proposed, in its filed Plan, to comply with the renewable portfolio standard in Section 1-75(c) of the IPA Act, and also to enter into long-term PPAs for renewable energy supplies to satisfy eligible retail customers' energy needs "outside of the RPS." Some of the other parties took issue with this proposal.

i. Objections and Responses to Objections

ComEd believes that the parties should explore entering into long term contracts, including those for low carbon and renewable resources, as part of the procurement Plan. However, ComEd says this would be a dramatic change in the procurement portfolio and must be done with careful consideration of its impact on customers, the utility and other stakeholders. ComEd believes that the IPA's proposal should be the subject of Commission-led workshops to determine its feasibility. In ComEd's view, there are a number of issues that must be resolved before such long-term contracts could be included in the portfolio. ComEd Objections at 6.

According to ComEd's Objections, the IPA's proposal needs to be modified in order to comply with legal requirements. The procurement of renewable energy in

Illinois is governed by section 1-75(c) of the IPA Act. ComEd says that section sets out both target amounts of renewable energy to procure as well as caps on the amount that may be spent in any one year to procure such resources. While the IPA indicates that it intends for ComEd to target approximately 3.5% of Eligible Retail Load or 1,400,000 MWH annually, ComEd complains that the IPA does not indicate how this would be limited by the annual cost caps in the PUA over the term of the proposed contracts. ComEd adds that it is not clear whether the IPA is proposing that the statutory cost caps would even apply to these resources. ComEd contends that this consumer protection must be honored in any long-term renewable purchase. *Id.* at 7.

ComEd states that while the PUA does permit the procurement of energy pursuant to long-term contracts, such resources must be "standard wholesale products" and such contracts must be "standard contract forms[.]" ComEd asserts that the reason this provision is in the law is to ensure that the IPA can select the lowest price bids by suppliers on a consistent basis without having to make difficult and potentially controversial evaluation assumptions to compare bids. If the Commission concludes that the benefits associated with long-term contracts outweigh the credit and load switching risks, ComEd insists that it should require that any such procurement be for standard wholesale products, be open to all market participants to ensure the lowest cost to customers and require the use of the same standardized contract for all suppliers. ComEd states that outside of the renewable provisions in the IPA Act, which are already being met, the PUA does not permit special preferences for any group of suppliers. *Id.*

ComEd also believes that before any long-term contracts are executed, a detailed and comprehensive risk analysis must be conducted to ensure that such a contract will lower, rather than increase, costs and risks to customers. ComEd complains that the IPA has not yet provided such an analysis. For example, ComEd says a prominent risk associated with long term supply contracts for utilities is the potential for stranded costs if a substantial number of customers use their option to switch from the utility's fixed price tariff if market prices fall. ComEd asserts that if the utility has signed substantial long term commitments for power that turns out not to be needed and must be sold at a loss, the remaining customers on the fixed price tariff would be forced to pay higher prices to cover any loss. As an example of how quickly load requirements can change, ComEd indicates that its Large Commercial and Industrial customer bundled load share dropped from 32% to 0% from 2004-2009. ComEd states that its Small Commercial and Industrial load dropped from 65% to 37% over the same time frame. Given the advent of smart grid initiatives and the utility consolidated billing and purchase of receivables ("UCB/POR") provisions recently implemented to facilitate residential switching, ComEd claims there is no way to know with reasonable certainty how much load the IPA is attempting to contract for 5, 10 or 20 years out. *Id.* at 8.

ComEd further complains that there is no analysis demonstrating that this proposal will produce "the lowest total cost over time," as required by the PUA. According to ComEd, the IPA notes on page 20 of its Plan that, "Renewable energy generation assets typically generate power at costs higher than those available in the market today." In ComEd's view, because it does not appear the IPA believes these contracts are subject to the consumer protections related to renewable energy that are built into the IPA Act, it is particularly important for the IPA to meet this requirement. ComEd believes that such risks should not be imposed on customers absent a thorough analysis demonstrating that the potential benefits outweigh the costs. While the IPA raises the issue of carbon cost risk and immediately concludes that long term renewables contracts are needed to hedge this risk, ComEd states that, contrary to what is implied by the IPA, standard product contracts provide the best hedge against potential future price increases driven by rising fuel and carbon related costs, because once the price is fixed, the supplier, not the customers, bear all risks of cost increases. *Id.* at 8-9.

ComEd believes it is clear that both the IPA Act and the PUA permit the procurement of long-term renewable resources. However, ComEd is concerned that there are many issues which need to be explored in order to ensure that any such procurement is done consistently with legal requirements and in the least risky and least costly manner for customers. Therefore, ComEd recommends that the Commission direct the IPA and the Commission Staff to conduct workshops on this issue with the expectation that any recommendations coming out of the workshops could be incorporated into future procurement plans. *Id.* at 9-10.

In its Response to Objections, ComEd notes that Staff, AIU and ExGen raised many similar objections to the proposal to procure long-term renewables. Staff objected to the proposal because it lacked justification, lacked details and failed to address many important issues. AIU, while not objecting to the concept of long-term wind energy procurement, notes that the Plan lacked any discussion of the details that were critical to the success of such a procurement. AIU went on to express its position on many of these issues. ComEd Response at 1-2.

ComEd states that in particular, both Staff and AIU raised the objection that it did not appear the IPA was proposing to subject this procurement of renewable energy to the rate impact caps set out in Section 1-75(c)(2) the IPA Act. In addition, ComEd says Staff objected that the IPA failed to address how its proposal can be made to comply with the "Standard Wholesale Product" requirement in the PUA. ComEd agrees with both of these Objections. ComEd believes it is critical that any long-term renewable proposal comply with the consumer protection provisions set out in the IPA Act. ComEd says nor can the IPA disregard, as its current proposal does, the legal restriction that it purchase only standard wholesale products. *Id.* at 2.

According to ComEd, the IPA should acknowledge that the purchase of renewables must comply with both the IPA Act and the PUA. In particular, ComEd says renewable purchases should be made under Section 1-75 of the IPA Act, not under Section 16-111.5 of the PUA, as the IPA proposes. If long-term renewable contracts are purchased under the correct statutory process, ComEd claims the inherent value of the REC in any bundled long-term bid for renewable energy will need to be determined.

ComEd contends that this is not a reason to use the wrong statutory process. ComEd believes that among the solutions is to conduct a simultaneous procurement of around-the-clock block energy for a similar term. ComEd says an adjustment would be required to the ATC price to put it on an equivalent basis to the wind energy, but ComEd is confident that such an adjustment could be reasonably made. ComEd claims this would determine the value of the energy in the bundled renewable product. According to ComEd, the REC value can then be easily backed out and applied against the rate cap in the IPA Act. *Id.* at 2-3.

AIU says its understanding of this IPA proposal is that: 1) the IPA will continue forward with the procurement of one-year, REC-only contracts to secure the necessary renewable energy resources for the period June 2010 through May 2011; and 2) the IPA will also issue one or more solicitations to secure longer term contracts that include both RECs and energy for the period beginning June 2011. AIUs also understand it to be the IPA's intent to solicit contracts that procure 600,000 MWh of energy along with the associated RECs for each year of these longer term contacts. While AIU is not objecting to the proposal at this time, it says that this lack of an objection should not be interpreted to mean that AIU supports the concept of longer term renewable energy supply contracts. AIU Objections at 1-2.

According to AIU, limiting the contract term will also benefit the benchmarking process, which is required by Section 1-75(c)(1) of the IPA Act. AIU asserts that procuring a product that includes energy along with the renewable energy credits will make it necessary for the Procurement Administrator, along with the other parties who are consulted in the benchmark calculation process, to make a projection of energy prices well beyond the one to three years for which the current energy markets are visible. AIU says that while there are various methods that can be used to make such a projection, from a simple trend model to an extremely complex simulation model, AIU believes that most parties would agree, that regardless of the methodology, the projections become less reliable the further out in time they go. AIU asserts that limiting the contract term of these longer term contracts to 10 years or less also limits the time period for which the Procurement Administrator will need to project energy prices beyond the period which current markets are visible. *Id.* at 2-3.

In addition, AIU submits that if the decision is made to use the generator bus as the delivery point, the estimated cost of congestion and any non-MISO transmission cost should be included in the calculation used to determine how the resulting contracts will count toward the Renewable Resource Budget ("RRB") and in the benchmark formulas that will be used for the longer term renewable energy supply solicitation. *Id.* at 5.

AIU claims another essential component that is missing from the longer term renewable energy supply proposal is a methodology for determining how the resulting contracts will count toward the RRB. AIU believes it is essential that 1) the methodology be known in advance of the solicitation, 2) such determination is for each year of the longer term contracts and 3) such determination is not subject to change in the future. *Id.*

AIU suggests that one possible method would be to assign a market value to the energy and capacity components of the product based on the best market information available at the time. The IPA will be procuring capacity for the 2011 and 2012 planning years and energy for the entire 2011 plan year and part of 2012. For these time periods, AIU says the actual results of these procurement events could be utilized. For years beyond that, AIU claims the energy and capacity price forecasts used in the benchmark calculation could be used. According to AIU, the difference between the sum of these energy and capacity values and the longer term renewable energy supply contract price would be determined to be the REC value imbedded in the contract price. AIU says this REC value multiplied by the contract quantity would then be applied to the budget. *Id.* at 5-6.

Staff states that the Plan does not appear to count these long-term renewable PPA contracts toward the attainment of the RPS goals. While it is not entirely clear to Staff, this conclusion is supported by the fact that the Plan discusses these long-term contracts in the section on energy contracts rather than the section on the RPS. Also, within the section on the RPS, Staff says the quantity of RECs planned to be purchased through one-year contracts has clearly been computed to completely satisfy the RPS goals (i.e., without any assistance from the long-run PPA contracts). Staff Objections at 12-13.

According to Staff, if the PPA energy were to be used toward the attainment of the Illinois renewable portfolio standard, then the IPA Act requires that the energy be accompanied by their associated RECs. Otherwise, Staff claims there is no value in purchasing the RECs, unless the IPA were to speculate on reselling them elsewhere at a profit, which Staff says the IPA is not proposing. Hence, it appears to Staff that the IPA does not plan on requiring the PPA suppliers to include RECs with the energy. Staff does not necessarily object to this arrangement because such an arrangement still permits PPA suppliers to market their RECs to the utilities and the IPA and/or others within or without Illinois. Thus, Staff believes that REC availability and REC prices should not be adversely affected, while PPA bid prices should also be lower than they would be otherwise, reflecting the retained value of the RECs to the suppliers. Furthermore, Staff states that separating the PPA solicitation from the REC solicitation avoids a host of issues associated with the application of the budget, wind, and location constraints and preferences of the IPA Act. However, Staff does object that the Plan is not entirely clear on these points. *Id.* at 13.

ExGen also expressed concerns regarding the IPA recommendation to solicit proposals from renewable energy providers under longer term contracts with ComEd and AIU. ExGen argues that in the event federal carbon legislation is passed, it will bind the carbon emitter (i.e., the generator) rather than the power consumer in Illinois. ExGen contends that any fixed-price power purchase agreement between an Illinois utility and a carbon-emitting power supplier would leave the risk of increased costs due to a carbon cap exclusively with the power supplier. As far as the carbon legislation is concerned, ExGen insists that there is no difference between a "renewable" and a conventional power supplier. According to ExGen, the IPA should continue its practice of placing environmental risks associated with electric generation on suppliers. ExGen Objections at 2.

ExGen also argues that to the extent "renewables" are capable of providing a lower long-term price because of their method of generation or federal and state subsidies, then they will win a competitive procurement. If, on the other hand, renewables are more expensive and cannot prevail on a "best price" basis, even taking into account all federal and state incentives, ExGen asserts that the selection of the renewables under the Plan by definition will result in a worse deal for Illinois consumers. Finally, ExGen contends that nuclear power, which generates almost no carbon emissions, should be considered on an equal basis to "renewable" resources; the Plan offers no reason it is not. *Id.* at 2.

According to ExGen, the Plan offers no evidence whatsoever that federal and state assistance to renewable energy is likely to decline in future years. In fact, ExGen believes it is unlikely to decline until such time, if ever, that renewable energy is price-competitive with conventional energy, even without these subsidies. Under these circumstances, ExGen asserts there is no need to "lock-in" any putative temporary price advantage of renewable energy through long-term contracts. ExGen maintains that the bottom line is price. ExGen argues that if federal and state subsidized renewables remain so expensive that they cannot win a "best price" procurement, then they should not be selected and the premise that they provide any consumer price "hedge" is flawed. *Id.* at 3.

In response to ExGen, the **IPA** states that while it agrees it may be beneficial for consumers to pursue longer term PPAs for standard, non-renewable energy, the IPA disagrees with ExGen's analysis. The IPA says first, the IPA Act requires that a minimum percentage of AIU and ComEd's total energy supply include a portion of energy derived from cost-effective renewable resources. The IPA believes it has no option but to comply with the RPS. The IPA says second, the Plan proposes long term PPAs for renewable energy supplies to satisfy eligible retail customers' energy needs outside of the RPS. The IPA believes that long term, renewable PPAs can provide eligible retail customers with a long-term hedge against potential new costs that may be applied against carbon-based energy. The IPA states that the Plan proposes long term PPAs to seek electricity from resources that would have low to no exposure to carbon risks – not renewable energy per se. IPA Response at 21.

In response to objections to its proposal to acquire long-term renewable resources, the IPA asserts that it has broad authority to meet the electricity procurement needs of the eligible retail customers and 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.* at 4, citing 20 ILCS 3855/1-5(A). The IPA says the IPA Act requires that the Plan include provisions to acquire cost-effective energy resources for a minimum percentage of each utility's total supply. According to the IPA, these renewable energy resources, purchased to satisfy the IPA Act's RPS are subject to a cap on the price to be paid for renewable energy. However, the IPA claims that neither the IPA Act nor the PUA limit the acquisition of renewable energy to only the amounts required to satisfy the RPS, which are actually minimum volume goals. Moreover, the IPA asserts that the cost caps that apply to the purchase of renewable energy apply only to the "renewable" energy acquired to satisfy the RPS. The IPA says there is no provision in the IPA Act or the PUA that would preclude the acquisition of energy, derived from renewable resources, outside of the minimums required to meet the RPS. *Id.* at 4-5.

The IPA states that to further the statutory requirement to develop "adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time," while also "taking into account any benefits of price stability," the Plan proposes to solicit bids from qualified renewable energy providers for longer-term renewable energy. The IPA intends for these long-term PPAs to satisfy eligible retail customers' energy needs outside of the RPS. The IPA believes that long-term PPAs can provide eligible retail customers with a hedge against potentially high-cost, or certainly unstable, carbon-based energy should the federal government impose restrictions or additional taxes on carbon-based energy. In the IPA's view, competitively sourced long term contracts may stabilize and minimize energy costs, and taken in a portfolio of spot, medium and long term contracts and RECs, may maximize benefits. *Id.* at 5.

The IPA believes it is prudent to further diversify the current energy exposure to predominantly nuclear, coal and natural gas fired power plants by modestly increasing the availability of renewable resources. The IPA argues that renewable resources provide an attractive mitigation to carbon legislation. The IPA says it may count the REC portion of the procurement toward the RPS requirements if doing so is beneficial to consumers. According to the IPA, as this procurement is being conducted outside of the RPS context, the RPS requirements do not apply. *Id.* at 8.

In response to concerns raised by AIU, the IPA indicates it plans to solicit proposals of a series of set lengths and durations, and select contracts based on lowest realized costs to eligible retail customers. The IPA says term and financing costs will be drivers in establishing realized costs. As such, the IPA believes that Plan is clear in this respect, and recommends that no modifications be made to the Plan at this time. *Id.* at 11-12.

Also in response to AIU, the IPA maintains that the longer term renewable PPA procurement is being conducted outside of the RPS context; therefore, the RPS requirements are not applicable. The IPA says it may count the REC portion of the procurement toward the RPS requirements if doing so is beneficial to consumers. *Id.* at 13.

In its Response, the **AG** states that several parties have filed objections relating to the plan to solicit bids for long-term renewable energy contracts to hedge against carbon risk. According to the AG, most of these objections raise questions regarding the process to be used for this procurement and the contract terms that would be specified in the solicitation. In this regard, the AG notes that ComEd asks the Commission to direct the IPA and Staff to convene workshops to address these details, and AIU appear to support a workshop approach, as well. AG Response at 9-10.

The AG is confident that the IPA Procurement Administrator and the IPA Procurement Monitor could, based on the framework set forth in the Plan and applicable statutes, design a solicitation for long term contracts that would protect consumers against carbon risk. However, the AG would not object to a workshop process that allows the parties to further define the details of such a solicitation, provided the workshop schedule is set to maximize the potential for Illinois consumers to realize savings through the many state and federal incentives now available to reduce the cost of generating renewable energy. The AG would not support a workshop in lieu of a solicitation to hedge carbon risk during the procurement cycle covered by the Plan. *Id.* at 10-11.

According to the AG, the IPA's proposal to solicit long-term renewable energy projects may be new to Illinois, but it's been done elsewhere. For instance, earlier this month, the AG says the Maine Public Utilities Commission issued an order directing two utilities to enter into 20-year contracts to purchase the output of a 60 MW facility located in the State of Maine. The AG asserts that in so ordering, the Maine Commission cited clearly articulated State energy policy of encouraging the development of wind facilities in Maine, and found that long-term contracts were necessary to finance new wind generating capacity. *Id.* at 11.

Because the AG maintains that details relating to the solicitation of long-term renewable energy contracts should be left to the IPA Procurement Administrator and ICC Procurement Monitor or resolved through a workshop process, the AG does not, at this time, take a position on the various contract and procurement process issues raised in other parties' objections. The AG does believe it is necessary to respond to questions that several parties have raised about the relationship between the proposed solicitation of long term renewable energy contracts to hedge carbon risk and the solicitation of bids to comply with the RPS. The AG views these as completely separate solicitations. *Id.* at 11-12.

The AG says the Plan correctly states that ComEd and AIU are required to procure 5% of their portfolio from renewable energy resources during Planning Year 2010 – 2011, provided they can do so without exceeding the cost cap imposed by 220 ILCS 3855/1-75(c)(2)(C). The AG believes all parties agree that the cost cap applies to this purchase. *Id.* at 12.

In the AG's view, the purpose of the IPA's proposed solicitation of long-term renewable energy contracts is to mitigate carbon risk. In order to accomplish this objective, the AG claims the IPA necessarily must purchase energy generated using renewable resources, but need not purchase the associated REC. The AG asserts that there is nothing in the Plan to indicate whether the solicitation would seek bids solely for energy or for energy plus the associated REC. Several parties, nonetheless, assume that the REC will be purchased along with energy and raise concerns about how to value the REC and whether the cost cap applies to the REC portion of this purchase. (AG Response at 12)

The AG maintains that purchases of renewable energy to mitigate carbon risk, with or without a REC, are not constrained by the cost cap that applies in the RPS context. However, the AG does not believe that the Commission needs to make a ruling on this issue at this time because the Plan does not say that the IPA intends to purchase RECs along with energy. The AG requests that the Commission defer a ruling on this issue until details of the solicitation are clarified. *Id.* at 12-13.

ICEA agrees with ComEd that the Plan does not address whether it would count the long-term PPAs toward the RPS goal and does not comply with the IPA Act or the PUA because it fails to describe how the amount spent on these resources would fit under the RPS cap. *Id.* at 2.

ICEA complains that the Plan provides no justification for limiting any aspect of the Plan to a singular type of generation. ICEA agrees with Staff and ExGen that it is anti-competitive to apply a requirement to a certain type of generation, to the exclusion of other types of energy products. ICEA believes that permitting all resources to compete for the same type of contracts provides more robust competition and the opportunity for a lower price outcome for ratepayers. ICEA asserts that the IPA should not provide preferential treatment to a certain type of resource, to the detriment of consumers and competitive markets. *Id.*

ICEA suggests this is a rather dramatic departure from last year's plan. ICEA states that the modification concerning long-term contracts for renewable resources appears to be entirely based on comments from certain parties after the IPA's initial filing of the Plan, to which other parties had no opportunity to comment. ICEA believes there is a need for a more rigorous review of this change to the Plan. *Id.* at 2-3.

IWEA argues that contrary to ExGen's objections, key federal incentives for renewable energy created under American Reinvestment and Recovery Act ("ARRA") have firm deadlines of December 31, 2010. IWEA says that while ARRA extended the federal production tax credit until the end of 2012, projects must be under construction by the end of 2010, and be in service by the end of 2012, to qualify for the most favorable ARRA benefit: the U.S. Treasury Department grant. According to IWEA, the acquisition of long-term contracts prior to this deadline is essential in order for developers to acquire financing and commit capital to projects. IWEA Response at 4.

According to IWEA, projects which receive both ARRA benefits and long-term contracts should have a cheaper cost of capital which will ultimately benefit Illinois ratepayers through cheaper compliance costs under the RPS. IWEA states that a procurement event for bundled renewable energy PPAs should reveal whether there are certain pricing advantages for the IPA as a result of federal stimulus funds that merit immediate action. If the IPA does not even offer a solicitation for long-term contracts, then IWEA says it cannot know what opportunities it may be missing. *Id.*

IWEA states that because these specialized credits expire at the end of 2010, it requests that the Commission approve the IPA Plan, and direct the IPA to hold a procurement event for long-term renewable PPAs as soon as possible. *Id.*

IWEA notes that in its objections, Staff questioned whether renewable contracts would be "bundled" contracts (power and RECs). IWEA says the IPA Act states that renewable energy resources used for compliance with the RPS must be either "energy and its associated renewable energy credit or renewable energy credits from wind" and other eligible renewable sources. IWEA states that considering this mandate, it is unclear why or how the IPA would procure renewable power without the associated RECs. Therefore, IWEA's recommendation is that the IPA hold a procurement event for long-term bundled renewable power supply and the associated RECs as soon as possible. *Id.* at 7.

IWEA believes that bundled contracts greatly simplify the entire process for bidders, the IPA and the Procurement Administrator. IWEA asserts that holding a renewable power-only solicitation, followed by a separate solicitation for the full portfolio of (short- or long-term) RECs is unnecessarily complicated. IWEA claims such a system would make the consumer protection threshold much harder to calculate, and could result in some projects winning power supply contracts but not REC contracts, and vice versa, which would further complicate project finance. *Id.*

IWEA argues that the IPA should hold a solicitation for bundled long-term renewable contracts. IWEA claims such a solicitation could fulfill approximately 60 percent of the RPS requirement. IWEA suggests that the remaining portion of the requirement can be met through a separate RFP for REC-only contracts of varying lengths. IWEA believes that adopting this system will lock in lower prices for renewables for long-term supply, while allowing the IPA flexibility (through the remaining 40% of the RPS requirement) to respond to load migration, possible market downturns or other concerns. *Id.*

IWEA notes that ComEd and Staff questioned how, or even if, the consumer rate impact threshold would be calculated under a long-term renewable PPA solicitation. IWEA agrees the statutorily mandated threshold must be respected, and looks forward to seeing the IPA and Procurement Administrator develop a viable application of the cost cap that meets the IPA Act's goals. IWEA maintains that the IPA and the Procurement Administrator have the ability under the statute to develop the structure of the consumer rate impact cap after the Commission's approval of the Procurement Plan. *Id.* at 11.

IWEA also responds to ExGen objections that the IPA's intent to bias the energy procurement of Illinois public utilities in favor of suppliers of renewable energy. According to IWEA, ExGen also states that power should only be evaluated on objective economic factors such as price, contract length, and risk of non-performance, and that nuclear power should be considered on an equal basis to renewable resources and the Plan offers no reason it is not. IWEA asserts that the IPA Act, not the Plan, defines what constitutes renewable energy, and nuclear generation is not included in those definitions. *Id.* at 12-13.

WOW/ELPC states that Staff and ExGen raise similar objections, asserting that the Long Term Renewable Portfolios for AIU and ComEd should be open to all forms of generation. WOW/ELPC says both arguments are based on the premise that the IPA is procuring all energy at the total lowest cost. WOW/ELPC asserts that this premise appears to gloss over the cost effective standard of the RRB, the Illinois RPS, the definition of "Renewable Energy Resources" and the need to promote environmentally sustainable electric service. WOW/ELPC contends that these four requirements set the parameters for the IPA's purchase of renewable resources until at least 2025. WOW/ELPC believes the Long Term Renewable Portfolio proposed by the IPA meets all of these parameters. WOW/ELPC Response at 6-7.

WOW/ELPC state that the IPA has to purchase increasing amounts of renewable resources over the next 15 years at a price somewhere between the lowest cost and the cost effective limit of the RRB. WOW/ELPC claims PJM has estimated that states' renewable portfolio standards, in it's territory, will require 26 million MWh of renewable energy in 2009 and increases to 200 million MWh needed in 2025. WOW/ELPC also asserts that MISO has 4,900 MW of wind as of the end of 2008 and needs 22,000 MW of renewable generation to meet the RPS requirements of the states in its territory. Therefore, WOW/WLPC concludes that there is a need for renewable generation to be built over the next 15 years. *Id.* at 7.

WOW/ELPC state that both AIU and ComEd raise questions about the application of the RRB to the procurement of Long Term Renewables. Both also assert that it is unclear whether the RRB is intended to even apply since the Long Term Portfolio proposal is in the energy only section of the Procurement Plan and not the Renewable Portfolio Standard section. According to WOW/ELPC, the underlying question to those objections is whether the IPA is procuring renewable energy, by itself, or procuring renewable energy and the associated RECs. WOW/ELPC states that because the IPA is proposing to purchase renewable resources, the RFP needs to bundle the energy and renewable energy credits. WOW/ELPC says the IPA Act requires a "renewable resource" to be either a purchase of energy and its associated RECs or the purchase of RECs, from a defined list of types of renewable energy producers. WOW/ELPC believes the purchase of these renewable resources should be applied to the Illinois renewable portfolio standard and be part of the RRB. *Id.* at 13.

According to WOW/ELPC, the significant concerns raised by AIU, ComEd, the Staff and ExGen are either already resolved, or will be resolved through these

Objections and Responses or will be addressed in December and January when the contract terms are developed. Therefore, WOW/ELPC believes no workshops are needed for the Commission to approve the use of Long-Term Renewables in this year's plan. However, WOW/ELPC would be more than amenable to participating in procurement plan design discussions for future procurement plans. *Id.* at 14.

ii. Replies to Responses

Given the clarifications included within the IPA response, **AIU** says it now supports the concept of procuring long-term renewable resources if certain additional modifications are made to the Plan that clearly state that the procurement of long-term renewable resources falls under Section 1-75(c) of the IPA Act and therefore will meet all the requirements of the Illinois RPS. According to AIU, the IPA has not provided sufficient analysis to allow the Commission to approve this aspect of the IPA Plan under Section 16-111.5(d)(4) of the PUA. AIU believes, however, that the Commission could approve the proposal to solicit bids for long-term renewable resources in the context of the RPS if specific modifications to the proposal were included. AIU Reply at 2.

AIU asserts that the IPA Act and the PUA do not preclude the IPA from proposing to procure energy derived from renewable resources beyond the minimum requirement of the RPS; nor do they preclude the IPA from proposing long term contracts. AIU says that Section 16-111.5(d)(4) of the PUA does, however, place certain requirements on what the IPA is to include in its Plan and defines the criteria the Commission should use when making its decision to approve or modify the Plan. *Id.*

According to AIU, the IPA has provided no analysis to support its proposal to procure long-term renewable resources under Section 16-111.5, nor has any party to this proceeding offered such analysis. To the contrary, AIU says the Plan, at pages 21-25, discusses the analysis performed in support of the hedging strategy included in the Plan and this analysis does not appear to support a long-term energy hedging strategy. *Id.* at 3.

AIU indicates that at page 25 of the Plan, it states, "The analysis supports a recommendation of fixing the price of 30% of requirements in the procurement immediately prior to the delivery period, 35% one year earlier, and 35% two years earlier." It is unclear to AIU how the Commission could make the determination required under Section 16-111.5, that the inclusion of the long-term renewable resource proposal is "at the lowest total cost over time, taking into account any benefits of price stability" when the only analysis included in the evidence, the IPA's Monte Carlo analysis, supports just the opposite. It is also unclear to AIU why the Commission would entertain the long term renewable resource proposal under Section 16-111.5, if in the IPA's view the solicitation may not be competitive and the resulting price may not be representative of a market result. *Id.* at 3-4.

According to AIU, the criteria the Commission must use to approve the long-term renewable resource proposal under Section 1-75(c) of the IPA Act is different than that of the PUA. The IPA Act includes three criteria that purchases made to satisfy the RPS must : 1) satisfy the minimum percentage requirements included in Section 1-75(c)(1); 2) not exceed benchmarks based on market prices for renewable resources; and 3) be "cost-effective" as defined in Section 1-75(c)(2) . AIU believes the current IPA proposal could meet these criteria with minor modifications to the proposal. *Id.* at 4.

AIU suggests that the Plan should be modified to make clear the long-term renewable resources will be procured under Section 1-75(c) and, therefore, the RECs derived from the long term purchases would count toward the utilities' RPS requirements. AIU does not believe there is sufficient modeling and analysis on the record to allow the Commission to make the "lowest total cost over time, taking into account any benefits of price stability" determination required under Section 16-111.5 of the PUA, but the Commission could approve this proposal under Section 1-75(c) of the IPA Act. *Id.*

AIU also believes the Plan should also be modified to make it clear that the IPA will perform the tasks necessary to meet the benchmarking requirements and the requirement to ensure the purchases are "cost-effective" as required under Section 1-75(c). Under AIU's proposal, the IPA would utilize a combination of actual procurement results and the energy and capacity components of the market-based benchmarks to estimate the non-REC value of the long term renewable resource contracts. AIU suggests that the REC value would then be calculated as the difference between the contract price and the non-REC value. *Id.* at 5.

The IPA indicates that "payment obligation under the PPA will be limited by the utility's ability to recover the cost in rates charged to customers." AIU is in agreement with the IPA position. *Id.* at 7.

The IPA indicates that it "may count the REC portion of the procurement toward the RPS requirements if doing so is beneficial to consumers. As this procurement is being conducted outside of the RPS context, the RPS requirements do not apply." AIU maintains that the REC portion of the procurement should count toward the RPS requirements. The IPA has also clarified that capacity will be included in the product and that it is the responsibility of the seller to register such capacity in the relevant RTO market. AIU supports this approach. *Id.* at 7.

AIU also comments on ComEd's suggestion, offered as a solution to determining the disaggregated value of energy and RECs from long term renewable contracts, to "conduct a simultaneous procurement of ATC block energy for a similar term." AIU acknowledges the approach suggested by ComEd may provide the most accurate methodology to identify the value of energy that will be embedded in the long-term renewable resource product being proposed by the IPA. With that said, AIU believes this fact alone does not provide the Commission with sufficient evidence to approve a long-term block energy product as part of the Plan. More specifically, AIU does not believe there is sufficient analysis demonstrating long-term block purchase as part of a least cost portfolio for the Commission to determine that including a long-term block energy product would result in "the lowest total cost over time, taking into account any benefits of price stability." *Id.*

The **AG** argues that ComEd's view of the IPA's authority to solicit long-term contracts for renewables, discussed below, is based on a selective and unduly restrictive reading of the PUA and the IPA Act. Contrary to ComEd's assertions, the AG insists that there is nothing in the PUA that precludes the purchase of long term renewable energy contracts to hedge against carbon risk – with or without the associated RECs. The AG says ComEd also fails to acknowledge that there are two separate provisions in the IPA Act that require the IPA to purchase renewable energy resources: (1) the utility RPS provision that mandates procurement of a minimum quantity of renewable resources for ComEd and Ameren customers, provided they can be procured without exceeding the cost cap, 20 ILCS 3855/1-75(c); and (2) the Alternative Retail Electric Supplier RPS provision that mandates the use of ARES' alternative compliance payments to purchase RECs. AG Reply at 5, citing 20 ILCS 3855/1-56.

The AG notes that the IPA is required to identify alternatives for those portfolio measures that are identified as having significant price risk. According to the AG, the IPA found that there is significant price risk associated with heavy reliance on the existing generation mix in PJM and MISO – because federal carbon controls will drive up costs for the fossil-fired generators in both RTOs. The AG asserts that to mitigate this risk, as required by statute, the IPA proposes an alternative: long-term renewable energy contracts. AG Reply at 5.

The AG claims that the ideal hedge against carbon risk is a long-term contract with a new, zero-carbon energy source, which the AG says will be able to replace fossil fuel-fired generation that becomes too expensive to operate in a carbon-constrained economy. In the AG's view, long-term renewable energy contracts, which can be used to finance new wind facilities, are the obvious choice. The AG alleges that there are numerous federal and state incentives available during the current procurement cycle that could benefit consumers by reducing the cost of these projects. *Id.* at 6.

The IPA proposes to solicit bids from renewable generators for long-term unit-contingent contracts. The AG asserts that unit-contingent contracts are standard wholesale products used by utilities around the country to serve load. The AG also says that unit-contingent contracts are not the IPA's only option. The AG states that the IPA could also procure long-term renewable energy contracts by soliciting bids for financial contracts for differences that are not production-dependent. Like the unit-contingent contracts that the IPA has proposed, the AG asserts that these financial contracts could be used by renewable energy project developers to obtain financing for new zero-carbon generation. *Id.*

The AG argues that long term renewable energy contracts, whether unit-contingent or financial contracts for differences, are "standard wholesale products," as that term is used in the section of the PUA that requires the IPA to develop a procurement plan. The AG asserts that while the list of standard wholesale products in Section 16-111.5(b)(3) of the PUA does not include long term renewable contracts, the list is not meant to be exhaustive. The AG claims that the General Assembly's decision to include the phrase "including but not limited to" makes clear that the IPA is free to solicit long-term renewable energy contracts and other standard wholesale products not expressly listed in the statute. In the AG's view, it is also important to note that this Section of the PUA expressly states that "[n]othing in this Section precludes consideration of contracts longer than 5 years." *Id.* at 7.

The AG believes that the Plan must include alternatives to mitigate significant price risk, such as the impact that pending federal carbon controls are expected to have on electricity prices. The AG insists that the IPA is authorized to solicit any standard wholesale products that reduce those price risks, and nothing precludes the use of contracts that exceed 5 years to achieve this objective. The AG is convinced that soliciting bids for long-term renewable energy contracts to mitigate carbon risk is clearly permitted under the PUA. *Id.* at 7-8.

Next, the AG states that if the IPA decides to solicit bids for long term renewable energy contracts that include RECs, those RECs could be used to help ComEd and AIU comply with the RPS, provided the cost of the RECs would not cause the utility to exceed the statutory cost cap. The AG says that determining the value of the REC could be as simple as assigning a default value, based on the average REC price produced by the IPA procurement process in the relevant year. The AG believes there is no need to use the elaborate process proposed by ComEd, which would require the IPA to simultaneously solicit bids for around-the-clock energy for a similar term. *Id.* at 8.

The AG states that earlier this year, a new section of the IPA Act was enacted which requires ARES to meet the same RPS targets that utilities are required to meet. The AG says ARES are required to remit Alternative Compliance Payments into a newly created Illinois Power Agency Renewable Energy Resources Fund, to meet at least half of their compliance obligation. The AG states that the Alternative Compliance Payment is based on the REC price that resulted from the most recent utility procurement event. *Id.* at 9.

According to the AG, the new law requires the IPA to use monies in the Renewable Energy Resources Fund to procure renewable energy resources at least once each year in conjunction with a procurement event for electric utilities required to comply with Section 1-75 of the Act and shall, whenever possible, enter into long-term contracts. The AG states that the price paid to purchase RECs using monies from the fund cannot exceed the winning bid prices paid for like resources procured to comply with the utility RPS. *Id.*

If this approach were used to purchase renewable energy and the associated RECs, the AG says that the solicitation could specify that the REC price to be paid would be indexed to the ARES alternative compliance payments over the term of the contract. In that case, the AG claims the bidders would compete solely on the basis of energy prices. The AG believes that using this approach avoids the type of complications that might arise in connection with the utility RPS cost-cap and insulates utility customers from any risks associated with the transaction. *Id.*

According to the AG, the IPA, not the Commission, is in the best position to determine which sections of the IPA Act should govern this aspect of the procurement process. The AG recommends that the Commission decline ComEd's invitation to impose an overly restrictive interpretation of the statute on the IPA. The AG asserts that because of the IPA's familiarity with its own statute, the Agency's statutory interpretation must be accorded "extreme deference." *Id.* at 10.

In its reply, **ComEd** argues that Section 16-111.5(b)(3)(iv) of the PUA provides that the procurement plan shall include the proposed mix of "standard wholesale products" for which contracts will be executed. ComEd says that while the PUA does not define what standard wholesale products are, it does provide a comprehensive list of what was intended to be included. So far as energy is concerned, ComEd says all of the provided examples are block products backed by standardized contracts and comparable on price alone amongst the product class. ComEd also asserts that these products are regularly traded on energy exchanges and/or over-the-counter markets. While this section of the PUA does not limit such products to those that are specifically listed, ComEd contends that any other products need to share similar characteristics to the listed products. ComEd Reply at 3-4.

According to ComEd, it is a standard maxim of statutory construction that where a statute lists certain examples of the use of a term, all other examples of the term should be interpreted consistently with the listed examples. ComEd argues that under the doctrine of *ejusdem generis* applied by Illinois courts, the long-term renewable energy contracts proposed by the IPA are not "standard wholesale products" within the meaning of Section 16-111.5(b)(3)(iv) of the PUA. ComEd contends that what all the listed examples share in common is that they are backed by standardized contracts and comparable on price alone amongst the product class. ComEd claims that as the energy markets develop and mature, the Illinois General Assembly did not want to lock the IPA into having to procure only those block energy products that were "standard" at the time the statute was enacted, but to have some flexibility to procure other standard wholesale products as the market developed them. ComEd states that in the last several procurements, the procurement administrator has procured block products consisting of two or more months and a product known as a strip. ComEd believes these are the types of other standard wholesale products that the Illinois General Assembly intended. *Id.* at 5.

ComEd claims that Section 16-111.5 (c)(1)(vii) also supports this conclusion because this section allows the procurement administrator to negotiate with the bidders, but limits the negotiations to "price" and to one day. ComEd says that for negotiations limited to price to have significance, all other aspects of the bid must be consistent between bidders. ComEd asserts that with block products this is the case, but it is not for other types of products that fail the “standard wholesale product” definition. ComEd argues that for the type of product envisioned by the IPA, the products being bid have complexities that could require negotiations on non-price factors because variables such as timing and quantity of delivery, and risk of project completion, would not be standard between bidders. *Id.* at 6.

ComEd states that Section 16-111.5(e)(4) of the PUA requires the development of an RFP process that allows for the selection of winning bids on the basis of price alone. ComEd believes that while the use of block energy products easily permit the use of such a process, the product that the IPA and IWEA wish to procure will require the evaluation of a host of variables. ComEd also says that Section 16-111.5(f) provides for a very truncated review and approval process of the winning bids. ComEd contends that while such a process can easily be accommodated with standard block energy products, other types of products that permit greater variation among bidders than price would require a significantly longer review and approval process that could not likely be performed within the statutory timeframe. *Id.* at 6-7.

ComEd claims it has submitted persuasive evidence about the meaning of “standard wholesale products” from an expert with extensive knowledge of the energy industry. ComEd says the affidavit of Scott G. Fisher discusses the industry practice and understanding, concluding that the examples listed in Section 16-111.5(b)3(iv) are consistent with the generally-accepted industry definition of a “standard wholesale product.” *Id.* at 7.

ComEd insists that the long-term renewable energy contracts proposed by the IPA are not “standard wholesale products.” ComEd maintains that the IPA cannot legally procure such products under Section 16-111.5(b)3(iv) of the PUA. *Id.* at 8-9.

ComEd argues that the IPA’s proposal is also illegal because it circumvents the consumer protections included in the IPA Act to limit the impact of renewable energy purchases on customer rates. Section 1-75(c) of the IPA Act requires that procurement plans include renewable energy resources. ComEd notes that it goes on to provide that “the total of renewable energy resources procured pursuant to the procurement plan for any single year” shall be limited to certain specified amounts. According to ComEd, this is an absolute statutory limit on the amount of renewable energy resources that can be procured in any one year. *Id.* at 9.

According to ComEd, the increased cost of building and producing renewable electricity generation relative to conventional electricity leads the marginal suppliers of renewable energy to require an additional source of revenue above and beyond that provided by wholesale energy and capacity markets and thus bid this revenue “shortfall” into renewable attributes markets, leading to a visible price being placed on renewable energy attributes. ComEd asserts that experience in the IPA’s procurement of Illinois RECs has shown that renewable attributes have been priced well above zero. ComEd says that in the IPA’s 2008 and 2009 REC procurements for ComEd and AIU, Illinois in-state wind RECs were priced between $16.66/MWh and $35.72/MWh, while in-state non-wind RECs were priced between $13.46/MWh and $21.85/MWh. ComEd claims that visible forward prices for Illinois energy, which extend through 2013, indicate that forward price levels are at a similar or lower level today to what they were at the time of the solicitations that yielded these REC prices, suggesting that renewable energy providers continue to require REC pricing at a level similar to that observed in the recent IPA REC solicitations. *Id.* at 9-10.

ComEd argues that these costs can have significant consequences for customer rates and the General Assembly balanced the benefits of renewable energy against the costs to customers by establishing a firm cap on the rate impacts flowing from the renewable energy requirement. ComEd claims the IPA's proposal directly affects the policy judgment made by the legislature. *Id.* at 10.

Under the IPA proposal, ComEd asserts that the cost of long-term renewable contracts will include an additional component not present in the cost of "standard wholesale products" used to meet expected load requirements. If the contracts are awarded, ComEd says customers will have to pay those additional costs. According to ComEd, the IPA Act permits the additional costs of renewable energy supply to be incurred, provided that the impact on customer bills does not exceed the statutory limitations. ComEd says the PUA procurement provisions under which the IPA seeks to proceed do not permit such costs to be incurred and passed on to customers. ComEd insists that the IPA's proposal is illegal because it circumvents the consumer protections included in the IPA Act to limit the impact of renewable energy purchases on customer rates. *Id.* at 10-11.

ComEd states that Section 16-111.5(d)(4) provides that the Commission shall approve a procurement plan only if it determines that the plan will result in the provision of electric service at the lowest total cost over time. ComEd argues that by restricting a solicitation for any given product to only renewable generation resources as opposed to all types of bidders, the lowest possible prices may not be achieved for customers for the product being procured, because lower prices possibly could be obtained if the bidder pool is expanded to include all creditworthy bidders. ComEd asserts that the hedge benefits cited by the IPA as a reason to proceed with the long-term procurement of energy are not dependent on requiring the contracts to be associated with renewable resources as the IPA has proposed. According to ComEd, the long-term carbon risk faced by electricity customers stems from the fact that the value of carbon allowances or taxes would be reflected in wholesale electricity prices. ComEd contends that any contract that has adequate credit protections, and that fixes the price with no adjustment possible for carbon allowance prices or carbon taxes, provides the same level of hedge benefit against carbon risk, regardless of whether the contract is tied to a particular generation resource of any type. *Id.* at 11.

ExGen notes that Section 16-111.5(b)(3)(iv) of the PUA limits energy procurements to the purchase of "standard wholesale products" through a competitive procurement process. ExGen adds that Sections 16-111.5(c)(1)(ii) and 16-111.5(e)(3) require the IPA to develop and use market-based price benchmarks as part of the process to evaluate bids. ExGen says Section 16-111.5(d)(4) provides that bids will be negotiated and compared on a best price basis to ensure that consumers obtain the “lowest total cost over time," without any need for adjustment due to differing non-price terms. According to ExGen, the Plan meets none of these statutory requirements. ExGen Reply at 2.

According to ExGen, the phrase “standard wholesale products” is well understood to define electricity products that deliver, to wholesale customers, a specific firm energy commitment for an established time period and volume. For example, ExGen says one of the standard wholesale products, “ATC” energy, delivers an agreed upon amount of electricity 24 hours a day, seven days a week. ExGen adds that ATC, on-peak, and other standard products are routinely traded in the over-the-counter bilateral power markets, and to a limited degree on exchanges like the NYMEX. *Id.*

ExGen believes the long-term wind contracts proposed by the IPA are not standard products. On the contrary, ExGen states that each contract is unique with output characteristics dictated by the particular location and topography of the site and the technology deployed. ExGen claims that because the characteristics of the site are critical, wind contracts require the negotiation of many non-standard items, including for example, capacity factors, metering, risk allocation for ancillary services and balance operating reserve charges, minimum generation curtailments, economic curtailments, financing costs, capital costs and return on equity. Given that none of these variables would be standard among bidders, ExGen believes that all would require the individual negotiation of non-standard terms well beyond the price-only negotiations permitted under Section 16-111.5(d)(4). *Id.* at 3.

ExGen argues that even if the results of long-term wind contracts were standard wholesale products that did not require individual negotiations, the IPA plan proposes no functional method of benchmarking these products to decipher the value of the energy and REC components. ExGen says the Plan does not identify any fundamental view of future energy markets that could be used to evaluate long-term offers for either energy or RECs. According to ExGen, it simply states that such long-term fixed-price agreements could mitigate the cost of compliance with carbon remediation. *Id.*

ExGen contends that there is no long-term market for energy or RECs. To the extent that markets exist for RECs, ExGen says the market extends no further than two years in term. ExGen argues that because wind power is not currently economic, the long-term PPA market in PJM is at a standstill. With regard to energy, ExGen claims the liquid market extends no further than three or four years. ExGen avers that given the absence of an actual competitive procurement for energy over a 10 to 25 year horizon, there simply is no market data that could establish a benchmark to evaluate wind contracts. *Id.* at 3-4.

According to ExGen, even if a long-term contract for energy were concurrently procured with the RECs, before comparisons with the prices from other sources, wind output prices would have to be adjusted to reflect unique risks and other disadvantages associated with its intermittency. *Id.* at 4.

To approve the Plan under Illinois law, ExGen says the Commission would have to conclude, based on the record that: (1) long-tem wind contracts are “standard wholesale products” under Section 16-111.5(b)(3)(iv); (2) Market-based benchmarks exist (or are proposed in the Plan) to evaluate a 20-plus year contract for RECs and energy as required by Sections 16-111.5(c)(1)(ii) and 16-111.5(e)(3); (3) wind contracts can be negotiated on the basis of price alone as required by Section 16-111.5(d)(4); and (4) wind energy is the best or only means of generation capable of providing a long-term energy hedge at the “lowest total cost over time” as required by Section 16-111.5(d)(4). ExGen believes that the record provides no basis for any of these conclusions, let alone all of them. *Id.* at 7.

In its Reply to responses to objections, the **IPA** disagrees with ComEd's assertion that long-term renewable contracts are not “standard wholesale products.” The Plan is required to meet the expected load requirements with a “proposed mix and selection of standard wholesale products for which contracts will be executed during the next year, separately or in combination, to meet that portion of its load requirements” taking into account “proposed term structures for each wholesale product type included in the proposed procurement plan portfolio of products.” The IPA says Section 16-111.5(b) provides examples of certain standard wholesale products, but expressly does not limit these stated products as the only wholesale contracts that can be awarded. The IPA says the PUA does specifically reference renewable energy as a wholesale product that must be acquired under the PUA and the IPA Act. IPA Reply at 2-3.

According to the IPA, renewable energy acquired through long-term contracts is also consistent with legislative finding of the Electric Service Customer Choice and Rate Relief Law of 1997 (“Rate Relief Law of 1997”). Section 16-101A of the Rate Relief Law of 1997 provides that “[i]ncluding cost‑effective renewable resources in a diverse electricity supply portfolio will reduce long‑term direct and indirect costs to consumers by decreasing environmental impacts and by avoiding or delaying the need for new generation, transmission, and distribution infrastructure.” Finally, the IPA says Section 16-111.5(b) of PUA further provides that “[n]othing in this Section precludes the consideration of contracts longer than 5 years . . . .” in developing and approving procurement plans. The IPA asserts that contracts for long term renewable energy are standard, and increasingly common. The IPA claims that as of June, 2009, the California Public Utilities Commission has approved over 116 contracts contributing 8,334 MW of capacity, many of which have contract terms the range of 10 years, 15 years, 20 years, and 25 years. *Id.* at 3-4.

The IPA alleges that the Michigan Public Service Commission ("MPSC") has approved numerous long-term public renewable energy purchase agreements (“REPA”) pursuant the Section 460.1033(3) of the Michigan Public Utilities Act, MCL 460.1033(3), including a recent 20-year contract for 50 MW of renewable energy between Indiana Michigan Power Company (“I&M”) and Fowler Ridge II Wind Farm, LLC. The IPA claims that the MPSC not only concluded that the acquisition of the renewable energy was appropriate, but also concluded that 20-year contract term “provides I&M customers with an adequate source of renewable energy for a reasonable time” and that the “contract is reasonable and prudent and provides opportunities that may not otherwise be available or commercially practical.” The IPA says the MPSC’s Order not only determined that the 20-year term was reasonable, but adopted and published the actual contract provisions. *Id.* at 4.

The IPA says the Indiana Utility Regulatory Commission has also approved long-term PPAs between regulated energy retailers and renewable energy providers of 100 to 200 MW of production in 2008, and approved two other 20-year contracts for renewable energy in 2007. The IPA also claims there are long-term contracts between energy producers and retailers occurring outside of regulated proceedings. The IPA asserts that in September 2009, Oklahoma Gas & Electric Co. entered into a 20-year power purchase agreement with CPV Renewable Energy Company ("CPV REC") for energy from the 152 MW Keenan II wind energy project in Woodward County, Oklahoma, beating out over 50 other respondents to a request for proposal. *Id.* at 5.

The IPA further disagrees with ComEd’s suggestion that “long term” contracts are barred by the PUA or the IPA Act. The IPA says that Section 16-111.5(b) of the PUA specifically permits the IPA to identify the appropriate “term structures for each wholesale product.” The IPA also argues that the Commission ultimately determines and adopts the Procurement Plan, and the Commission has authority to adopt a procurement Plan that incorporates long-term PPAs as part of the portfolio. *Id.* at 5.

The IPA also disagrees that renewable energy can only be acquired under the limits set forth in Section 1-75(c)(2) of the IPA Act. The IPA insists that under 20 ILCS 3855/1-5(A), it has broad authority to meet the electricity procurement needs of the eligible retail customers and 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 . . . ." The IPA Act further requires that the Plan include provisions to acquire cost-effective energy resources for a minimum percentage of each utility’s total supply. The IPA believes these renewable energy resources, purchased to satisfy the IPA Act’s RPS are subject to a cap on the price to be paid for renewable energy.

The IPA asserts that neither the IPA Act nor the PUA limit the acquisition of renewable energy to only the amounts required to satisfy the RPS, which are actually minimum volume goals. Moreover, the IPA claims the cost caps that apply to the purchase of renewable energy apply only to the “renewable” energy acquired to satisfy the RPS. The IPA argues that there is no provision in the IPA Act or the PUA that would preclude the acquisition of energy, derived from renewable resources, outside of the minimums required to meet the RPS. *Id.* at 5-6.

With regard to ComEd’s recommendation that the Plan conduct a simultaneous procurement of ATC block energy for a similar term, the IPA does not believe this is required. The IPA argues that there is no statutory requirement that energy derived from renewable sources only be included in the Plan under Section 1-75. Second, while the IPA recognizes the variable nature of power generated from certain renewable energy resources, the IPA does not believe that the simultaneous procurement of additional ATC blocks in the spring 2010 procurement cycle should occur at this time. Rather, the IPA believes delivery volume guarantees should be provided by individual bidders as part of the standard terms and conditions of any awarded contracts. *Id.* at 6.

In its Reply, the IPA indicates that it agrees with certain comments contained in the AG's Response. The IPA also states that terms for the procurement contracts will be addressed through the contract formation and RFP process set forth in Section 16-111.5(c) of the PUA. Under this process, the IPA and its Procurement Administrator manage the bidder pre-qualification and registration, obtain the electric utilities' agreement to the final form of the supply contracts and credit collateral agreements, and may negotiate price with bidders. The IPA says this process is verified and overseen by the Commission's Procurement Monitor. *Id.* at 10.

The IPA also replies to the IWEA's argument that a solicitation for long-term renewable contracts with the associated RECs could fulfill approximately 60 percent of the RPS requirement. The IPA disagrees with IWEA's characterization of the long-term PPAs. According to the IPA, the IPA Act requires that the Plan acquire renewable energy supplies for a specified minimum percentage of each utility's total supply. The IPA says these renewable energy resources, purchased to satisfy the IPA Act's RPS are subject to a cap on the price to be paid for renewable energy. However, the IPA argues that neither the IPA Act, nor the PUA limit the acquisition of renewable energy to only the amounts required to satisfy the minimum RPS volume requirements. For long-term PPAs, the IPA asserts that the Plan is not bound by the cost-cap associated with the RPS. Under the proposed Plan, the IPA says it may count the REC portion of the long-term PPA procurement toward the RPS requirements if doing so is beneficial to consumers, but the long-term PPAs are not required to fulfill the RPS. *Id.* at 12-13.

In its Reply, **WOW** replies to ComEd's assertion that the IPA failed to explain how the long term renewable PPAs can be made to comply with the standard wholesale product requirement of Section 16-111.5(b)(3)(iv) of the PUA. WOW contends that there are industry standard contracts for long-term power purchase agreements for wind and one of those should be used by the IPA. Moreover, WOW says the IPA is not limited to the list of standard wholesale products listed in Section 16-111.5(b)(3)(iv), as implied by ComEd. WOW asserts that Section 16-111.5(b)(3)(iv) provides a list of standard wholesale products, but expressly states that the mix of products are not limited to those listed therein. WOW contends that the IPA can adopt or use one of the industry's standard contracts for long-term power purchase agreements for wind for purposes of initiating discussions during the solicitations period in December and January. WOW Reply at 4.

Staff argues that the IPA's long-term PPA proposal is a significant departure from the "standard" contracts as presumably required by the PUA and as exclusively used for the last two procurement cycles. In Staff's view, the IPA's current proposal for the procurement of long-run PPA is incompatible with the selection of winners solely on the basis of price. Rather, with the IPA's new proposal, Staff says the Procurement Administrator will have to compare offers that differ not just in price, but in many other factors as well. Staff asserts that to consider all the factors at play will require the Procurement Administrators to plug all non-uniform elements of the offer in a mathematical model with various assumptions to rank offers, or, alternatively, to use more subjective means, which Staff assumes would be both unacceptable to the Commission and impossible to manage within the 2-day turn-around times required by the PUA.

Staff states that the IPA does not explain what this evaluation model will look like, but seems to put faith in the ability of the Procurement Administrators and other parties involved in the implementation phase of the Plan to work it out. But Staff believes this is problematic; even if those bid evaluation details could be worked out, and even if the IPA's proposal were generally meritorious, the proposal is simply incompatible with the clear intent of the legislature to limit procurement events to a straightforward ranking of highest to lowest price offers. Staff Reply at 2-4.

On the other hand, Staff states that all other procurements under the Section 16-111.5 have given bidders uniform contracts for identical products, enabling the Procurement Administrator to consider one thing and one thing only: who had the lowest price. In contrast, with the IPA's new proposal, Staff says the Procurement Administrator will have to compare offers that differ not just in price, but in other factors as well. With this particular detail, Staff says the IPA would introduce these two non-price elements of non-uniformity: delivery start date and contract duration. In Staff's view, to factor these elements into the evaluation process would require computations of the present value of purchasing arbitrary quantities throughout a time period encompassing all the offers received through a combination of (a) the offer quantities (times the offer prices) and (b) the difference between the arbitrary quantities and the offer quantities (times a projection of market prices).

With respect to different start dates and different durations, Staff believes such an analysis would require a common baseline forecast of power and REC costs (that would be displaced by the PPAs), as well as an assumed set of nominal discount rates. Staff asserts that other dimensions for which the IPA proposes to allow differences between offers will introduce the need for further assumptions and computational complications. Staff questions whether this type of evaluation process is compatible with Section 16-111.5 of the PUA. *Id.* at 5-6.

The IPA also clarified that these long-term PPAs would satisfy eligible retail customers' energy needs outside of the RPS and that they will be bundled contracts to include both the sale of electricity and RECs over the life of the PPA. Staff notes that the IPA says that as this procurement is being conducted outside of the RPS context, the RPS requirements do not apply. Staff also observes that the IPA says it may count the REC portion of the procurement toward the RPS requirements if doing so is beneficial to consumers. Staff notes that the IPA also proposes that the procurement will bid out PPAs for renewable energy from all sources, whether in Illinois or outside. *Id.* at 12-13.

Staff questions when and how the IPA would decide if the REC portion of the procurement would count toward the RPS requirements. If it does decide to count them, then Staff wonders how the IPA can take the position that the RPS requirements do not apply. Staff disagrees with the assertion that the PRS requirements can be side-stepped by simply declaring that the purchases are not being made to meet minimum requirements. In any event, Staff argues that the RPS requirements must apply if the RECs are counted toward the RPS requirements. Staff believes the IPA Act is clear that it is the total renewable resources procured under the Plan which must be cost effective, not just the amount necessary to meet the minimum renewable resources requirements. *Id.* at 13.

Staff insists that it is necessary to impose the budget limitation on the amount of renewable energy resources procured to the total of renewable energy resources procured pursuant to the procurement plan and not simply renewable energy resources procured to meet the minimum requirement. According to Staff, it is the limitation on the procurement of renewable energy resources in Section 1-75(c)(2) that sets the maximum to be procured pursuant to a procurement plan. Staff believes there is no question that the proposed procurement of renewable energy resources is a procurement to occur under the procurement plan, and as such it must comply with the budget restriction on RPS procurement under the law. *Id.* at 14.

Staff suggests that there should be a computation of the extra cost of buying the PPA/REC combination versus the cost of buying standard energy contracts in order to determine the former’s contribution toward each utility’s statutorily mandated renewable budgets. Staff questions how that computation would be made, and when. Staff also questions how that information will get integrated into the overall process of selecting renewable energy resources to comply with the RPS. In deciding whether to count RECs from the PPAs toward the RPS, Staff wonders if the IPA will only consider Illinois wind RECs. Otherwise, it is unclear to Staff how the IPA will ensure that the RPS preferences for Illinois resources and wind resources will be maintained.

If the IPA decides not to use the RECs for the Illinois RPS, Staff questions whether the utilities should be required or at least encouraged to resell those RECs in whatever markets they can, in order to offset at least part of the additional costs that were incurred to acquire RECs with the power. For instance, Staff suggests they could be sold to alternative retail electric suppliers that are now subject to their own RPS in Illinois. Staff believes such questions are not the type that the Commission should leave to the Procurement Administrators to answer during the implementation phase of the Plan. Rather, Staff believes they are fundamental policy issues that should be resolved by the Commission. Staff maintains that these questions must be answered to determine that the procurement Plan is consistent with the applicable requirements of the IPA Act and the PUA as required by Section 16-111.5(b). *Id.* at 14-15.

Staff states that although IPA did not share it with parties until weeks after the Plan was due, the IPA at last has made a concerted effort to outline a long-run renewable power contract proposal. Staff believes it is still unacceptable; however, Staff is willing to help the IPA reshape the proposal into something workable, reasonable, and legal, if such an opportunity were to arise. *Id.* at 15.

According to Staff, the present proposal would force a conscientious procurement administrator to select winning bids on the basis of factors other than the bid price. Staff believes the proposal leaves open the possibility of receiving widely divergent types of offers, involving different start dates, contract durations, inflation adjustment provisions, and output profiles. Staff says there is nothing inherently wrong with that, and if this was going to be a private (unregulated) RFP, then a rationale buyer may very well choose to structure the RFP in such a manner. Staff says such a buyer could take whatever time it wanted to choose among bidders and use whatever criteria it wanted to make that choice. Staff states, however, that the proposed procurement is not a private unregulated RFP; rather, it is one that is governed by very strict provisions of Illinois law, which require winners to be identified in two days based solely on their bid prices.

Staff is not suggesting that, generally, taking bids for absolutely uniform products and basing selection on price alone, as required by the PUA, is a bad idea, because Staff believes it is not. Staff claims such a process has been purported to help convince bidders that the selection process will be absolutely objective and fair. To eliminate as many contract differences as possible and permit the selection of winners based solely on price to be reasonable, Staff would recommend restructuring the proposal to specifying one start date, one contract duration, and no inflation adjustment provision. *Id.* at 15-16.

According to Staff, the IPA's position is that RECs will be included with all purchases, but that they will not be used toward satisfaction of the Illinois RPS, except sometimes they will, if and when the IPA makes a determination that doing so would be in the best interest of ratepayers. Staff believes the Plan approved by the Commission must be as clear about this issue as possible. Staff says it raised the same concerns during the last procurement cycle when long-term renewable power contracts were proposed. Staff contends that the long-term renewable contract proponents have failed to address these concerns in the present Docket as well. This is understandable to Staff because the matter is complex, there are no straight-forward solutions, and any solution settled upon is going to be "messy." Staff suggests the Commission might wish to avoid the issues altogether by continuing to rely on the simple, clear-cut, clean approach of one-year fixed-quantity REC procurements. *Id.* at 19-20.

According to Staff, IWEA says it is unclear why or how the IPA would procure renewable power without the associated RECs. Staff responds that the IPA is not obligated by the IPA Act or anything else to buy RECs whenever it buys power from renewable resources. Instead, Staff claims it is only obligated to buy RECs with power from renewable resources if it uses that purchase to comply with the State's renewable portfolio standard. In addition to purchases used to comply with the RPS, Staff says the IPA is free, pending Commission approval, to purchase power from any legal source, regardless of type (coal, nuclear, natural gas, wind, etc.), as long as that purchase is consistent with IPA Act, including the requirement 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.

Staff asserts that the IPA has already planned, and the Commission approved, the purchase by ComEd and AIU of hundreds of thousands of megawatt-hours of electricity generated with renewable resources, by virtue of the fact they purchase most of their physical power directly from the PJM and MISO energy markets, where about 1% of the total annual supply is from renewable resources; and RECs were not provided with any of those purchases. *Id.* at 29.

b. Non-Statutory Issues

i. Objections and Responses

According to **ComEd**, the IPA Plan is completely silent on many important terms and conditions that will impact risks associated with long-term contracts and contracts intended to support new generation. ComEd says that among these key issues are: (1) Development and evaluation of supplier credit requirements sufficient to protect consumers over the life of the contract; customers will need protection from supplier defaults through very high credit rating requirements and/or strict margining provisions; (2) Specifying the delivery point for the energy; this is especially important for contracts for generation located away from load; (3) Addressing infrastructure costs, such as transmission interconnection costs; if they are not included in the bid, a cost comparison cannot be made. ComEd also asserts that its own credit rating and corresponding cost of debt can be impacted by long-term contracts if some or all of the contract value is imputed as debt on ComEd's balance sheet. ComEd says none of these risks has been addressed by the IPA proposal. ComEd Objections at 9.

In **AIU**'s view, the longer term renewable energy supply proposal, as included in the current version of the Plan, lacks certain details critical to its success. AIU complains that the current IPA proposal is silent as to what is meant by "longer term." AIU believes that the term of these renewable energy supply contracts should be 10 years or less for the following reasons. First, AIU claims the financial community will likely calculate an equivalent debt value for these contracts and include that level of debt on AIU's balance sheets. AIU says rating agencies typically impute a portion of the net present value of such contracts as debt, making the length of the contract a very important factor in the calculation. Sizable longer-term contracts would lead to considerable debt imputations added to the AIU's balance sheets. AIU asserts this will have a direct effect on AIU's credit metrics which could ultimately pressure ratings, which just recently returned to non-junk levels, and could possibly raise AIU's cost of securing debt. AIU suggests that limiting these longer term contracts to 10 years or less will help to minimize net present value of these contracts and hence the effect on AIU's balance sheets. AIU Objections at 2.

AIU notes that the IPA is silent as to whether the longer term contracts they propose will be for fixed quantities of energy and renewable energy credits or if they will be unit contingent which means AIU would receive the output from one or more specific renewable energy facilities regardless of the amount produced by those facilities. AIU believes that if the Commission approves the longer term renewable energy supply proposal, it should require these contracts to utilize the unit contingent approach.

According to AIU, the unit contingent approach makes contract development and administration much simpler in that it avoids the need to address how and when energy would be replaced should the renewable energy facility for which the product is intended to originate is unable to meet the contract quantity. AIU claims it also eliminates the supplier's ability to game the contract by sourcing the product from a facility that produces more than what is required under the terms of the longer term contract and then optimizing its own value by choosing to deliver the energy and RECs during the hours with the lowest energy market prices while keeping the energy and RECs for themselves during the hours when the energy has the most value. *Id.* at 3.

According to AIU, it is likely that the each generating facility bidding into the longer term renewable energy supply solicitation will have some capacity value in the MISO market. As such, AIU says the solicitation could require that this capacity value be included in the product being procured. AIU claims it does not have preference at this time whether capacity should or should not be included in the product definition. *Id.* at 4.

AIU states that if capacity is included in the product definition, the Commission should make it the seller's responsibility to register that capacity at MISO. AIU claims that the registration would include following MISO's Tariffs and Business Practice Manuals to convert the capacity to Planning Resource Credits ("PRCs"), transferring the PRCs to AIU and following all Must-Offer responsibilities associated with selling capacity in the MISO Market. In addition, AIU believes that worthy of consideration is the fact that due to the operational dependency of unpredictable weather, MISO currently only credits 20% of wind generation's nameplate MW to be eligible to be converted to PRCs. *Id.*

AIU states that the IPA is silent on the issue of where long term renewable energy will be delivered. AIU prefers such energy be delivered at its load zone because it will eliminate any congestion cost to customers that would be incurred from moving the energy from the generator to the load zone. AIU says the suppliers of such energy will, of course, prefer the generator bus as the delivery point, because it will shift this congestion cost from them to the AIU customers. In addition, AIU states that if the renewable generation resource is outside the MISO footprint then transmission service will be required to get the energy from the generator bus to the MISO border. *Id.*

In rendering a decision, AIU says the Commission should consider that using the generator bus as the delivery point will complicate the RFP evaluation process due to the fact that the congestion cost and potentially the need for non-MISO transmission service will be different for each generator. AIU also says a cost estimate of each, congestion from generator bus to AIU load zone and non-MISO transmission service, would need to be made for every bidder to the RFP process. AIU asserts that this would require analysis of historical congestion for each bidder and/or modeling of future congestion which, given the dynamic nature of the MISO market, may be difficult to accurately assess. In AIU's view, while these tasks appear to be manageable given sufficient time and resources, they should be considered by the Commission as it is determining how it will rule on this issue. *Id.* at 5.

It is not clear, AIU states, how the IPA intends to adjust the quantities of energy swap contracts based on the longer term renewable energy contract proposal, or if the IPA is intending to change them at all. According to AIU, Table J-1 does not appear to have any changes due to the proposal and Table J-2, which now includes a new column labeled “2010 IPA Procurement Cycle A," does have changes although it is not apparent to AIU how to interpret said changes. It is AIU's opinion that because the IPA proposal does not to seek to procure energy along with the RECs until the period beginning June 2011, there is no need to change the energy swap quantities included in these tables other than to restore the 1.1 hedge ratios for the July and August on-peak periods based on what now appears to be the IPA’s recommendation. *Id.* at 6-7.

By not adjusting the energy swap quantities based on the longer term renewable energy contract proposal, AIU says the hedging levels will only increase from 70% to 73.5% in the second plan year and from 35% to 38.5% in the third plan year if the longer term solicitation is successful. AIU says it sees no harm in allowing this minor increase in the hedge percentages and by doing so it avoids the need to: 1) attempt to determine when the energy from intermittent resources will show up (how much in the on-peak vs. how much in the off-peak) and 2) make adjustments to the energy swap quantities on the fly should the longer term solicitation not be successful. *Id.* at 7.

AIU appreciates that many issues remain to be addressed at a later date, including but not limited to, contract development, RFP issuance, price benchmarks, RFP evaluation and operational issues associated with AIU being within MISO. AIU believes this will require diligent coordination between the IPA, ICC Staff, Procurement Administrator, Procurement Monitor and AIU, as well as Parties to this case and various market participants to make this proposal successful. *Id.*

According to its Objections, **Staff's** understanding is that in addition to the month-by-month fixed-quantity energy forward contracts that extend three planning years into the future (as in last year’s plan), this year’s Plan also includes long-term purchased power agreements for renewable power. The quantity to be sought is 600,000 MWh per year for AIU and 1,400,000 MWh for ComEd. Staff is not, in principle, opposed to long-run PPAs with renewable or conventional power producers. However, Staff believes this particular proposal lacks justification, lacks details, and fails to address many important issues. Furthermore, Staff is concerned that these deficiencies are unlikely to be rectified in the time available for this proceeding. Therefore, in this particular instance, Staff objects to the IPA's proposal. Staff Objections at 10.

Staff finds it noteworthy that the IPA's draft Plan, provided to the parties on August 17, 2009, included no such proposal, and that comments on that draft Plan submitted to the IPA on or about September 16, 2009, included similarly sparse recommendations by various renewable energy advocates for long-term renewable contracts. It appears to Staff that the IPA's proposal for long-term PPAs was quickly "developed" in the span of two weeks. In Staff's view, this level of development is unacceptable for planning multi-billion dollar procurements. For this reason, Staff recommends that the Commission provide some guidance to the IPA, in addition to rejecting the IPA's long-term PPA proposal. However, while the proposal should be removed from this year's Plan, Staff does not recommend that the Commission close the door on any subsequent plans' long-run PPA proposals, provided that the proposals are well-specified and well-justified. *Id.* at 10-11.

Staff also offers comments highlighting the type of analyses and details that it believes should have accompanied this type of proposal, and Staff recommends that such analyses and details be included in any plan presented to the Commission for approval. Staff complains that the Plan provides almost no details about the type of PPA contract envisioned by the IPA. Staff indicates that the Plan does not specify whether it reflects fixed or variable quantities. If the Plan is to reflect variable quantities, Staff complains that it fails to specify whether it will reflect the total output in any hour, a fixed percentage of the total output in any hour, or some other variable quantity specification. Staff further complains that the Plan fails to specify whether the energy be provided on a "firm" basis or a "unit contingent" basis. Staff also complains that the Plan fails to specify whether the sellers be responsible or liable for any failures to produce, deliver or sell any energy to the extent such failure is the result of scheduled outages, unscheduled outages, or other acts or omissions by the sellers. Staff objects that the Plan included no such details. *Id.* at 11.

According to Staff, the Plan does not specify or justify the acceptable locations of the generating resources. Staff questions whether they can be anywhere in North America, anywhere in the Eastern Interconnect, anywhere in PJM or MISO, anywhere in Illinois, or anywhere in the AIU or ComEd service territories. Staff objects that the Plan provides no indication about where generating resources are expected to be inadequate and thus where new resources are needed and should be located to be eligible under the proposed PPA contracts. *Id* at 11-12.

Staff also complains that the Plan does not specify the length of the proposed long-term contracts. *Id.* at 12.

Staff states that the Plan specifies that the PPA contract delivery period could begin "as early as" June 2011, rather than June 2010. Assuming the long-term PPA proposal is adopted, Staff says it may support this aspect of the proposal, provided that further analysis is provided by the IPA. According to Staff, the solicitation of long-term contracts will have a more significant effect on incentive or support for the development of new generation resources if they permit enough time after the awarding of contracts to enable the winning suppliers to plan, construct, and make operational those new resources. Staff believes that the span of time between May 2010 and June 2011 may be adequate time to plan and construct some new generating resources. However, Staff objects that the Plan does not specify if the IPA is seeking only new resources or if it is also seeking existing resources. If it is the former, then Staff also objects that the Plan does not provide adequate justification for the designated generation start date. *Id.*

Staff also states that the Plan provides no justification for limiting the procurement of long-term PPAs from renewable energy producers. Staff insists that the hedge value of entering into long-term contracts with fixed prices applies equally well to coal, nuclear, and natural gas plants. Furthermore, Staff believes that permitting all resource types to compete for the same type of contracts provides a more robust competition and a lower-price outcome for ratepayers. Staff objects that the Plan does not include all resource types in the proposal for entering into long-term PPAs or justify the inclusion of only renewable resources. *Id.* at 13-14.

Staff states that assuming that the IPA is contemplating unit-specific PPAs citing specific renewable energy power plants (like particular identified wind farms), it is unlikely that the contract can be anywhere near as standardized as the energy contracts that AIU and ComEd have been entering into over the last few years. Staff alleges that specific plants are idiosyncratic, with differing availability rates, capacity factors, and patterns of output over time. Staff says the IPA may be forced by necessity to issue an open-ended RFP, allowing bidders to specify considerably more than just a price (as has been possible with the RFPs issued by ComEd, AIU, the IPA, or their procurement administrators over the last few years). Staff expresses concern that evaluation of RFP responses will not be limited to a simple automatic mathematical comparison of prices. Staff claims that evaluation and selection of more open-ended RFP responses will involve a more subjective and probably more time-intensive process. Staff says that assuming that the IPA is contemplating this type of open-ended RFP for unit-specific power, the Plan fails to describe if and how the IPA will ensure a transparent, objective, selection process, that can be completed within the 2-day time limit imposed by the IPA Act. *Id.* at 14.

According to Staff, even if the above problems associated with open-ended RFPs were adequately handled, there are other issues with unit-specific unit-contingent contracts for renewable resources (like wind farms) that should be analyzed and considered when constructing a hedging portfolio. Staff asserts that a wind farm's output can be predicted with accuracy only when the forecast is made a few hours ahead of time. Staff says the forecast becomes much less accurate as the forecast date becomes more distant. *Id.* at 14-15.

Staff is concerned that entering into contracts only with this type of resource (for their expected average output) would result in an unpredictable hedge ratio. Staff believes that the uncertainly associated with the supply just adds to the uncertainty associated with demand. Staff states that in contrast, a fixed quantity hedge contract (like the ones that have been used in recent years by ComEd and AIU), can be precisely specified at whatever level is desired. Staff adds that within any given month or day, the output of a wind farm varies considerably. *Id.* at 15-16.

Staff believes that the issues it identified do not disqualify the use of long-run unit-contingent PPAs with wind farms (or other resources for that matter), but such factors should be taken into account. In Staff's view, there are advantages to using fixed-quantity contracts over unit-contingent PPAs, which provide added value. Staff asserts such factors should be modeled as part of the IPA's planning process. Staff asserts however, that there is no indication the IPA took any of these considerations into account. If such resources are to be considered further, now or in the future, Staff insists the relevant procurement plan should reflect such an analysis. *Id.* at 17-18.

In its **Response to Objections**, the **IPA** asserts that similar to any new energy project, development costs of renewable energy resources are concentrated in the upfront installation capital costs. If project developers can only sell power on a short-term basis, the IPA claims the costs are higher because of the uncertainty of recouping project costs. The IPA contends that long-term contracts allow the developer to spread the cost of the project over the length of the contract, thereby providing certainty and allowing for a lower unit power price. The IPA also asserts that many renewable projects were delayed due to financing difficulties as a result of the credit crisis and recession. These projects, the IPA claims, could be revived if financing can be structured using a combination of federal/state financial support and long-term contracts through the IPA. According to the IPA, this funding may now be available through grants, loans and credit enhancement provided by the U.S. Department of Energy, Department of Commerce and Economic Opportunity and the Illinois Finance Authority. The IPA says this government supported funding, combined with low, long-term interest rates, may lower the cost of capital and thereby reduce the cost of renewable energy projects that are developed before the end of 2012. IPA Response at 5-6.

The IPA believes it is prudent to solicit proposals from renewable energy providers to secure a modest level of renewable energy under long-term PPAs. Because both the cost and the availability of other hedging options associated with cap and trade are unknown, the IPA has proposed to limit the volume of PPAs to 1,400,000 MWh per annum for ComEd, and 600,000 MWh per annum for AIU. The IPA says the long-term contracts will represent a small portion of the energy portfolio, currently estimated at approximately 3.5%. *Id.* at 6.

In its Response, the IPA provides details on the terms and conditions of the proposed PPA's. Generally, the IPA says the PPAs will be of staggered duration and begin purchasing power as soon as June 2011. The IPA adds that the PPAs will include an indexed escalator and will be bundled contracts to include both the sale of electricity and renewable energy credits (RECs) over the life of the PPA. *Id.*

To obtain a competitive cost base for energy generated from renewable sources, the IPA says it will solicit bids for long term PPA contracts on a per MWh basis, with the following three alternatives: 10 years; 20 years; and 25 years. The IPA claims this model will provide a predictable revenue stream for projects, which will generate the interest of qualified project development groups. The IPA also says it will solicit bids on both a fixed-rate basis, as well as a fixed-rate basis with indexed escalation. The IPA states that the bids will be unit contingent – payments will only be made by the purchaser for units of energy delivered. *Id.* at 6-7.

In its Response, the IPA also states that bidders will commit and guarantee a minimum level of energy production to be delivered per year, and will pay to Purchasers an amount per MWh of energy generated and delivered that is below that minimum guaranteed level. The IPA states that calculations of total energy delivered will be completed at the end of each year, or at some other mutually agreed upon interval, and payments for any shortfall will be immediately due and payable. The IPA also says that procurement will bid out PPAs for renewable energy from all sources – whether in Illinois or outside. According to the IPA, all responses to the request for proposal will be required to provide an all-in cost that incorporates the generation of the power and cost of interconnection to deliver the power generated to the relevant utility load zone. The IPA does not contemplate that this cost would include regional or national capacity expansion requirements which may be addressed in future FERC initiatives. *Id.* at 7.

The IPA's Response also indicates that timing of delivery of produced energy will depend on project type and completion. The IPA says final contracts will incorporate a set date for the commencement of delivery. The IPA adds that the procurement will consider bids from new and existing qualified resources. The IPA procurement process will be on a bundled basis, for both the power generated from the project as well as the REC. The IPA indicates that payment obligation under the PPA will be limited by the utility's ability to recover the cost in rates charged to consumers. *Id.* at 7-8.

The IPA says it generally agrees with AIU that given the uncertainty of whether long-term renewable contracts will be included in the procured electricity, and the uncertainty of the type of long-term renewable energy, no changes should be made to either the swap quantities or the hedging levels. *Id.* at 13.

In response to concerns raised by Staff, the IPA says that opportunity warrants action, even if that requires changes in course and schedules from the norm. The IPA asserts that financial incentives for the development of renewable and low-carbon assets are available in the short term and not likely available in the next planning cycle. The IPA says it will work with the utilities, Staff, and other interested entities during the Plan review at the Commission to develop a more robust approach should the Commission agree on the underlying value of moving forward with the approach put forth in the Plan. *Id.* at 16.

The IPA notes that Staff provides various suggestions as to what details should be covered if the proposal remains or is presented in future plans, including, for example, the type of PPA contract (fixed and fixed with CPI escalations); whether the energy will be provided on a “firm” or “unit contingent basis” (unit contingent); the acceptable locations of the generating resources (no restrictions); the length of proposed long-term contracts (10 year, 20 year, 25 year); the new and/or existing resources (both) and generation start date justification (no restriction). The IPA believes its response to other parties, discussed above, satisfies Staff concerns. The IPA states that remaining contract terms will be established according to the process established in Section 16-111.5(e) and in the contracts among the parties. *Id.* at 16-17.

Finally, the IPA states, Staff addresses what it believes are issues concerning the intermittent nature of wind resources. The IPA notes that the longer term procurement is not limited to wind, but all renewable resources. In addition, the IPA says that at the volumes considered in the Plan, variability of wind and other renewable resources is a manageable issue. *Id.* at 17.

In its Response to Objections, **ICEA** complains that the proposal contains no details other than the simple statement that long-term contracts for renewables are required. ICEA says the Plan provides no definition or guidance as to what constitutes “long term” for these purposes, and does not specify the nature of the power purchase agreements (“PPAs”) that are envisioned by the proposal. Without such basic information, ICEA claims it is impossible to ascertain the risks and potential impacts on consumers. ICEA Response at 2.

In its Response to Objections, **IWEA** refers to Staff comments that “the span of time between May 2010 and June 2011 may be adequate time to plan and construct some new generating resources.” IWEA agrees with this statement, and urges the IPA to accept bids for delivery commencing on dates after June 1, 2011 during the 2010 procurement cycle. IWEA claims a June 1 commencement date is not ideal for project development in the Midwest. IWEA states that due to weather conditions and the difficulties of building in winter, wind projects generally have construction timelines that begin between April and September, with commissioning of the facilities following shortly after completion. A project with a PPA in place that commences June 1 must either begin construction during winter months (which risks construction delays) or construct the project the previous summer and fall and sell merchant power until the PPA commences in June. IWEA suggests a commencement date in late fall or early winter provides the most beneficial timeline. IWEA Response at 5-6.

According to IWEA, renewable energy developers need contract terms of 20 years to finance new generation at lowest cost. IWEA says that 20-year PPAs, especially those secured while U.S. Treasury grants are available, will lock in low energy prices for ratepayers during the current period of low power pricing and adequate renewable energy supply. IWEA asserts that contracts of less than 20 years, especially 10-years or less as recommended by AIU, should result in higher bid prices and raise RPS compliance costs for ratepayers. *Id.* at 7-8.

IWEA notes that several stakeholders objected to the lack of specifics about contract structure in the Plan. Although several aspects of the procurement are not described in the Plan, IWEA believes the Plan does provide a workable framework that will allow the procurement administrator sufficient time to create a viable RFP, as well as solicit input from the Commission and other stakeholders. IWEA states that the statute gives the IPA and procurement administrator the authority to develop the RFP after the Commission's approval of the Plan. *Id.* at 8.

IWEA asserts that the IPA and the procurement administrator have the ability to develop a standard form contract to be used for the procurement of long-term renewable energy. IWEA says such contracts have been developed and used by utilities across the U.S. in recent years, and the IPA and procurement administrator would not have to "reinvent the wheel" to create a viable contract for use in Illinois. *Id.* at 9.

According to IWEA, such a standard form contract will require the IPA to take into account several unique aspects of a renewable energy project. IWEA says that while the process for procurement of short term energy has bidders making offers with price as the sole variable, the Plan appears to contemplate a bidding process for long-term renewable contracts in which bidders make offers with multiple variables such as expected output, capacity values, financing costs, capital costs, and return on equity. As a result, IWEA believes the evaluation process for these bids will entail more complexity than has been the case for energy-only contracts. *Id.*

IWEA states that the procurement administrator, the IPA, Staff, and the procurement monitor will need to develop a methodology for evaluating and comparing the RFP offers. IWEA says Staff referred to this concept as an "open-ended RFP." IWEA asserts that standard contracts and generally accepted industry practices often follow such an approach wherein multiple bid variables (such as energy, capacity and REC value) are evaluated and risk-weighted to develop a single comparison price that is then the basis for awarding a contract. IWEA claims that concerns over bias and self-dealing that might otherwise exist are mitigated by the fact that the bid evaluations and weighting will be done by independent third parties and state regulatory agencies, not by industry participants. *Id.*

In IWEA's view, while the process for soliciting and awarding contracts for long-term renewable energy may require more complexity and entail more price uncertainty than purchasing only short-term energy, the long-term renewables procurement proposed by IPA will advance the statutory mandate given to IPA in ways that the short-term energy-only and REC-only procurements cannot. By proposing to offer some amount of long-term contracts for renewable energy that can support the financing needs of developers, IWEA claims the IPA is acting consistently with the state's RPS and in accordance with the requirement that the IPA concern itself not only with the lowest price obtainable for a one to three year period, but also with the goals of supply adequacy, environmental sustainability, and price stability over time. *Id.* at 10.

IWEA believes that to miss the unique opportunity presented by the tax and financing incentives that are available at this time, by failing to approve the IPA's plan for long-term renewable energy procurement, would be contrary to the direction set by the Illinois legislature and counter to the long-term benefit of Illinois consumers. *Id.*

It is IWEA's position that contracts solicited under the IPA's renewable energy RFP must be unit-contingent, as most supply contracts with wind projects are based on unit-contingent output. Also, IWEA's position is that the delivery point should be at the generator bus, as this is the delivery point for most traditional generation contracts. IWEA says it is not clear why renewables should be required to pay to move energy from the generator to the load zone when other sources are not. *Id.* at 10-11.

IWEA says AIU and ComEd also noted that long-term renewable energy supply contracts could have negative impacts on the utilities' credit ratings. It is unclear to IWEA why ComEd and AIU cautioned against long-term renewable supply contracts, but simultaneously advocated for long-term supply contracts with traditional generators, which would present theoretically larger potential negative impacts to credit ratings due to the larger amounts of electricity under contract. Still, IWEA takes no position on whether or not utilities should enter into long-term supply contracts with traditional generation, but questions why parties believe this is recommended for traditional power sources but not renewables. IWEA Response at 11-12.

According to **WOW/ELPC**, there are a number of unknowns surrounding smart grid such as if it will even be built in Illinois. WOW/ELPC states that in Docket No. 07-0566, the Commission directed ComEd and AIU to conduct a Statewide Smart Grid Collaborative that yields a Collaborative Report that includes a proposed smart grid vision for Illinois. WOW/ELPC says the Statewide Smart Grid Collaborative is still ongoing and a Collaborative Report has not yet been filed with the Commission. Even after the development of a strategic plan, WOW/ELPC says there is no guarantee, or even requirement, that either utility move forward with development of a smart grid. WOW/ELPC states that the types of benefits of a smart grid -- heightened demand response and energy efficiency, ability to use distributed energy resources, ability to use photovoltaic hybrid electric vehicles – have not been clearly identified in Illinois.

According to WOW/ELPC, ComEd's approach would be to wait and evaluate the long-term power contracts presumably while ComEd and AIU better define the benefits and energy reductions caused by a smart grid. WOW/ELPC suggests that to take a wait and see approach would result in the loss of a valuable opportunity to establish long term renewable resources within Illinois at a discounted rate (because developers can take advantage of the Federal Stimulus Bill and receive federal grants or credits if they construct turbines before the end of 2010). WOW/ELPC Response at 2-3.

WOW/ELPC states that if a smart grid is constructed, the grid effects on the near term should be small since the penetration of the applications technologies is slow and probably would occur over a number of years and not months. WOW/ELPC argues that during that time the IPA and Commission have the ability to evaluate the likelihood of customer migration and reductions in load to make the necessary corrections to minimize or control the risks. *Id.* at 3.

According to WOW/ELCP, neither ComEd nor AIU provided any information or forecasts showing the relationship between the migration of commercial/industrial customers and what residential customers might do. WOW/ELPC contend they provided no facts that outweigh the IPA's consideration of migration and its determination that laddering-in purchases was the best way to minimize risk for consumers in light of smart grid and customer migration. *Id.* at 3-4.

WOW/ELPC notes that Staff raised a concern that the level of output from a wind farm is variable and thus a long range plan is impossible to determine. In WOW/ELPC's view, this concern is really an operations issue (managing variability and uncertainty in operations planning and real-time operations) and has little relationship to long range planning. WOW/ELPC argues that "to the extent the variability of output that Staff is related to long range planning and procurement it affects the hedge that is proposed." WOW/ELPC claims that hedging for wind energy is similar to hedging for variability between generation and demand (load), which requires sufficient flexibility and resources to match the generation and load.

WOW/ELPC believes the variability Staff is concerned with is managed at two levels. First, within the total portfolio developed by the IPA sufficient flexibility is provided to accommodate that variability by laddering-in purchases over time. The closer in time one is to the event for which the procurement is being made, the information one bases that purchase upon is more accurate and thus your portfolio should be more accurate. WOW/ELPC argues that purchasing only 3.5% of the load at this time still provides plenty of head-room to make adjustments over the life of the long term contract. Second, as an operational concern, WOW/ELPC asserts that the wind variability is managed by the regional transmission operator or independent system operator. WOW/ELPC says the issues related to this operational concern are currently being addressed by MISO and PJM in a number of forums. *Id.* at 4.

According to WOW/ELPC, when there is a shortfall between the contracted output and the energy delivered the contract has terms that address such situations. WOW/ELPC says the PPA for the Long Term Renewable Portfolio has not been finalized. WOW/ELPC states that the Procurement Administrator, in consultation with the Commission, AIU, ComEd and any other interested parties, are to develop the standard contract form for the PPA. WOW/ELPC believes there is an opportunity to address the assignment of liability for the concerns raised by Staff at that time. *Id.* at 5-6.

WOW/ELPC argues that the IPA's decision to procure long-term renewable PPAs takes advantage of the sharp drop in material and energy prices from peaks in 2008. WOW/ELPC claims that from 2002 to 2008 the capacity-weighted average price of wind energy increased from approximately $33/MWh to $54/MWh. WOW/ELPC asserts that some of the key factors driving those prices up, such as cost of materials and energy, have reversed course since late 2008. WOW/ELPC claims copper is 25% lower than its peak in 2008, aluminum is approximately 40% below its peak in 2008 and closer to 2004 market prices, steel is in the range of 45% to 65% of its peak in 2008, and diesel is about 45% off the 2008 peak and more comparable to the rates the U.S. experienced in 2006-2007. WOW/ELPC says energy prices are also lower: coal is 50 to 55% lower than its peak in 2008 and a little above its prices prior to the run-up in prices that started at the tail-end of 2007; the average price of natural gas in 2009 is 35% less than the average price of 2008 and "our prices" currently are comparable to prices in 2004. These trends indicate to WOW/ELPC that wind energy prices should be favorable for ratepayers; therefore, this is an opportune time to issue a letting for long term renewable contracts to see the price range of the bids. *Id.* at 7-8.

WOW/ELPC avers that the long-term renewable PPA fosters environmentally sustainable electric service in two ways: by taking advantage of grants, loans and credit enhancements being offered by the Department of Energy, as a part of The American Recovery and Reinvestment Act of 2009, better known as the Economic Stimulus Plan; by furthering the creation of renewable resources in Illinois. *Id.* at 8.

For wind developers to be able to access the most beneficial federal stimulus funding, the 30% Investment Tax Credit which can be converted into a grant from the U.S. Treasury Department, WOW/ELPC says projects must meet the Federal Internal Revenue Service's definition of "under construction" by the end of 2010 and have the project in-service by the end of 2012. According to WOW/ELPC, long-term PPA's for renewable resources would yield the following benefits in the wind industry: (1) allows wind developers to acquire least-cost financing; (2) enables investments in in-state projects which bring the commensurate economic development and price suppression benefits, and; (3) uses federal dollars to promote investments in Illinois. WOW/ELPC believes the timing of the long-term renewable PPA meets the requirements of Section 16-111.5(d)(4) by promoting environmentally sustainable electric service at a time when wind prices are low. *Id.* at 9.

WOW/ELPC states that furthering the development of wind generation in Illinois ensures that environmentally sustainable electric service comes from within the State. WOW/ELPC adds that developing wind farms is a capital intensive endeavor. Investors that finance such developments need certainty on the project cash flows in order to finance the projects. According to WOW/ELPC, projects being built now are those that have the highest wind capacity or are closest to transmission and therefore have the lowest cost. WOW/ELPC claims that the best wind locations will be developed first and less efficient and more costly sites will be developed as time progresses. If the long term renewable energy contracts are not entered into now, WOW/ELPC avers that the developers of the current sites will enter into long term contracts to sell their wind elsewhere to meet another states RPS. WOW/ELPC claims that the result is that as the Illinois RPS increases, only the most costly and or least efficient wind farms will be available for Illinois ratepayers to purchase energy from. WOW/ELPC believes that entering into long term renewable contracts as soon as possible fosters environmentally sustainable electric service at the lowest cost over time. *Id.* at 9-10.

WOW/ELPC indicates AIU, ComEd and Staff all identified terms of the PPA that need to be explained, developed, or clarified if the Commission is to approve a Long Term Renewable Portfolio. The procurement process set forth in Section 16-111.5(e)(2) of the PUA states that the IPA and utilities will work with the Commission and other interested parties to develop standard contract forms for the supplier contracts that meet generally accepted industry practices. WOW/ELPC asserts that while most of these issues raised by AIU, ComEd and Staff are typical contract terms that WOW/ELPC are confident can be handled through that process, WOW/ELPC provides comments intended to inform the IPA and Commission of the wind industries' general views or preferences on these terms. *Id.* at 10.

WOW says AIU, ComEd and Staff pointed out that there is no stated duration or length of contract. AIU states its preference is for the contracts to be ten years or less. WOW/ELPC would prefer the duration be twenty or twenty-five years. If the IPA's intent is to leave this term open-ended for the bidder to submit, WOW/ELPC would support such action. WOW/ELPC says if the Commission were to accept AIU's proposal to consider a ten year contract to be long term, then new wind farms would have to rely on merchant energy prices and spot REC prices from years 11 through 20. According to WOW/ELPC, while it could be possible, though very difficult, to hedge the unsold energy from years 11 through 20, the spot RECs in that same period are impossible to hedge that far out. WOW/ELPC asserts that the uncertainty in years 11-20 will drive up the cost of capital of the investment, which will result in a higher price per MWh. *Id.* at 11.

WOW/ELPC alleges that most utilities in the country that seek long term PPAs with terms of 15-20 years typically assume that the price for energy and renewable energy will increase over the long term. According to WOW/ELPC, the value of the PPA contract, therefore, is likely to be at its highest during the later years of the PPA term. In addition, WOW/ELPC claims there are two features on the horizon that could cause energy prices to increase, the expiration of the production tax credit at the end of 2012, and the establishment of a national renewable energy standard. WOW/ELPC believes both have certain likelihoods of happening and entering into PPAs that have durations that are beyond those events could allow Illinois ratepayers to capitalize on lower bid prices. *Id.*

WOW says AIU and Staff raised a concern about whether the PPA would be for fixed or variable quantities of energy. WOW/ELPC would prefer variable quantities. If the IPA's intent is to leave this term open-ended for the bidder to submit, WOW/ELPC would support such action. *Id.* at 12.

AIU and Staff raised a concern about whether the energy would be provided on a firm or unit contingent basis. WOW/ELPC would prefer unit contingent basis. According to WOW/ELPC, the overwhelming majority of renewable energy PPAs are provided on a unit contingent basis, where the wind generator is paid on an as-available basis. If the IPA's intent is to leave this term open-ended for the bidder to submit, WOW/ELPC would support such action. *Id.*

WOW says AIU "raised a concern whether capacity be included in the product definition." WOW/ELPC believe that the bid prices will flow through all products, to the extent they exist. *Id.*

AIU and ComEd raised concerns regarding the delivery point of the energy. AIU states that it prefers the load zone over the generator bus. WOW/ELPC prefers the generator bus because the generator cannot manage the congestion risk from their bus bar to the load zone on a long term basis (15 to 20 years). WOW/ELPC states that usually, the generator would need to include a price premium high enough to hopefully recover the potential losses that could result from congestion between the generation bus and the load zone. WOW/ELPC claims that having the delivery point be the generation bus bar removes that risk and should yield the lowest possible price. *Id.* at 12-13.

According to **Invenergy**, the United States generally, and Illinois specifically, have made the policy choice to grow renewable energy generation, for both environmental and economic development reasons. Invenergy states that new wind generation not only provides a supply of clean, renewable energy, but also brings new jobs to rural areas, new income to farmers, and new tax dollars to local communities. For the Procurement Plan to achieve its purpose of incenting the construction of new renewable resources in Illinois and bringing the benefits of such economic development to Illinois, Invenergy believes it is important that the Procurement Plan focus on new resources. Invenergy asserts that more than any other single item, execution of long-term contracts is the key threshold step for new renewable projects to get financing and be completed in the next two to three years. Invenergy Response at 2.

ii. Replies to Responses

A procedural ruling was issued in which Parties were given leave to file replies, on October 26, 2009, to other parties' responses. That ruling did not provide leave to file objections to the IPA's filed Plan, or responses to objections. Those filing opportunities were provided in earlier rulings, and the dates applicable to those filings were stated in those earlier rulings.

In its Reply to Responses, **Ameren** says the IPA now states that it will solicit bids for the following three alternatives: 10 years; 20 years; and 25 years. While AIU continues to prefer contract terms of 10 years or less, the IPA has added a 10 year term to its list of alternatives to be sought. AIU acknowledges other parties in this proceeding have stated longer term contracts may have some benefit to wind developers for reasons such as improved access to financing. AIU says the IPA's proposal to accept contract terms of 10, 20 and 25 years will allow for evaluation of a wide variety of scenarios, and will enable the market to decide which contract term is most efficient. AIU Reply at 5.

AIU says the IPA states that it will solicit bids for a unit contingent product on both a fixed-rate basis and a fixed rate with an indexed escalator. AIU supports the unit contingent approach and while the AIUs prefer that if escalators are to be used that they be fixed escalators, the use of indexed escalators are acceptable to the AIUs. AIU Reply at 6.

AIU comments on the IPA statement that "bidders will commit and guarantee a minimum level of energy production to be delivered per year, and will pay to Purchasers an amount per MWh of energy generated and delivered that is below that minimum guaranteed level. Calculations of total energy delivered will be completed at the end of each year, or at some other mutually agreed upon interval, and payments for any shortfall will be immediately due and payable." AIU believes the IPA position is reasonable and therefore AIU is in agreement with said position. *Id.*

AIU says the IPA clarifies in its Response Comments that the "IPA procurement will bid out PPAs for renewable energy from all sources – whether in Illinois or outside." AIU is in agreement with the IPA position. *Id.*

AIU says the IPA also clarifies that the delivery point will be the load zone and the supplier will be responsible for costs associated with delivering power to the load zone. AIU says the clarification by the IPA supports AIU's position that the load zone should be the delivery point for long term renewable energy contracts. *Id.*

AIU replies to the IPA's indication that the "timing of delivery of produced energy will depend on project type and completion. Final contracts will incorporate a set date for the commencement of delivery." AIU's only comment is that the details pertaining to this issue should be addressed among the various parties responsible for RFP solicitation and evaluation such that all parties have a clear understanding of the process. The IPA also clarifies that the procurement will consider bids from new and existing qualified resources, and AIU agrees with the IPA position. *Id.* at 7.

In its Reply to Responses, **ComEd** comments on several of the proposed PPA terms and conditions contained in the IPA's response to objections.

Regarding IPA's proposal to solicit bids for terms of 10, 20, and 25 years, ComEd believes it prudent to limit the term of these contracts to 10 years or less for the same reasons stated by AIU in its Objections. ComEd claims the financial community will likely impute some portion of the net present value of these contracts as debt on ComEd's balance sheet. Limiting the term will limit the net present value. In addition, ComEd believes it will be difficult to develop reliable benchmarks for periods of time beyond 10 years. Without reliable benchmarks, ComEd says it is uncertain how much of a true hedge value these long-term contracts provide, which is the IPA's stated basis for entering into them in the first place. However, if the Commission decides that a longer term is necessary, ComEd believes the bids should be solely for a term of 20 years. ComEd asserts that allowing bids for different terms would require a complex evaluation process that could not be completed within the short time that is available to evaluate the bids. ComEd Reply at 12-13.

In reply to the IPA's proposal to solicit bids on both a fixed-rate basis, as well as a fixed-rate basis with indexed escalation, ComEd believes the bids should be limited to a fixed-rate basis, which could include a fixed escalation rate. ComEd asserts that the value of long-term contracts as a hedge is dependent on the price of the energy being fixed for the term of the agreement. If the price is permitted to rise by some unknown amount, ComEd believes it has limited value as a hedge. ComEd Reply at 13.

ComEd agrees with the need for a performance guarantee. If the supplier fails to provide some minimum amount of either energy or RECs on an annual basis, ComEd believes they should be allowed to address the shortfall by providing replacement RECs or energy. Alternatively, ComEd suggests damages based on replacement costs should be provided for. ComEd also agrees that all renewable resources, wherever located, should be allowed to bid. *Id.*

ComEd agrees that the delivery point should be the ComEd zone and the supplier is responsible for all costs, including transmission costs, to that point, just as it is for all other energy that ComEd procures. ComEd disagrees with the recommendation not to include regional or national capacity expansion requirements in the cost that the supplier is required to bear. ComEd again asserts that the value of long-term contracts is the hedge against future rising prices. However, if the risk of future cost increases is on the purchaser, ComEd insists the value of the resource as a hedge is lost. *Id.*

ComEd believes that delivery should commence June 1, 2011. ComEd says this does not mean that delivery must occur on that date. According to ComEd, suppliers will be subject only to a minimum annual requirement and can delivery the required amounts any time over that term. ComEd believes that if the commencement of delivery is allowed to vary it will complicate the review and evaluation process. *Id.* at 13-14.

ComEd agrees that the procurement should be open to both new and existing generation. ComEd supports procuring both energy and RECs on a bundled basis. ComEd also agrees that its payment obligation needs to be limited to its ability to recover costs in rates charged to customers. In addition, ComEd says payment needs to be conditioned on the rate caps contained in the IPA Act. *Id.* at 14.

ComEd states that while the IPA did not include a discussion of capacity in its discussion of terms and conditions, in response to an Objection submitted by AIU as to a lack of clarity on this point, the IPA stated that capacity would be included in the product definition and that the seller would register the capacity with either MISO or PJM. ComEd believes that while this may be appropriate for AIU, it is not for ComEd. ComEd obtains all of its capacity requirements from PJM pursuant to the RPM. ComEd says that if capacity is included in the renewable product this will result in ComEd procuring more capacity than it needs in the near term, and thus in higher rates for customers. According to ComEd, suppliers should be required to bid their capacity into the PJM auction and use the projected proceeds to reduce their bid. If this is not done, the value of capacity should be included in the REC value, as described below, and counted against the statutory cap, as it would represent a cost that would not be incurred but for the decision to procure long-term renewable energy. *Id.*

ComEd believes that the additional terms need to be addressed in any procurement of long-term renewables. ComEd maintains that if long-term renewable contracts are purchased, the inherent value of the REC will need to be determined. One solution would be to conduct a simultaneous procurement of ATC block energy for a 5 or 10 year term and use the weighted average of the winning bids for each year as a benchmark. ComEd says an alternative to an ATC procurement solicitation would be to use a forward price projection determined by the IPA procurement administrator, the procurement monitor, and the Commission Staff. ComEd suggests the IPA, in consultation with the procurement administrator, Staff, and the procurement monitor, could on that basis establish a discount that would account for the wind production profile (based on historical data of wind farms in the ComEd territory) and ATC energy. ComEd says the ATC price determined through the solicitation or the forward price projection would be reduced by this discount and the resulting amount would be backed out of the wind bids to determine the REC value. *Id.* at 14-15.

ComEd also argues that bidders should be required to post a $5 million pre-bid performance collateral in order to assure that the project gets built. ComEd proposes for losing bidders to receive the collateral back immediately and winning bidders would receive the collateral back when the project is commissioned. ComEd also asserts that bidders should be required to post margin on both the REC and the energy component of the product. ComEd says margining would be similar to that used for block products. Bidders would post collateral of $5 per remaining REC on the contract, and three years of margin for the energy using standard margining determinations. *Id.* at 15.

In its Reply to Responses, **ExGen** argues that unlike other forms of generation, wind output is generally not coincident with periods of peak load demand. ExGen states that the wind often does not blow when energy use and prices peak. ExGen says that in contrast to an ATC, or even more so, a premium product such as on-peak energy, which guarantees delivery of a price hedge for times of the day and year when energy prices are highest, a wind contract provides no such guarantee. Instead, ExGen claims that depending upon the wind characteristics of the particular site, a wind farm might deliver most of its energy in off-peak hours or during shoulder months when demand and energy prices are low. According to ExGen, because the timing of the energy delivery is so important to the value of a contract, a wind contract is virtually never as valuable as an ATC contract even if it provides for exactly the same amount of capacity.

ExGen says that to attempt to compare any wind product to a standard wholesale product, the Commission would first have to negotiate the individual PPAs further compounding the difficulty of individual negotiations and winning bidders' selection. ExGen Reply at 4-5.

Although the IPA Plan states that wind energy is predictable, ExGen claims its actual experience with large scale wind PPAs in Illinois and elsewhere reflects that predicting wind resources presents a difficult challenge even on a day-ahead basis. ExGen states that under PJM rules, operating reserve charges must be paid for differences between the day-ahead energy bid from a unit and the actual performance in real time. In ExGen's experience, these charges can add another $1 to $3 per MWH to the delivered cost of wind, meaning the total operating reserve costs for 500 MWs of wind would exceed $70 million over the life of a 20-year PPA. ExGen says the IPA's Plan does not explain how these charges would be allocated, who would bear responsibility for bidding the units, or how the costs would be compared against standard energy products that promise the delivery of firm energy. ExGen Reply at 5.

ExGen asserts that in order to compensate for intermittency and to ensure system reliability, the regional transmission organizations compensate for wind by running additional back-up generation. ExGen says this backup generation is normally comprised of expensive and inefficient fossil fuel generation resources, all of which emit greenhouse gases that partially offset the carbon abatement attributes of wind. According to ExGen, Illinois consumers pay these costs as a separate ancillary services charge. ExGen asserts that several studies have quantified the substantial increased ancillary services costs associated with specified percentages of wind energy on systems that not only can add hundreds of millions in additional consumer costs but that also partially offset wind's environmental benefits. ExGen Reply at 5-6.

The IPA's stated purpose in the Plan is to provide a long-term price hedge for consumers against carbon and future energy price volatility. ExGen says the Plan inexplicably precludes all other forms of generation from competing on a best price basis. According to ExGen, the Plan's purported rationale to obtain a long-term price hedge against carbon does not justify eliminating all other competitors. ExGen says the IPA's most recent filing not only fails to explain this elimination, but instead raises the question whether there is evidence that only wind energy can provide a lowest cost, long-term price hedge to consumers over time. ExGen argues that lacking any proof on that critical point, the IPA's hedge rationale appears to be nothing more than a false pretext to contract with nearby renewable suppliers, while avoiding the PUA's consumer protections and price caps. *Id.* at 6.

ExGen says it owns the output of several wind farms including a significant Illinois farm. ExGen is interested in the expansion of this important generation segment and would welcome the opportunity to participate in further workshops as some parties have suggested. However, ExGen believes the argument that wind power provides the only and best option for consumers is unsupported. *Id.* at 6-7.

In reply to IWEA, the **IPA** says IWEA's recommendation that stakeholders develop the RFP and the contracts is not technically consistent with the PUA. Under the PUA, the IPA says the Procurement Administrator, in consultation with the Commission, AIU, and other interested parties, may develop the contract form that will be used for the wholesale products to be procured through the RFP. The IPA indicates that it does not oppose further discussion to develop the standard contract terms to be used for the bid process, but this is already contemplated by Section 16-111.5 of the PUA. In past procurement events, the IPA states that "interested parties," meaning the potential suppliers and the utilities, have held discussions among themselves to fix the terms of the contracts, and the IPA anticipates this will be required again. However, the IPA asserts that only the Procurement Administrator designs and issues a request for proposals to supply electricity in accordance with each utility's procurement plan. The IPA believes the Commission cannot order the IPA to formally include "other stakeholders" in the RFP process. IPA Reply at 11-12.

The IPA agrees with IWEA when it advocates that the procurement of long-term PPAs begin with the first procurement event in March 2010 to allow project developers the greatest amount of time to finance new construction of renewable facilities, and to secure funding under the American Reinvestment and Recovery Act. *Id.* at 12.

According to **IWEA**, the IPA, in its response, states that contract terms will be established according to the process established in Section 16-111.5(e), and in the contracts among the parties. IWEA agrees with this view, and believes that sufficient aspects of the contract structure were laid out in the IPA's response, and the IPA, in conjunction with the procurement administrator and other stakeholders, can work out the details of the RFP after the Commission's approval of the Plan. IWEA Reply at 2.

IWEA cautions against types of delay that could cause the IPA to miss several extremely short-term opportunities created by the specialized tax credits approved in the American Reinvestment and Recovery Act. IWEA applauds the IPA for recognizing that long-term renewable energy PPAs will go far to reducing the cost of procuring renewable energy resources and will be instrumental in promoting the development of new renewable energy projects. IWEA believes that providing incentives for new renewable projects in Illinois should be a goal of the IPA, as supply increases will help achieve the IPA Act's requirement that the Agency procure environmentally sustainable electric service at the lowest total cost over time. *Id.* at 2-3.

IWEA asserts that while using utility load zones as the delivery point for a long-term renewable energy contract simplifies cost calculations, this structure could be detrimental, especially for new project finance, and could result in drastically reduced participation in the renewable energy RFP, possibly negating the benefits of using long-term contracts entirely. *Id.* at 3.

According to IWEA, because firm transmission rights are not available for the 10, 20 and 25-year terms under which the IPA intends to procure renewable energy, projects with a contract specifying load zone as delivery point will have a large cost uncertainty when seeking financing that would require bidders of both new and existing projects to include massive risk premiums to hedge future transmission and congestion costs. Even then, IWEA alleges it is extremely difficult for a wind project owner, especially a smaller organization, to hedge transmission price risk for a 20-year period. IWEA believes these price uncertainties could even stop some new projects from securing financing, as potential lenders would be unable to estimate transmission costs for the life of the project. *Id.*

IWEA argues that generator bus is the delivery point for most traditional generation contracts, and renewable energy sources should not be required to cover "all-in" costs not required for other energy sources. Instead, IWEA recommends that renewable energy generators be required to deliver energy to a generator bus located in either PJM or MISO territory. IWEA Reply at 4.

If the IPA intends to move forward with a procurement that requires generators to deliver renewable energy to the load zone, IWEA suggests one approach could be to require transmission and congestion costs to be added by the IPA as a cost-of-service pass-through under FERC tariffs. IWEA believes this approach would encourage greater participation by bidders and would shield consumers from risk premiums associated with the long-term procurement of transmission rights. *Id.*

In its Reply to Responses, **WOW** notes that the IPA provides details on the terms and conditions of the proposed PPA. The AG also comments on the terms and conditions, stating that it is confident the IPA Procurement Administrator and the Procurement Monitor could design the necessary solicitation and that it would not object to a workshop process that allows the parties to further define the details of such a solicitation. WOW agrees that the details in the terms and agreements can be discussed and agreed upon among the parties in December and January when the Procurement Administrator develops the solicitation and power purchase agreement. WOW Reply at 3.

WOW comments on ComEd's suggestion that the IPA conduct a simultaneous procurement of around-the-clock block ("ATC") energy for a similar term and that value would substitute as the energy value of the long term renewable PPA. It appears to WOW that the difference between the around-the-clock block energy value and the bundled price for long term renewable PPAs would be the value of the REC. WOW argues that such a proposal cannot work. WOW says ATC energy prices are not equivalent to wind energy prices because wind energy is not available around-the-clock; thus distinguishing bid prices of wind from those of ATC energy. WOW Reply at 3-4.

According to **WMRE/WMILRE**, most new renewable energy projects require long term contracts in order to finance the project at a reasonable cost. WMRE/WMILRE asserts that existing projects require the price stability and reliable cash flow available through long term contracts to ensure the continuing long-term operation of existing renewable energy facilities. For that reason, WMRE/WMILRE urges the Commission to allow the execution of long term power purchase agreements for renewable energy as part of the Power Procurement Plan. WMRE/WMILRE believes this will allow Illinois consumers to enjoy the benefits of reliable renewable energy such as landfill gas fueled generation. WMRE/WMILRE Reply at 1-2.

In its Reply to the IPA response, **Staff** states that the IPA provided many but not all of the details that were missing from the Plan and the draft plan. For those details not provided, Staff says it appears to be the IPA's position that those details can be developed later, not before the Commission enters its order in this docket, but during the implementation phase of the plan pursuant to Section 16-111.5(e) of the PUA. In Staff's view, while the details of implementing the plan can occur after the conclusion of this plan approval proceeding, the plan should contain sufficient details to identify the sum and substance of the planned procurement and to determine compliance with applicable laws. Staff believes the implementation process can neither replace adequate plan development nor remedy an insufficiently defined plan. Staff insists that the implementation phase is not the appropriate forum to develop the plan. Staff attempts to highlight some of the issues associated with these missing details, so that the Commission can make a more informed choice about how to proceed. Staff Reply at 2.

According to Staff one detail that the IPA provided in its response to objections is that bidders would be free to propose any delivery start date and any one of three contract durations: 10 years, 20 years, and 25 years. Staff states that on the plus side, permitting bidders to choose any start date and any of three significantly different durations may attract potential suppliers who would not be as willing or able to respond to a more rigid contract. Furthermore, Staff believes that including a small portion of 10, 20, or 25-year contracts within a portfolio otherwise relying on contracts extending out only up to three years into the future is certainly not inherently unreasonable. *Id.* at 4-5.

Staff states that the IPA plans to solicit bids on both a fixed-rate basis, as well as a fixed-rate basis with indexed escalation, later clarifying that the indexed escalation would be based on changes in a consumer price index. Staff claims that allowing bids to be either for fixed prices or indexed to inflation introduces another dimension of heterogeneity between offers, further complicating the evaluation process. Describing this as a "new twist," Staff says will require the procurement administrator and Commission to have a way to compare contracts with CPI indexes to those without CPI indexes. In Staff's view, this would require a forecast of annual rates of change in the CPI to be integrated into the analysis. Staff says this again raises the question of whether the IPA and the Commission are authorized to solicit products that cannot be judged purely on the basis of the offer price. Staff Reply at 6.

Staff is somewhat confused about why the IPA wants to allow for bids to be indexed to inflation. It was Staff's understanding that renewable fuels are free (wind and solar) or nearly so (waste products) and, hence, variable operating costs are a relatively small proportion of total costs. Staff agrees with the IPA that the vast bulk of the costs for power plants are the original construction costs, which would not increase over the term of a PPA. In Staff's view, indexing price to inflation is unnecessary. *Id.* at 6-7.

Staff says that under the IPA's Plan, the quantities supplied under the PPAs would be "unit contingent" rather than fixed and that actual production levels would depend on project type and completion. Staff believes the fact that output will not be fixed and will in fact vary from bidder to bidder introduces another dimension of potential heterogeneity between offers, further complicating the evaluation process. Staff claims this new dimension will require a way to compare a project with one expected output profile to another project with a different profile. According to Staff, power prices have a tendency to be higher in some months than others, some types of days than others, and some parts of the day than others. Thus, to thoroughly take into account one offer's expected value versus another, Staff says it would be necessary to incorporate within the evaluation model a forecast of the relative value of power at different sub-periods within a year. Staff claims this forecast would have to be matched with each project's expected output profile over the same sub-periods. *Id.* at 7.

Staff states that while in principle, adding this additional level of detail to the analysis is achievable, in practice, it would likely be time-intensive, perhaps inconsistent with the 2-day turn-around time required of the procurement administrator and monitor. In addition, Staff expresses concern that it would further call into question whether the IPA and the Commission are authorized to solicit products that are not judged purely on the basis of their own price. Staff asserts that the actual output profiles of each project would be subject to extreme uncertainty. Staff believes it would have been helpful if the IPA had provided an analysis of how significant such differences between project types tend to be. If the differences were small enough, Staff says it might be reasonable to ignore this element of offers. *Id.* at 8.

Staff indicates the IPA specified that bidders would be required to commit and guarantee a minimum level of energy production to be delivered per year, and would pay ComEd and AIU an amount per MWh of energy generated and delivered that is below that minimum guaranteed level. In general, Staff would support the basic idea of quantity guarantees, if the Commission were inclined to approve the IPA's long-term PPA proposal. Since the IPA does not specify the level of the penalty charge, Staff presumes that the IPA would require the procurement administrator to come up with a number during the implementation phase. *Id.* at 8-9.

Also, while Staff would support annual quantity guarantees, Staff notes that they would be very blunt instruments for providing suppliers an incentive for performance during important (high-priced) sub-periods within the year, such as summer on-peak hours. Staff is concerned that poor performance in supplying summer on-peak hours would be treated the same as poor performance in supplying spring and fall off-peak periods. Staff believes this is a limitation that will negatively affect the IPA's ability to integrate the renewable PPA supply forecasts into the overall supply plan. For example, Staff questions whether it would be reasonable to assume that the renewable PPA suppliers would produce at the expected level of their July capacity factor, or whether it would be more reasonable to de-rate that capacity factor for planning purposes. Staff says the IPA has not addressed this concern. *Id.*

Staff explains that if the Commission were inclined to approve the long-term PPA proposal, Staff would have no objection to specifying the relevant utility load zone as the delivery point. However, Staff notes IWEA and WOW stated the contrary view. (Staff Reply at 9-10) Staff states that while WOW/ELPC provides a succinct, understandable, believable, and completely rational motivation for its position, Staff believes IWEA's explanation of its position is confused. *Id.* at 10.

Staff contends that it "comes down to a question of who should bear that risk." In Staff's view, the PPA proposal already lays a good portion of the risk of these projects onto the utilities and their ratepayers, and adding congestion risk would not be advised. Staff argues that it would not be advised because: neither the IPA nor any other party has presented any analysis (let alone a credible analysis) of the degree of this risk; and yet the risk is obviously significant enough that WOW/ELPC is seeking to shield its members from it and shift that risk onto the shoulder of ratepayers. *Id.* at 10-11.

Staff is concerned that if the PPA delivery points for a given utility are not at that utility's load zone, then there will be yet another element of heterogeneity between offers, and Staff believes this one could be significant. Staff says the procurement administrator would have to add a different amount to the bid price for each bidder to account for the additional transmission costs. Staff is also concerned with how the procurement administrator is supposed to forecast these amounts and whether the procurement administrator should do this for every bid that arrives on bid day within the two-day turn-around time afforded by the PUA. Staff questions whether the procurement monitor will have time to verify these calculations or if the procurement administrator and the Commission should simply ignore these costs. Staff suggests that ignoring them would mean that a plant located in New Jersey, Delaware, Texas, Nevada or Florida would be treated the same as a plant located in Illinois, even though both the expected locational basis differentials as well as their variability are liable to be significantly different. According to Staff, the IPA avoids the above problems by requiring settlement at the relevant utility load zone. *Id.* at 11-12.

The IPA also clarified that its proposal is to consider bids from both new and existing renewable resources. On the other hand, Staff notes that a major rationale expressed by the AG, IWEA, and WOW/ELPC is that developers absolutely need these long-term contracts to obtain financing and make the needed investments in new plants. However, Staff says these claims are not corroborated in the instant record and Staff is not yet convinced of those claims. For this reason and because it is likely to lead to lower prices, at this time, Staff takes no position on this aspect of the proposal. *Id.* at 12.

As far as the specific start date is concerned, Staff would recommend the latest date consistent with ensuring the bidder can obtain the federal subsidies. Staff's review of other parties' comments suggests that such a date might reasonably be a June 2012 through May 2013 plan year. Staff suggests that since the performance guarantees are annual, the start "date" may as well be an entire annual period. The reason Staff is not suggesting an earlier date is to attract as many potential bidders as possible, including those that may not be far enough along to make any output assurances prior to the June 2012 through May 2013 plan year. However, to deal with the possibility that some bidders may be able to begin delivery earlier than others, Staff would also recommend that the contract give all suppliers the option of beginning delivery at any time prior to June 2012, without any quantity guarantees and without the RECs, and at real-time LMP prices. *Id.* at 16-17.

The reason Staff proposes such a pricing structure for "early" deliveries is tied into the need to integrate any additional costs of RPS purchases into the annual RPS budget constraint. Staff says this early delivery clause basically takes the early deliveries out of the RPS. However, Staff also says that the supplier, during this early start period, could still market its RECs anywhere it may wish, including to the IPA, Illinois utilities, Illinois alternative retail electric suppliers, or other in-state or out-of-state REC buyers. *Id.*

As far as the specific contract duration is concerned, Staff has no firm preference for 15, 20, or 25 years, as long as just one of those periods is chosen. Staff notes, however, that IWEA claims that renewable energy developers need contract terms of 20 years to finance new generation at lowest cost. Meanwhile, WOW/ELPC would prefer the duration be 20 or 25 years. While Staff has no firm preference, it would appear that a 20-year term certainly would be reasonable and would satisfy the IPA, IWEA, and WOW/ELPC. *Id.* at 18.

As far as the issue of unit-contingent contracts is concerned, Staff reiterates the concern that different projects may have significantly different patterns of output over the course of a year, week, and day, which leads to value differences. Staff says it would have been appropriate and helpful if the IPA had actually analyzed the potential magnitude of these differences. If they are minor enough, Staff believes it may be reasonable to ignore them when selecting winning bidders. If these differences are significant, then Staff does not believe they can be taken into account during the selection process in a manner consistent with the PUA. In that case, Staff suggests it would be more appropriate to abandon unit-contingent and require fixed-quantity contracts. According to Staff, the risk of over or under producing relative to those fixed quantities would then shift from ratepayers to suppliers. Because of that risk shift, Staff understands why wind interests such as IWEA and WOW/ELPC strongly favor unit-contingent contracts over fixed quantity contracts. Until a reasonable analysis of this issue is provided to the Commission, Staff strongly recommends limiting the magnitude of purchases through unit-contingent contracts. *Id.*

Staff supports the IPA's proposal to incorporate minimum quantity guarantees into the contracts, with penalties for amounts that fall below the minimum levels. The specific standard and the specific penalty structure is an implementation issue that Staff believes can be proposed by the procurement administrator and decided on during the implementation phase. *Id.* at 18-19.

Staff firmly concurs with the IPA that the delivery location should be the utilities' load zone, regardless of the generator's busbar location. That basically means that suppliers would sell its actual output to the RTO or other buyers at the busbar, buy the same busbar quantity from the PJM or MISO RTO at the relevant utility's load zone, and get paid a fixed price (specified in the long-term PPA) by the utility. According to Staff, this does leave the seller, rather than the buyer (ultimately ratepayers) exposed to changes in the price differential between the two locations. Staff says suppliers would be free to try to hedge that risk with third parties and would, of course, be free to include the cost of such hedges in their bid prices. *Id.* at 19.

Staff proposes some ideas for dealing with its concerns. First, Staff assumes that RECs will be bundled with the energy, as proposed by the IPA, except during the early delivery phase of the contract. Second, Staff proposes that the purchase of renewable energy resources, including RECs, through the long-term PPAs should be considered a part of RPS compliance, except during the early-delivery phase. If the PPAs are not considered part of the RPS, then Staff would continue to object that the solicitation would be discriminatory vis-à-vis non-renewable resources. Staff says discrimination would exist given that under the Act, the Commission must ensure that the IPA's purchases of power and energy will result in adequate, reliable, efficient and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability. *Id.* at 20-21.

Staff's understanding is that for the proposed long-run renewable energy resource PPA purchases, the IPA does not intend to accept competing bids from non-renewable resources. Staff believes such exclusion would be discriminatory on its face. Staff claims another end result of what the IPA proposes would be a back-door attempt to evade compliance with various aspects of the RPS, not the least of which would be the budget constraint. *Id.*

Staff proposes that a long-run PPA's expected contribution to increasing the cost of retail service (its contribution to depleting the renewable budget for any given year) would be defined as the expected expenditures on the PPA's energy/REC bundle in that year minus the expected expenditures for the same quantity of energy procured at least-cost regardless of generation type over the same period in a "standard representative output pattern." Fourth, before the RFP for long-run PPAs is issued, Staff recommends that the expected annual budget for renewables for the June 2012 to May 2013 plan year be divided between the long-run PPO procurement RFP and the one-year RECs-only RFP. Staff says the expected budget can be divided between the two RFPs in any manner deemed reasonable by the Commission, and Staff would defer to the IPA to recommend the split or the method for determining the split. However, Staff notes that the RPS requirement for that year is 7% of load, while the IPA has proposed using long-term renewable PPAs for about 3.5% of load, which might suggest a 50-50 budget split would be reasonable. Staff says that any funds left over from the first RFP (the long-run PPA RFP) would be added to the budget for the second RFP (the one-year RECs-only RFP held two years later). *Id.* at 21-22.

Staff claims that one goal of splitting the renewable budget in this manner is to avoid expending the entire budget for that particular year (and all future years for that matter) on the first of the two RFPs, especially in light of the resource type and location preferences that must also be abided during any procurement event used toward satisfaction of the RPS. Nevertheless, Staff says if the long-run PPAs are going to be unit contingent (as the IPA and other parties have proposed), the actual output levels, and hence the actual payments, and hence the expected and actual level of costs above and beyond the cost of just purchasing energy during any given plan year, will not be known at the conclusion of the two RFPs. Staff asserts that this is a major difference between this type of purchase and all the other RFPs. In Staff's view this is one of the "messy" aspects of this proposed solution that simply cannot be avoided, as long as unit-contingent contracts are contemplated. *Id.*

Fifth, once the final RFP is held for a given plan year, Staff recommends that there would be no process for carrying forward to future plan years revised estimates of over-spending or under-spending. Alternatively, Staff says future budgets could be decreased or increased, respectively. Similarly, once the final RFP is held for a given plan year, Staff recommends that there would be no process for carrying forward surpluses or deficits in the actual level of RECs that are obtained in any given plan year. Staff states that by way of rationale for these policies, they are the easiest ways to deal with uncertain quantities and costs inherent in these unit-contingent PPAs and they can always be revisited after a few years of data collection. *Id.* at 22.

Sixth, Staff recommends that any penalty revenues paid to the utility by suppliers who fail to satisfy performance requirements should be credited to the utility's purchased power cost recovery rider and implicitly used to pay those suppliers who produce more than their expected output levels. Staff says that actual quantities and net costs (taking into account penalty revenues) relative to planned levels should be tracked for a period of several years before deciding if other balancing measures are worth pursuing. *Id.* at 23.

Staff is concerned that WOW/ELPC has misinterpreted Staff's comments concerning risk. Staff does not contend that, relative to some idealized standard, long-term renewable contracts are "risky." Rather, it is Staff's position that one type of contract can and will have a different impact on certain elements of risk than another type of contract. For example, Staff says the fixed-quantity energy and energy swap contracts that the IPA has adopted have provided very good (but not perfect) short-term (a few months to a few years) hedges against potential spot market price increases. Staff claims this hedge is further bolstered by the contracts' mark-to-market collateral provisions. In Staff's view, they have fallen short, however, as price hedges for intra-month price volatility, and they have provided absolutely no hedge against demand quantity fluctuations or for prices beyond three years.

In contrast, Staff says a 20-year unit-contingent PPA provides a good (but not perfect) long-term price hedge. Unfortunately, it is Staff's understanding that collateral provisions tend to be far more supplier-friendly, increasing the buyer's risk if and when the supplier defaults. Staff claims they are also not as valuable a hedge as similarly-termed fixed-quantity contracts, since the specific level of supply over any given month is far less certain. Staff believes WOW/ELPC is correct when it likens this to demand quantity risk, but that still does make it a good thing, or even a neutral thing. Staff contends that it is a bad thing, and, in fact, this additional uncertainty over output levels may be greater for some resources (like wind generators) than others (like coal or nuclear generators). Thus, in an annual plan, Staff asserts that one will not know how much of the preferred quantity of hedge will actually materialize in any given future month. *Id.* at 30-31.

According to Staff, such differences do not necessarily disqualify one contract type versus another, but Staff believes these differences should be recognized and modeled during the planning process. Staff notes that the IPA, in the last two plans, has presented extensive numerical analyses of how different levels of fixed-quantity contracts affect the plans' overall risk levels. Staff is merely asking that some similar analysis of long-term renewable unit-contingent PPAs also be performed. Unfortunately, Staff is concerned that the apparent last-minute frenzy to secure federal renewable subsidies may make such an analysis impossible to perform for the upcoming plan, which is one reason why Staff would recommend moderation in setting the quantity and length for such contracts. *Id.* at 31.

2. Supplemental Recommendations of the IPA and Parties' Responses

On November 9, 2009, the IPA filed a "Motion for Leave to File Supplemental Recommendations for the Procurement Plan." In that Motion, the IPA says its supplemental recommendations, contained in Appendix A, are intended to provide clarification and additional detail regarding the conflicting issues surrounding the proposal to procure long-term renewable resources. The IPA's motion further asserts that the appendix to its motion supplements and modifies the IPA's prior proposal to procure long-term renewables in a way that is intended to address the concerns identified by the Commission Staff, ComEd, AIU and the AG.

Parties were given leave to file responses to the IPA's filing on or before November 13, 2009. They were also given leave to file replies to those responses.

a. IPA's Supplemental Recommendations

The IPA indicates that it now intends to solicit bids for long-term power purchase agreements to procure renewable energy. The IPA says the purpose of this solicitation is to protect ComEd and AIU customers from price risk associated with federal carbon controls. Having considered all of the parties' comments, the IPA concludes that the Plan contains sufficient information to enable this process and provides additional information in Appendix K to the Plan. The IPA indicates that Appendix K sets forth the framework under which the IPA plans to procure long-term PPAs for renewable resources, as well as providing further detail regarding the contract terms and conditions for these PPAs. Appendix K at 1.

The IPA asserts that long-term PPAs will represent a small portion of the overall portfolio, currently estimated at approximately 3.5% of ComEd and AIU's annual electricity requirements. The IPA proposes for long-term PPAs to provide price certainty for acquiring long-term renewable energy and RECs, which will assist the IPA in partially meeting the Illinois RPS requirements for ComEd and AIU. *Id.*

The IPA alleges that it has broad authority to meet the electricity procurement needs of the State through a variety of means in order to ensure the maximum benefit to the citizens of Illinois. The IPA says it has elected for this year's Plan to solicit bids for long-term PPAs to procure renewable energy under and in compliance with the terms of the RPS established by Section 1-75(c) of the IPA Act. The IPA, however, notes that long-term PPAs for renewable energy are also permissible under Section 16-111.5 of the PUA, if such procurements comply with the terms and conditions specified therein. *Id.*

The IPA plans to solicit bids for twenty-year PPAs to purchase up to two million MWhs of renewable energy and the associated RECs each year. The IPA says this will result in a total of 40 million MWhs of renewable energy purchased through the long-term PPAs over their twenty-year lives. The IPA indicates that this amount represents less than 4% of the IPA total expected energy requirements in the 2012 planning period. Having considered the need to hedge carbon risk, the opportunity to capture consumer benefits by procuring long-term PPAs at a time when unprecedented federal and State incentives are available to renewable energy producers, and the potential uncertainties associated with variable generation and interconnection costs, the IPA concludes that two million MWhs is the appropriate near-term target for this planning cycle. The IPA plans to acquire 600,000 MWhs each year for the life of the PPA for AIU and 1,400,000 MWhs each year for the life of the PPA for ComEd. *Id.* at 2.

The IPA states that under the modified Plan, the Procurement Administrator, in consultation with the IPA, the Commission Staff, the Procurement Monitor, and the utilities will perform a pre-qualification process with eligible bidders, open to both existing renewable energy projects not under long-term power purchase agreements and renewable energy projects under development that have completed appropriate development and interconnection milestones. The IPA plans to keep all responses and conclusions confidential to promote competition. *Id.*

According to the IPA, prices will be set through the IPA's competitive RFP process, where the contract terms will be standardized and winning bids will be selected on the basis of price alone. The IPA says the procurement process for long-term PPAs, on a stand-alone basis, will be designed and conducted in accordance with Section 16-111.5 of the PUA and Section 1-75 of the IPA Act and the preferences set forth in

Section 1-75(c) of the IPA Act shall be applied to the selection process (e.g., "[t]o the extent it is available, at least 75% of the renewable energy resources . . . shall come from wind generation;" it shall be "cost-effective" as defined in that Section; the locational preferences shall be applied as set forth in that Section). *Id.*

The IPA states that the Procurement Administrator, in consultation with the IPA, the Procurement Monitor, and the Commission Staff shall develop confidential benchmarks to protect consumers that will be approved by the Commission for the resources procured under this solicitation. The IPA says benchmarks will be used to evaluate bids and to reject bids that exceed the benchmarks. *Id.*

The IPA intends to count the REC portion of the procurement toward the RPS requirements and bill-impact cap. The IPA says that to quantify the annual cost of the RECs for the purpose of the RPS, the Procurement Administrator, in consultation with the IPA, Commission Staff, and the Procurement Monitor shall develop a confidential 20 year forward price curve for energy at the load zone, including the estimated magnitude and timing of the price effects related to federal carbon controls. The IPA indicates that each forward curve shall contain a specific value of the forecasted market price of electricity for each annual delivery year of the contract. The IPA states that in every delivery year, the imputed REC component of expenditures under the bundled renewable contracts will be determined as the difference between the expected annual contract expenditures for that year (based on the winning target Contract Quantities and Contract Prices) and the total target Contract Quantities times the forward price curve for each respective load zone for that year. *Id.* at 2-3

For purposes of determining the maximum expenditure allowed under the RPS bill-impact cap, the IPA indicates that the forward price curve values will be fixed over the life of the contracts and cannot be subsequently changed or updated, except as follows: if, in any year, the expected annual contract amount spent is lower than the total Contract Quantities times the forward price curve value for that year, the forward price curve will be updated by the Procurement Administrator, in consultation with the IPA, Commission Staff, and the Procurement Monitor using then currently available price forecast data. If the expected annual contract amount spent is still lower than the total Contract Quantities times the updated forward price curve value for that year, the IPA says the REC portion of the bundled bids will essentially become a credit, and the Commission will determine at that time, how to account for that credit in the determination of the bill-impact cap. *Id.*

According to the IPA, because the quantities of RECs purchased under long-term PPAs will be insufficient to meet the statutory renewable targets, the IPA, subject to Commission approval, will determine how to address the remainder consistent with the statute. The IPA states that the way in which it proposes to address such targets for the current procurement cycle are addressed in the main body of the filed Plan. Following the successful conclusion of a long-term renewable procurement event, the IPA plans to submit a confidential report to the Commission and the affected utility which contains the REC amount spent in each year of the resulting contracts that will be counted toward the renewable resources price cap. *Id.* at 3.

Under the IPA's proposal, generally, the PPAs will be standardized to allow for direct comparison of the bids on the basis of price alone. The IPA states that renewable suppliers will have an opportunity to offer an annual target fixed quantity of energy and RECs. The IPA indicates that while some flexibility is included in the timing of certain delivery requirements, recognizing year-to-year and intra-annual variability of renewable resources, the PPAs will: (1) provide for reasonable minimum deliveries of energy and RECs, as a percentage of the target annual fixed quantity, on both a rolling 2-year basis and over the contract term; (2) provide for reasonable collateral to cover damages to the extent such minimums are not met; and (3) make clear that over the life of the contracts, the utilities will be obligated to purchase no more than the amount of energy and RECs equal to the annual quantity times 20 (years) at the contract price. The IPA states that the Procurement Administrator, in consultation with the IPA, the Commission Staff, and Procurement Monitor may also make appropriate price adjustments, for bid evaluation purposes, to allow for direct comparison of offers from renewable resources that have significantly different expected production profiles. *Id.*

In order to obtain a competitive, transparent price for the energy generated from renewable sources, the IPA plans to request long-term power purchase agreement contracts on a per MWh basis, for a term of 20 years. The IPA indicates that the RFP criteria will require all offers to be in the form of a base price with a fixed escalation rate of 2% per year, provided that short-falls and carry-overs will be priced as of the year delivery was/is due. *Id.* at 4.

The IPA states that all resources that qualify as renewable energy resources under Section 1-10 of the IPA Act are eligible to submit offers in this procurement event. The IPA says sellers will specify an annual target Contract Quantity for energy plus the associated RECs that are expected to be provided on average in each delivery year (June through the following May). According to the IPA, a seller will identify the specific generating unit or units that will be the source of the renewable energy and RECs. The IPA indicates that capacity is not part of the product being purchased. The IPA proposes that the seller’s price must include and take into account any relevant transmission interconnection costs as well as the scheduled lead times to accomplish any required transmission interconnection work. *Id.*

The IPA expects that delivery of energy will be accomplished through a fixed for floating financial swap. The IPA says the fixed price for the swap will be the full bundled contract price for the renewable PPA. The IPA states that the floating price will be the LMP at the utility’s load zone for each hour in the day-ahead market of the applicable Regional Transmission Organization. The IPA says the quantity of energy swapped under these agreements will be directly tied and equal to the bid percentage multiplied by the actual energy produced by the sellers' specified unit or units. The IPA plans for the seller to provide hourly-integrated generation meter data (from a revenue quality meter that satisfies RTO requirements) on a day after basis to the utilities and the IPA to enable them to perform the necessary calculations. *Id.*

For all energy produced by the applicable percentage of the seller's specified unit(s), the IPA says the utilities will calculate the difference between the hourly LMP in the day ahead market for their zone, and the Contract Price. According to the IPA, the price differences will be multiplied by the applicable percentage of the volume of energy produced by the specified unit(s) in each hour. The IPA says that for every hour that the unit(s) produced energy, if the LMP in the day ahead market at the utility's zone is less than the Contract Price, the utility will pay the seller the difference in these costs multiplied by the quantity of energy produced by the unit(s) multiplied by the bid percentage related to the output from the relevant generating unit. For every hour that the unit(s) produces energy, the IPA states that if the LMP in the day ahead market at their zone is higher than the Contract Price, the seller will pay the utility the difference in these costs multiplied by the quantity of energy produced by the unit(s) multiplied by the bid percentage related to the output from the relevant generating unit. Under the IPA's proposal, the net of the positive and negative payments will be settled on a monthly basis. The IPA states that use of this swap mechanism for the delivery of energy will not affect sellers' obligation to deliver all RECs associated with all of the energy swapped. *Id.* at 4.

The IPA asserts that ComEd and AIU have Commission-approved pass-through tariffs to recover all reasonable costs incurred to comply with Commission-approved procurement plans, and all such costs are statutorily deemed to be prudently incurred. In accordance with that authorization, the IPA says ComEd and AIU will recover the costs of purchasing, under the terms of the long-term PPAs, the quantity of annual energy and RECs specified in the long-term PPAs, as it may vary year-to-year subject to a total cap on the contract quantity over the duration of the long-term PPAs. The IPA asserts that ComEd and AIU will not be liable under the long-term PPAs (or any related financial swap agreements) for any costs that cannot be recovered from customers through those pass-through tariffs. *Id.* at 5.

Under the IPA's proposal, a seller will commit and guarantee a minimum quantity of energy and RECs to be delivered, ("Contract Quantity"). The IPA says the same Contract Quantity will apply to both the energy and the RECs. In each delivery year (June 1 through May 31), the IPA indicates that all energy produced by the unit or units specified in the Contract, multiplied by the applicable percentage, will be used first to satisfy the annual Contract Quantity commitment along with any carry-over quantity for a future year and/or short-fall quantity for a prior year. After the annual contract commitment is fully met, the IPA says the seller may retain the full benefit and value of all energy and RECs produced by the unit(s) until the beginning of the next delivery period. *Id.*

As the IPA proposes it, at the seller's option, seller may deliver and be paid for up to 10% of the Contract Quantity above and beyond the annual commitment, which will be applied by the utilities to meet the Contract Quantity for the upcoming delivery year. The IPA says that in no event will the utility accept more than 120% of the Contract Quantity in any delivery year. The IPA also says the 120% would consist of 10% shortfall from the previous delivery year, 100% of the Contract Quantity in the current delivery year, and 10% carryover into the next delivery year. *Id.*

According to the IPA, if at the conclusion of any delivery year the supplier has delivered, through the up to 10% carryover from the previous year and actual deliveries from the current year, less than 90% of the Contract Quantity, the seller will have 90 days to deliver replacement RECs, without the associated energy, to the utility so that sellers' total deliveries are not less than 90% for the delivery year. The IPA says no payment will be made by the utilities for these replacement RECs. The IPA also says that replacement RECs must be of the same type (wind, solar, landfill, etc.) and locational preference (Illinois and adjacent State, non-adjacent State) as the RECs provided under the contract. In the event that the seller delivers at least 90%, but less than 100% of the Contract Quantities for any year, the IPA indicates the seller may cure that deficiency in the following delivery year by producing and delivering excess RECs plus energy in that year equal to the previous year's shortfall. According to the IPA, in no event will a seller be allowed to carry a shortfall of RECs greater than 10% of the annual Contract Quantity for more than 90 days into the next delivery year. *Id.*

Similarly, the IPA indicates that energy shortfalls of no more than 10% may be carried forward and satisfied in the next delivery year. In the event that the seller fails to produce at least 90% of the Contract Quantity, the IPA says the utility will compare the Contract Price to the average LMP Price at the utility load zone for the previous delivery year. If the average LMP Price is lower than the contract price, the IPA indicates the seller will not be required to make any payment. If the average LMP Price is higher than the contract price, the IPA says the seller will pay the utility the difference between the average LMP price and the contract price, times a quantity that would bring the shortfall to within 10% of the Contract Quantity. *Id.* at 6.

The IPA indicates its procurement will solicit bids for long-term PPAs for renewable energy from all sources, whether in Illinois or outside consistent with Section 1-75(c)(3) of the IPA Act. The IPA plans for the delivery point for financially settling the contract will be the utility load zone. The IPA says REC deliveries under this contract will be accounted for through the PJM GATS system or MISO M-RETS system. *Id.*

For PPAs, the IPA indicates that there will be separate credit requirements for energy and for RECs. For energy, the IPA says this will be a non-margining contract as long as the Contract Value (Contract Quantity times Contract Price) for a three-year forward period is higher than the three-year forward ATC energy price at the utility load zone multiplied by the applicable Contract Quantity and then multiplied by a factor that reflects the average energy value of the specific resource type compared to the average ATC value. The IPA states that the utilities will perform daily mark to market calculations to enable this calculation. If however, the three-year forward ATC energy price multiplied by the applicable Contract Quantity and then multiplied by a factor reflecting the average energy value of the resource is greater than the three-year forward Contract Value, the IPA says the supplier will post cash or a letter of credit (net of any unsecured credit allowance) with the utility equal to the difference in these two values. *Id.*

For RECs, the IPA plans for the seller to post $5 per REC in the form of cash or a letter of credit to guarantee delivery of the RECs over the three-year forward period (Contract Quantity times three). If the seller fails to deliver the required annual Contract Quantity of RECs and fails to cure that shortfall in the manner described above, the IPA says the utilities may seize the REC collateral and direct the IPA to use the proceeds to procure as many replacement RECs as possible with the funds. In addition, the IPA says the utility will have the right to terminate the contract if the seller fails to deliver all of the RECs in a delivery year (up to the Contract Quantity) associated with the specific unit(s) identified in the contract. *Id.*

The IPA proposes that delivery under the Long-Term PPAs will begin on June 1, 2012. The IPA indicates that the procurement will solicit bids for long-term PPAs for renewable energy from new or existing projects. The IPA says the procurement process will be on a bundled basis, for both the energy generated from the project as well as the RECs generated from the project. The IPA proposes for the capacity value of the renewable asset to PJM or MISO to remain with the owner of the asset. Furthermore, the IPA says any energy and RECs produced in excess of the PPA Contract Quantity remains an asset of the owner, available for sale to other buyers. *Id.* at 7.

b. Responses to IPA's Supplemental Recommendations; Replies Thereto

ComEd supports the IPA's motion and recommends that it be granted. ComEd indicates that Appendix K to the IPA's Proposed Plan would resolve ComEd's objections to the IPA's Plan for long term renewable contracts raised by ComEd in its Reply Comments. If the Commission grants the IPA leave to file Appendix K and the IPA withdraws the proposal for procuring long-term renewables as originally set forth in the Plan and as described in greater detail in the IPA's response to objections, ComEd says it would no longer object to the IPA's Plan for long term renewable contracts.

The **AG** requests that the Commission approve the IPA Plan, as supplemented by Appendix K, and direct the IPA to submit a compliance filing that includes any changes to the Plan that are necessary to ensure conformance with Appendix K. The AG supports the approach to procuring long-term renewable resources set forth in Appendix K.

AIU indicates that it has reviewed the IPA supplemental filing to its procurement Plan and does not object to the findings or conclusions therein.

Staff supports the IPA's motion for leave to submit Appendix K to the Proposed Plan. Staff says Appendix K to the IPA's Proposed Plan would resolve concerns raised by Staff in its Objections to the Procurement Plan and Staff's Reply to Responses to the Plan. Thus, if the Commission grants the IPA leave to file Appendix K and the IPA withdraws the proposal for procuring long-term renewables as originally set forth in the Plan and as described in greater detail in the IPA's response to objections, "Staff would no longer object to the IPA's Plan for long term renewable contracts." Staff Response at 1-2.

"While Staff would no longer object to the IPA's Plan for long term renewable contracts, as revised by the IPA's Appendix K, Staff believes that the Commission should be aware of certain ambiguities raised by that Appendix." It is Staff's expectation that these ambiguities would be resolved by the procurement administrator in consultation with Staff, the Procurement Monitor, utilities and other interested parties during the implementation phase of the Plan. *Id.* at 2.

In Staff's view, it is unclear if Appendix K refers to (a) margining of three years' worth of contract quantities or (b) margining just one year's worth of contract quantities but using the average prices for the upcoming three years. Staff says the former interpretation would provide ratepayers with approximately three times the security as the latter interpretation, and would be more commensurate with the three-year approach proposed for the RECs and with previously-approved energy and capacity contracts. Staff asserts that when there is less than three years remaining until the contract expiration date, the margining periods should reflect the actual amount of time remaining until the contract expiration date. Staff believes there should be additional language clarifying the provision stating, "the lesser of three years or number of years remaining until the contract expiration date." *Id.* at 3; Staff BOE at 6-7, 10.

Staff also complains that the Appendix does not explicitly indicate who will derive the "factor that reflects the average energy value of the specific resource type compared to the average ATC value." According to Staff, the Appendix implies that this factor would be derived by the utilities, but another likely candidate would be the procurement administrator in consultation with the Staff, Procurement Monitor, utilities and other interested parties. Staff also believes it is unclear if this factor will be included in the PPA or if it will be recalculated from time to time, and, if the latter, how often it will be recalculated. Staff Response at 3.

With respect to the supplier credit requirements described on page 6 of Appendix K, it would be Staff's preference that, commensurate with past practice, all such credit requirements be determined during the implementation phase by the procurement administrator in consultation with the Staff, Procurement Monitor, utilities and other interested parties. Staff says this would not only provide it with additional time to analyze the terms, but would also provide all interested parties with the opportunity to provide input on standard contracts and credit terms, as required by Section 16-111.5(e)(2). (Staff Response at 3-4) In its BOE, Staff expresses concerns over with the IPA's proposal to require suppliers to post collateral equal to $5 per REC. Staff BOE at 7-8, 10.

In its reply to Staff, **ComEd** indicates that Staff's Response argues that there are several provisions of the proposed Appendix K that are "ambiguous" or do not set forth all of the details of the implementation of the process proposed. ComEd agrees that there are details that remain unspecified, but believes in most cases that those details are minor and can be resolved during the implementation phase of the Plan. ComEd Reply at 1-2.

ComEd does not believe that the proposed Appendix K is ambiguous in each of the respects Staff claims. For example, ComEd says Appendix K does call for margining a rolling three years of the contract quantities of energy. ComEd indicates that Staff also appears to suggest that much or all of the determination of supplier credit requirements be left to the procurement administrator in consultation with Staff and others. ComEd believes the IPA has made specific proposals regarding the credit requirements for both energy and RECs. When viewed in total, ComEd has no objections to the IPA's proposal outlined in Appendix K. However, ComEd would object to signing long-term contracts with what it views as weak credit protection for consumers. ComEd argues that is why the Commission should reject suggestions to potentially change a key component of the IPA's balanced proposal. According to ComEd, if accepted by the Commission, the procurement administrator could help work out the proper contract language, but could not alter the basic approved credit requirements. *Id.* at 2.

Appendix K to the IPA's Proposed Plan would in principle resolve concerns raised by **ExGen**. Thus, if the Commission grants the IPA leave to file Appendix K and the IPA withdraws the proposal for procuring long-term renewables as originally set forth in the Plan and as described in greater detail in the IPA's response to objections, ExGen would no longer object to the IPA's Plan for long term renewable contracts. Pending Commission approval of IPA's motion for leave to file supplementary comments, Commission approval and incorporation into the Plan of these comments substantially as proposed, and no new issues arising with respect to these matters or additional amendments, ExGen says it is ready to suspend its earlier objections on this issue. ExGen Response at 3.

WOW states that Appendix K describes a performance guarantee with the seller committing to provide a minimum quantity of energy and RECs. While WOW does not object to the carry-over or shortfall requirements proposed by the IPA, WOW believes that this is not really a Procurement Plan issue but can be addressed in the development of the solicitations. In the Procurement Plan filed on September 30th, the IPA was of that mind, stating: "standard terms and conditions regarding performance guarantees and penalties are agreed to by bidders prior to solicitation." If the IPA is going to ask the Commission to make determinations on these contract related terms, then WOW recommends that there be some accountability for force majeure occurrences. WOW is not recommending language at this time, because WOW believes that can be addressed during the development of the solicitation documents; however, WOW does request the Commission find that energy and RECs lost due to a force majeure occurrence be removed from the shortfall calculations of energy and RECs so that they are not counted against the bidder. WOW Response at 2-3.

In the "Short-fall – Energy" section, WOW indicates that the IPA proposes that the seller pay the utility the difference between the average LMP price and the contract price if the average LMP price is higher than the contract price. In WOW's view, the term "Average LMP," as it is used in the context of this section, is ambiguous and if used improperly could unjustifiably cause harm to either party. Instead, WOW recommends that a Volume Weighted Average LMP be used. WOW argues that the Volume Weighted Average LMP would be calculated for the hours the project did generate during the Contract Year in which the Energy Shortfall occurred. WOW believes this approach is consistent with the overall methodology used to determine settlement against the Contract Price, which is based on actual generation, and will more accurately reflect the LMP that would have been settled against had the seller achieved the Contract Quantity. *Id.* at 3.

According to WOW, the structure of the Energy and REC Shortfall provisions, as presented in Appendix K, creates an idiosyncrasy that could result in the seller not being adequately compensated for replacement RECs when the Average LMP is lower than the Contract Price. WOW states that within the paragraph titled "Short-fall – RECs" it states that in the event the seller delivers less than 90% of the Contract Quantity of RECs at the conclusion of the delivery year, the seller has 90 days to deliver "replacement RECs" to the utility so that the total delivery of RECs for the year is not less than 90% of the Contract Quantity. WOW adds that it says "No payment will be made by the utilities for these replacement RECs." *Id.* at 4.

WOW asserts that in the instance in which the Average LMP is below the Contract Price, the buyer receives both energy and RECs at a discount to the Contract Price. WOW says this discount is potentially due to the seller not being compensated for delivering replacement RECs. In WOW's view, it is reasonable to suggest that the buyer should at a minimum be made whole in the event of an energy and REC shortfall; however, it does not seem reasonable to WOW that the seller should be forced to sell replacement RECs to the buyer at a discount to what the Seller would have otherwise paid under the terms of the agreement. WOW claims it is important to recognize that in low Average LMP scenarios the seller is already penalized for its failure to generate because (1) it has been deprived of payment that would otherwise have been due under the swap and (2) it has had to obtain Replacement RECs at market value. WOW claims that more generally, the seller will not be receiving any revenue from energy and RECs when it fails to generate, so it always has an incentive to achieve the Performance Guarantee. *Id.* at 4-5.

To address this idiosyncrasy and ensure an outcome commensurate with the harm caused to the buyer, WOW proposes that a formula for determining whether a payment is owed to seller for Replacement RECs be developed during the period in which standard contract forms and credit terms are developed. WOW asserts that formula should be guided by the following principles:

- buyer shall not pay seller for Replacement RECs if Average LMP is greater or equal to Contract Price.
- If Average LMP is < Contract Price, buyer shall pay seller the positive difference between Average LMP and Contract Price.
- buyer shall not be required to pay seller a price greater than the Imputed REC Component of the Contract Price.

In its BOE, WOW further asserts its arguments that the short-fall for energy should be determined using volume-weighted average LMP and not average LMP. WOW BOE at 1-5.

According to **ComEd**, in its reply to responses, WOW makes three specific recommendations regarding Appendix K. First, WOW suggests that the procurement administrator develop language indicating that standard Force Majeure events be taken into consideration when shortfalls of RECs and Energy are calculated under the performance guarantee section of Appendix K. ComEd claims it is not necessary for the Commission to take a position on this issue as ComEd believes such language can be reasonably worked out with the Procurement Administrator. ComEd Reply at 2.

ComEd says WOW also suggests that the shortfall for energy calculation should be based on a Volume Average LMP instead of an Average LMP as contained in the IPA proposal. ComEd disagrees. ComEd states that the IPA's proposal uses average LMP for this calculation because of the unit contingent nature of the proposed contract. ComEd says it is impossible to know when energy should have been provided by a non-performing generator and the most reasonable estimation is that the energy would have been delivered ratably over time. Consequently, ComEd asserts that an average LMP is the proper price at which to value the energy shortfall. In addition, ComEd contends that using a volume weighted average based on actual deliveries for the generator could result in erroneous estimates. ComEd provides an example that assumes the generator only produced for 1 day in the Contract Year and prices for that day happened to be low. Based on a Volume Average LMP, ComEd says there could be no penalty due for the power promised for the remainder of the year and customers could be forced to make up the difference if, on average, those prices turned out to be high. ComEd insists this is an improper result and urges the Commission to reject this change to the IPA proposal. *Id.* at 2-3.

The third suggestion by WOW is to effectively reduce the price of non-performance under the contract by eliminating the requirement for delivery of replacement RECs to utilities and sharply limiting when any payments for RECs are required for non performance. ComEd recommends that these suggestions be rejected. ComEd says the IPA has already provided significant flexibility to generators to avoid payments for non performance by including provisions to pre-deliver 10% of requirements for a Contract Year and also allowing up to a 10% shortfall. In ComEd's view, additional relief from obligations by the generators is unwarranted. In addition, ComEd asserts that the changes proposed by WOW could clearly raise costs to consumers. For example, ComEd claims its first suggested principle calls for non-payment for RECs if the average LMP is greater than the Contract Price. In this case, ComEd argues that the utility would need to purchase replacement RECs from the market at potentially high prices and pass this additional cost on to customers in order to meet the RPS requirements in the PUA. According to ComEd, this would not only be unjust to customers, but would also undermine the value of the hedge these contacts are supposed to provide in the first place. *Id.* at 3-4.

ComEd says WOW invites the Commission to avoid resolving important issues concerning renewable resource procurement, leaving them instead for the implementation stage. ComEd believes the Commission should reject WOW's invitation. ComEd asserts that Section 16-111.5 of the PUA requires the Commission, in this proceeding, to review and approve a complete plan. While implementation details may be resolved during implementation, ComEd argues that issues such as credit security, the determination and measurement of shortfalls, and the payments due if a shortfall occurs are not implementation details. ComEd says one of the concerns with the IPA's initial proposal, which the Motion attempts to address, was its failure to provide sufficient details to allow parties to determine if they supported the Plan and to allow the Commission to determine if it was sound. In ComEd's view, WOW's suggestion that important features be left unresolved would both confound the Commission's task and invite future disputes among parties, delaying or derailing the procurement of renewable resources. *Id.* at 4.

IWEA believes the majority of Appendix K is acceptable, but that some aspects of the credit requirements section could make it impossible for wind and other renewable energy projects to secure financing. IWEA says the Appendix proposes a system of non-margining contracts to calculate supplier credit requirements for energy. While IWEA believes this system itself is not objectionable, IWEA complains that the lack of a limitation on the amount of those credit requirements could prevent lenders from financing a project. To the knowledge of IWEA and its members, no wind PPA is without a limitation on supplier credit requirements, and such a limit is a requirement for financial institutions. IWEA asserts that allowing open-ended letters of credit, such as those described in the Appendix K, could endanger the success of the entire procurement event. To remedy this situation, IWEA urges the Commission to direct the IPA to include some form of limitation on credit, with the details of those limitations to be developed during the implementation phase, in consultation with Commission Staff, the procurement monitor, utilities and other interested parties. IWEA Response at 2.

The Appendix states that "the utility will have the right to terminate the contract if the seller fails to deliver all the RECs in a delivery year." IWEA claims this requirement could also prevent projects from securing financing, as it allows the utility to terminate the contract even if the performance guarantees are achieved. IWEA says the Appendix details a system of performance guarantees, with provisions to remedy any possible short-falls for RECs or power, but complains that the credit requirements section allows utilities to terminate the contract regardless if any REC shortfalls are remedied. IWEA recommends the Commission direct the Agency to remove the statement giving utilities this right from the Appendix. *Id.* at 2-3.

IWEA believes that while the majority of the Appendix's Performance Guarantees provisions are acceptable, there are aspects of this section that are unclear and could prevent financing of wind and other renewable energy projects. The Appendix states that in the case of REC short-falls, suppliers must deliver replacement RECs to the utility, but that "no payment will be made by the utilities for these replacement RECs." It is unclear to IWEA why suppliers would ever be expected to provide replacement RECs without payment, and the IPA provides no justification for this statement. IWEA believes it is reasonable that suppliers be paid for providing this commodity, and IWEA urges the Commission to direct the Agency to remove the statement about non-payment for RECs from the Appendix. *Id.* at 3.

The Appendix states that "Replacement RECs must be of the same type (wind, solar, landfill, etc.) and locational preference (Illinois and adjacent State, non-adjacent State) as the RECs provided under the contract." IWEA complains that there is no mechanism for remedying non-compliance with this regulation. It is possible that in the case of a short-fall, the supplier may not be able to provide replacement RECs from another source with identical attributes during the compliance year. IWEA urges the Commission to direct the IPA to develop an alternative compliance mechanism, with the details of that mechanism to be developed during the implementation phase in consultation with Commission Staff, the procurement monitor, utilities and other interested parties. *Id.* at 3-4.

In reply, **ComEd** states that while generally supportive of the IPA's recommendations, IWEA makes four recommendations regarding Appendix K. First, the IWEA argues that Appendix K should be amended to include some form of limitation on the supplier credit requirements for energy. In particular, the IWEA states that "the lack of limitation on the amount of those credit requirements could prevent lenders from financing a project." ComEd believes this recommendation should be rejected. According to ComEd, the standard product contracts used for procurement contain no limits on margining and there is no reason they would be required here. ComEd claims these provisions are key to protecting customers and the Commission should not allow a key credit provision to be potentially eliminated by the procurement administrator through setting a very low margining cap. Furthermore, ComEd asserts that the margin amount has already been reduced for suppliers by limiting the margin horizon to three years even though the contracts extend for twenty years. As a result, ComEd would have no credit protection in the latter years of the contract when the loss of the contract would cause the greatest harm to ComEd, the buyer, and provide the greatest benefit to the seller. ComEd Reply at 4-5.

Second, IWEA argues that the provision allowing utilities to terminate the contract if the seller fails to deliver all the RECs in a delivery year should be eliminated. ComEd recommends that the Commission reject this argument as IWEA misconstrues the provision. ComEd asserts that contrary to IWEA's argument, the termination provision only applies if the generator fails to cure a shortfall in RECs as required by the Performance Guarantee (e.g., if RECs are actually generated from the unit(s), but the generator fails to deliver them). If a shortfall is cured through replacement RECs that meet the supplier's annual obligation, ComEd agrees that termination is not appropriate. However, if the seller cannot meet minimum performance levels agreed to in the contract over a year, ComEd insists that it is appropriate for the buyer to have the right to terminate the contract. *Id.* at 5.

Third, IWEA recommends the elimination of the provision in Appendix K that in the case of REC shortfalls, suppliers must deliver replacement RECs to the utility, but that no payment will be made by the utility for the replacement RECs. In ComEd's view, IWEA essentially wants to have its cake and eat it too. ComEd contends that IWEA wants utilities to buy bundled energy and RECs, but wants suppliers to be compensated at market value even when they do not deliver the RECs that are contractually owed. ComEd believes the Commission should reject this recommendation. *Id.* at 5.

ComEd states that the suppliers under the IPA Plan will be paid a price that, on an expected basis, will completely recover all their capital and operating and maintenance expenses plus a profit. ComEd says that suppliers are, in turn, obligated under the contract to commit to a performance level. If a supplier fails to do that, ComEd insists it is the supplier's responsibility to make a utility whole by replacing the RECs and covering the utility's damages, if any, on the energy replacement. Otherwise, ComEd contends that customers are not protected. Moreover, while this performance obligation places some operational risk on the suppliers, ComEd argues that risk can be managed by adjusting the contract quantity to which they commit as well as through their own operating behavior. According to ComEd, IWEA's argument that there is no justification for not paying a supplier for the provision of replacement energy ignores the fact that in buying bundled energy, the utility has already paid for this energy. If a utility is paying for bundled energy and a supplier does not deliver, ComEd believes the utilities' customers should not bear the cost of replacement. *Id.* at 5-6.

Finally, IWEA also objects to the provision requiring the Seller to provide replacement RECs of the same type and locational preference to the utility for no payment. ComEd asserts that for the same reasons it provided in the response to WOW, the Commission should leave the IPA's Plan as updated by Appendix K unchanged. *Id.* at 6.

APX believes its North American Renewables Registry™ ("NAR") should also be available for meeting the REC registry portion of the Plan, especially for RECs produced by generators located outside of Illinois. APX claims its proposal directly relates to the Motion and the proposed supplement to the Plan and Appendix K. The IPA modified its Plan to clarify and address issues related to RECs counting toward the RPS requirement and PPA standardization to allow renewable suppliers to offer a target quantity of RECs over the contract term, including the identification of renewable energy sources and RECs and the methodology for Replacement RECs, which includes the possibility that RECs will be delivered from adjacent and non-adjacent states to Illinois under the locational preference requirements, consistent with Section 1-75(c)(3) and other sections. APX Response at 2.

APX argues that its proposal to add NAR as an option for REC tracking is important and should be adopted in this proceeding because it provides at least two important benefits to Illinois consumers. APX contends that the addition of NAR will provide potential bidders with an additional REC tracking and delivery option, which will allow suppliers and the Illinois utilities additional choices from which to source RECs under certain circumstances. APX believes that having additional options will likely attract more suppliers to the solicitation and thus increase competitive pressure and a downward trend on PPA pricing, to the benefit of Illinois consumers. According to APX, having additional REC delivery options likely will allow those suppliers participating to develop more competitive pricing overall. APX claims that adopting NAR as an additional REC tracking and delivery method for renewable generation located outside of Illinois will reduce regulatory uncertainty for suppliers and Illinois utilities and thus will tend to reduce any risk premiums that suppliers might add to bids to address concerns they might have regarding the delivery of RECs in shortfall situations. *Id.* at 3.

APX insists that incorporating NAR in the Plan as an option and in addition to PJM-GATS and M-RETS is particularly important as the percentage renewable generation requirement under the PUA and the RPS rules increase substantially over time, increasing the potential that RECs from generating facilities located in adjoining states to Illinois (and possibly other states if cost-effective resources are not available) may be used to satisfy Illinois's RPS requirements. *Id.* at 3.

In its reply to APX, the **IPA** claims APX presents no new arguments to its position that NAR could be used as an option, in addition to PJM-GATS and M-RETS. The IPA reiterates its position that renewables should continue to be tracked and registered through PJM-GATS and M-RETS. The IPA says both AIU and ComEd have asserted that any RECs should be registered through the applicable tracking associated with their Regional Transmission Organization The IPA does not wish to impose on ComEd and AIU additional administrative obligations to track RECs acquired through the Procurement Plan. IPA Reply at 1-2.

In **ComEd's** view, APX's "response" offers no argument against granting IPA's Motion. Rather, ComEd claims APX attempts to graft onto IPA's Motion its own proposal to add its own proprietary "North American Renewables Registry™" to the IPA-proposed registries operated by PJM and MISO. ComEd contends that APX's effort is not only procedurally improper – it is not a response to the Motion – but also has not been justified. ComEd believes insufficient information has been provided about this registry. ComEd asserts that although they are filled with assertions about the registry, neither APX's October 27 comments nor its response to the Motion are verified. In ComEd's view, any potential use of NAR in the future needs to be studied further and should not be resolved in response to IPA's Motion. ComEd Reply at 6.

The objections of the **ICEA** to the IPA's Supplemental Recommendations are set forth in the ICEA's response to those recommendations and in its BOE. Among other things, the ICEA expresses concerns about what it sees as a lack of transparency surrounding the development of the Supplemental Recommendations as well as the procedure surrounding submission and consideration of the "Supplemental Recommendations." ICEA says it appreciates the opportunity to file Responses to the Supplemental Recommendations and refinement of the IPA's proposal to enter into 20-year contracts to procure renewable resources. However, ICEA is concerned about what it believes to be a significant departure from the statutory process outlined for the IPA's annual procurement plans and Commission consideration of those procurement plans. ICEA Response at 1-2; ICEA BOE at 3-5.

ICEA says the IPA has filed "supplemental recommendations" with respect to long-term procurement of renewable energy that appear to be borne out of negotiations involving four selected parties. ICEA indicates that its members and other certified ARES in Illinois currently serve 70% of non-residential customers and supply over 90% of non-residential load delivered to customers in AIU and ComEd. ICEA states that none of its members or any other ARES were invited to participate in any such discussions. ICEA Response at 2.

ICEA asserts that the Supplemental Recommendations contain no analysis or fundamental view of the market showing that these long-term contracts are in the best interests of consumers. (ICEA BOE at 5, 16) Although stylized as "Supplemental Recommendations," ICEA avers the filing is more properly characterized as a new Plan, and as such is untimely under this Commission's rules. While the IPA argues that the filing merely "clarif[ies] and provide[s] additional detail regarding the conflicting issues surrounding the proposal to procure long-term renewable resources," ICEA describes it as a whole new Plan with new benchmarking mechanisms, and dozens of new terms and procedures never identified in the original Plan. ICEA claims this new Plan should have been filed on September 30, or sooner, and not 40 days into this proceeding. ICEA believes it is untimely and should be rejected. *Id.* at 3.

According to ICEA, at issue is whether the Commission should bind Illinois consumers to hundreds of millions of dollars in long-term energy contracts on the basis of a slim record and logic untested by a hearing on the merits. ICEA has concerns about the reasonableness and asserted benefits of introducing long-term contracting into the procurement process including all of the new terms, conditions and processes described for the first time in this filing. Additionally, ICEA has concerns with how the IPA's Supplemental Recommendations will affect the costs imposed upon retail electric suppliers ("RESs") and the customers of RESs due to the operation of the alternative compliance payment ("ACP") contained in Section 16-115D of the PUA. ICEA says those concerns are further magnified by looming subsidies that RESs and Illinois businesses, not-for-profits, schools, universities, religious institutions, and units of government are or may be forced to pay to generation developers based on existing or proposed legislation. *Id.* at 3-4.

ICEA states that the Commission has long favored fair and open hearings and inclusive workshops before making critical decisions involving hundreds of millions of dollars of ratepayers funds. ICEA says those principles are critically important today where the origins of this Plan are so murky, the benefits of the Supplemental Recommendations so unclear, and the consumers' costs are so high. ICEA believes the Commission should rule that the Supplemental Recommendations are untimely and order workshops with all stakeholders. *Id.* at 4.

ICEA says the Supplemental Recommendations fail to articulate the alleged imminence of a carbon price risk. (ICEA BOE at 5-6) ICEA complains that the IPA failed to articulate what specific price risk any federal carbon control will impose on Illinois consumers (or the basis for this assertion). ICEA says the IPA failed to provide any analysis of how this alleged carbon price risk compares to what costs will be imposed upon Illinois consumers as a result of entering into 20-year PPAs. ICEA asserts that the IPA failed to demonstrate how it will ensure maximum benefit to the citizens of Illinois. ICEA claims the IPA failed to demonstrate how implementing the recommendations in the Plan will lead to the "lowest total cost over time, taking into account any benefits of price stability." *Id.* at 5-6.

ICEA states that while the Supplemental Recommendations do not include any information as to the impact upon Illinois customers, it has roughly estimated that the combination of the Supplemental Recommendations with the Taylorville and proposed FutureGen obligations is approximately 9% of eligible customer load in ComEd and AIU. ICEA believes the Commission should reject elements of a procurement Plan that "dramatically" increases the obligations of Illinois ratepayers by increasing the obligations of Illinois ratepayers by increasing the term by a factor of almost 7 times (from three to twenty years) of any portion of the IPA's procurement, when so many important questions and assumptions remain either unanswered or unsubstantiated. *Id.* at 6.

ICEA states that the manner in which the Commission allows the IPA to manage the default service procurement obligations of ComEd and AIU, including compliance with the RPS has a direct impact on competitive wholesale and retail markets and, ultimately, on consumers' interests. ICEA does not support adoption by the Commission of policies and protocols for the IPA that has the IPA and the electric utilities entering into long-term contracts for which they receive full cost pass-through protection. ICEA asserts that such policies create an untenable investment and competitive conundrum. While competitively bid long term contracts provide for a modicum of competition among developers, ICEA claims they retain little or no exposure to competitive market outcomes. *Id.* at 6-7.

As outlined in Appendix K of the IPA's Supplemental Recommendations, ICEA states that if the proposed Long-Term Renewable Resources plan ("LTRR") is approved by the Commission, the premiums for renewable energy implicit in the 20-year, long-term contracts will be included in the annual calculation of the RPS bill-impact cap. By definition, ICEA says this also means that the premiums implicit in the 20-year, long-term contracts will also be included in the RES funded ACP since the ACP rate is a direct derivation of the IPA'S RPS procurement price. ICEA states that since by law at least 50% of RES RPS compliance is via payment of ACPs, the premiums created by these contracts will potentially increase prices for all Illinois customers, not just eligible retail customers served by the IPA. *Id.* at 7.

According to ICEA, while the stated purpose of the LTRR "is to protect ComEd and Ameren customers from price risk associated with federal carbon controls," ICEA is concerned that the exact opposite will occur. ICEA says that in 2009, when the IPA procurement was limited to solely buying one year RECs, the full RPS procurement was accomplished at a price below the bill-impact cap. With the inclusion of 20-year contracts in the procurement for 4% of the procurement (57% of 2012 RPS requirement of 7%), ICEA claims it is highly likely that the full premium allowed under the bill impact cap will be incurred by both "eligible retail customers" and, through the ACP rates, RES-served customers. *Id.* at 7-8.

ICEA says it is puzzled as to why the IPA is proposing to enter into 20-year PPAs rather than utilizing the 2009 and 2010 ACP collections (IPA Renewable Energy Resources Fund) to fund long-term procurement. ICEA says the IPA will have two full years of ACP payments in hand by the time the proposed 20-year contracts are to begin in 2012. ICEA understands that one of the stated benefits of the ACP mechanism was to use ACP payments to create a fund for "premiums" for long term contracts without further increasing the costs and price risks to eligible customers. *Id.* at 8; ICEA BOE at 17.

ICEA would suggest that the stated goals of minimizing customer bill impacts and providing a funding source for long-term renewable energy contract premiums via the IPA Renewable Energy Resources Fund is a preferable and statutorily correct approach to hedge any asserted impact of carbon controls on the state and to support the development of incremental renewable resources in the state. Further, since the minimum amount of the 2009 and 2010 payments can be reasonably projected by the IPA now (since the 2009 ACP rate has been set, and the 2010 ACP can be reasonably projected based upon forward curves), ICEA insists there is no reason that the IPA cannot utilize those funds in a 2010 procurement for long term REC delivery that begins in 2012 and therefore captures any purported benefits of current federal renewable energy incentives and hedging of the impact of potential federal carbon controls. ICEA would also remind the Commission and the IPA that Public Act 96-0159 states that the IPA Renewable Energy Resources Fund procurement "shall not exceed the winning bid prices paid for like resources procured for electric utilities required to comply with 1-75 of this Act." ICEA believes this statutory provision is another reminder of the intent of the Illinois General Assembly as it relates to long-term contracting. ICEA would suggest that if the premium under any long-term contract is not projected to be equal to or less than the procurement of one year RECs, then the proposed Attachment K process would be in violation of the IPA Act. ICEA Response at 8-9.

ICEA is concerned with what appears to be an ever growing list of state mandated long-term ratepayer and customer funded contracts that are already approaching a significant percentage of the eligible and ARES customer portfolio. ICEA believes the IPA should continue to buy RECs according to the traditional three-year energy procurement horizon and instead utilize the ACP Fund proceeds for any commitments longer than three years. ICEA would suggest that the limit for customer subsidization of private development has already been met, if not exceeded. with the existing Taylorville and pending FutureGen obligations. In other words, ICEA argues that state mandated or supported long term contracts have already become such a large part of the state's supply portfolio that customers are already in peril of stranded costs and market dysfunction. *Id.* at 9-10.

According to the **IPA**, in its reply to ICEA response, ICEA's argument attempts to limit the ability of the Commission to consider alternatives to the IPA's proposed procurement Plan. The IPA asserts that its proposed supplement is no different than what other parties have proposed as alternatives to the September 30, 2009 Proposed Plan. The IPA says the Plan is now pending before the Commission for approval, modification or amendment, and any recommendation by the IPA on how the Plan can be improved is subject to the Commission's discretion. The IPA indicates that Section 16-111.5(d)(3) of the PUA provides that once the Plan is submitted to the Commission, it is the Commission, not the IPA that "shall enter its order confirming or modifying the procurement plan . . . ." In addition, the IPA claims that the Act authorizes the Commission to modify the Plan without triggering a requirement that the IPA resubmit a new Plan. IPA Reply at 2.

In the IPA's view, "any modification to the proposed Plan, whether made at the suggestion of the IPA or any other party, is made by the Commission, not the IPA, and a modification made by the Commission is neither inappropriate, nor does it preclude the Commission from considering any suggestions." The IPA also notes that ICEA criticizes portions of the proposed supplement. The IPA does not respond to these criticisms, other than to point out that the proposed supplement is endorsed by ComEd, AIU, the AG, and the Commission Staff. *Id.* at 3.

The IPA also responds to ICEA's argument that the IPA should be proposing to use the 2009 and 2010 Alternative Compliance Payments to fund the purchase of long term PPAs. The IPA recommends that ICEA's comments be disregarded. The IPA asserts that the use of the Renewable Energy Resource Fund to purchase Renewable Energy Credits or long term PPAs is outside the scope of the procurement Plan. Therefore, the IPA believes it would have been inappropriate for the IPA to include the IPA's acquisition of long term PPAs as a solution in the Procurement Plan for ComEd and AIU to comply with their obligations under the Renewable Portfolio Standard set forth in Section 1-75 of the IPA Act. *Id.*

In its reply to the ICEA, the **AG** says the ICEA claims the IPA has failed to provide support for the proposition that "procurement of 20-year PPAs for renewable resources will protect consumers from the price risk associated with federal carbon controls." The AG contends that this assertion is wrong. According to the AG, the IPA specifically "articulate[d] the alleged imminence of a carbon price risk" by noting:

> On June 26, 2009, the U.S. House of Representatives passed HR 2454, the Clean Energy and Security Act of 2009, which would limit the emission of greenhouse gases from stationary sources. The U.S. Senate is currently considering the Clean Energy Jobs & American Power Act (S. 1733), which contains similar provisions.

AG Reply at 2, citing IPA Supplemental Recommendations at 1m fn. 2.

The AG also claims that contrary to ICEA's further assertions, the IPA addresses the "specific price risk any federal carbon control will impose on Illinois consumers" in the body of the Plan. AG Reply at 2, citing Plan at 20.

The AG says the ICEA also expresses concerns as to "how this alleged carbon price risk compares to what costs will be imposed upon Illinois consumers as a result of entering into 20-year PPAs" and whether these PPAs will produce the "lowest cost over time, taking into account any benefits of price stability." The AG asserts that these concerns have been addressed in the Supplemental Recommendations, which make clear that the IPA intends to use benchmarks and the statutory cost caps set forth in 20 ILCS 3855/1-75(c) to protect utility customers. AG Reply at 2-3.

According to the AG, a major reason for soliciting bids for long term renewable energy contracts during 2010, is to maximize opportunities for Illinois consumers to capture the benefits from bid prices that reflect decreased costs due to grants, loans and credit enhancement available currently from US Department of Energy, the Illinois Department of Commerce and Economic Opportunity and the Illinois Finance Authority for projects developed through the end of 2012. *Id.* at 3.

In further reply to the ICEA, the AG states that after the ICEA raises concerns about the impact of long term renewables contracts on the residential and small commercial customers served by utilities, the ICEA turns to a discussion of issues that may have an actual impact on ICEA members, the ARES that serve Illinois industrial and commercial customers. The ICEA is particularly "concerned with what appears to be an ever growing list of state mandated long-term ratepayer and customer funded contracts." The AG insists that this is the wrong forum to air such complaints – which should be directed to the General Assembly. *Id.* at 4.

The AG says the ICEA is puzzled as to why the IPA is proposing to enter into 20-year PPAs rather than utilizing the 2009 and 2010 ACP collections (IPA Renewable Energy Resources Fund) to fund long-term procurement. The AG argues that this statement erroneously assumes that the IPA is somehow faced with an "either/or" proposition – procuring long-term contracts for the utilities' portfolios "rather than" procuring long-term contracts with ACP funds. The AG contends that the IPA Act clearly contemplates that the IPA will do both. *Id.*

The AG also replies to comments by the ICEA that the IPA Act requires the IPA to use ACP funds to "whenever possible, enter into long-term contracts," 20 ILCS 3855/1-56(c) and that the prices paid for these long-term contracts "shall not exceed the winning bid prices paid for like resources procured for electric utilities required to comply with [Section] 1-75 of this Act." By mandating this comparison, the AG believes the statute clearly contemplates that there will be long-term utility contracts that can be used as a basis of comparison for long-term contracts procured using ACP funds. *Id.* at 4-5.

In its reply, **WOW** expresses the view that the concerns raised by ICEA do not warrant postponing procuring long-term renewables, and if such procurement is delayed until 2012 there is potential to miss benefits inherent in the market and provided by the federal government. WOW asserts that the potential price reductions attributed to The American Recovery and Reinvestment Act of 2009 and offered through grants, loans and credit enhancements being offered by the Department of Energy are available only if companies take action in 2010. Without contracts awarded in 2010, WOW claims that benefit would be lost. In addition, WOW says the sharp drop in the prices of materials that go into wind turbines, since their peak in 2008, indicate that wind energy prices should be favorable for ratepayers than in recent years. WOW argues that if a long-term renewable plan is put off until 2011, ratepayers would not receive the benefits from the federal stimulus package in the prices submitted by wind developers and the procurement Plan risks the price of material increasing between now and then. WOW Reply at 2-3.

WOW also responds to ICEA's argument that IPA's Supplemental Recommendations "fail to demonstrate how implementing the recommendation in the Plan will lead to the 'lowest total cost over time, taking into account any benefits of price stability.'" *Id.* WOW contends that parties in the case differ on how this provision is to be applied. WOW states that while the IPA has stated that its procurement proposal is to be conducted in compliance with Section 1-75(c) of the IPA Act, it also maintains that it has authority to make such purchases under Section 16-111.5 of the PUA. WOW says ComEd has argued that the purchase must be under one of the previously cited provisions, but not both. WOW's interpretation of the statutory provisions underlying the procurement process is similar to the IPA's position. WOW believes the renewable portfolio standard set forth in Section 1-75(c) of the IPA Act is clearly part of the Section 16-111.5 procurement procedures, which includes a provision that every party overlooks – "environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." *Id.* at 3.

WOW maintains that the "cost effective" provision of Section 1-75(c) provides an exception to the "lowest total cost over time." Nonetheless, WOW believes the IPA should be structuring its procurement of renewables to obtain the best price for ratepayers. WOW asserts that would be accomplished through long-term procurements at this time and that the IPA's proposal ensures environmentally sustainable electric service. WOW believes the proposal in Appendix K doesn't need to meet the "lowest total cost over time" but still meets the requirement of Section 16-111.5(d)(4) and by furthering environmentally sustainable electric service. *Id.* at 3-4.

3. Commission Analysis and Conclusions

In the Commission's view, the proposal in the IPA's September 30, 2009 Plan regarding the procurement of long-term renewable resources, while well intended, was vague and, as several parties pointed out, potentially problematic. In its response to objections, the IPA provided additional information which attempted to clarify the Plan and mitigate the problems.

On November 9, the IPA filed supplemental recommendations on the issue. The Commission believes that the proposed modifications filed by the IPA on November 9, 2009, as set forth in Appendix K, simplify and clarify the IPA's proposal to acquire long-term renewable resources, and they appear to satisfy or at least mitigate many of the concerns raised by various Parties in earlier filings. In that regard, ComEd, Ameren Illinois Utilities and the AG all support approval of those recommendations, and Staff does not object to them.

Having reviewed the positions of the Parties on this difficult issue, the Commission finds that the IPA's current recommendations for acquiring long-term renewable resources pursuant to and in compliance with Section 1-75(c) of the IPA Act, as set forth in the IPA's supplemental filing on November 9, are appropriate and are hereby approved for the 2010-2011 procurement cycle.

That said, the Commission shares the concerns raised by ICEA, WOW, IWEA, and other interveners about the process that resulted in Appendix K and the terms therein. The Commission encourages the parties to address residual concerns regarding multi-year or long-term renewable resources in future procurement periods. Such consideration, dialogue, and debate should be conducted in an open and transparent process to ensure that all parties and all interested stakeholders have an opportunity to participate in such important discussions that will affect the rates paid by consumers for years to come. The Office of Retail Market Development should be an active participant in these discussions.

With regard to specific terms of the 2010-2011 Procurement Plan, the proposal to solicit 20-year bids for the annual amounts previously specified for ComEd and AIU simplifies the solicitation and, in the Commission's view, is a reasonable approach at this time. The prequalification process described in Appendix K clarifies the process by which the IPA will administer the acquisition of long-term renewable resources; the Commission finds that it is reasonable and should be incorporated into the approved Plan.

With regard to the "Procurement Process" described on pages 2-3 in Appendix K, the Commission finds this discussion useful in clarifying the IPA's intent in acquiring long-term renewable resources. The Commission finds the proposal to set prices through the IPA’s competitive RFP process, where the contract terms will be standardized and winning bids will be selected on the basis of price alone, to be reasonable and it is hereby approved for the 2010-2011 procurement.

The Commission also finds the proposed use and application of benchmarks to the acquisition of long-term renewable resources to be appropriate. As discussed above, the Commission agrees that it is appropriate for the REC portion of long-term renewable resources acquired to be applied to the RPS requirements. As discussed in Appendix K, the entire RPS requirements cannot be met through the acquisition of long-term renewable resources. Except as modified by conclusions contained elsewhere in this Order, the acquisition of the remaining RPS requirements through short-term REC acquisitions, as explained in the Plan, is reasonable and is hereby approved.

In Appendix K, the IPA's discussion of the proposed "PPA Structure" sufficiently modifies and clarifies the manner in which it intends to acquire long-term renewable resources to be useful for the 2010-2011 procurement. As discussed above, the Commission finds the proposed 20-year term to be reasonable for this Plan. The Commission also finds the proposed fixed-price escalation for long-term renewable resources as explained in Appendix K to be reasonable for this Plan. Similarly, the product definition and proposed financial settlements for energy clarify the IPA's plan to acquire long-term renewable resources and, in the Commission's view, are appropriate.

The Commission has also reviewed the proposed "Contract Payment" and "Performance Guarantee" provisions contained on pages 5-6 in Appendix K. The Commission believes these discussions provide sufficient clarity to the proposed acquisition for the upcoming procurement. The proposal to solicit bids for long-term PPAs for renewable energy from all sources, whether in Illinois or outside, consistent with the requirements of Section 1-75(c)(3) of the IPA Act, is reasonable and is hereby approved for this Plan.

In the Commission's view, and as asserted by several parties, the only reasonable delivery point for financially settling the contracts is the appropriate utility load zone, as specified in Appendix K. The Commission also believes the proposal to require that REC deliveries under this contract will be accounted for through the PJM GATS system or MISO M-RETS system is reasonable. The Constellation proposal regarding Green-e certification has been refuted by several parties to this proceeding and it is not adopted at this time, as discussed elsewhere in this order. This matter may be discussed in any workshop process going forward.

Similarly, the Commission finds that there is not adequate information about or support for APX's proposal to utilize the North American Renewable Registry at this time. This matter may be discussed in any workshop process going forward.

Commencing delivery under the long-term PPAs on June 1, 2012, appears reasonable as well. The Commission finds that the proposal to solicit bids for long-term PPAs for renewable energy from new or existing projects is appropriate and it is hereby approved for this Plan. The IPA's proposal for the procurement process to be on a bundled basis, for both the energy and the RECs generated from the project will, in the Commission's view, resolve concerns raised by ComEd and AIU and will potentially benefit utility customers; the proposal should be approved for this Plan. Finally, the proposal whereby the capacity value of the renewable assets to PJM or MISO will remain with the owner of the assets appears reasonable for this Plan. Similarly, the proposal that any energy and RECs produced in excess of the PPA Contract Quantity remains an asset of the owner, available for sale to other buyers, also appears appropriate at this time.

Appendix K includes certain supplier credit requirements for PPAs and RECs. Several parties express concerns that such requirements may have an adverse impact on suppliers and the ability of long-term renewable resources to participate in the acquisition event. The Commission understands those concerns and the perspectives of those offering such comments. In the Commission's view, while these concerns merit consideration, the IPA and the Commission share the unique obligation to balance the concerns of suppliers, the utilities and the customers in an impartial manner. In this Plan, the Commission believes that the IPA's proposed supplier credit requirements for PPAs and RECs, as outlined in Appendix K, strikes a proper balance which provides appropriate protection for the utilities and their customers. This matter may be discussed in any workshop process going forward.

Finally, the Commission observes that in its brief on exceptions, Staff expressed some reservations about whether the Commission should approve the proposed $5 per REC supplier credit requirement as is set forth in Appendix K. On this issue, the Commission finds that the proposed supplier credit requirements for RECs in Appendix K shall be applicable, unless the IPA and the Procurement Administrator, in consultation with the utilities, Staff and other interested parties in the implementation process reach a consensus on an alternative to the proposed $5 per REC supplier credit requirement for long-term RECs.

As the parties recognize, some details of the contracts will be left for the implementation process, as is normally the case in the acquisition process under the current statutory scheme. This includes the specifics of how force majeure events are to be handled, an area of concern raised by WOW. Additionally, the details of supplier credit requirements not specified in Appendix K can and will be addressed in the implementation process. This includes the development of specific language relating to the margining provision with which Staff is concerned. *See*, Staff BOE at 5-7.

The IPA proposed the use of average LMP in the energy shortfall calculation while WOW recommends the use of volume average LMP. As the parties have recognized, Appendix K clarifies and provides significant details regarding the IPA's proposed long-term renewable resource acquisition. It appears to the Commission that the use of average LMP in the energy shortfall calculation is more consistent with the overall terms of the proposed acquisition. In contrast, the Commission believes that use of the volume average LMP would be unique in the energy shortfall calculation and would have the potential to adversely impact customers. WOW's proposal to use volume average LMP is therefore not adopted at this time. This matter may be discussed in any workshop process going forward.

IWEA expresses concern that the utility will have the right to terminate the contract if the seller fails to deliver all REC in a delivery year. As the Commission understands it, however, this termination provision applies only to the extent a seller fails to deliver within the 90% to 110% bandwidth described in Appendix K and, as such, is reasonable for this Plan. This matter may be discussed in any workshop process going forward.

WOW and IWEA object to the IPA proposal that a seller must provide replacement RECs of the same type and locational preference to the utility for no payment. As an initial matter, the Commission understands that this provision applies only in those instances where the seller fails to deliver at least 90% of the contracted REC as discussed immediately above. Additionally, any such replacement REC does not include associated energy. While the Commission certainly understands the view of WOW and IWEA, there is concern that in the absence of such a requirement, there would be no incentive for a seller to meet the requirements of its contract. Given that concern, it appears the provision at issue would help prevent a seller from gaming the system and abandoning its contractual commitments in the event that the price of bundled energy and REC exceed the price to which the seller contracted. The Commission concludes that the shortfall provisions proposed by the IPA are reasonable and should be authorized at this time. This matter may be discussed in any workshop process going forward.

IWEA also expresses concern that there is no limitation on supplier credit requirements for energy. *See* also WOW BOE at 5-7. ComEd responds that the standard product contracts used for procurement contain no limits on margining and that it sees no reason to limit credit requirements for renewable sellers. As ComEd points out, the standard products contracts contain no limits on margining, and there has been adequate interest in bidding in all previous procurement events.

The Commission acknowledges that the proposed credit requirement may affect the willingness of some renewable suppliers to participate in the procurement event or may affect the price at which participants bid. Nevertheless, given that this is the first attempt to acquire long-term renewable resources and that the credit requirements are intended to provide protection for customers, the Commission concludes that the IPA's proposal should be adopted for this procurement event for the 2010-2011 procurement. The Commission also notes that the concerns by IWEA are somewhat similar to those expressed by suppliers in the earlier procurement proceedings. As observed at that time, the statute appears to contemplate that the IPA and the Administrator will have considerable latitude in these types of matters. In any event, the Commission finds that the terms in Appendix K regarding an appropriate limit on supplier credit requirements for energy shall be applicable unless the IPA and the Procurement Administrator, in consultation with the utilities, Staff and other interested parties in the implementation process, reach a consensus on use of an alternative thereto. These issues may be discussed in any workshop process going forward.

The Illinois Competitive Energy Association provided extensive comments on Appendix K, which are laid out in detail above. These comments include a concern with an ever growing list of state mandated long-term ratepayer and customer funded contracts that are already approaching a significant percentage of the eligible and ARES customer portfolio. ICEA argues that state mandated or supported long-term contracts have already become such a large part of the state's supply portfolio that customers are already in peril of stranded costs and market dysfunction. The IPA, the AG, and WOW rebut the arguments of ICEA.

While the Commission understands ICEA's concerns, the IPA and the Commission simply implement Illinois laws. Importantly, ICEA does not appear to suggest that the IPA proposal is illegal or inconsistent with the statute. Additionally, the Commission understands that the proposal to acquire long-term renewable resources is intended to be combined with shorter-term REC acquisitions to meet the RPS requirements in the statute. At this time, the long-term renewable acquisition is not intended to supplement the statutory requirements.

It appears to the Commission that the proposed procurement process for long-term PPAs, on a stand-alone basis, is intended to be designed and conducted in accordance with Section 16-111.5 of the PUA and Section 1-75 of the IPA Act, including the preferences to be applied to the selection process as set forth in Section 1-75(c) of the IPA Act. In this regard, the Commission finds the proposed process to be appropriate at this time. Thus, ICEA's recommendations regarding RECs are not adopted.

The Commission notes the ICEA’s concern that Appendix K contains no analysis or fundamental view of the market showing that these long-term contracts are in the best interests of consumers. ICEA also has concerns about the reasonableness and asserted benefits of introducing long-term contracting into the procurement process including all of the new terms, conditions and processes described for the first time in this filing. Additionally, ICEA has concerns with how the IPA’s Supplemental Recommendations will affect the costs imposed upon retail electric suppliers and the customers of RESs due to the operation of the alternative compliance payment ACP contained in Section 16-115D of the PUA. Notwithstanding ICEA’s concerns, the Commission believes the IPA’s Appendix K is sufficient for the 2010-2011 procurement. These issues should be discussed in any workshop process going forward.

The Commission further notes ICEA’s concern that the IPA failed to articulate what specific price risk any federal carbon control will impose on Illinois consumers (or the basis for this assertion) or to provide any analysis of how this alleged carbon price risk compares to what costs will be imposed upon Illinois consumers as a result of entering into 20-year PPAs. ICEA asserts that the IPA failed to demonstrate how it will ensure maximum benefits to the citizens of Illinois, including any information as to the impact upon Illinois customers. ICEA claims the IPA failed to demonstrate how implementing the recommendations in the Plan will lead to the “lowest total cost over time, taking into account any benefits of price stability.” Notwithstanding ICEA’s concerns, the Commission believes the IPA’s Appendix K is sufficient for the 2010-2011 procurement. These issues should be discussed in any workshop process going forward.

ICEA also complains that IPA’s supplemental recommendations filed November 9 are essentially “a new Plan," and as such are untimely and inconsistent with the statute. As observed by the IPA, however, the Commission is expressly authorized by statute to make modifications to the filed plan. In determining whether modifications should be ordered, the Commission has given consideration to filings by many parties. With regard to the IPA’s November 9 filing, which was intended to resolve a number of problems cited by other parties, the ICEA and other parties were afforded an opportunity to file responses to it, as well as replies to responses. The Commission also notes that the November 9 filing addressed one issue, that being long-term renewables. All things considered, it is difficult to see how those recommendations somehow constitute a “new plan.”

In summary, the Commission finds that the recommendations set forth in the IPA’s November 9 filing are reasonable, and should be approved for the 2010-2011 procurement. As observed above, the Commission is authorized by statute to make modifications to the filed plan. The modifications contained in the IPA’s November 9 recommendations are appropriate and they are hereby adopted for the current Plan.

Lastly, the Commission notes that procedures and standards for the reconciliation and review of costs recovered via pass-through procurement tariffs are set forth in those Commission-approved tariffs, prior Commission orders, and 220 ILCS 5/16-111.5(l). The Commissions determinations in the instant order are not intended to depart therefrom.

B. Short-Term Renewable Resource Procurement Event and Related Issues

Statutory provisions applicable to the procurement of renewable energy resources, including associated renewable energy credits, are set forth above in the section on long-term renewables. With regard to short-term renewable resources, it appears the IPA contemplates utilizing one-year RECs as was the case in the procurement Plan approved in Docket 08-0519. In the Plan approved in 08-0519, separate renewable resource events were approved for AIU and ComEd. In the current Plan before the Commission, the IPA has proposed to conduct a single renewable resource procurement event for AIU and ComEd, jointly.

1. Positions of the Parties

According to **Staff**, the Plan proposes utilizing one rather than two procurement events for the acquisition of RECs. In its objections, Staff complained that the Plan provides no explanation of how its single procurement event will work. Staff questions whether bidders will submit separate bids for ComEd and AIU (i.e., will there be two RFPs and two separate selection processes that happen to take place at the same moment), or will the ComEd and AIU bids and bid evaluations be consolidated in some fashion. Staff Objections at 6.

Staff claims it is unclear whether bidders will be permitted to offer different prices for ComEd and AIU contracts. It is also unclear to Staff whether bidders will be permitted to offer "contingent" bids where the procurement administrator may select X RECs for ComEd or X RECs for AIU but not for both. Additionally, Staff wonders whether bidders will be required to offer just one set of bids (the same quantities and prices that will be applicable to ComEd, AIU, or both) that the procurement administrator can use for fulfilling any combination of the ComEd and AIU requirements. Staff does not know how the selection algorithm will be modified to take into account the law's budget constraints, wind requirements, and location preferences for both AIU and ComEd simultaneously. *Id.* at 7.

While the option of merely holding simultaneous but separate RFPs with separate selection processes avoids all the questions associated with the consolidation approach, Staff nevertheless believes that it would be a mistake to adopt the former approach. According to Staff, the reason for avoiding the separate but simultaneous approach is that bidders will have to decide, ex ante, how they want to bid their available supply: all in the ComEd RFP, all in the AIU RFP, or part in ComEd and part in AIU. Staff states that under the existing method of staggering the two procurement events, the bidders can offer all their supply in the first RFP and then offer whatever is left in the second RFP.

Staff is concerned that "if forced to bid simultaneously, if the bidders bid all their supply in AIU (or ComEd), they cannot (without incurring additional risk) bid any in ComEd (or AIU), lest the bidders find that they have 'won' the obligation to provide twice the level of RECs that they expect to have available." Staff claims this may lead to more pronounced differences between the outcomes of the ComEd and AIU RFPs. On the other hand, Staff says that requiring bidders to offer all their supply in one event may lead to more aggressive (lower-priced) bidding, since bidders will know that (at least with the IPA), they will only have "one bite at the apple" per year. *Id.* at 7-8.

Staff believes the potential problem of lopsided bidding can be avoided while retaining the potential advantage of more aggressive bidding by consolidating the two RFPs. Staff may support such an approach, provided that the consolidated process remains consistent with the various legal mandates surrounding Illinois' renewable portfolio standard (e.g., the results must conform to the budget constraints and the wind and location preferences). However, Staff believes the procurement Plan should specify how that consistency will be maintained and how the process will work so that the Commission can make an informed decision about modifying the current two-RFP system. *Id.* at 8.

Staff recommends that the IPA begin by considering a process whereby all bids would be required to be utility-neutral (applicable to either ComEd or AIU or both). This recommendation is for simplicity, but Staff says it runs the risk of reducing participation to a degree, if some bidders believe it is much more costly for them to do business with ComEd versus AIU, or vice versa. *Id.* at 8.

Under Staff's proposal, after bids are received, the selection algorithm would begin in precisely the same manner as in the last two procurement cycles (including the application of the location preferences), except that: for the budget constraint, the procurement administrator would use the sum of the two utilities' budget constraints; for the target number of RECs, the procurement administrator would use the sum of the two utilities' targets; and for the target number of wind RECs, the procurement administrator would use the sum of the two wind REC targets. *Id.* at 8-9.

After the bid selection algorithm is completed under Staff's proposal, a second algorithm would be used to allocate all the accepted RECs between the two utilities. Staff recommends that the goal of this second algorithm should be to minimize the disparity between the two utilities in the average cost per unit of customer load (rate disparity), subject to each utility's individual budget constraint. Staff says this would ensure that the IPA Act's goals for renewable resources and its preferences for wind power and proximity to Illinois, would be honored to the maximum extent feasible, but it would do so at a state-wide (combined ComEd and AIU) level rather than at the individual utility level. *Id.* at 9.

Staff believes that its proposed process is not without its potential drawbacks, at least from some perspectives. For instance, Staff says it could lead to one utility incurring greater costs than it would under the current process, although those costs would still be less than or equal to that utility's budget constraint. More generally, Staff is not entirely convinced that holding one rather than two procurement events for renewable resources has been adequately justified, given the type of problems discussed above. In any event, if such a change is to be considered by the Commission, Staff believes it is necessary for the procurement Plan to contain considerably greater detail than it does now about how the proposal is intended to work. *Id.* at 9-10.

Staff objects that the Plan provides inadequate justification for shifting to a single event for the procurement of RECs, that the Plan provides virtually no explanation of how the single procurement event will be conducted, and that the Plan fails to completely address various problems associated with such a shift. Therefore, Staff recommends that the Plan be revised to eliminate the proposal to use one rather than two events to procure RECs, unless and until the IPA provides a solid justification for the switch in policy, far greater detail on how the proposal would work in practice, and how the proposal would adequately address the various problems and issues Staff identified. *Id.* at 10.

In its Response, the **IPA** says it seeks a single procurement event for the RPS because it believes that a single procurement event will increase competition and capture process efficiencies. The IPA asserts that Staff recognizes this when it states that “requiring bidders to offer all their supply in one event may lead to more aggressive (lower-priced) bidding since bidders will know that . . . they will only have ‘one bite at the apple.’” IPA Response at 15, citing Staff Objections at 8. The IPA argues that a single registration process will also reduce the burdens for bidders and will provide for standardized definitions, terms and conditions for RECs statewide. IPA Response at 16.

In its Reply to Responses, **Staff** says that the IPA completely ignores Staff’s request for clarification on several aspects of the IPA’s proposal. As a result, Staff claims that we still do not know the answer to several questions. Staff Reply at 26-27.

Staff maintains that the consolidated approach would be significantly more complex than the separate but simultaneous approach. Nevertheless, Staff still recommended that the Plan utilize the consolidated approach rather than the simultaneous but separate approach. Staff says the IPA has remained silent on the choice and, would therefore presumably leave it to the procurement administrator to decide. In Staff's view, the potential difficulty with leaving this decision up to the procurement administrator is that the consolidated approach would in fact require very significant modifications to the bid selection process in order to take into account the law’s budget constraints, wind requirements, and location preferences for both AIU and ComEd simultaneously. Staff states that during the initial procurement plan dockets (Docket Nos. 07-0527 and 07-0528), the legal requirements to consider budget constraints, wind percentages, and resource location (20 ILCS 3855/1-75(c)(1)(-(3)) were very deliberately considered by the Commission, as a matter of statutory interpretation. *Id.* at 27-28.

Given the IPA’s failure to address these issues in its Plan, Staff recommends that the IPA’s proposal to conduct a single RFP event for the procurement of RECs for both utilities be rejected and tabled until next year’s procurement cycle, where, hopefully, the IPA will explicitly deal with these issues in its plan filing. *Id.* at 28.

IWEA is unclear about the benefits of consolidating even the REC-only procurement events, and the Plan does not provide significant justification for consolidating the two. Taking into consideration several concerns raised by Staff, IWEA believes that consolidating the events is not entirely necessary, but looks forward to the IPA and the procurement administrator addressing this issue in the RFP. IWEA Response at 12.

Constellation believes the Plan can benefit by providing greater clarity surrounding products that are to be included in REC procurements; specifically, environmental attributes should be addressed. For example, it was unclear to

Constellation in the most recent procurement whether NOx was a part of the product in the Ameren REC procurement, and thus Constellation says potential suppliers had to make assumptions or submit FAQs. Constellation claims the FAQ process did not yield an answer that provided sufficient clarity for bidders. Constellation asserts that although the use of a single REC procurement administrator may lead to greater specificity regarding the REC procurement, the IPA's Plan does not provide sufficient certainty or specificity as to this particular issue. Constellation insists that establishing those clear product definitions at the outset alleviates any unnecessary uncertainty. Constellation Objections at 7.

Constellation also argues that permitting RECs that are "Green-e" certified to be bid into the competitive REC procurements will provide for a greater number of RECs, and a more competitive and potentially more cost-effective rate for consumers. Currently, Constellation says bidders are permitted to deliver RECs only through PJM-EIS GATS or M-RETS, and are therefore precluded from utilizing RECs that carry a Green-e wholesale certification, which Constellation alleges is commonly recognized in the national renewables market. *Id.*

According to Constellation, in order to be certified as Green-e, organizations offering such products must meet the requirements for renewable resources detailed in the national Green-e Energy Standard; abide by a professional Code of Conduct that governs the marketing and business practices of the participating organizations; follow the Green-e Energy Customer Disclosure Requirements including providing the customer with a Product Content Label for the certified renewable energy option, which identifies the renewable resource type they supply (such as wind or solar) and the geographic location of the renewable energy generator, and providing customers with simple, clear Price, Terms and Conditions for the renewable energy option; and undergo an annual verification process audit to ensure that they are buying enough of the right types of renewable energy to match their certified sales to customers.

Constellation argues that use of a Green-e product carries sufficient rigor that it ought to be viewed (and is widely viewed) as possessing the same reliability as a GATS or M-RETS product, and thus permitted to be utilized for REC supply in future REC procurements. Constellation believes that increasing the number of reliable, eligible products can only serve to increase the number of offers, and thus ensure that the utilities and ultimately Illinois customers are receiving the best possible price for RECs. *Id.* at 7-8.

In its Response, the **IPA** addresses Constellation's request that the Plan be clarified to identify which products are to be included in REC procurements – specifically environmental attributes, e.g., NOx. The IPA says it agrees that the products to be included in the REC procurements should be identified, but the IPA disagrees that the Plan should specifically identify the REC products. According to the IPA, the purpose of the Plan, with respect to the renewable portfolio standard, is to identify the volume of renewable energy supplies required for AIU and ComEd to satisfy the RPS set forth in Section 1-75(c)(1) of the IPA Act. The IPA says there are certain categories of RECs that are required to be acquired under Section 1-75(c)(1), and based on price, subject to certain benchmarks. The IPA believes that the products to be acquired could not be fixed as part of the Plan, because the price and the other factors in the IPA Act have priority. Instead, the IPA says that the products to be acquired should be disclosed and identified through the public comment phase of the RFP. IPA Response at 20-21.

The IPA also responds to Constellation's suggestion that Green-e certified products should be permitted to be utilized for REC supply in future REC procurements since it will provide for a greater number of RECs, and a more competitive and potentially more cost-effective rate for consumers. The IPA says it appreciates Constellation's suggestion and will take it under advisement with regard to whether the products are consistent with the language in the Illinois RPS. *Id.* at 21.

ComEd notes that Constellation argued that Green-E certified RECs should be allowed to be bid into the procurement on the same basis as those RECs that are tracked by PJM EIS GATS and the M-RETS. According to ComEd, both GATS and M-RETS are very robust systems that can verify location of generation, resource type and month and year of generation, and can be used to efficiently transfer ownership of RECs. ComEd has much experience with these systems and is very satisfied with their operations. On the other hand, ComEd has little experience with or knowledge of the Green-E system, and very little information about the tracking capabilities of Green-E presented by Constellation. ComEd does not believe that there is sufficient information in this docket to justify changing the proposal by the IPA to continue using GATS and M-RETS exclusively to track RECs. ComEd Response at 3-4.

The **AG** also disagrees with Constellation on this point. The AG states that "Green-e" is a certification protocol, not a system of creating RECs. According to the AG, while PJM-EIS GATS and M-RETS are designed to create a unique and verifiable REC for every megawatt-hour of renewable energy created by a generator located within PJM and MISO, and suppliers that wheel power through those RTOs in a unit-specific transaction, Green-e simply certifies that a seller has met certain standards of product content and standards of conduct. The AG says that Green-e certification occurs through an after-the fact audit that occurs well after the transactions are concluded. As such, the AG believes that Green-e is a lower standard of verification which provides its information on a substantially time-lagged basis. AG Response at 8.

The AG asserts that M-RETS and GATS were specifically designed to track RECs in a uniform and low-cost manner. According to the AG, any generator within PJM or MISO (and suppliers wheeling power through PJM or MISO for delivery to Illinois utilities) will automatically receive a REC from MRETS or GATS. The AG asserts that allowing suppliers to use Green-e certification instead of or in addition to MRETS and GATS would impose additional costs over and above the systems already in place. In the AG's view, while Green-e, while potentially useful in the voluntary renewable energy marketplace, it is not designed to be used for RPS compliance purposes. *Id.* at 8.

In its Reply, **WMRE/WMILRE** states that PJM GATS and M-RETS have developed accurate and reliable methods of verifying that RECS comply with applicable state RPS requirements and then transferring those RECs to a purchaser. WMRE/WMILRE asserts that both of these systems allow for verification of the RECs in advance of the generation of the RECs. In addition, WMRE/WMILRE says both are routinely used and widely accepted as the “gold standard” for verifying and transferring RECs in the Midwest. WMRE/WMILRE believes that while Green-e is an acceptable means of transferring voluntary RECS, there is no need to utilize this lesser method of verifying RECs in Illinois when PJM GATS or M-RETS are available for that purpose. WMRE/WMILRE Reply at 2.

Staff notes that GATS or M-RETS record all the characteristics of RECs needed to determine compliance with the IPA Act’s location, type, and timing requirements. Furthermore, Staff says that they track ownership of the RECs and thereby guarantee that, upon “retirement” (for purposes of someone complying with one state’s RPS), the RECs cannot continue to be counted (by anyone toward compliance with the same state’s or another state’s RPS). Staff believes this tracking service fits the needs of the IPA, the Commission, and the utilities very well, as well as the needs of other states with mandatory RPS requirements. Staff Reply at 32.

It is Staff’s understanding that Green-E certification is often obtained for RECs offered into the “voluntary” REC market, but is not generally a requirement of mandatory RPS programs. Staff also points out that, among the characteristics recorded by GATS and M-RETS, is whether or not the generator of the REC is Green-E certified. Hence, Staff believes that Constellation and other suppliers may certainly use Green-E certified RECs to satisfy their REC contracts with ComEd and AIU under the Illinois RPS, but, in Staff’s opinion, those RECs should still be tracked by GATS or MRETs. *Id.* at 33.

2. Commission Analysis and Conclusions

In the procurement plan approved in Docket 08-0519, separate renewable resource events were approved for AIU and ComEd. In the Plan before the Commission in the instant proceeding, the IPA has proposed to conduct a single renewable resource procurement event for AIU and ComEd, jointly. Staff objects to this proposal, arguing that the IPA has not sufficiently justified its proposal or explained how it would work, and did not respond to Staff’s objections.

First, it is the Commission's understanding that this issue is separate and distinct from the issues surrounding the proposed procurement of long-term renewable resources addressed earlier in this Order. The Commission understands that the IPA plans to acquire short-term RECs to meet the minimum RPS required under the PUA and IPA Act. It also now appears to the Commission that the single resource procurement event relates to this short-term REC acquisition and that any long-term renewable resource acquisition will supplement the short-term REC acquisition.

Having reviewed the positions of the Parties, the Commission finds that the IPA should be authorized to conduct a single short-term REC acquisition event, instead of conducting separate short-term REC acquisition events for AIU and ComEd. The Commission agrees with Staff's argument in the alternative that the REC acquisition should be one event where all bidders bid their supply for both ComEd and AIU. The IPA states in its plan that the purpose of this change is to simplify the bidding environment while drawing greater levels of competition from providers of renewable energy resources. IPA Plan at 2. There is room for improvement in conducting the short-term REC acquisition. The Commission agrees with the IPA that a simultaneous REC acquisition event will encourage more robust competition among the bidders. Although the Commission disagrees with Staff that the IPA's proposals should be rejected, the Commission recognizes Staff's valid concerns regarding switching to a single REC acquisition event. In consideration of Staff's concerns and questions we request that Staff's questions listed herein be resolved when the short-term REC benchmarks are presented for approval.

Staff's questions to be resolved are as follows:

- Will bidders be permitted to offer different prices for ComEd and Ameren contracts?
- Will bidders be permitted to offer "contingent" bids where the procurement administrator may select X RECs for ComEd or X RECs for Ameren but not for both?
- Will bidders be required to offer just one set of bids (the same quantities and prices that will be applicable to ComEd, Ameren, or both) that the procurement administrator can use for fulfilling any combination of the ComEd and Ameren requirements?
- How will the selection algorithm be modified to take into account the law's budget constraints, wind requirements, and location preferences for both Ameren and ComEd simultaneously?

These conclusions will also address the recommendation by Constellation that permitting RECs that are Green-E certified to be bid into the competitive REC procurements will provide for a greater number of RECs, and a more competitive and potentially more cost-effective rate for consumers. This proposal is generally opposed by the IPA, Staff, ComEd, the AG and IWEA. They argue, among other things, that there is not sufficient information about the tracking capabilities of Green-E to support Constellation's proposal.

Having reviewed the positions of the Parties, the Commission finds that there is not sufficient support for Constellation's recommendation to warrant its adoption in this proceeding over the objections of other Parties.

C. Demand Response Measures

Section 8-103(c) of the PUA establishes specific requirements for utility company Demand Response Programs. Section 16-111.5(b) of the PUA requires that the procurement Plan include an analysis of the impact of demand side initiatives established by Section 8-103(c) of the PUA. The IPA states that those demand side initiatives include the impact of demand response programs (both current and projected) and the impact of energy efficiency programs (both current and projected). As discussed below, several parties have taken issue with the IPA's Plan to procure demand response measures.

For both ComEd and AIU, the IPA recommends that the initial solicitation of demand response as an alternative to standard capacity be conducted in the 2010 Procurement Cycle. Specifically, the IPA recommends that Demand Response Procurement be specified as a bid alternate in the spring 2010 solicitation for capacity. In the event that Demand Response providers do not exist or do not participate in the spring solicitation, the IPA proposes that a secondary solicitation will be conducted in the fall of 2010; the second event would seek to establish capacity contracts that will encourage the development of demand response programs within the AIU and ComEd service territory. IPA Plan at 38, 52.

As discussed below, one of the issues in dispute is whether the IPA should be permitted to supplement the demand response currently acquired for ComEd, through the PJM RPM auction, with the IPA’s own independent demand response acquisition event targeted more specifically at ComEd's eligible retail customers.

1. Positions of the Parties

ComEd states that PJM acquires capacity for the markets that it administers under the Reliability Pricing Model through an auction process. In those auctions, demand-resource providers are eligible to bid on the same basis as generation resources. PJM selects the lowest bids from either the generation resources or the demand response resources and pays the winning bidders the clearing price. ComEd contends that the RPM process satisfies the requirements of the PUA. ComEd says the auction process ensures that PJM acquires demand-response resources whenever their bid/cost is lower than other capacity resources. ComEd states that overall capacity costs may be reduced more by having all demand response resources bid into the RPM auction rather than being acquired in a separate process outside of the auction. According to ComEd, increasing the supply of demand response in the auction should reduce the overall capacity price for the entire ComEd zone helping to lower the price for all ComEd customers. ComEd Objections at 3-4.

ComEd asserts that while the RPM process meets PUA requirements by ensuring that all available demand-resources that are less costly than comparable capacity products are acquired, a separate procurement for demand response resources held outside of the RPM process does not meet the requirement of lowering customer costs. According to ComEd, under the PJM RPM process, PJM effectively procures capacity, including demand resources, for utilities three years in advance through an auction process. ComEd says these are the prices paid to generators and Curtailment Service Providers ("CSP"), i.e. demand-response providers, for capacity that they have committed to provide in each planning year.

ComEd states that the load serving entities in PJM, such as ComEd, are billed for capacity for a particular year based on their share of the PJM load. To determine the amount of capacity that must be purchased, ComEd says PJM uses an econometric model that incorporates load data going back to 1998. To affect the PJM load forecast, ComEd contends that any demand-resources procured through the IPA process would have to be implemented (not just available) during the time of the PJM peak load each year. In addition, because PJM's load forecasting process is based on many years of historical data, ComEd says the impact of new demand-reduction resources would not be fully reflected for a number of years into the future. *Id.* at 4-5.

ComEd provided an example intended to demonstrate that if approved, the IPA-proposed demand response procurement would likely lead to higher rather than lower costs for customers. ComEd claims that even if additional demand response measures were available outside of the RPM auction, could be procured at half the RPM clearing price, and the demand response measure could somehow be called on at exactly the right times to reduce ComEd's contribution to the PJM peak load, costs to consumers would still be higher than the current process of purchasing all capacity, including demand response, through the RPM auction. *Id.* at 5-6.

For periods beyond which an RPM auction has been held (June 2013 and beyond), ComEd asserts that there are no credible benchmarks that can be used to determine what price would meet the requirements of the Act. ComEd says that contractually, this may be accomplished by requiring winning bidders to lower their price below the price PJM ultimately charges ComEd for capacity. In ComEd's view, however, it seems doubtful bidders will agree to such terms when they can just bid into the RPM auction directly. *Id.* at 6.

In its Response to ComEd, the **IPA** agrees that the PJM procures demand response resources in accordance with the PUA; however, it disagrees that the Plan's proposal to procure additional or different demand response resources is inconsistent with the PUA. The IPA argues that Section 16-111.5(b)(3)(ii) of the PUA requires the Plan to include a mix of demand response products where the cost of the demand response is lower than procuring comparable capacity products. According to the IPA, these demand response products are to be procured <u>from</u> eligible retail customers. The IPA says that PJM's demand response program relies on curtailment service providers, who act as agents for the customers in participating in demand response. It is not clear to the IPA that the demand response measures made available through PJM's demand response program would be acquired from or on behalf of eligible retail customers participating in the Plan. In addition, the IPA asserts that the PJM demand response programs do not represent the entire universe of demand response or capacity options.

The IPA claims that eligible retail customers purchasing energy through the Plan may benefit from more stable pricing, or at least alternative demand response options, outside of the PJM process. IPA Response at 2-3.

With respect to ComEd's argument that the IPA-proposed demand response procurement would likely lead to higher costs for customers, the IPA claims the Plan proposes that demand response measures be acquired only where the costs of such demand response is less than the cost of traditional capacity. *Id.* at 3, citing ComEd Objections at 5. The IPA recommends that no modifications be made to the demand response procurement proposal.

AIU believes it is imperative that any demand response suppliers who are successful in either of these procurement events be directly responsible for satisfying the MISO registration requirements. According to AIU, this means that it would be the demand response supplier, not AIU, who is responsible for: 1) ensuring that the demand response product satisfies the MISO requirement for being utilized as a planning resource; 2) registering the demand response resource with the MISO; and 3) transferring the associate resource adequacy qualities (PRCs or the equivalent) to AIU. AIU Objections at 7-8; AIU BOE at 2-3.

AIU claims this will ensure that demand response resources are viewed by MISO in the same manner as traditional capacity resources, thus eliminating the risk that AIU could be contractually obligated to pay for demand response resources on behalf of its customers while not receiving the corresponding resource adequacy credit for the resources through the MISO. AIU says it also ensures that the demand response suppliers will be placed on an even playing field with traditional supply-side capacity suppliers in the context of the IPA procurement process. AIU Objections at 8.

The **IPA** agrees with AIU's recommendations that "successful demand response suppliers should be directly responsible for satisfying the MISO registration requirements." Section 16-111.5(b)(3)(ii)(B) of the PUA requires that demand response procured through the Plan "satisfy the demand-response requirements of the regional transmission organization market in which the utility's service territory is located, including, but not limited to, any applicable capacity or dispatch requirements."

The IPA also recommends that the Plan be modified with respect to ComEd's procurement to reflect a similar requirement – that successful demand response suppliers be directly responsible for satisfying PJM registration requirements. IPA Response at 13-14; see also AIU BOE at 2-3. The Commission agrees with this recommendation with respect to both AIU and ComEd.

In **Staff's** view, the Plan's proposed implementation of the IPA Act's new demand response requirements is deficient in several respects. Staff says it is unclear why ComEd customers should be required to purchase demand response contracts "that will incent the development of demand response programs within the Ameren service territory." Whether this was intended or an inadvertent error, Staff objects to this aspect of the proposal and recommends that it be removed from the Plan. Staff Objections at 19.

According to Staff, if the Plan's reference to the AIU service territory in the context of ComEd's resource requirements was an inadvertent error, then it is unclear how the IPA would propose to implement its proposal for ComEd, which purchases all of its capacity and demand response resources from PJM through PJM's RPM process. Staff states that this is a PJM-wide process that accepts both capacity and demand-response bids, competing head-to-head, and, in ComEd's case, appears to automatically satisfy the requirements of Section 16-111.5(b)(3)(ii) of the PUA. Staff says the Plan makes note of this very fact on page 52, yet seems to disregard its significance. Staff recommends that the Plan be modified to recognize that the RPM process already ensures that demand-response is procured whenever the cost is lower than procuring comparable capacity products. *Id.* at 20.

Staff believes that the benefit of holding a second demand response procurement in the fall is totally unclear and probably non-existent. Staff says the IPA Act requires the purchase of demand-response products whenever their cost is lower than that of procuring comparable capacity products. Staff contends that the only way to ensure this is to hold demand-response and capacity procurements at the same time and to evaluate and select them at the same time. Staff also asserts that by the fall of 2010, the summer of 2010 (where the upcoming plan year's capacity and demand response will like be most valuable) will already have come and gone. Hence, Staff presumes, the fall 2010 procurement would be for capacity in the 2011 to 2012 plan year (and beyond). Staff complains that it is unclear why the Plan does not include "comparable capacity products" for the 2011 to 2012 plan year (and beyond) competing in that same procurement event. *Id.*

It is also unclear to Staff why demand response products should be procured as 5-year contracts, while the comparable capacity products are being procured as one-month contracts that are bought separately on a laddered basis for up to three years into the future. Staff argues that this difference in approach would tend to thwart a clear-cut price comparison between the demand response products and their "comparable capacity products." Therefore, Staff objects that the Plan calls for procuring demand response products in a manner that is not comparable to the capacity products that are included in the Plan. Staff recommends that the specification of the demand response products be modified accordingly. *Id.* at 21.

In response to Staff, the **IPA** notes that Staff correctly identifies a typographical error at page 52 of the Plan. The phrase "that will incent the development of demand response programs within the Ameren territory" should read "that will incent the development of demand response programs within the ComEd territory."

The IPA also responds to Staff's assertion that the Plan be modified to recognize that the PJM Reliability Pricing Model "automatically satisfies the requirements of 220 ILCS 5/16-111.5(b)(3)(ii)." The IPA believes Staff's presumption and reading of the

PUA is not accurate. The IPA says Section 16-111.5(b)(3)(ii) of the PUA requires the Plan include a mix of demand response products where the cost of the demand response is lower than procuring comparable capacity products. As discussed above, the IPA says these demand response products are to be procured from eligible retail customers. The IPA maintains that PJM's demand response program relies on curtailment service providers, who act as agents for the customers in participating in demand response.

It is not clear to the IPA that the demand response measures made available through PJM's demand response program would be acquired from or on behalf of eligible retail customers participating in the Plan. In addition, the IPA says any qualified capacity procured from demand response resources in the ComEd region that is bid at lower than the PJM RPM prices will be procured under the Plan. In the IPA's view, the result is that, unless new demand response measures are developed, there will be less demand response products available to ComEd through the PJM RPM offering, particularly in future periods. According to the IPA, the Plan is intended to solicit bids for additional demand response products that also meet the requirements of the PUA, including the requirement that the demand response products be lower in cost than procuring comparable capacity requirements. IPA Response at 17-18.

The IPA also responds to Staff's criticisms of a second demand response procurement event occur in the fall in the event that the spring demand response procurement event is unsuccessful. The IPA says it is also unclear whether a second demand response procurement event would produce qualified demand response products. However, the IPA says the intent of the Plan is to conduct a procurement event in the spring, and plan for a procurement event in the fall to account for the possibility that demand response projects will not yet be available in the market by the spring 2010. According to the IPA, a second demand response procurement event "offers the opportunity to solicit bids with different or alternative terms and conditions are developed from the first procurement event, and provide additional incentives to develop such projects." *Id.* at 18.

As noted above, Staff further requests an explanation or clarification for the Plan's proposal to procure demand response products through 5-year contracts, while comparable capacity products are being procured as one-month contracts that are bought separately on a laddered basis for up to three years. The IPA says Staff's comments are based on a mistaken reading of the Plan in that the 5-year term for demand response projects would occur only for projects that are bid in the fall 2010 bid, which would occur only if the first solicitation is unsuccessful. According to the IPA, the Plan proposes that demand response providers participating in the spring capacity solicitation be allowed to bid on all months and volumes under the same terms and conditions as other traditional suppliers. If the secondary solicitation is necessary, the Plan proposes that the 5-year term for demand response projects be included to provide stability that may be necessary to incent the development of alternative demand response projects. *Id.* at 18-19.

Constellation expresses concern that the Plan lacks the requisite specificity on certain fundamental aspects of the demand response procurement. It is not clear to Constellation whether the IPA's Plan intends to limit participation in the demand response procurement exclusively to demand response resources associated with "eligible retail customers" as that term is defined under the PUA. Constellation says the IPA should pursue a demand response procurement strategy that attracts the largest possible amount of demand response resources at the lowest possible cost. According to Constellation, such a strategy necessarily should include demand response resources from all retail customers in the ComEd and AIU service territories; not just eligible retail customers. Constellation Objections at 4.

Constellation states that the competitive procurements in Illinois over the last several years have been aided by workshops and educational/collaborative sessions in advance of the procurements. Constellation says potential bidders have gained valuable knowledge regarding the bidding process and documents, and the procurement managers have learned of areas of confusion or potential issues sufficiently in advance of the procurement events to alleviate or mitigate those concerns. Constellation believes this forum is even more important when launching a new type of competitive procurement, such as is the case with the procurement of demand response resources. Constellation therefore suggests that the Plan be revised to specifically include bidder information workshops and planning sessions for the fall procurement cycle, devoted to this new demand response procurement event. *Id.* at 4-5.

In Response to Constellation, the **IPA** says Section 16-111.5(b)(3)(ii) of the PUA requires the Plan to include a mix of demand response products where the cost of the demand response is lower than procuring comparable capacity products. The IPA states that these demand response products are to be procured from eligible retail customers. Therefore, the IPA believes that the PUA limits the demand response products to be procured from eligible retail customers. The IPA also agrees to conduct workshops and/or other planning sessions devoted to the demand response procurement events in order to further develop these issues. IPA Response at 19-20.

In its response, the **AG** observes that several parties object to the manner in which the IPA proposes to solicit bids for demand-response resources. According to the AG, recently enacted amendments to the PUA require the IPA to procure demand-response "whenever the cost is lower than procuring comparable capacity products." The AG says these demand-response measures must be procured from and share benefits with eligible retail customers, satisfy applicable regional transmission organization rules, guarantee reimbursement to utilities, and meet the same credit requirements that apply to suppliers of capacity. AG Response at 3-4.

According to the AG, ComEd and Staff erroneously state that there is no need for the IPA to solicit demand-response bids for ComEd because the utility purchases capacity through PJM RPM auctions. The AG asserts that in making these objections, ComEd and Staff appear to overlook express PUA language requiring comparison of capacity bids with demand-response measures “procured by a demand-response provider from eligible retail customers.” In the AG's view, the requirement to solicit bids for demand response from eligible retail customers harmonize the new demand response requirement with existing PUA provisions specifying that “customers that are excluded from the definition of ‘eligible retail customers’ shall not be included in the procurement plan load requirements . . . .” AG Response at 4-5, AG BOE at 1, citing 220 ILCS 16-111.5(a).

In the AG’s view, ComEd’s claim that the PJM RPM meets PUA requirement is not supported by any evidence in the record indicating that any demand response measures procured from ComEd’s eligible retail customers have been accepted – or even offered -- in PJM RPM auctions. It seems unlikely to the AG that any such evidence exists because the Curtailment Service Providers certified by PJM to submit bids for demand-resources focus on large commercial and industrial customers, rather than the residential and small commercial customers that ComEd now serves. *Id.* at 5.

According to the AG, the only way to determine whether there are demand-resources that can be procured from ComEd’s eligible retail customers that are less costly than comparable capacity products is to solicit bids for these resources and to compare the resulting bid prices with RPM capacity prices. The Plan properly proposes that the IPA solicit bids to determine whether any such demand response resources are available at a price that is less than the current RPM forward price curve. The AG suggests that in future years, it may be possible to satisfy PUA demand-response requirements by asking demand-response providers to submit bids in the RPM auction that include demand response from ComEd’s eligible retail customers. The AG says that since the RPM auction has already occurred for the time-period covered by the Plan, the only option available this year is an IPA solicitation of bids for demand-response procured from ComEd’s eligible retail customers. *Id.* at 5-6.

The AG supports Constellation's suggestion that that the IPA should procure demand response resources from all retail customers in the ComEd and AIU service territories; not just eligible retail customers. The AG supports IPA procurement of any and all demand-side resources that cost less than supply-side resources stating there is nothing in the PUA to preclude such a solicitation. However, the AG emphasizes that the PUA specifically requires the IPA to solicit bids for demand response resources procured from ComEd and AIU eligible retail customers. In the AG's view, any procurement of demand-side resources from other customers would have to be in addition to the solicitation of demand-side resources procured from eligible retail customers. *Id.* at 6.

The AG also supports Constellation's suggestion that the IPA hold informational workshops and planning sessions to facilitate implementation of the newly mandated demand response procurement requirements. The AG believes public workshops and planning sessions would help to generate interest in the new demand-response solicitation and would provide a forum to answer any questions that prospective bidders may have about the new process. *Id.* at 6-7.

The AG also responds to Staff objection to the IPA's Plan to solicit demand response bids twice during the upcoming procurement cycle, during the spring of 2010, when capacity bids are solicited, and again in the fall of 2010. The AG agrees with Staff's argument that one solicitation in the spring of 2010 is sufficient. *Id.* at 7.

The AG indicates that the statute requires the IPA to procure demand-response whenever the cost is lower than procuring comparable capacity products. In order to comply with this requirement, the AG says the IPA must solicit demand response bids in the spring of 2010, when the IPA plans to procure capacity for Ameren. The AG notes that ComEd capacity prices, determined through the RPS process, will be known at that time. Hence, the AG concludes that a single solicitation during the spring of 2010 should be sufficient to comply with the statutory requirement to procure demand response from eligible retail customers that costs less than capacity. If, however, the IPA adopts Constellation's proposal to procure additional demand-side resources from ComEd and AIU delivery customers, the AG believes it would make sense to hold that procurement event in the fall. (AG Response at 7)

In its Reply to the AG, the **IPA** states that it agrees with the AG's comments regarding Demand Response procurement. IPA Reply at 9.

As noted above, both the IPA and the AG claim that the PJM RPM process does not satisfy the statutory requirement because it is not clear that PJM procures demand response measures from eligible retail customers. In response, **ComEd** says it is not aware of any restrictions on the size of a customer that may be recruited to participate in the RPM process, and neither the IPA nor the AG cite to any. In fact, ComEd says it provides 60 MW of demand response from its residential customers under ComEd's air conditioning cycling program to PJM through the Full Emergency Load Response portion of RPM. ComEd Reply at 15-16.

As explained above, ComEd maintains that any procurement of demand response outside of the RPM process would likely lead to higher costs to customers. In response to the IPA's claim that it will procure demand response measures only when they are less costly than traditional capacity, ComEd asserts that the IPA provides no explanation of how it will be able to do so under the RPM structure. According to ComEd, it appears that the IPA intends to procure demand response measures without regard to the ultimate cost effect on consumers. ComEd insists that even if the IPA could procure demand response measures for half the price of capacity, the ultimate cost to consumers would still be higher than if no demand response measures had been procured by the IPA.

ComEd believes a simple cost comparison is inadequate to comply with the statute. ComEd argues that the PUA does not permit just any demand response measures to be procured. Instead, ComEd says the PUA allows only "cost-effective demand-response measures" to be procured. ComEd asserts that demand response measures which increase costs to customers surely cannot be considered to be cost-effective. ComEd argues that since the IPA has failed to set forth any reasonable process for procuring cost-effective demand-response measures outside of the RPM process, the Commission should reject this proposal and find that the PJM RPM process satisfies the PUA. ComEd Reply at 15.

With regard to Constellation's suggestion that the IPA procure demand-response measures from anyone offering them and not just eligible retail customers, ComEd agrees with the Response of the IPA that the PUA only permits the procurement of demand response measures from eligible retail customers. ComEd argues that procurement of such measures from other types of customers would violate the cost cap placed on the procurement of demand response measures by the Illinois General Assembly. *Id.*

2. Commissioner Elliott's Questions and Parties' Responses

On November 2, 2009, six questions related to demand response were distributed to the parties at the request of Commissioner Elliott. Those questions are stated and the parties' responses, filed November 6, 2009, are summarized below.

1. On page 3 of Commonwealth Edison's (ComEd) comments on the procurement Plan, the following statement was made:

   "Under the PJM RPM process, PJM effectively procures capacity, including demand resources, for utilities three years in advance through an auction process. RPM prices from the most recent annual auctions held by PJM are listed in the table above. These are the prices paid to generators and Curtailment Service Providers (CSP), i.e. demand-response providers, for capacity that they have committed to provide in each planning year. The load serving entities, such as ComEd, are billed for capacity for a particular year based on their share of the PJM load. To determine the amount of capacity that must be purchased, PJM uses an econometric model that incorporates load data going back to 1998. To affect the PJM load forecast, any demand resources procured through the IPA process would have to be implemented (not just available) during the time of the PJM peak load each year. In addition, because PJM's load forecasting process is based on many years of historical data, the impact of new demand-reduction resources would not be fully reflected for a number of years into the future."

   It is my understanding of PJM's RPM construct that estimates for capacity to meet future demand are indeed based upon a forecast process as described in ComEd's comments. However, it is also my understanding that the allocation of capacity costs within the ComEd zone when the delivery year occurs is based upon the ratio of that customer's peak usage of the five highest coincident peak

> demands in the prior calendar year. It is also my understanding that the methodology to recover the annual RPM capacity cost divides the cost over 365 days to determine a capacity cost per megawatt day, in essence spreading the capacity costs for the peak period equally over each day of the year and effectively reducing the actual cost of capacity during the peak period and increasing the cost of capacity over the off-peak period compared to a more market-based construct.
>
> Given the above context, if the economic cost of a megawatt (MW) of demand response (DR) was higher than the averaged RPM cost per MW day, but lower than the actual cost of a MW of capacity for the peak period, would it meet the criteria for a lower cost alternative to a MW of RPM capacity?

In its response, **ComEd** asserts there are two separate issues to respond to in this question:

1. Can an additional DR resource that has annual costs that are less than RPM annual costs be a lower cost alternative given the PJM requirement to purchase capacity three years in advance?
2. Does the PJM practice of amortizing capacity costs over the entire year impact whether a resource is found to be the lowest cost alternative?

In ComEd's view, the answer to both questions is no. (ComEd Response at 2-3) ComEd explains its answer with an illustrative example. ComEd says these numbers are not actual costs and capacity obligations, but simplified values that it believes are consistent with the premises of the Question and illustrate the analysis.

ComEd says to assume for purposes of its example:

- Capacity Obligation: 1 MW
- Actual Peak Demand Capacity Cost: $365/MW
- Average RPM Capacity Cost: $1/MW-Day
- Additional DR Cost: $182/MW

According to ComEd, PJM effectively procures capacity, including demand resources, for utilities three years in advance through an auction process. Consequently, in this example, ComEd would have committed to purchase the 1 MW from PJM for $365 (paid on a daily basis of $1/MW-Day as noted in the question). If ComEd were to also procure the Additional DR for $182, the total amount paid for by customers for the year would be $547 ($365 to PJM and $182 to the Additional DR provider). Consequently, while the price of the Additional DR is lower than what cleared in the PJM auction, ComEd claims its purchase does not lower its capacity obligation to PJM and purchasing it outside of PJM would not be a "cost-effective" option as the total cost to customers would increase rather than decrease. ComEd asserts that while actual costs will differ from the example, the conclusion remains the same. ComEd insists that Section 16-111.5(b)(3)(ii) requires not only that the DR cost less than the comparable capacity product, but also that the DR be “cost-effective." (ComEd Response at 3)

In regard to the second part of the question, ComEd says the decision by PJM to recover capacity costs on a daily average basis rather than only during the summer peak period (or some other period) does not effect this conclusion. In ComEd's view, the question of when costs are recovered is one of rate design and does not change the cost of the resource. ComEd agrees with the implication of the question that it would be inappropriate to compare an effectively annual provider of DR cost to a daily RPM value when performing an analysis and ComEd claims it did not make such a comparison when it reached the conclusion that this DR proposal would raise, rather than lower, customer costs. ComEd Response at 3.

According to **Staff**, if the question is asking about demand response offered into the PJM RPM auction, the short answer is “yes.” If the question is asking about demand response not offered into the PJM RPM, Staff says the answer is probably not. (Staff Response at 2)

Staff states that where the question states “the allocation of capacity costs within the ComEd zone when the delivery year occurs is based upon the ratio of that customer’s peak usage of the five highest coincident peak demands in the prior calendar year,” it should be clarified that this is an allocation performed by ComEd rather than PJM, where the ComEd load zone’s peak load contribution is allocated between all the load serving entities in that zone (e.g., ComEd and ARES).

According to Staff, it is not correct, or it is at least misleading, to say that “the methodology to recover the annual RPM capacity cost divides the cost over 365 days to determine a capacity cost per megawatt day, in essence spreading the capacity costs for the peak period equally over each day of the year and effectively reducing the actual cost of capacity during the peak period and increasing the cost of capacity over the off-peak period compared to a more market-based construct.” Staff asserts that the capacity charge imposed by PJM is indeed usually expressed as dollars per MW-day. However, Staff says it is not applied each day of the year to a load serving entity’s daily average load or daily peak load; rather, it is applied to a value tied to the load serving entity’s projected summer system peak load contribution. Furthermore, Staff asserts that the fact that PJM recovers the costs of securing capacity to serve that peak load over the course of a year, rather than at a few summer peak days of the year, does not change the fact that the LSE’s bill is related to its summer peak contribution rather than to an annual average load. Staff Response at 3.

On the other hand, Staff contends that the intent of the question may not have been directed at the way PJM bills LSEs for its RPM costs, but rather at the way LSE’s (like ComEd) bill their retail customers. Staff says the retail recovery of capacity costs allocated to individual LSEs varies. Staff has no information on how ARES recover their capacity costs from retail customers. However, for “eligible retail customers” taking fixed price service from ComEd, Staff says ComEd’s cost-recovery rider allocates total monthly capacity costs billed by PJM based on monthly on-peak and monthly off-peak energy usage of customers in each class. Staff states that for a given class, the allocated costs are recovered through either two or four different per kWh energy rates, depending on customer class.

For ComEd’s hourly-priced customers, Staff asserts that capacity costs are recovered in one of two ways. For a retail customer to which the Self-Generating Customer Group is applicable, Staff states that a Daily Capacity Charge ("DCC") is applicable to the highest 30-minute demand established by the retail customer each day during the monthly billing period. Staff says the DCC is the same as PJM’s capacity charge (per MW-day) adjusted by loss factors and an uncollectible factor. For any other retail customer receiving service with hourly pricing, Staff asserts that a monthly capacity charge is applicable to the Capacity Obligation established by the retail customer for the monthly billing period. According to Staff, the customer’s Capacity Obligation is the customer's share of the annual peak electric load assigned to ComEd by PJM. Staff states that the monthly capacity charge is PJM’s daily capacity charge multiplied by 365/12 and adjusted by an uncollectible factor. Staff contends that the manner in which ComEd recovers its costs from ratepayers is a matter of rate design over which the Commission has regulatory authority. Staff believes that the charge to ComEd’s fixed-price customers for capacity costs (just like the charge for energy costs) is not strictly based upon the principles of “marginal cost pricing.” *Id.* at 3-4.

In Staff's view, the question itself appears to contain the implicit assumption that the demand response is not bid into the RPM auction. Staff claims, however, that if the demand response were bid into the RPM auction, and if it were bid in at a price below the auction clearing price for peak period capacity, it would be selected by PJM. Thus, in the words of Question 1, Staff says the demand response would “meet the criteria for a lower cost alternative to a MW of RPM capacity” from both PJM’s perspective and an economic efficiency perspective. *Id.* at 4.

Staff asserts that if the demand response was not bid into the RPM, but was instead offered to a load-serving entity, like ComEd, at a price greater than the average RPM cost per MW day, but less than PJM’s auction clearing price (assuming that is what it meant by the actual cost of a MW of capacity for the peak period), it would have uncertain and limited value but definite costs to the load-serving entity. Specifically, Staff believes it is conceivable that such demand response would have a second-order impact on energy market prices, which, depending on the LSE’s hedge position, could either increase or decrease its ultimate cost of supplying energy to its customers (reducing those costs if under-hedged, increasing them if over-hedged). Staff contends that not offering the load response into PJM would mean foolishly foregoing the opportunity to sell demand-response capacity and other demand-response services to PJM, without decreasing the LSE’s own capacity costs. Thus, Staff claims such a transaction by an LSE (like ComEd), most likely, would not reduce the LSE’s costs. In general, Staff says the best hope for recognition of demand response capacity benefits is to offer demand response capacity into PJM's RPM. *Id.* at 4-5.

Staff states that if the question was asking if the hypothetical demand response would meet the IPA Plan's criteria for a lower cost alternative to a MW of RPM capacity, Staff cannot answer this question because, in relation to the ComEd portion of the procurement Plan, the IPA has not provided sufficient information about its proposal to answer the hypothetical. Staff says its responses to the other questions may also be relevant to Question 1. *Id.* at 5.

The **IPA** states that it can only interpret the applicable statute directing the procurement of capacity sourced from demand response resources when it is available at a lower cost than other options as a nominal price comparison. IPA Response at 2.

2. Based on the above context, if DR was acquired, does the reduction in demand caused by the acquisition of the demand response become totally realized by the calculation of an end customers' pro-rata share in the following RPM delivery year? Or does the value of the DR capacity not become recognized anytime sooner than the fourth year from when the DR was actually implemented?

In response, **ComEd** states that if the additional DR were acquired, total customer costs would increase for the period already covered by RPM auctions (3 years) as described in the response to Question 1. However, ComEd asserts that it is not clear that the benefits of such DR would be "totally realized" even in the fourth year. ComEd says this is because PJM bases its capacity obligation estimate on an econometric model with 10 years of data. Consequently, ComEd contends that the benefit of the additional DR acquired outside of the PJM auction might be effectively "averaged down" by being combined with the other years of data. Also, ComEd asserts that the additional DR would have to be implemented, or called, on coincident peak days in order to have any effect on PJM's forecast of capacity obligations to in turn lower ComEd's capacity payments to PJM. ComEd claims those peak days are not, however, known or identified as peak days in advance of when they occur; they can only be determined after the fact. Therefore, ComEd insists that simply procuring additional DR does not guarantee that it will have any effect on lowering ComEd's capacity obligations or the costs of meeting those obligations to ComEd's customers. ComEd Response at 4.

Staff states that outside the context of a recognized demand response resource, a reduction in peak demand by a load serving entity would only be recognized by PJM via its modeling of a load zone's peak load. Furthermore, Staff says that if the brief account of that process described in the Commissioner's excerpt from ComEd's comments on the procurement Plan is assumed to be accurate, that recognition by PJM would be gradual, as indicated in the excerpt. On the other hand, Staff says a reduction in demand by a load serving entity could be recognized by ComEd in the next year's allocation of capacity obligation among load-serving entities. For example, if there was a reduction in ComEd's eligible retail customer load that was not mimicked by other load serving entities in the ComEd load-zone, Staff claims ComEd could allocate less of the load-zone's capacity obligation to itself. However, Staff asserts that recognized demand response is generally treated as a resource and not as a reduction in a load zone's unrestricted peak load. Staff believes this is true of PJM and Staff also believes ComEd forecasters treat demand response in a similar manner. Staff Response at 6.

The **IPA** states that while the point made by the Commissioner is well taken, the subject of realized value from demand response assets lies beyond the scope of the IPA's involvement in this case. IPA Response at 2.

> 3. Based on the above context, it appears that even if the DR is acquired, ComEd is obligated to pay for RPM capacity costs for at least three years forward, based upon historic levels of peak demand contributions, even though ComEd's contribution to peak demand after the DR is procured would be reduced by that corresponding amount. Is this correct?

ComEd states that yes, this is correct. ComEd adds that, to be precise, the ComEd capacity obligation established by PJM is based on a PJM forecast, which in turn uses historical data. Also, as noted in the response to Question 2, ComEd says its capacity obligation would not immediately, if ever, be fully reduced by the additional DR. ComEd Response at 5.

Staff's only response is a reference to its response to Question 2.

In the **IPA's** view, while the point made by the Commissioner is well taken, the subject of realized value from demand response assets lies beyond the scope of the IPA's involvement in this case. The IPA suggests that it may be answerable by ComEd and AIU based on their use (or non-use) of demand response assets under the control of the companies. IPA Response at 2).

> 4. In reference to demand response products purchased for ComEd, please have the parties address exactly how the DR value for both energy and capacity products are derived and settled between the Curtailment Resource Provider, PJM and ComEd and the ultimate end use customer, i.e., how would each party be compensated and revenues recovered, through what settlement mechanisms? Please provide an example transaction where a resource bid might be accepted for a MW of DR capacity, how that capacity makes it into the PJM RPM auction and if that MW of DR capability is bid into the energy or ancillary services markets exactly how would the settlement process work between all affected parties including the end use customer?

ComEd states that the following describes the current structure of participation in PJM administered programs by ComEd or an entity like it.

Capacity

Currently, ComEd says it contracts with business customers for firm load reductions, and aggregates residential customers participating in its AC Cycling program to create a DR capacity resource. ComEd adds that this resource is then registered in the PJM Interruptible Load for Reliability Program. ComEd says PJM takes funds from retail suppliers' capacity purchases and compensates ComEd as the CSP. ComEd then uses these funds to compensate customers participating in the programs. In ComEd's program these terms are defined by Rider CLR. ComEd Response at 6.

ComEd asserts that CSPs have also been able to monetize the capacity value of DR by bidding into the PJM Base Residual Auction for capacity. ComEd states that megawatts bid into this auction are compensated at the clearing price, in the planning period covered by the auction – three years forward. According to ComEd, the same cash flow results; retail suppliers' capacity purchases to PJM are paid to CSPs for providing DR capacity resources, and a portion of these resources are used to compensate customers per the CSP/Customer agreement. *Id.*

ComEd believes it is important to note that neither of these processes results in the lowering of the aggregate capacity obligation for retail suppliers, and if they did, funds would not be available to pay the DR resources. Simply put, that is because the same DR cannot be counted both as a reduction in load and an increase in supply. *Id.*

Energy

Currently, ComEd says that it contracts with business customers for voluntary energy reductions in response to a customer defined strike price. According to ComEd, these resources are submitted into the Economic Demand Response Program administered by PJM. When the customers strike price is reached, ComEd says PJM will send a dispatch signal to the CSP (ComEd) to initiate a DR energy event. ComEd then notifies participating customers to reduce energy consumption. ComEd states that this reduced consumption results in a direct avoided cost benefit of the quantity reduced multiplied by the retail cost of generation from retail supplier's in the form of a lower bill. ComEd says the retail supplier is then the beneficiary of the reduced energy, receiving a value equal to the quantity reduced multiplied by the real time market price. According to ComEd, PJM then bills the retail supplier a charge equal to the quantity reduced multiplied by the product of the real time market value less the marginal retail generation price.

Charge = Quantity x (Real Time Value – Retail Generation Rate)

ComEd says this leaves the retail supplier in the same economic position it would have been if it had sold the energy at retail. PJM pays this quantity to the participating customers CSP (ComEd), who then compensates the participating customer per the terms of the retail DR agreement. In ComEd's case these terms are defined by Rider VLR. ComEd Response at 6-7.

With this in mind, ComEd offers a generic example of DR related cash flows within the PJM settlement process. For purposes of the example, ComEd offers the following assumptions:

- ComEd purchases 10 MW of capacity through RPM auction for $10/MWD
- CSP Sells 1 MW capacity in the RPM auction for $10/MWD
- ComEd has 10 customers with 1 MW peak loads
- Capacity charges are illustrated.

a) ComEd pays PJM on a weekly basis. The charge for capacity for the 10 MW used by its customers would be $100/day.

b) The CSP receives the clearing price for 1 MW or $10/day from PJM.

c) Each customer pays to ComEd a capacity charge of $10/day for its peak load contribution (Industrial customers pay a demand charge, residential customers pay via a cents/kwh charge for their customer class).

d) To provide the DR capacity to PJM, the CSP signs an agreement with one or more customers to reduce load when called upon. For this example, assume one industrial customer agrees to drop its entire load (1MW) when called upon for an upfront payment of $500 and $1000 if called upon.

e) Assume the CSP is called upon two times for the year. The customer reduces their load and is paid $1000 each time. In future years, this customer's peak load contribution and that of ComEd will be the same because PJM calculates peak demand by adding back any DR that cleared in the auction.

Total annual DR cash flow:	ComEd pays PJM for capacity	($36,500)
	ComEd charges to customers	$36,500
		0
	PJM payments to the CSP	($ 3,650)
	PJM RPM payments to others	($32,850)
	PJM charges ComEd	$36,500
		0
	CSP payments to customer	($2,500)
	CSP revenue from RPM	$3,650
		$1,150
	1 DR customer pays ComEd	($ 3,650)
	1 DR customer receives from CSP	$ 2,500
		($ 1,150)

ComEd Response at 8.

In its response, **Staff** states that the services provided to PJM by Curtailment Service Providers, or by other PJM members (like ComEd) acting in the capacity of a CSP, may include demand-response energy, demand-response day-ahead scheduling reserves, demand-response synchronized reserves, demand-response regulation, and demand-response capacity. Staff asserts that most services provided to PJM by CSPs do not directly involve specific load-serving entities (like ComEd), and settlements between a CSP and PJM would not involve ComEd. Staff Response at 7.

According to Staff, demand-response economic energy offers ("economic" rather than "emergency") that are accepted by PJM would involve a payment to the CSP of the PJM locational marginal price minus the ComEd marginal retail rate applicable to the load being reduced. Staff claims the payment is made by PJM but is recovered from ComEd (similar to the MISO proposal discussed in the Commission's Questions 5 and 6, below). Staff says the net impact, per unit, on ComEd and its retail customers is that they would give up the retail rate, plus the PJM LMP minus the retail rate, and would save ComEd's marginal cost of energy ("MC"). The retail rate in that equation cancels, so the net impact is added costs (or savings) of LMP minus MC. Starting in June 2010, Staff asserts that ComEd's marginal cost of acquiring energy will be the same as the PJM LMP. Staff says this is because all of the load-following contracts currently held by ComEd (from the 2006 Illinois auction) will have expired; ComEd's energy portfolio will consist of all fixed-quantity fixed-price hedges (some physical and some financial).

According to Staff, ComEd's marginal supply will all come from the PJM energy market, priced at the load zone LMP. Hence, ignoring any additional transactions costs or any system savings from reduced peak demand, Staff claims the net impact on ComEd and its retail customers will be zero. Meanwhile, Staff says the net impact on the CSP and its customers would be to save the ComEd retail rate, to earn the PJM LMP minus the ComEd retail rate, and to incur the costs of the demand response ("DRMC"). Staff contends that the retail rate cancels, leaving LMP minus DRMC, providing a price signal consistent with pursuing efficient levels of demand response. Staff Response at 7-8.

Staff argues that if ComEd or a contractor hired by ComEd were acting as a CSP within the ComEd load zone with a group of eligible retail customers, then the analysis above would be modified as follows. Acting in the capacity of a CSP, ComEd and its demand-response customers would be paid (on paper) LMP minus the retail rate, would save the retail rate ("MRR"), but would incur DRMC. As the LSE, ComEd and all of its eligible retail customers would pay (on paper) the LMP minus the retail rate, would lose the retail rate, but would save the MC of energy supply (which, as explained above, is the same as the LMP for ComEd starting in June 2009). Ignoring the fact that not all of ComEd's eligible retail customers would be demand-response customers, Staff asserts that after putting the above expression in equation form and simplifying, the net gain to ComEd and its customers is:

Net Gain (loss) = (LMP – MRR) + MRR – DRMC – (LMP – MRR) – MRR + LMP

= LMP – DRMC (i.e., just as if ComEd were an unaffiliated CSP).

Staff claims that the sharing of this net gain or loss between demand response contractors, customers participating and those not participating in the demand response activities is a matter of Commission ratemaking and demand-response program policy, constrained by the supply of demand response as a function of price. Staff would expect that most if not all (or even more than all) of any net gains would be realized by contractors and participating demand response customers, rather than non-participating customers. *Id.* at 9.

Staff believes that all of the above would also be true under the MISO proposal, discussed in response to the Commissioner's Question 5, although some of the nomenclature differs. For demand response capacity, Staff says a CSP's offer of capacity into the PJM RPM auction is accepted when its bid price is below the auction-clearing price. Staff states that the utility as an LSE (rather than CSP) is not involved in the capacity transaction, although LSE's may also offer demand response capacity into the PJM RPM auction. *Id.*

The **IPA** says it can only interpret the applicable statute directing the procurement of capacity sourced from demand response resources when it is available at a lower cost than other options as a nominal price comparison for capacity. As such, the IPA believes the true cost of capacity derived from demand response is not relevant to the IPA – a bidder could bid in capacity as a loss leader if they so chose. IPA Response at 3.

5. In FERC Docket No. ER09-1049-002, the Midwest ISO (MISO) recently filed revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"). The objective of the proposed revisions is to accommodate the participation of Aggregators of Retail Customers ("ARCs") in the Midwest ISO's Energy and Ancillary Services markets in accordance with Orders 719 and 719-A. The proposal by the Midwest ISO that the appropriate compensation for ARCs is the Locational Marginal Price (LMP) – Marginal Foregone Retail Rate (MFRR). Under MISO's reconstituted load solution, each Load Serving Entity's (LSE) actual hourly energy withdrawals in the energy market are "reconstituted" to include MWh load reductions during that hour which had been sold into the energy market by ARCs from each LSE's load zone. That is, a quantity of MWhs equal to the MWhs of load reduction are added back to the LSE's hourly metered MWh quantity and the total settled at the LMP. The ARC would be paid for the MWh load reductions at the same LMP. In effect, payments to the ARC would be directly billed to the LSE. The LSE thus becomes the source of the second payment. While this is only a pending proposal currently before the FERC for consideration and may or may not be implemented in its current form, because the current IPA proposal

> includes a demand response procurement proposal it would be beneficial for the Commission to understand how the interaction of MISO's proposal, if implemented in its current form, and the actions of DR providers in the IPA procurement bid process and the settlement processes of MISO and Ameren are affected.

In its Response, **AIU** states that to the extent MISO grants the ARC Planning Resource Credits ("PRCs"), for what they are bringing to market, and these PRCs are deemed deliverable to AIU's loads by MISO, the ARC has the option but not the obligation to bid those PRCs into the IPA capacity solicitation and compete directly with supply side resources. AIU Response at 2.

Staff states that under the MISO proposed Tariff revisions, ARCs would be allowed to offer demand response of eligible retail customers into the Midwest ISO's markets for Energy (including for Emergencies), and Operating Reserves (including Resource Adequacy Requirements). In addition to the compensation for energy described in the question, Staff says an ARC that provides Regulation or Contingency Reserves will be paid the average hourly Market Clearing Price ("MCP") for that Ancillary Service at the CPNode where the capacity was delivered in that hour. In addition, Staff indicates that an ARC may qualify as a Load Modifying Resource ("LMR") under Module E, and, as such, may participate in either the Midwest ISO administered capacity auctions or engage in bilateral transactions for such capacity. Staff Response at 10.

To expand on the compensation scheme summarized in the question, Staff states that under the MISO proposal, when an ARC participates in the MISO energy market, the per unit cash flows resulting from demand response organized by the ARC would be as follows:

	ARC/Customer Coalition	LSE (like Ameren) and/or its customers	MISO
Payment from MISO	LMP - MFRR		- (LMP - MFRR)
Payment from LSE		- (LMP - MFRR)	LMP - MFRR
Rate Avoidance	MFRR	- MFRR	
Added Costs	DRMC		
Reduced Costs		MC	
System benefits		?	
Transaction costs	?	?	
Net Profit (Loss)	LMP - DRMC	MC - LMP	0

where: LMP and MFRR are defined in the Commission's question,
DRMC is the marginal cost of demand response, and
MC is the LSE's marginal cost of energy.

Staff Response at 10-11.

Staff says the question marks indicate that we are ignoring system benefits, which would inure to the benefit of LSEs and their customers, and transaction costs, which would be absorbed by both the ARC/Customer Coalition and LSEs and their customers.

According to Staff, the cash flows work out the same as in the case of PJM demand response economic energy transactions, discussed in response to the previous question, but that slightly more explicit detail is provided in this response. *Id.* at 11.

Staff states that the first column tells us that the ARC/Customer Coalition will engage in demand response as long as the LMP is greater than the DRMC, which, ignoring positive and negative externalities, is consistent with inducing efficient levels of demand response. Staff indicates that the second column tells us that the utility and its customers will be indifferent to the ARC's demand response activities if the LMP equals the LSE's marginal cost of energy, would benefit from such activities when MC > LMP, and would suffer losses when MC < LMP. For a utility like AIU, Staff asserts that starting in June 2010, its marginal cost of energy purchases will be the LMP. That is, even though it will have in place fixed-quantity fixed-price energy price hedges, those contracts will be insensitive to actual customer demand levels. Staff asserts that the marginal cost will be the MISO LMP. Staff Response at 11-12.

Staff contends that if AIU were to begin entering into load-following contracts again (like the 2006 Auction contracts); it is more than likely that its marginal costs would sometimes be above and would sometimes be below the MISO LMP. Thus, Staff believes there would likely arise situations when ARCs would be properly incented to engage in demand response (when LMP > DRMC) but only at the expense of the utility's customers (if, at the same time, MC < LMP). Under load-following contracts (with relatively fixed prices), Staff claims it would be likely to arise because the ARC's gain and the utility's loss both would increase with the level of LMP. On the other hand, Staff says it is important to stress that this hypothetical is irrelevant, provided that the approved procurement plans continue to rely on fixed-quantity price hedges. Staff Response at 12.

From the above analysis, Staff says it may appear that the role of the IPA or AIU, vis-à-vis ARCs, would be to ignore them, since any additional payments by the utility could only result in price signals to ARCs that are less consistent with efficient levels of demand response. However, Staff claims that is true only of the payments for actual energy reductions. Staff says we have not yet considered the utilization of demand response as a means of fulfilling resource adequacy requirements. Staff maintains that ARCs would be able to engage in bilateral transactions to provide capacity to entities like Ameren. Furthermore, Staff says the demand-response mandate recently added to the PUA (220 ILCS 5/16-111.5(b)(3)(ii)) and cited in the IPA Plan requires procurement of "cost-effective demand-response measures . . . whenever the cost is lower than procuring comparable capacity products." With or without that mandate Staff believes it would be appropriate to permit ARCs to compete against capacity providers as part of a solicitation to obtain the least-cost means of satisfying MISO's resource adequacy requirements. Staff Response at 12-13.

The **IPA** states that it can only interpret the applicable statute directing the procurement of capacity sourced from demand response resources when it is available at a lower cost than other options as a nominal price comparison for capacity. As such, the IPA says the true cost of capacity derived from demand response is not relevant to the IPA – a bidder could bid in capacity as a loss leader if they so chose. IPA Response at 3.

6. In reference to demand response products purchased for Ameren, please have the parties address exactly how the DR value for both energy and capacity products are derived and settled between the Aggregator of Retail Customers (ARC), MISO and Ameren and the ultimate end use customer under MISO's proposed ARC compensation methodology, i.e., how would each party be compensated and revenues recovered, through what settlement mechanisms? Please provide an example transaction where a resource bid might be accepted for a MW of DR capacity, how that capacity is used to offset Module E requirements in MISO and if that MW of DR capability is bid into the energy or ancillary services markets exactly how would the settlement process work between all affected parties including the end use customer?

AIU provides a response based on its current understanding of the MISO proposal. AIU notes that the approach provided for in the tariff defines the process at a high level and that the specific details will be later defined by MISO in the Business Practice Manuals which are currently under development. AIU Response at 2.

AIU states that under the MISO proposal, the ARC has numerous options to extract value from its DR products, including participation in the energy market, participation in the operating reserves market, participation in the voluntary capacity auction (assuming the product meets the MISO aggregate deliverability requirements), registering the resource as an emergency demand response resource and finally, through bi-lateral capacity transactions with other Market Participants.

- When the DR product is bid into the energy markets, the ARC will be paid by MISO the relevant LMP minus the Marginal Forgone Retail Rate ("MFRR"). The LSE responsible for the load of the ARC customers will be charged by MISO the relevant LMP minus the MFRR leaving MISO revenue neutral.
- When the DR product is bid into the ancillary services markets, the ARC will be paid the market clearing price for the relevant ancillary services product. That cost will then be recovered by MISO via the ancillary services charges to all LSEs in the respective reserve zone again leaving MISO revenue neutral.

- When the PRCs derived from the DR product are bid into the Voluntary Capacity Auction, the ARC is paid the auction clearing price by MISO. That cost is then recovered by MISO via charges to the relevant Market Participant(s) who purchased PRCs in that auction.
- When the DR product is registered as an emergency demand response resource and an energy emergency event is called, the ARC is paid by MISO on the same basis as all other emergency demand response resources. That cost will then be recovered by MISO via charges to all MP's within the local balancing area in which the event occurred.
- When the PRCs derived from the DR product is sold to a MP via a bilateral transaction, the compensation between the ARC and the Market Participant will be governed by the terms of the bilateral transaction.

AIU Response at 2-3.

AIU says its settlement relative to ARC demand response resources who successfully bid into the IPA capacity solicitation, will be dependent on whether the AIUs are also the LSE for the ARC customer load. AIU asserts that if it is not the LSE for the ARC customer load, the only payment AIU would make would be based on the contracts that resulted from the IPA capacity solicitation process. AIU Response at 3.

AIU claims that if it is the LSE for the ARC it would, in addition to the payments based on the contracts that resulted from the IPA capacity solicitation process, be charged the relevant LMP minus the MFRR whenever the ARC successfully bid the demand response resource into the MISO energy markets. AIU notes however, that AIU would receive this charge based on the ARCs participation in the MISO energy markets regardless as to whether or not the ARC was a successful bidder in the IPA capacity solicitation process. According to AIU, the ultimate end use customer will not be directly compensated through the MISO settlement process. AIU says the end use customer's compensation will be defined in any contract it enters into with the ARC. AIU Response at 3-4.

AIU provides an example to illustrate its understanding of how a transaction that would occur under MISO's proposed rules:

In AIU's example, an ARC who is physically located and metered behind the LSE's load would direct its end use customers to reduce their load consistent with the terms of the contract between the ARC and the end use customer. The following day, AIU says the ARC will measure the amount of load reduction and submit this data to MISO in its request for compensation.

AIU states that the ARC's compensation will be the average hourly LMP at the CP Node where it is located. AIU says MISO will deduct from these payments the applicable MFRR for each MWh delivered. In addition to the hourly LMP paid to the ARC, AIU states that they are eligible to be paid the hourly Market Clearing Price for any ancillary services that cleared.

In AIU's example, the LSE will be compensated the MFRR for the amount of MWhs provided by the ARC. In addition, the LSE's load will be reconstituted by the ARC reduction.

AIU says the end-use customer and the ARC will be under a separate contractual agreement that is out of the scope of MISO (since the MISO manages wholesale transactions only) and the LSE (since the ARC and the customer are under no obligation to share the contractual arrangements with the LSE); therefore, the actual compensation received by the end-use customer is undefined at this time.

Finally, AIU says it is necessary to point out the final details are still being worked out at MISO and in the MISO Committees. According to AIU, more detailed settlement examples are to be provided by MISO in the next Demand Response Working Group meeting on November 30, 2009. AIU says its understanding of the process may be modified depending on the information provided in these examples. AIU Response at 4-5.

Staff states that the settlement of energy reductions would occur as described in its previous answer. Staff says the settlement of capacity transactions between an ARC and AIU would be in accordance with a standard contract to be developed by the procurement administrator in consultation with the potential suppliers, AIU, and other interested parties. Without prejudging that development process, Staff would anticipate a contract that requires payment from AIU to the ARC at the fixed price (or prices, if more than one month of demand-response capacity is involved) times the quantity (or quantities) of capacity set forth in the contract, payable in the following month. Settlement for other services provided by the ARC to MISO (e.g., Regulation or Contingency Reserves) would not involve AIU, directly. Staff Response at 13-14.

Again, the **IPA** says it can only interpret the applicable statute directing the procurement of capacity sourced from demand response resources when it is available at a lower cost than other options as a nominal price comparison for capacity. As such, the IPA states that the true cost of capacity derived from demand response is not relevant to the IPA – a bidder could bid in capacity as a loss leader if they so chose. IPA Response at 4.

3. Commission Analysis and Conclusions

Section 8-103(c) of the PUA establishes specific requirements for utility company Demand Response Programs. Section 16-111.5(b) of the PUA requires that the procurement Plan shall include an analysis of the impact of demand side initiatives established by Section 8-103(c) of the PUA. The IPA states that those demand side initiatives include the impact of demand response programs, both current and projected, and the impact of energy efficiency programs, both current and projected. As discussed above, several parties have taken issue with the IPA's Plan to procure demand response measures.

For both ComEd and AIU, the IPA recommends that the initial solicitation of demand response as an alternative to standard capacity be conducted in the 2010 Procurement Cycle. Specifically, the IPA recommends that Demand Response Procurement be specified as a bid alternative in the spring 2010 solicitation for capacity. In the event that Demand Response providers do not exist or do not participate in the spring solicitation, the IPA proposes that a secondary solicitation will be conducted in the fall of 2010. The second event would seek to establish capacity contracts that will promote the development of demand response programs within the AIU and ComEd service territory. IPA Plan at 38, 52.

As discussed below, one proposal in dispute is whether the IPA should be permitted to supplement the demand response currently acquired for ComEd, through the PJM RPM auction, with the IPA's own independent demand response acquisition event targeted more specifically at ComEd's eligible retail customers.

It appears, for the most part, that there is no longer a dispute between AIU and the IPA regarding how demand response will be obtained for AIU. Staff, however, takes exception to the IPA's proposal to potentially conduct a second demand response procurement event in the fall of 2010, and it appears that this objection is intended to apply to demand response obtained for both AIU and ComEd. On this point, the Commission believes that Staff has raised valid concerns regarding the proposed demand response solicitation in the fall of 2010. Most importantly, in terms of cost, it is not clear how such a solicitation for demand response measures could be directly compared to comparable capacity products as required by Section 16-111.5 of the PUA. The Commission concludes that as part of the current annual procurement Plan, the IPA should not be authorized to conduct a second demand response solicitation in the fall of 2010 for either AIU or ComEd. To the extent appropriate, the Commission will consider additional demand response solicitations in the next annual procurement planning process.

Additional disputes remain over the acquisition of demand response for ComEd. ComEd appears to advocate that all demand response be acquired through PJM's RPM auction process. ComEd believes this proposal will lead to the lowest costs for customers. ComEd also asserts that the PJM process includes demand response bids from eligible retail customers, thereby complying with the statutory requirement, cited by the IPA and AG, to obtain demand response from eligible retail customers.

No party seems to question that the PJM RPM auction has the potential to identify and produce demand response measures that are less costly than comparable capacity products. The IPA and the AG, however, express concern about whether the demand response measures acquired through the PJM RPM process constitute demand response "from eligible retail customers" within the meaning of Section 16-111.5 of the PUA. It also appears that the IPA is interested in promoting the development of new demand response measures to ensure that an adequate supply of demand response products are available to ComEd in the future. Constellation and the

AG also advocate acquiring demand response from ComEd customers other than eligible retail customers.

While it is not entirely clear, it appears to the Commission that at least some of the demand response measures bid into the PJM RPM auction are likely procured from ComEd's eligible retail customers, while other such measures are not.

The IPA states, in response to ComEd's proposal to rely exclusively on the PJM RPM auction, "While the IPA agrees that the PJM procures demand response resources in accordance with the PUA, it disagrees that the Plan's proposal to procure additional or different demand response resources is inconsistent with the PUA." Thus, it appears the IPA has clarified what was not entirely clear in the filed Plan, namely, that the IPA proposes to supplement demand response acquired through the PJM RPM auction with its own independent demand response acquisition targeted more specifically at ComEd's eligible retail customers.

Section 16-111.5 of the PUA specifies, "The cost-effective demand-response measures shall be procured whenever the cost is lower than procuring comparable capacity products, provided that such products shall: (A) be procured by a demand-response provider from eligible retail customers; (B) at least satisfy the demand-response requirements of the regional transmission organization market in which the utility's service territory is located, including, but not limited to, any applicable capacity or dispatch requirements."

Section 8-103 of the PUA requires the acquisition of cost effective demand response measures. As used in Section 8-103, "cost effective" means that the measures satisfy the total resource cost test. The total resource cost test or "TRC test" is defined in Section 1-10 of the IPA Act. Also, Section 16-111.5(d)(4) of the PUA states, "The Commission shall approve the procurement plan, including expressly the forecast used in the procurement plan, if the Commission determines that it will 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."

The Commission observes that a determination on this issue is difficult. Sorting through the parties' positions while simultaneously reconciling the various statutory provisions is complicated and the path to an appropriate result is not entirely clear.

It appears that in responses to the IPA's Plan, as well as the Commissioner's Questions discussed above, both ComEd and Staff are concerned that the IPA's proposal to supplement demand response measures acquired through the PJM RPM process will not produce "the lowest total cost over time." Among other things, they assert that PJM effectively procures capacity, including demand resources, for utilities three years in advance through an auction process. The IPA does not appear to directly address this concern.

No party seems to question that the PJM RPM auction has the potential to identify and produce demand response measures that are less costly than comparable capacity products and meet the other statutory requirements related to cost-effectiveness. The question is whether the IPA's proposed supplemental demand response acquisition can also meet all of the relevant statutory requirements.

In its BOE, ComEd states that the Proposed Order recognizes the proper cost test. Nevertheless, ComEd claims it is highly unlikely that additional cost-effective demand response resources can be procured outside of the PJM process. ComEd BOE at 2-4. ComEd contends that a supplemental demand response RFP should not be permitted. In the alternative, ComEd recommends that if a supplemental RFP is not stricken from the IPA's proposed Plan, then "any demand response resulting from a supplemental RFP must be demonstrated in advance to lower costs." *Id.* at 5. ComEd provides language to implement that alternative. ComEd Exception #1.

In its BOE, Staff argues that the IPA should not be permitted to proceed with supplemental demand response measures. In Staff's view, there is little chance such a procurement could end successfully, and thus would be an unwarranted gamble of time and resources. Staff BOE at 2-4.

It would appear highly unlikely that the IPA could successfully reduce ComEd's capacity costs by procuring supplemental demand response measures, unless it were somehow tied to the PJM process. Any demand response measures outside of the PJM RPM process would be additive to ratepayer bills due to the RPM construct of obligating capacity resources 3 years in advance. The Commission deems this element of the IPA Plan to be vague and unviable. We believe that we would be remiss in our oversight responsibility to endorse such a choice especially when a more tenable alternative is readily at hand. Specifically, ComEd has noted that overall capacity costs may be reduced more, and all the PUA requirements met automatically, simply by continuing to allow all demand response resources to bid into the RPM auction. The Commission hereby directs that the Plan be modified accordingly.

In future proceedings, the parties are welcome to offer further information and arguments on any of the issues addressed above, at which time they will be duly considered by the Commission.

D. The Structure of the IPA's Proposed Acquisition

In this proceeding, the IPA has proposed the same laddered approach to acquiring supply as was adopted in Docket No. 08-0519:

- 35% of projected energy needs procured two years in advance of the year of delivery;
- 35% of projected energy needs procured one year in advance of delivery;
- 30% of projected energy needs procured in the year in which power is to be delivered.

The IPA believes this approach reduces risks for bidders, thereby reducing risk premiums, and also provides price stability.

1. Positions of the Parties

In last year's procurement plan docket, **Staff** indicated that it had no objection to this approach for the 2009 procurement events. However, Staff also cautioned that prices for later years may reflect greater credit costs or risk premiums. Staff recommended that the results of the 2009 procurements should be evaluated to determine the extent, if any, of such costs and/or premiums. Staff also recommended that any conclusions from that evaluation should be taken into account in designing future procurement plans. Therefore, Staff objects that the Plan for 2010 does not report on any such evaluation and recommends that the Plan be modified to include the IPA's analysis of this issue. If no such analysis has been performed, then the Staff recommends that the Commission encourage the IPA to perform such an analysis prior to next year's Plan filing. Staff Objections at 4-5.

Constellation says it appreciates the IPA's desire to utilize the "dollar-cost averaging" methodology for energy needs in this initial Plan, but encourages the IPA to obtain products in such a manner that it retains the flexibility to evaluate and procure the full complement of energy products in future years, including a full requirements product. Constellation is concerned that by continuing to chart a course for a laddered procurement strategy that utilizes standard wholesale block products, it will be difficult or more challenging to alter the product mix and move to a more traditional full requirements contract product. Constellation Objections at 5.

Constellation believes that procuring full requirements contracts achieves several benefits. According to Constellation, a full requirements procurement structure relieves the IPA from active portfolio management responsibility, and instead places the planning responsibility into the hands of the winning full requirements suppliers, who have extensive experience in managing portfolios. Constellation states that in doing so, full requirements procurement demands far less regulatory involvement in evaluating the specifics of a procurement Plan to assess whether the IPA is buying the "right" products, in the "right" amounts, and at the "right" times, than would an approach for Block Energy Products.

Constellation also claims this approach yields the lowest fixed price at which these customers can be served, so it provides a fully competitive price while at the same time minimizing short term price volatility and insulating customers from other risks that would be borne by the full requirements suppliers. Constellation also asserts that it will continue to offer an efficient way to bring the benefits of wholesale competition to residential and small commercial customers that do not select alternative retail electric suppliers. *Id.* at 6.

Constellation recommends that the IPA consider alternative percentages or contract duration other than those that are set forth in the Plan, such that if full requirements products were found to be a preferred alternative for any future procurements, the IPA would retain the flexibility to make such adjustment. Constellation asserts that the recent reduction in wholesale electric market prices over the past year suggests that now may be an opportune time to solicit full requirements products in order to take advantage of favorable economic conditions, as opposed to continuing with the standard wholesale block product approach. *Id.*

The **IPA** opposes the Staff's request that the IPA conduct an analysis of the credit costs or risk premiums embedded in the prices for energy procured under the laddered approach. First, by submitting requests for bids for the requirements under the Plan in laddered increments, the IPA claims the Plan already reduces risk for bidders, and therefore reduces the risk premiums. Moreover, because the requests for bids are available to all bidders, the IPA asserts that risk premiums would be equalized among all bidders for any particular contract. Finally, the IPA says the laddered approach is intended to provide price stability for energy purchases over time, even if there are different risk premiums associated with different contract years. Therefore, the IPA insists that conducting an analysis of the risk premium associated with the laddered approach is not necessary to accomplish the goals and objectives of the Plan. IPA Response at 14-15.

In response, Staff takes issue with the IPA's assertion that by submitting requests for bids for the requirements under the Plan in laddered increments, the Plan already reduces risk for bidders, and therefore reduces the risk premiums. Staff argues that there is no support provided for this statement, either theoretical or empirical. Furthermore, it is not clear to Staff that the IPA fully grasps that its laddered structure of holding three consecutive RFPs, rather than just one, for the exact same product creates a different and more complex set of incentives for bidders. Staff says it is odd that the IPA seems to recognize the issue with respect to the REC RFPs, but not with the energy and capacity RFPs. Staff Reply at 25.

By way of example, Staff suggests considering the January 2013 on-peak energy (or capacity) product. Under the IPA's laddered approach, Staff says bidders will be able to bid on this same product in the spring 2010, 2011, and 2012 procurements. Staff asserts that by providing three bites at the apple, it would not be surprising if bidders tried to get away with really good prices (bidding very high) in the 2010 RFP, got a little more conservative (bidding lower) in the 2011 RFP, and finally started sharpening their pencils (bidding aggressively) in the 2012 RFP. Staff believes this is, however, a highly technical issue to analyze and is one that would probably benefit from a specialist's talents. Staff suggests that it is the type of issue that could be analyzed by the professional planning expert that the IPA is authorized under the IPA Act to hire each year. *Id.* at 25-26.

According to Staff, the IPA's statement that because the requests for bids are available to all bidders, the risk premiums would be equalized among all bidders for any particular contract, may or may not be true but, in either event, Staff believes it completely misses the point. Staff suggests that the risk premiums could be equalized among all bidders but, at the same time, be very high. *Id.* at 26.

Staff believes the IPA states the obvious, that the laddered approach is intended to provide price stability for energy purchases over time, even if there are different risk premiums associated with different contract years. Staff claims the IPA is agreeing with Staff that there is, or may be, a trade-off between price stability and risk premiums. Staff would like the IPA to investigate the magnitude of that trade-off, but Staff asserts that the IPA simply wants to avoid the issue. Staff expresses frustration that the IPA has ignored its suggestion to do so and says the Commission "might also consider encouraging the IPA to perform such an analysis..." *Id.*

2. Commission Analysis and Conclusions

In this proceeding, the IPA has proposed the same laddered approach to acquiring supply as was adopted in Docket No. 08-0519:

• 35% of projected energy needs procured two years in advance of the year of delivery;
• 35% of projected energy needs procured one year in advance of delivery;
• 30% of projected energy needs procured in the year in which power is to be delivered.

The IPA believes this approach reduces risks for bidders, thereby reducing risk premiums, and also provides price stability. In the IPA's view, such a ladder provides a reasonable hedge while allowing sufficient flexibility in future procurement cycles to incorporate longer-term contracts for certain products should the planning process find that they are appropriate elements of the portfolio.

Constellation recommends that the IPA "consider" alternative percentages or contract duration other than those that are set forth in the Plan, such that if full requirements products were found to be a preferred alternative for any future procurements, the IPA would retain the flexibility to make such adjustment. The Commission notes that this recommendation appears to be made by Constellation to the IPA, and requires no Commission determination at this time.

Staff recommends that the Commission "encourage" the IPA to perform an analysis to determine the extent, if any, of such costs and/or premiums associated with the laddering approach, prior to next year's Plan filing. The IPA opposes Staff's recommendation.

The Commission has reviewed the parties' positions and finds that Staff's recommendation that the IPA be encouraged to perform such an analysis prior to next year's Plan filing is reasonable. While the laddered approach may remain the best approach to procurement, it is possible that other approaches may now be better. In the absence of quantitative analyses, it is difficult to be sure.

With respect to the current Plan now before the Commission, the laddering approach proposed by the IPA is reasonable and is approved.

E. Hedging Ratio

In this proceeding, the IPA has proposed to use the same hedging approach to acquiring supply as was adopted in Docket No. 08-0519, involving oversubscription by 10% in the peak periods in the months of July and August and no oversubscription in other months. This is also referred to as a hedging ratio of 110% or 1.1.

1. Positions of the Parties

According to the **ComEd** objections, it is not clear from the Plan whether the IPA proposes to oversubscribe for July and August as was done for the last procurement event. ComEd notes that on pages 16-17 of the proposed Plan, the IPA recommends some oversubscription for the peak periods of July and August and includes the additional 10% in Tables U, V-1, V-2 and Attachments I and J. However, on page 19, the IPA indicates the oversubscription strategy has cost consumers more money than it has saved; thus, it proposes procuring at the 100% subscription level for those two months. ComEd believed the continued inclusion of the 10% oversubscription was an inadvertent oversight and should be removed. ComEd Objections at 11.

ComEd claims its analysis indicates that the better approach is to procure at the 100% subscription level for all months. To determine if the risk associated with weather driven price spikes in the summer would be reduced by purchasing more than 100% of expected monthly requirements for peak periods in July and August, ComEd says it first determined the average portfolio energy cost assuming a high case (spot prices +40%, spot load +10% for July and August) and a low case (spot prices -30%, loads -8% for July and August). ComEd then looked at three change cases with purchases of 110%, 120% and 130% of July and August peak loads. ComEd says it did not assume there to be any correlation between spot prices and gross-up factors, consistent with historical monthly data. *Id.* at 11-12.

According to ComEd, the results of its analysis imply that hedging 90-100% of expected peak requirements in July and August is reasonable. ComEd says this is in contrast to last year's conclusion that ~110% of expected requirements was appropriate. ComEd claims this change is driven primarily by (1) the decline in market prices and (2) the increased impact of fixed capacity costs. ComEd says the lower market price means that even with a 40% price stress, the cost of purchased power is below the average embedded portfolio cost. Therefore, even without the benefit of the extra 10% hedge, the average portfolio cost will drop in our high case. ComEd also states that the higher capacity costs this year means that an increase in load (which ComEd assumes in its high stress case) will help reduce the average $/MWh impact of the fixed capacity costs. *Id.* at 12.

Given the volatile nature of prices and loads, ComEd recommends that 100% of expected requirements be purchased for all periods of the current plan year. *Id*. **AIU** also requested clarification of the IPA's Plan on this issue. AIU Objections at 8.

Staff states that the IPA Plan appears to recommend reducing the on-peak July and August hedging ratio to 1.0. While Staff will not necessarily object to this recommendation, Staff notes that the primary justification for adopting a hedging ratio over 1.0, barring speculation on rising electricity prices, was (and still is) the recognition that unexpectedly high energy prices and unexpectedly high usage levels are positively correlated. Staff notes that there are other factors to consider in addition. For example, as the IPA also recognizes, there is reason to believe the contracts that the IPA has been soliciting on behalf of ComEd and Ameren include risk premiums and therefore are greater than expected average future spot market prices. Staff believes there are trade-offs when considering when and by what degree to over-subscribe. Staff Objections at 5.

Staff objects that a detailed summary of the IPA's analysis was excluded from the Plan, and believes that the Plan should provide the Commission with a more solid basis for altering the existing hedging policy. Finally, Staff states while it is stated in the text on page 19 and implicit from numbers in the tables on pages 30, 31, 47, and 48 that the IPA has abandoned the 1.1 hedge ratio, statements on pages 16-17 contradict that policy shift. *Id.* at 5-6.

In its Reply to Responses, Staff indicates that it has decided to remain neutral on the proper hedge ratio. Nevertheless, if the Commission decides on 1.1, then Staff points out that one of the tables adopted by the IPA would need to be modified accordingly. Specifically, “The IPA recommends that ComEd’s revised Tables F, T, U, V-1 and V-2, as well as Attachments D, H, I and J (attached as Exhibit A), be incorporated into the Plan, and that the Plan be modified accordingly.” IPA Response, p. 10. However, if the hedging ratio is changed again back to 1.1 for July and August on-peak, then Staff says that table V-1 from ComEd’s Objections will also need to be modified. Staff Reply at 24.

In its Response, the **IPA** agrees that the language used in the Plan inadvertently creates an inconsistency with respect to oversubscription for peak contracts in July and August. However, the IPA disagrees with ComEd’s contention that the better approach would be to procure at 100% during that period. The IPA maintains that the potential for spikes in consumption in the portfolio are greatest during the July and August peak periods. The IPA insists that oversubscription will mitigate weather risk associated with this period. The IPA asserts that prices in the current market are relatively low, but future spot prices can be far above current future prices due to variables in plant outages, transmission constraints, natural gas prices, and evidence of growing economic recovery. Additionally, the IPA provides suggested language to clarify the Plan regarding hedging/oversubscription. IPA Response at 8.

In its Response, the **AG** states that the Plan alludes to a more complete analysis of the cost and benefits of oversubscription. AG Response at 3, citing Plan at 19. The AG believes that analysis should be described more completely in the Plan. The AG says that if the full analysis supports a change in hedging policy, the text recommending oversubscription on pages 16-17 of the Plan should be deleted. If the full analysis does not support a change in hedging policy, the AG suggests that the text on page 19 and the tables on pages 30, 31, 47 and 48 of the Plan should be revised accordingly. *Id.* at 3.

In its Reply, the **IPA** indicates that it believes it has adequately addressed the AG's concerns. IPA Reply at 9.

In its reply to responses, and in its BOE, **ComEd** asserts that it is not merely ComEd's contention that over-subscribing during peak summer hours is inappropriate, but a conclusion from using the IPA's own analysis method from last year's plan with updated market data. ComEd claims the analysis provided in its Objections is the only analysis presented to the Commission on this issue in this docket. According to ComEd, this analysis demonstrates that purchasing 110% of requirements for July and August peak periods will result in additional risk in the rate customers pay for energy compared to procuring 100% of the actual projected requirements. ComEd Reply at 17, ComEd BOE at 6-7, ComEd Exception #3.

ComEd believes that since the IPA does not explain why its prior analytical methods were inappropriate or provide its own analysis using current market data, the Commission should modify the IPA Plan to reflect procurement of 100% of projected requirements for all periods. ComEd argues that to do otherwise would allow the IPA to effectively speculate on future market prices by purchasing more power than needed with ComEd customers holding all the risk. ComEd Reply at 18. In ComEd's view, the Commission must also take into account the fact that over-hedging, just as under-hedging, poses a risk to customers. ComEd Exception #3.

2. Commission Analysis and Conclusions

In this proceeding, the IPA has proposed to use the same hedging approach to acquiring supply as was adopted in Docket No. 08-0519, involving oversubscription by 10% in the peak periods in the months of July and August and no oversubscription in other months. This is also referred to as a hedging ratio of 110% or 1.1. This proposal appears to be supported by the AG.

ComEd objects to the proposal, arguing that oversubscription in July and August is not cost effective, and provides some analysis in support of its position. Although Staff complains that the IPA's proposal is not supported by quantitative analysis, Staff takes no position on the question of whether the proposal should be adopted or rejected.

As an initial matter, the Commission notes that it has approved an oversubscription by 10% for peak periods in July and August in the last two procurement events. In fact, the original decision regarding hedging was based upon analyses presented by ComEd in Docket Nos. 07-0528, 07-0531 (Cons.). Order, Docket Nos. 07-0528, 07-0531 (Cons.) at 54-57.

The Commission believes that on a qualitative basis, the AG has a point that merits consideration. AG Response at 3. That is, caution should be taken before rejecting a continuation of the current level of oversubscription based on an analysis of actual historical data, involving only a few data points, particularly considering that such hedging can provide customers with some degree of price protection and stability when prices and usage are at their highest.

As both Staff and ComEd suggest, it would have been beneficial if the IPA had provided quantitative analyses in support of its proposed hedging approach. On the other hand, these parties do not allege that the two most recent procurement events, which incorporated the same hedging approach as is proposed by the IPA in this proceeding, have been unsuccessful. Given this factor, along with the statutory framework under which the IPA's Plan and objections are filed, the Commission will defer to the IPA's judgment on this issue.

Accordingly, the Commission will not adopt ComEd's recommendation with regard to the hedging ratio, and instead approves the IPA's Plan on this issue. The Commission finds, however, that performance by the IPA of a quantitative analysis on the hedging issue in the preparation of its next filed Plan would be beneficial to the assessment of the issue.

F. One-day Turnaround After Procurement Events

To mitigate risk premiums, the IPA recommends that the post-bid review processes be abbreviated and automated to an extent that allows for approval of bids to occur on the same day they are submitted.

1. Positions of the Parties

Staff notes that the Plan correctly points out that, following the receipt of bids, the process described in the PUA allows two business days for the preparation of confidential reports by the procurement administrator and monitor and an additional two business days for the Commission to consider the reports and make its determination. Staff says this lag of four business days creates risk for bidders that they will most likely reflect in their bids through the addition of risk premiums. The Plan estimates the added cost at between $1.40 and $1.60 per MWH, which translates into $166 million over the next three 12-month planning cycles. To mitigate this risk, the IPA recommends that review processes be abbreviated and automated to an extent that allows for approval of bids to occur on the same day they are submitted. The IPA recommends that the Commission, its procurement monitor, and the procurement administrator work together to devise a timely process to address this risk while maintaining appropriate oversight functions. Staff Objections at 21-22.

Staff does not necessarily concur with the IPA's cost estimates, but Staff does concur that the added cost due to a four-business-day time lag could be significant. Staff also agrees that, if feasible, responsible parties should try to reduce the time lag as much as possible, without violating the letter or the spirit of the PUA. *Id.* at 22.

Nevertheless, Staff believes the Plan should also reflect that for each of last spring's five procurement events, both the procurement monitor hired by the Commission and the two procurement administrators hired by the IPA made and kept commitments to issue their confidential post-bid reports to the Commission by the close of business on the first day following bid day. Staff states that while the Commission made no commitments to do so, it is noteworthy that it too acted within one day (in fact, prior to noon of the day following receipt of the confidential reports). It is currently inconceivable to Staff how either the report creation or the Commission review process can be compressed any further.

Staff remains confident that the Commission's procurement monitor can and will continue to provide its confidential report by the close of business on the day after bid day. However, Staff can speak for neither the Commission nor future procurement administrator(s). In Staff's view, this matter can be resolved by the Commission using its order in this docket to commit to whatever turn-around times it deems feasible for itself. Staff suggests that later, the procurement administrator(s) and procurement monitor should confer, prior to RFP issuance, to determine turn-around times they deem feasible for themselves. While a same-day turn-around is unlikely to be jointly feasible, Staff does believe that the turn-around time can continue to be reduced below the full four business days allowed in the PUA. Staff says the RFPs should clearly indicate the combined turn-around time. In Staff's view, such indication will reduce uncertainty to the bidders and should have a beneficial impact on utility customers. *Id.* at 22-23.

Staff also asserts that if the IPA is proposing to pursue more open-ended RFPs for these contracts, then the selection and evaluation process is guaranteed to be longer. In this case, Staff believes even the full four days allowed by the PUA are unlikely to be sufficient. *Id.* at 23.

2. Commission Analysis and Conclusions

To mitigate risk premiums, discussed above, the IPA recommends that post-bid review processes be abbreviated and automated to an extent that allows for approval of bids to occur on the same day they are submitted.

Staff objects to the proposal, explaining, among other things, that it does not know how either the report creation or the Commission review process can be compressed any further.

The IPA did not directly respond to Staff's objection or more fully explain why the IPA's proposal should be adopted. For the reasons provided by Staff, the IPA's one-day proposal is not one that the Commission can formally adopt without potentially compromising its statutory oversight responsibilities. The Commission emphasizes, however, that it remains committed to do anything it reasonably can to accommodate and expedite the bid review process, while still fulfilling its statutory duty to exercise appropriate oversight functions.

G. Description of Plan Approval Process and Procurement Plan Execution

As discussed below, Staff believes the Plan is vague in some respects and proposes what it believes is an improved description of the Plan approval process and procurement plan execution.

1. Positions of the Parties

Staff states that the description of the Plan approval process contained at pages 7-9 of the Plan does not reference requirements contained in the IPA Act with respect to the process for selection and retention by the IPA of an expert or experts to develop procurement plans. Similarly, Staff says while the selection of a procurement administrator is mentioned at page 8 of the Plan, there is no discussion of the selection and retention process for a procurement administrator. *Id.* at 23.

While it does not appear to Staff that a plan development expert is required by the IPA Act, and while the IPA has chosen not to hire a plan development expert for the present Plan (as well as last year's plan), Staff believes it would be beneficial to the planning process for the IPA to hire a plan development expert in the future. Staff says the Commission's procurement monitor (Boston Pacific Company) made this same suggestion during the informal hearing process that took place at the end of the spring procurement events. In any event, Staff suggests the IPA may wish to add the process for qualifying and selecting experts or expert consulting firms to develop the procurement plans to the procurement process description. *Id.* at 24-25.

To accomplish this, Staff says the Plan could be modified by adding a new step to be inserted on page 7, after "1. Utilities Submit Load Projections," as follows:

> 2. IPA Retains Plan Development Expert. The IPA Act allows the IPA to retain experts or expert consulting firms to develop the procurement plans in accordance with Section 16-111.5 of the PUA. As set forth in the IPA Act, such experts are identified through a request for qualifications process and selected by the IPA after issuing requests for proposals. The IPA intends to consider retention of such experts or expert consulting firms for future procurements. *Id.* at 25.

According to Staff, while the Plan references the selection of a procurement administrator by the beginning of December 2009, it does not reference the qualification and selection process discussed above. Staff suggests that the IPA may wish to add the following sentence on page 8, at the end of "1. Procurement Administrator Selected": "As set forth in the IPA Act, qualified experts to serve as procurement administrator are identified through a request for qualifications process and selected by the IPA, with approval of the Commission, after issuing requests for proposals." *Id.* at 25.

Staff also notes that Table C on page 8 of the Draft Plan stated that a procurement administrator will be selected in December 2009. While there are no specific deadlines for selection of a procurement administrator identified in the PUA or the IPA Act, Staff submits that the sooner a procurement administrator is selected the better so that preparation for the procurement events can begin as soon as possible. More specifically, as Staff recommended during the informal hearing process following the end of the spring procurement events, the procurement administrator hiring process should be completed by at least the end of December 2009. *Id.* at 25-26.

To accomplish its proposal, Staff provides a specific schedule that it suggests the IPA include in the Plan. Based on a review of the Illinois Procurement Bulletin, Staff says it appears that the IPA has not initiated this process. Staff recommends that, if an RFP for procurement administrator has not yet been issued by the IPA, that the IPA do so as quickly as possible. Staff Objections at 26.

2. Commission Analysis and Conclusions

Staff believes it would be beneficial to the planning process for the IPA to hire a plan development expert in the future. Staff suggests "the IPA may wish to add the process for qualifying and selecting experts or expert consulting firms to develop the procurement plans to the procurement process description." Staff offered specific language which could be added to the Plan for that purpose. Staff also believes that the procurement administrator hiring process should be completed by at least the end of December 2009. Staff "recommends that, if an RFP for procurement administrator has not yet been issued by the IPA, that the IPA do so as quickly as possible." For the most part, the IPA did not respond to the recommendations of Staff.

It appears to the Commission that these Staff's recommendations are intended for the IPA's consideration, rather than as formal requests for Commission approval of modifications to the Plan. Therefore, while these recommendations appear to have merit, no Plan modifications will be formally ordered at this time.

The Commission also observes that Staff possesses impartiality and expertise, and is a willing and potentially valuable resource to the IPA in many aspects of the procurement process. The Commission encourages the IPA to engage in constructive communications with the Staff, whenever feasible, and to give Staff's suggestions and recommendations meaningful consideration.

H. Adjustments to Load Forecast and Updated Load Forecast

The IPA says the PUA requires it to provide the criteria for portfolio rebalancing in the event of "significant shifts in load." The IPA proposes that it be allowed to readjust load projections should retail switching differ significantly from ComEd's or AIU's projections, resulting in changes of 200 MW or more.

Additionally, ComEd filed an updated load forecast that it believes should be approved as part of the procurement Plan.

1. Positions of the Parties

ComEd complains that the IPA provides few details about how this proposal would be implemented. In ComEd's view, without those details, it is not clear that this proposal complies with the PUA. ComEd Objections at 10.

ComEd notes that the PUA specifically requires that the Commission approve the forecast used in the Plan. In fact, ComEd says during last year's procurement plan approval process, the Commission rejected a similar proposal by Staff to be allowed some discretion to adjust the load forecast for certain events. *Id.*

The IPA proposes that it be allowed to readjust load projections whenever, due to retail switching, there is a change in supply quantity of 200 MW or greater. The IPA proposes to use Commission-generated reports to make this determination. However, ComEd is unaware of any such Commission generated reports. ComEd says the individual utilities do file monthly switching reports with the Commission. According to ComEd, these reports provide switching activity based on number of customers and kWhs, not demand. It is unclear how the IPA would use these reports (if these are the reports that the IPA is referring to) to determine a change in demand. *Id.*

It is not clear to ComEd what the 200 MW change relates to or how it would be implemented. ComEd questions whether it is on an annual basis, a monthly basis or a monthly on-peak or off-peak basis. Moreover, if something does change by 200 MW, ComEd wonders if this would authorize the IPA to revise the quantity for every time period, or only those that do show this 200 MW change. It is also unclear to ComEd by how much could the IPA readjust the load projections: by 200 MW, the amount of the change, by any amount the IPA deemed reasonable. *Id.* at 10-11.

In ComEd's view, this lack of detail is made worse by the fact that the IPA does not propose that it will consult with Staff, the procurement monitor or the utilities prior to readjusting the load projections. Without more details and parameters limiting the IPA's discretion to readjust the Commission-approved load forecast and procurement plan, ComEd says it is difficult to see how such a proposal complies with the PUA. (*Id.* at 11.

In its Response, the **IPA** notes that ComEd does not offer specific alternative wording to the Plan to implement its suggestions. The IPA, however, agrees that the Plan should be amended to include language that load forecast adjustments will be done in consultation with Staff, the procurement monitor, and the utilities. IPA Response at 8-9.

ComEd states that it issues load forecasts for internal planning purposes twice a year, once in the spring and once in the fall. The load forecast that ComEd provided to the IPA in July 2009 was based on its spring 2009 load forecast. ComEd says that due largely to continued deteriorating economic conditions since the spring, ComEd's most current forecast shows that, on average, expected loads have dropped 63 MW per month. This equates to ~ 550,000 MWh for the 2010-11 period. According to ComEd, carrying this unnecessary energy to the spot market will subject customers to additional price risk of ~ $0.5M for every dollar change in price between contract execution and liquidation. Since there is no offsetting benefit to this risk, ComEd recommends the Commission require the updated forecast be used. ComEd Objections at 13.

Should the Commission decide to take this data into account, ComEd claims it would not be necessary for ComEd to provide a completely updated forecast, or for the IPA to rewrite its entire Plan. ComEd says the Commission can simply require that the amount of standard wholesale product that the IPA has proposed to be procured be revised to reflect the numbers above. To assist the Commission and the IPA, ComEd provided tables that compare the old and new forecast data. ComEd has also attached to its Objections revised Tables F, T, U, V-1 and V-2, as well as Attachments D, H, I and J to the Plan, which ComEd says all reflect the updated forecast data. *Id.* at 13-15.

According to ComEd, the revised forecast will also cause a change to the budget amount of renewable energy certificates to be procured. ComEd says that information is contained in Table AA on page 55 of the Plan. ComEd asserts that the Renewable Energy Resource Budget number should be changed to $57,523,715. *Id.* at 15.

In its Response, the **IPA** agrees that ComEd's revised forecast should be incorporated into the Plan. The IPA recommends that ComEd's revised Tables F, T, U, V-1 and V-2, as well as Attachments D, H, I and J (attached as Exhibit A), be incorporated into the Plan, and that the Plan be modified accordingly. IPA Response at 10.

In its Response, **Staff** indicates that it has no objection to that update being adopted by the Commission. Staff also agrees with ComEd that the revised forecast lowers the amount of energy contracts to purchase as detailed in ComEd's Objections, and also reduces the ComEd REC budget from $58,247,099 to $57,523,715. Staff Response at 4.

2. Commission Analysis and Conclusion

Section 16-111.5(b) of the PUA states in part:

> A procurement plan shall include each of the following components:
>
> (1) Hourly load analysis. This analysis shall include:
>
> (i) multi-year historical analysis of hourly loads;
> (ii) switching trends and competitive retail market analysis;
> (iii) known or projected changes to future loads; and
> (iv) growth forecasts by customer class.

Additionally, Section 16-111.5(b)(4) of the PUA states:

> Proposed procedures for balancing loads. The procurement plan shall include, for load requirements included in the procurement plan, the process for (i) hourly balancing of supply and demand and (ii) the criteria for portfolio re-balancing in the event of significant shifts in load.

Finally, Section 16-111.5(d)(4) states:

> The Commission shall approve the procurement plan, including expressly the forecast used in the procurement plan, if the Commission determines that it will 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.

As the Commission understands the statutory scheme, in this proceeding load forecasts are approved for ComEd and AIU. Based upon the approved load forecasts, the IPA undertakes procurement activities and develops a portfolio consistent with the requirements of Illinois law. The statute also requires that the approved plan include criteria to determine if there is a "significant shift in load" and a process whereby the portfolio is revised in the event of a significant shift in load.

Having reviewed the filings of the parties, the Commission finds that the load forecast for ComEd attached to the IPA's September 30, 2009 Plan (Attachment C), as modified to incorporate the update contained in ComEd's October 5, 2009 Objections and its attachments thereto, should be approved. The record indicates that this approved load forecast represents the best estimate of residual load requirements of ComEd for which the IPA must develop a supply portfolio. The Commission also finds that the load forecast for AIU attached to the IPA's September 30, 2009 Plan (Attachments A and B) should be approved. The record indicates that this load forecast is reasonable and the most current estimate of the residual load requirements of AIU for which the IPA must develop a supply portfolio.

The IPA's proposal for modifying its portfolio for ComEd and AIU in the event of a "significant shift" in load, as laid out in its September 30, 2009 Plan (See IPA Plan at 39 and 53), is deemed to be reasonable and is hereby approved. In order to determine whether it is necessary for the IPA to modify the portfolio in the event of a significant shift in load, however, the Commission believes it would be appropriate for ComEd and AIU to provide the IPA with updated load forecasts, in addition to the notifications required by the Plan. Therefore, the Commission directs ComEd and AIU to provide the IPA with updated load forecasts by April 15, 2010 or such other date as may be established by the mutual agreement of the Procurement Administrator, Staff, the Procurement Monitor and either ComEd or AIU, as appropriate. Thus, upon receipt of the notifications and updated forecasts, the IPA shall utilize the process described on pages 39 and 53 of the Plan. Among other things, this process calls for the IPA to "convene a meeting with [the utility], the Commission and the Procurement Administrator to determine whether it is appropriate to rebalance the portfolio, and if so, to what extent and how such a rebalancing can be achieved"; it also identifies customer switching as a significant driver of load shifting levels.

If the portfolio must be modified in a manner other than as allowed under the Portfolio Rebalancing procedures described and approved above, the revised forecast and proposed revisions should be submitted to the Commission for review and approval. A petition seeking such approval shall be filed at least 21 days prior to the date by which such approval is requested.

I. Alternative Compliance Payments Rate

Also in its Response, Staff states that law Public Act 96-0033 (SB 1918 enrolled) makes several revisions to the PUA, including the creation of a new Section 16-115D "Renewable portfolio standard for alternative retail electric suppliers and electric utilities operating outside their service territories." Staff says the new Section requires both alternative retail electric suppliers and electric utilities operating outside their service territories (referred to collectively as "Alternative Suppliers") to procure renewable energy resources in amounts at least equal to the annual percentages set forth in item (1) of subsection (c) of Section 1-75 of the IPA Act times the actual amount of metered electricity delivered by the Alternative Suppliers during each 12-month period June 1 through May 31, commencing June 1, 2009. According to Staff, Section 16-115D(b) also requires Alternative Suppliers to meet at least 50% of their renewable quota through alternative compliance payments ("ACPs"). Staff Response at 1-2.

Staff says that while the IPA Plan itself does not presently specify "ACP rates," the numbers are provided in the Plan as the "Planning Year Net RPS Cost Limit Unit Price" in tables Q and Y. Staff claims that the "forecasted load of eligible retail customers, at the customers' meters" is also included in those tables in the rows labeled as "Planning Year Projected Total Delivery Volume" (although Staff noted in its October 5 Objections a slight error in the ComEd value).

While it may be sufficient for the Commission to leave things there, Staff recommends that the Commission adopt the relevant values explicitly and in terms of the Section 16-115D provisions. That is, Staff recommends that the Commission include in its Order in this docket: (1) the maximum alternative compliance payment rates; and (2) the forecasted load of eligible retail customers, at the customers' meters, for purposes of computing actual ACP rates for the 2010 to 2011 plan year. At the same time, and to avoid any ambiguity in the minds of alternative suppliers, Staff says the Commission may wish to reaffirm the values it adopted in Docket 09-0342 for the 2009 to 2010 plan year. *Id.* at 2-3.

Staff presents a table, recreated below, that shows the ACP rates that it believes the Commission should include in its Order in this docket.

Alternative Compliance Payments Rate Information Derived form the Plan

	2009-2010 Plan Year		**2010-2011 Plan Year**	
	Max ACP Rate ($/MWh)	Projected Deliveries (MWh)	Max ACP Rate ($/MWh)	Projected Deliveries (MWh)
AIU	$ 0.938	17,700,274	$ 1.476	16,525,235
ComEd	$ 1.007	39,469,952	$ 1.598	36,445,657
ComEd updated forecast	$ 1.007	39,469,952	$ 1.598	35,993,039

Id. at 4.

In its Reply, the IPA indicates it does not oppose Staff's recommendations. IPA Reply at 7-8.

Having reviewed the filings, the Commission finds Staff's proposal regarding ACP rates to be reasonable. The ACP rates are hereby included this Order as shown in the table below.

Alternative Compliance Payments Rate Information Derived form the Plan

	2009-2010 Plan Year		**2010-2011 Plan Year**	
	Max ACP Rate ($/MWh)	Projected Deliveries (MWh)	Max ACP Rate ($/MWh)	Projected Deliveries (MWh)
AIU	$ 0.938	17,700,274	$ 1.476	16,525,235
ComEd	$ 1.007	39,469,952	$ 1.598	35,993,039

J. Miscellaneous Clarifications and Corrections

Beginning on page 15 of its objections, **ComEd** identifies errors in the Plan that it believes should be corrected. Specifically, ComEd says that Table F on page 5 contains several errors. Under the column labeled “SF (MWH)” for “September-10," ComEd says the correct number is 1,788,543. Under the column labeled "Total (MWH)" for "September-10," ComEd says the correct number is 3,100,995. ComEd Objections at 15.

On page 20 of the Plan, in the last sentence in the second paragraph from the bottom, ComEd says the IPA refers to target volumes of renewable resources. It appears to ComEd that a reference to ComEd has been left out of that sentence. ComEd believes that the sentence should read as follows: "Target volumes for Ameren and ComEd would range around 600,000 MWH/annum, and 1,400,000 MWH/annum, respectively, representing approximately 3.5% of annualized volumes for each utility. *Id.* at 15-16.

On page 24, in the second full paragraph, ComEd says the IPA refers to the 2012-2013 period as being beyond the swap. ComEd believes this should be the 2013-2014 period. *Id.* at 16.

ComEd says that Table V-2 on page 48 of the Plan contains an extra column labeled "2010 IPA Procurement Cycle A (MW)" that is unnecessary and confusing. According to ComEd, it should be deleted. *Id.* at 16.

ComEd asserts that Table V-2 on page 49 of the Plan, Projected Volume (MW) for December 2012, should be 4,600. Also, ComEd states that on page 51, in the second paragraph from the bottom, a reference is made to Ameren that should be to ComEd. Finally, ComEd states that Attachment I of the Plan, Off-Peak Projected Volume (MW) for December 2012, should be 4,600 and that Attachment J of the Plan, Off-Peak Projected Volume (MW) for December 2012, should be 4,600. *Id.*

In its responses, the IPA agrees with the ComEd assertions and recommendations described in the five paragraphs above. IPA Response at 10-11.

In Tables U, V-1, V-2 and attachments I and J in the Plan incorporate a 10% oversubscription for the months of July and August. ComEd says it is unclear whether the IPA intended this or not. It is ComEd's belief that the IPA did not intend to do so. Assuming this is so, ComEd says these numbers need to be corrected. (ComEd Objections at 16) This issue is discussed in the "Hedging Ratio" section above. The IPA recommends that ComEd's revised Tables F, T, U, V-1 and V-2, as well as Attachments D, H, I and J, be incorporated into the Plan, and that the Plan be modified accordingly. *Id.* at 10.

It appears to the Commission that the changes proposed by ComEd are essentially agreed to or adopted by the IPA. Of course, the issue of the appropriate hedging ratio or oversubscription for the months of July and August was not resolved among the parties; it is addressed above in this Order. The Commission finds the changes proposed by ComEd, to the extent consistent with remainder of the conclusions in this Order, are reasonable and are hereby approved for inclusion in the approved Plan.

AIU indicates that it has found two instances of the Plan pertaining to long-term renewable energy that creates confusion as to the quantity expected to be procured and for which utility the quantities apply. AIU says that in the section on Carbon Liabilities, target volumes pertaining to AIU is listed as around 600,000 MWh per annum; however, another quantity of 140,000,000 MWh is also mentioned. AIU believes this second quantity is intended to be the ComEd target and thus should be verified for accuracy and the text should be edited to make it clear that this is the ComEd target. In addition, under the section of the Plan pertaining to long term portfolio energy quantities for ComEd, AIU indicates a quantity of 1,400,000 MWh is attributed to AIU when it should be attributed to ComEd. AIU recommends this be changed as well. AIU Objections at 8.

In its Response, the IPA agrees with AIU's assertions and recommendations described in the paragraph above. IPA Response at 14. It appears to the Commission that AIU has essentially identified typographical errors, with which the IPA agrees. These errors relate to the contested issue of long term renewable resources which is addressed above in this Order.

The Commission finds the changes proposed by AIU, to the extent consistent with the remainder of the conclusions in this Order, are reasonable and are hereby approved for inclusion in the approved Plan.

Staff also lists what it characterizes as clerical and typographical corrections, for which no debate was anticipated. Staff states that some of these same clerical and typographical corrections were presented in Staff's comments on the IPA's draft plan, and were ignored. Hence, Staff concludes that the IPA may believe that these corrections need not be made to the Plan, and if that is that case, then Staff objects and recommends that the Commission requires these corrections to be made. Staff Objections at 26-27.

Staff asserts that on page 40 of the Plan, the quoted portion of the IPA Act's definition of "renewable energy resource" is out of date, since passage of Public Act 96-0159 (SB2150). Staff also says that on page 41, within Table R, only one column of numbers (rather than three) is needed. The IPA agrees with Staff's assertion and recommendation. IPA Response at 19.

Staff also says that column is for the 2010-2011 plan year, based on a load forecast for 2010-2011 and on actual revenues and load for the reference year 2006-2007. Staff provides what it says is a corrected table in its Objections. Staff Objections at 27. Staff alleges that on page 55, within Table Y, in the row labeled, "(I) Planning Year Projected Total Delivery Volume," "39,422,473" should be "39,469,952." Staff says that on page 55, within Table Z, only one column of numbers (rather than three) is needed. Staff also claims that the column needed is for the 2010-2011 plan year, based on a load forecast for 2010-2011 and on actual revenues and load for the reference year 2006-2007. Staff has provided corrected versions of Tables Y and Z.

Id. at 28. Although the IPA did not initially respond to Staff's proposed "corrections", the IPA currently believes that all columns in Table Z should remain in the Plan. IPA Exceptions at 2.

The Commission has reviewed the filings and it appears that Staff's recommendations, except for one of its recommendations regarding Table Z on page 55 of the IPA's Plan, are appropriate; the IPA is directed to incorporate them into the approved Plan. With regard to Table Z on page 55 of the IPA's Plan, Staff's recommendations regarding the last column (the column on the far right) apply to the Plan for the current year, and are appropriate; the IPA is directed to incorporate them into the approved Plan. As for Staff's recommendations regarding the second and third column, as these apply to previous years' Plans, the Commission will leave it to the IPA to decide whether it will incorporate Staff's recommendations.

VIII. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having reviewed the entire record, is of the opinion and finds that:

(1) Commonwealth Edison Company, Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are Illinois corporations engaged in the retail sale and delivery of electricity to the public in Illinois, and each is a "public utility" as defined in Section 3-105 of the Public Utilities Act and an "electric utility" as defined in Section 16-102 of the Public Utilities Act;

(2) the Commission has jurisdiction of the parties hereto and the subject matter hereof;

(3) the recitals of fact and conclusions reached in the prefatory portion of this order are supported by the record and are hereby adopted as findings of fact;

(4) subject to the modifications explicitly adopted in the prefatory portion of this order, including such recommendations, supplemental recommendations and objections as are approved above, the Plan filed by the Illinois Power Agency pursuant to Section 16-111.5 of the PUA should be approved; as modified, the Plan, and load forecasts found appropriate above, will 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; in making this finding, the Commission is not expressing its concurrence in every statement or opinion contained in the Plan and no presumptions are created with respect thereto.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that subject to the modifications, recommendations and objections explicitly adopted in the prefatory portion of this order, the Plan filed by the Illinois Power Agency pursuant to Section 16-111.5 of the PUA is hereby approved.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 28th day of December, 2009.

(SIGNED) CHARLES E. BOX

Chairman

* A Dissenting Opinion will be filed by Commissioner Elliott at a later date.