STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	**:**	
	:	
Petition for Approval of the 2016 IPA Procurement Plan pursuant to Section 16-111.5(d)(4) of the Public Utilities Act.	**:**	**15-0541**

ORDER

DATED: December 16, 2015

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ORDER

By the Commission:

I. BACKGROUND

Section 16-111.5(d)(2) of the Public Utilities Act, (the “PUA” or the “Act”) 220 ILCS 5/1-101 *et seq.*, requires the Illinois Power Agency (the “IPA”) to prepare a power procurement plan (the “Draft Plan”), which is to be posted on the IPA and Illinois Commerce Commission (the "Commission") websites. Among other things, the purpose of the power procurement plan is to secure electricity commodity and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company, ("ComEd") Ameren Illinois Company d/b/a Ameren Illinois ("AIC" or “Ameren”) and MidAmerican Energy Company (“MidAmerican”).

Section 16-111.5(d)(2) does not require that the Draft Plan be docketed by the Commission. Any comments on the Draft Plan are to be submitted to the IPA for its review. The PUA requires the IPA to make revisions as necessary based on the comments submitted, 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. On September 28, 2015, the IPA filed with the Commission its eighth annual Power Procurement Plan, (the “Plan”) initiating this proceeding.

Section 16-111.5(d)(3) of the PUA provides that within five days of the annual filing of the Plan any Objections to the Plan must be filed with the Commission. The same subsection also provides that the Commission shall enter an order approving or modifying the Plan within 90 days after the filing of the Plan. The Plan was filed on September 28, 2015; thus, the deadline is December 28, 2015. Pursuant to Section 16-111.5(d)(4) of the Act, the Commission shall approve the Plan, including expressly the forecast used in the 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.” 220 ILCS 5/16-111.5(d)(4).

Section 16-111.5(e) specifies the major components to be included in the procurement process. Section 16-111.5(e)(4) provides that a Procurement Administrator shall design and issue a request for proposals (an “RFP”) to supply electricity in accordance with each utility's 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) concerns the confidential reports to be submitted to the Commission by the Procurement Administrator and Procurement Monitor after the opening of the sealed bids. Subsection (f) provides that the Commission shall review the confidential reports submitted by the Procurement Administrator and Procurement Monitor, and it shall accept or reject the recommendations of the Procurement Administrator within two business days after receipt of the reports.

II. PROCEDURAL HISTORY

Following the receipt of the IPA's Plan on September 28, 2015, the following entities were granted leave to intervene: the Environmental Law and Policy Center ("ELPC"); Wind on the Wires; the Retail Energy Supply Association (“RESA”); and the Renewables Suppliers.

On October 5, 2015 Objections and Comments to the Plan were filed by Ameren; ComEd; the Renewables Suppliers; MidAmerican ELPC; Wind on the Wires; and the Commission Staff ("Staff"). Parties were notified that pursuant to Section 16-111.5(d)(3) of the PUA, no hearing in the above-referenced matter was determined to be necessary.

Pursuant to a schedule issued by the Administrative Law Judges, Responses to Objections were filed on October 20, 2015 the IPA; Staff; ComEd; Ameren; ELPC; Wind on the Wires; and the Renewables Suppliers. Thereafter, Replies to Responses were filed by the above-named parties on October 30, 2015.

An Administrative Law Judges’ Proposed Order (“ALJPO” or “Proposed Order”) was duly filed and served on the parties on November 13, 2015. The Illinois Attorney General (the “AG”) and the above-named parties, except MidAmerican, filed Briefs on Exception on November 20, 2015. The AG, MidAmerican and the other parties listed above filed Reply Briefs on Exception on December 1, 2015.

III. OVERVIEW OF THE IPA PROPOSED PROCUREMENT PLAN

This section of the Order describes the IPA's Plan as filed on September 28, 2015, after the IPA received Comments from various parties and made modifications to its Draft Plan. Objections to and proposed modifications to the Plan, Responses and Replies are described later in this Order. According to the IPA, this is the eighth electricity and renewable resource procurement plan prepared by the IPA under the authority granted to it under the Illinois Power Authority Act, ("the IPA Act") 20 ILCS 3855/1-1 *et seq.,* and as further regulated by the PUA.

The IPA states that its Plan addresses the provision of electricity and renewable resource supply for the "eligible retail customers" of Ameren, MidAmerican and ComEd as defined in Section 16-111.5(a) of the PUA. Section 16-111.5(a) 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.

220 ILCS 5/16-111.5(a).

The Plan considers a 5-year planning horizon that begins with the 2016-2017 delivery year and lasts through the 2020-2021 delivery year. The IPA reports that the 2015 Procurement Plan was approved by the Commission in Docket No. 14-0588. At its core, the Plan consists of: a) a forecast of how much energy (and in some cases capacity is required by eligible retail customers; b) the supply currently under contract; and c) what type of and how much supply must be procured to meet load requirements and other legal requirements (such as renewable/clean coal purchase requirements or mandates from previous Commission Orders).

The Plan must contain an hourly load analysis that includes multi-year historical analysis of hourly loads, switching trends and competitive retail market analysis, known or projected changes to future loads, and growth forecasts by customer class. The Plan must analyze the impact of demand side and renewable energy initiatives, including the impact of demand response programs and energy efficiency ("EE") programs, both current and projected. Based on the hourly load analysis, the Plan must detail the IPA's plan for meeting the expected load requirements that will not be met through preexisting contracts. *See,* 220 ILCS 5/16-111.5(b)(1) (i)-(iv), (b)(2) and (b)(3).

Overall, the Plan defines the different Illinois retail customer classes for which supply is being purchased, including monthly forecasted system supply requirements, and expected minimum, maximum, and average values for the planning period. It also includes a proposed mix and selection of standard wholesale products, for which contracts will be executed during the next year to meet the portion of the load requirements not met through pre-existing contracts. Such standard wholesale products include, but are not limited to, monthly 5 x 16 peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity obligations, a capacity purchase plan, and ancillary services. The Plan further details the proposed term structures for each wholesale product type in the portfolio.

The Plan assesses price risk, load uncertainty, and other factors associated with the proposed portfolio measures. Those factors include contract terms, time frames for security products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment. For those portfolio measures that have significant price risk, the Plan identifies alternatives. The Plan includes the proposed procedures for balancing loads, including the process for hourly load balancing of supply and demand and the criteria for portfolio re-balancing in the event of significant shifts in load. Finally, it includes renewable resource and demand-response products.

The following tables summarize the IPA's proposed hedging strategy:

Summary of Proposed Energy Hedging Strategy for all Utilities

Spring 2016 Procurement			Fall 2016 Procurement		
June 2016-May 2017 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	October 2016-May 2017	Upcoming Delivery Year + 1	Upcoming Delivery Year + 2
June 100% peak and off peak July and Aug. 106% peak, 100% off peak Sep. 100% peak and off peak Oct. - May 75% peak and off peak	25%	12.5%	100%	25%	12.5%

Summary of Capacity Procurement for ComEd

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2018	June 2018-May 2019	June 2019-May 2020
100% PJM RPM Auctions[1]	100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions

Summary of Capacity Procurement for Ameren[2]

June 2016-May 2017 (Upcoming Delivery Year)[3]	June 2017-May 2018	June 2018-May 2019
50% RFP in Sep. 2015 50% MISO PRA[4]	75% RFP in Fall 2016 25% MISO PRA	25% RFP in Fall 2016 50% RFP in Fall 2017 25% MISO PRA

Summary of Capacity Procurement for MidAmerican:

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2018	June 2018-May 2019
100% of expected shortfall (approximately 16.7% of the capacity requirements) from MISO PRA	100% of expected shortfall (approximately 17.0% of the capacity requirements) from MISO PRA	100% of expected shortfall (approximately 17.6% of the capacity requirements) from MISO PRA

Summary of Procurement Plan Recommendations Based on July 15, 2015 Utility Load Forecast (Quantities to be Adjusted Based on the March and July 2016 Load Forecasts):

[1] The "RPM" is a Reliability Pricing Model. Plan at 75.
[2] The Table shows the incremental percentage of capacity requirements to be hedged or purchased in the indicated procurement events.
[3] Procurement approved in the 2015 Procurement Plan.
[4] A "PRA" is a Planning Resource Auction held by the Midcontinent Independent System Operator ("MISO"). Plan at 77.

	Year	Energy	Capacity	Renewable Resources	Transmission and Ancillary Services
	2016-2017	AMEREN	50% RFP in Sep. 2015 50% MISO PRA (procurement approved in the 2015 Procurement Plan)	One-year SREC [5]procurement up to 34.2GWh Five-year DG[6] REC procurement up to 7.8GWh* No RPS[7] procurement or sales for other resources, targets exceeded	Will be purchased from MISO
	2017-2018		75% RFP in Fall 2016 25% MISO PRA	No RPS procurement: shortage of 52.8 GWh, revisit next year	Will be purchased from MISO
	2018-2019		25% RFP in Fall 2016 50% RFP in Fall 2017 25% MISO PRA	No RPS procurement: shortage of 413.4GWh, revisit next year	Will be purchased from MISO
	2019-2020		No further action at this time	No RPS procurement: shortage of 522.7GWh, revisit next year	Will be purchased from MISO
	2020-2021		No further action at this time.	No RPS procurement: shortage of 633.1GWh, revisit next year	Will be purchased from MISO

[5] "SREC" is a solar renewable energy credit. Plan at 1.
[6] "DG" is distributed generation. Plan at 186.
[7] "RPS" is the Renewable Portfolio Standard. Plan at 125.

COMED	**2016-2017**	Up to 1,925MW forecasted requirement (Spring Procurement) Up to 725MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	One-year SREC procurement up to 69.9GWh Five- year DG REC procurement up to 16.3GWh* (Total renewables are 68GWh short of target, but will be met via the SREC procurement)	Will be purchased from PJM
	2017-2018	Up to 475MW forecasted requirement (Spring Procurement) Up to 475MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	No RPS procurement: shortage of 827.7GWh, revisit next year	Will be purchased from PJM
	2018-2019	Up to 450 MW forecasted requirement (Spring Procurement) Up to 425MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	No RPS procurement: shortage of 1,616.6GWh, revisit next year	Will be purchased from PJM
	2019-2020	No energy procurement required	100% PJM RPM Auctions	No RPS procurement: shortage of 2,182.4GWh, revisit next year	Will be purchased from PJM
	2020-2021	No energy procurement required	No further action at this time	No RPS procurement: shortage of 2,527.7GWh, revisit next year	Will be purchased from PJM

MIDAMERICAN	**2016-2017**	Up to 100MW forecasted requirement (Spring Procurement) Up to 75MW additional forecasted requirement (Fall Procurement)	100% of expected shortfall (approximately 16.7% of the capacity requirements) from MISO PRA	One-year SREC procurement for 13.2GWh One-year wind REC procurement for 165.3 GWh One-year REC procurement (any technology) for 39.7 GWh Five-year DG REC procurement up to 2.2GWh	Will be purchased from MISO
	2017-2018	No energy procurement required	100% of expected shortfall (approximately 17.0% of the capacity requirements) from MISO PRA	No RPS procurement: shortage of 258.9GWh, revisit next year	Will be purchased from MISO
	2018-2019	No energy procurement required	100% of expected shortfall (approximately 17.6% of the capacity requirements) from MISO PRA	No RPS procurement: shortage of 289.3GWh, revisit next year	Will be purchased from MISO
	2019-2020	No energy procurement required	No further action at this time	No RPS procurement: shortage of 320.5GWh, revisit next year	Will be purchased from MISO
	2020-2021	No energy procurement required	No further action at this time	No RPS procurement: shortage of 351.9GWh, revisit next year	Will be purchased from MISO

*The total DG RECs to be procured will be adjusted based on the results of the Fall 2015 DG procurement event.

The Commission understands that the energy volumes in the above table are preliminary, and the IPA may adjust them.

In this plan, the IPA recommends the following items for Commission action:

1.) Approve the base case load forecasts of ComEd, Ameren and MidAmerican, as was submitted to it in July 2015.

2.) Require the utilities to provide an updated load forecast by March 15, 2016 which will be preapproved by the ICC as part of the approval of this Plan, subject to the review of the IPA. The IPA states that the consensus of each utility, the IPA, the ICC Staff, and the Procurement Monitor will be required if a utility load forecast triggers the curtailment of the Long-Term Power Purchase Agreements. (*See,* Plan at 6-7).

3.) Approve two energy procurement events scheduled for the Spring of 2016 and Fall of 2016. The IPA avers that energy amounts to be procured in Spring will be based on the updated March 2016 load forecast and in accordance with the hedging levels stated in this Plan and as ultimately approved by the Commission as a part of the approval of this Plan. It further avers that the energy amounts (and capacity for Ameren) to be procured in the Fall will be based on the July 2016 updated base load forecast developed by Ameren, MidAmerican and ComEd, and subject to the review of the IPA.

4.) Approve procurement by ComEd, Ameren, and MidAmerican of capacity, network transmission service and ancillary services from their respective RTOs.

5.) Approve a Fall capacity procurement for Ameren in a quantity of 75% of its forecast requirements for 2017-2018 and 25% for 2018-2019.

6.) Approve the monthly peak and off-peak allocation of the Ameren and ComEd 2010 long term power purchase agreements' annual contract energy volumes.

7.) Approve pro-rata curtailment of ComEd and/or Ameren's 2010 long-term power purchase agreements for renewable energy in the unlikely event that the updated March 2016 expected load forecast indicates that such a curtailment is necessary. The IPA contends that this forecast will form the basis for pro-rata curtailment of long term renewable contracts, assuming consensus is reached among the parties identified in Item 2.) above. Otherwise, the July 2015 forecast will form the basis for curtailment.

8.) Approve a Spring 2016 procurement of RECs using the renewable resources budget ("RRB") for the prompt delivery year to allow the utilities to meet their RPS requirements other than for DG (solar photovoltaic only for Ameren and ComEd, all categories for MidAmerican). The volume for the procurement will be determined based upon the "Remaining Target" quantities resulting from the utilities' March 2016 load forecasts and limited to the funds available according to the utilities' updated budgets.

9.) Approve an early Summer 2016 procurement of DG RECs using already collected hourly Alternative Compliance Payments ("ACP") funds for Ameren and ComEd minus the total dollar value of each utility's DG REC contracts awarded through the Fall 2015 procurement and any hourly ACP funds committed to the purchase of curtailed RECs stemming from the 2010 long-term power purchase agreements. Approve an early Summer 2016 procurement of DG RECs using the RRB for MidAmerican.

10.) Approve specific consensus items from the EE stakeholder workshops related to the implementation of Section 16-111.5B of the PUA that are set forth in Section 7.1.3 Prior Year Consensus Items.

11.) Approve the Section 16-111.5B incremental EE programs. (*See,* Chapter 7 of the Plan).

A. Load Forecasts

Load forecasts are addressed in Section 3 of the Plan. The PUA provides that a procurement plan must be prepared annually for each "electric utility that on December 31, 2005 served at least 100,000 customers in Illinois." 220 ILCS 5/16-111.5(a). That same statute allows small multi-jurisdictional electric utilities to elect to have the IPA procure power and energy for all or a portion of its eligible load in Illinois. MidAmerican has elected to have the IPA procure incremental amounts of electricity,[8] as well as statutorily-mandated renewable resources for its eligible customers in Illinois, starting with this Plan.[9] The Plan must include a load forecast based on an analysis of hourly loads. The statute requires the analysis to include:

- Multi-year historical analysis of hourly loads;
- Switching trends and competitive retail market analysis;
- Known or projected changes to future loads; and
- Growth forecasts by customer class.

220 ILCS 5/16-111.5(b)(1). The statute also defines the process by which the procurement plan is developed. The load forecasts themselves are developed by the utilities as follows:

[8] The IPA states that MidAmerican registers with MISO, its Regional Transmission Operator, (”RTO”), its generation resources allocated to serve its Illinois customers as historical resources. Incremental amounts of electricity refer to the capacity and energy that would be needed in addition to the historical resources to meet the projected loads.

[9] The IPA points out that MidAmerican serves fewer than 100,000 electric customers in Illinois and, as a small multi-jurisdictional electric utility, is not obligated to but "may elect to procure power and energy for all or a portion of its eligible Illinois retail customers" using the IPA process. 220 ILCS 5/16-111.5(a). This is the first procurement process in which MidAmerican elected to have the IPA procure power and energy for a portion of its Illinois jurisdictional load.

> Each utility shall annually provide a range of load forecasts to the Illinois Power Agency by July 15 of each year, or such other date as may be required by the Commission or Agency. The load forecasts shall cover the 5-year procurement planning period for the next procurement plan and shall include hourly data representing a high-load, low-load and expected-load scenario for the load of the eligible retail customers. The utility shall provide supporting data and assumptions for each of the scenarios.

220 ILCS 5/16-111.5(d)(1).

The IPA recommends adoption of the Ameren, ComEd, and MidAmerican base case load forecasts. The Ameren and ComEd forecasts include already approved EE programs, and MidAmerican's forecast includes verified EE program impacts as well. The IPA also recommends that the Commission approve the additional incremental EE programs and measures as presented in Chapter 7 of the Plan. The March 2016 load forecasts will reflect those newly approved programs. *See,* Plan at 19.

According to the IPA, Ameren's forecast provides a base case and two complete excursion cases: a low forecast and a high forecast. Each excursion case addresses three different uncertainties that simultaneously move in the same direction: macroeconomics, weather, and switching. This means, for example, that a high load case should represent the combination of stronger-than-expected economic growth, which increases load, extreme weather (which increases load) and a reduced level of switching (which increases the "eligible" fraction of retail load for which the utility retains the supply obligation). A low load case should represent the combination of weaker-than-expected economic growth, mild weather and an increased level of switching.

The Ameren base case load forecast is based on a Statistically Adjusted End-use forecast that combines technological coefficients (efficiencies of various end-use equipment) and econometric variables (income levels and energy prices). Ameren did not define "high" and "low" cases by varying the econometric (or other) variables. Instead, Ameren looked at the statistics of the residual from the model fit and the high and low cases are based on a 95% confidence interval. Ameren's "high" and "low" forecasts are uniform modifications of the expected case, excluding incremental EE, by rate class. Specifically, the IPA continues, a single multiplier is defined for each of the three non-fully competitive delivery service rate classes, and the "before switching" load forecast for every hour is multiplied by the rate class multiplier. *Id.* at 22.

The IPA avers that Ameren includes "high weather" and "low weather" in its characterization of the high and low cases. It did not re-compute its load forecasting models with different values for the weather variables. The high and low scenarios only account for an averaged impact of weather, as well as macroeconomics, which is proportionally the same in each hour. *Id.* at 23.

Ameren has reported to the IPA that customer switching to alternative suppliers, in particular through municipal aggregation, is the greatest driver of load uncertainty. Switching through April 2015 has resulted in approximately 58-64% of residential and small commercial load seeking service from alternative suppliers. Ameren expects that the amount of load supplied by alternative retail electric suppliers ("ARES") will remain flat across the planning horizon based on indications from municipalities that have expiring contracts. Ameren's current year tariff price is similar to comparable ARES prices. While, according to the IPA, ARES offerings to the individual customers appear to be generally higher than the default utility rate, the rates offered by ARES to the aggregated loads may be lower and thus more comparable to the Ameren default service rate. *Id.*

A high load scenario envisions a situation where an even larger return of residential and, to a lesser extent, commercial customers is realized, especially in June 2016 when governmental aggregation contracts serving approximately 30% of residential load will expire. Residential and commercial switching rates under the high load scenario are forecasted to be 24% and 54%, respectively, in May 2017, 23% and 51%, respectively, in May 2018, and 19% and 42%, respectively, by the end of the planning horizon. *Id.* at 23-24.

Conversely, should future Ameren tariff prices exceed customers' perceived value of ARES contracts, a higher switching scenario is possible. Thus Ameren's low load scenario assumes that residential and small commercial customer classes will approach 71% and 76%, respectively, in May 2017, 77% and 82%, respectively, in May 2018, and 95% and 94%, respectively, by the end of the planning horizon. *Id.* at 24.

According to the IPA, ComEd forecasts load by applying hourly load profiles for each of the major customer groups to the total service territory annual load forecast and subtracting loads projected to be served by hourly pricing, ARES, and municipal aggregation. ComEd's hourly load profiles are developed based on statistically significant samples from ComEd's residential, non-residential watt-hour, and 0 to 100 kW delivery customer classes. The profiles show clear and stable weather-related usage patterns. Using the profiles and actual customer usage data, ComEd develops hourly load models that determine the average percentage of monthly usage that each customer group uses in each hour of the month. ComEd did not supply its forecasts for medium and large commercial and industrial customers, whose service has been deemed to be competitive and who are not eligible retail customers. *Id.* at 27.

In determining the expected load requirements for which standard wholesale products will be procured, the ComEd forecast is adjusted for the volume served by municipal aggregation and other ARES. The ComEd 5-year annual load forecast is based on the rate of customer switching in the past, expected increases in residential ARES service, and the anticipated additional migration of 0 to 100 kW customers to ARES and municipal aggregation. *Id.* at 28.

With respect to MidAmerican's load forecast, the IPA states that MidAmerican forecasts its load by using econometric models on a monthly basis. For the residential, commercial and public authority classes, the IPA continues, sales are determined by multiplying customers by use per customer. For the industrial class, sales are modeled directly. For the street lighting class, sales are forecast using trending. The gross peak numbers used in the analysis are the historical gross peaks, which take into account demand-side management impacts. Because there are planned large load additions, using the model results alone for the peak demand forecast would result in a forecast that is too low. Therefore, the planned large load additions are added to the model results to achieve the final peak demand forecast. *Id.* at 34-35.

The IPA avers that MidAmerican has one active ARES in its Illinois service territory, and none of its customer classes have been declared competitive. The IPA opines that the low level of switching among MidAmerican's eligible customers relative to levels for Ameren and ComEd is likely due to market conditions in MidAmerican's service area including a relatively low cost of MidAmerican-owned resources allocated to its Illinois load, which would lead to little or no municipal aggregation activity and little profit opportunity for ARES. *Id.* at 35.

According to the IPA, MidAmerican provided a forecast of total usage for the entire service territory combining the projected customers and sales numbers modeled using data specific to the area being forecast. A suite of econometric models, adjusted for other considerations such as customer switching, is used to produce monthly usage forecasts. The hourly customer load models are applied to create hourly forecasts by customer class. Some variables, such as customer numbers, price, sales, revenue class, jurisdiction, etc., were obtained internally from the company database. Some variables were obtained from external sources such as economic, demographic and weather information. *Id.*

MidAmerican provided the IPA with a base case and two excursion cases: a low forecast and a high forecast. The IPA states that the required low and high hourly load forecast scenarios were created by taking the 95% confidence interval around each class-level sales, customer and use per customer forecast and the 95% confidence interval around the non-coincident gross peak demand forecast. The load forecasting software used for the sales, customers use per customer and non-coincident peak demand forecasts provided the upper and lower bounds of a 95% confidence interval around each monthly forecast value. *Id.* at 37.

1. Load Forecast Uncertainty

According to the IPA, it has procured power for the utilities to meet a monthly forecast of the average hourly load in each of the on-peak and off-peak periods. It has addressed the volatility in power prices by "laddering" its purchases: hedging a fraction of the forecast two years ahead, another fraction one year ahead, and a third fraction shortly before the beginning of the delivery year. Even if pricing two years ahead were extremely advantageous, the IPA does not purchase its entire forecast that far ahead because the forecast is uncertain. *Id* at 40.

The IPA further states that even if it could perfectly forecast the average hourly load in each period, and perfectly hedge that forecast, it would still be exposed to power cost risk. This is because energy in one hour is not a perfect substitute for energy in another hour, as the hourly spot prices differ. *Id.*

With regard to weather, on a short-term basis, the IPA opines that weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. Ameren treats weather uncertainty together with load growth uncertainty. ComEd's forecasts are built around two sample years. The IPA maintains that much of the impact of weather is on load variability within the year. MidAmerican's reference case weather-related assumptions are not changed for the high and low load forecasts. The reference case load forecast is based on the "weather normalized" historical sales. *Id.*

In the IPA's opinion, the "average hour" load forecast is not an accurate forecast of each hour's load. This is because within the sixteen-hour daily peak period, mid-afternoon hours would be expected to have higher loads than average, and early morning or evening hours would be expected to have lower loads. *Id.*

Ameren projected a rate of 60.8% switching by eligible retail customers by the end of the 2016-2017 delivery year and ComEd projected about 46.2%. These levels, Ameren states, represent a decline in the switching statistics that were assumed in the July 2014 forecasts and are informed by lower than forecasted actual switching through April 2015. The IPA opines that the decline in switching is driven in part by communities deciding to suspend and/or not renew their municipal aggregation programs and return to utility service. It states that savings opportunities that existed before 2014 drove the growth in residential switching, but since 2014 these savings have diminished. It states that it is possible that customer migration away from utility supply could resume within the planning horizon. *Id.* at 43.

The IPA avers that approximately one quarter of the current supply contracts for municipal aggregation will expire in the 2015-2016 delivery year. The majority of the aggregated supply contracts are scheduled to expire by the end of Summer 2017. It opines that there may be a considerable amount of return to utility service, especially if market prices rise between now and the expiration of municipal aggregation contracts. It states that it is possible to see switching at higher than expected levels, resulting in an over-hedged position. Expanding on the hypothetical, assuming that the utilities' hedges are above market prices, the remaining load taking bundled utility service would be subject to higher bundled rates. The IPA contends that both Ameren and ComEd have assumed a wide range of switching fractions in their low and high scenarios. *Id.*

Although switching from default service to an ARES by individual customers has some impact, the IPA maintains that Ameren and ComEd switching forecasts have been dominated by municipal aggregation. While the IPA recognizes that many ARES focus on individual residential switching, it is not aware of a significant number of residential customers leaving default service to take ARES service outside of a municipal aggregation program. *Id.*

The IPA avers that customers who could have elected bundled utility service but take electric supply pursuant to an hourly pricing tariff are not "eligible retail customers." It states that these hourly rate customers are not part of the utilities' supply portfolio and the IPA does not have to procure energy for them. Ameren and ComEd did not include customers on hourly pricing in their load forecasts by considering these customers switched. The IPA states that the amount of load on hourly pricing is small and unlikely to undergo large changes that would introduce significant uncertainty into the load forecasts. MidAmerican does not have hourly billed customers. *Id.* at 44.

The IPA reports that Public Act 95-0481 created a requirement for ComEd and Ameren to offer cost-effective EE and demand response measures to all customers. It states that both Ameren and ComEd have incorporated the impacts of these statutory and spending-capped efficiency goals, as applied to eligible retail customers, as well as achieved and projected savings in the Plan's forecasts. MidAmerican has EE programs operating in its Illinois service territory. MidAmerican expects that the projected EE program impact would be consistent with historical levels; therefore, no adjustment was made to its forecasting models. *Id.* at 45.

The IPA concludes that demand response programs do not impact the weather-normalized load forecasts. As such, the IPA notes that they are more like supply resources. *Id.*

The IPA opines that recent announcements such as Tesla's Powerwall home energy storage system suggest that energy storage is now an emerging technology. It also is of the opinion, however, that it is too early to forecast the impact on load forecasts, and the Agency notes that there are no clear provisions in Illinois law to encourage the adoption of these technologies. *Id.*

2. Existing Resource Portfolio and Supply Gap

Starting with the 2014 Procurement Plan, the IPA has purchased energy supply in standard 25MW on-peak, and off-peak blocks. The IPA states that the energy block size was reduced from 50 MW prior to the 2014 Plan in order to more accurately match supply with load, citing page 93 of that plan. It contends that the 2016 Procurement Plan includes procurement of energy supply to meet the needs of MidAmerican's, ComEd's, and Ameren's eligible customers. These purchases are driven by the supply requirements in the current year procurement plan. Plan at 47.

In addition to purchasing energy block contracts in the forward markets, the IPA continues, Ameren, MidAmerican, and ComEd rely on the operation of MISO and PJM to balance their loads and consequently may incur additional costs or credits. Purchased energy blocks may not perfectly cover load, triggering the need for spot energy purchases or sales from or to MISO and PJM. The IPA's procurement plans are based on a supply strategy designed to balance price risk and cost. The underlying principle of this supply strategy is to procure energy products that will cover all or most of the near-term load requirements and then gradually decrease the amount of energy purchased relative to load requirements for the following years. *Id.*

The current IPA procurement strategy involves hedges to meet a portion of the hedging requirements over a three year period. It includes two procurement events in which the July and August peak requirements will be hedged at 106%, while the remaining peak and off-peak requirements will be hedged at 100%. In the Spring procurement event 106% of the July and August expected peak, 100% of the July and August off-peak, 100% of the June and September peak and off-peak, and 75% of the October through May peak and off-peak requirements for the 2016-2017 delivery year will be targeted for procurement. The Fall procurement event will bring the targeted hedge levels to 100% for October through May of the 2016-2017 delivery year. 50% of the targeted hedge levels for the 2017-2018 delivery year and 25% of the levels for the 2018-2019 delivery year will be acquired in two equal portions in the Spring and Fall procurement events. *Id.*

The IPA contends that because of the uncertainty in the amount of eligible retail load in future years, it has not purchased energy beyond a 3-year horizon, except in a few circumstances. These include:

- A 20-year bundled REC and energy purchase (also known as the 2010 long-term power purchase agreements "LTPPAs"), starting in June 2012, made by Ameren and ComEd in December 2010, pursuant to the Final Order in Commission Docket 09-0373.

- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period of time June 2013 through December 2017.

See, Plan at 47.

The IPA opines that, due to the forecasted return of some load to ComEd, and the relatively small change in load for Ameren, curtailment of the LTPPAs is unlikely for the 2016-2017 delivery year. MidAmerican is not covered by either LTPPAs or Rate Stability procurements. Twenty-year power purchase agreements between Ameren and ComEd and the FutureGen Industrial Alliance, Inc., although not procured by the IPA, were directed by the Commission Order approving the IPA's 2013 Procurement Plan. The IPA states, that in February 2015 the funding for FutureGen 2.0 was suspended, potentially eliminating the project as a source of supply. *Id.* at 47-48.

It reports that Ameren's existing supply portfolio, including long-term renewable resource contracts, is not sufficient to cover the projected load for the 2016-2017 delivery year. It states that additional energy supply will be required for the entire 5-year planning period. Approximately 58% of the Ameren residential load has switched to ARES suppliers. Ameren's expected scenario load forecast assumes that switching will be flat across the current planning horizon. *Id.* at 48. Under the expected load forecast scenario, the IPA continues, the average supply gap for peak hours of the 2016-2017 delivery year is estimated to be 456 MW, the peak period average supply gap for the 2017-2018 delivery year is estimated to be 686 MW, and the average peak period supply gap for the 2018-2019 delivery year is estimated to be 857 MW. While the planning period is five years, the IPA's hedging strategy is focused on procuring electricity supplies for the immediate three delivery years. *Id.* at 49.

According to the IPA, ComEd's current energy resources will not cover load starting in June 2016. The average supply gap during peak hours for the 2016-2017 delivery year under the expected load forecast is estimated by the IPA to be 1,350 MW. The average supply gaps during peak hours for the 2017-2018 and 2018-2019 delivery years are estimated to be 2,189 MW and 2,789 MW respectively. *Id.* at 49.

MidAmerican has requested that the IPA procure electricity for the incremental load that is not forecasted to be supplied in Illinois by MidAmerican's Illinois jurisdictional generation. The IPA states that MidAmerican's existing eligible load is served by a 10.86% allocation of capacity from MidAmerican's historical Illinois resources. In reviewing load forecast and resource portfolio information supplied by MidAmerican for the first time in preparing its 2016 Plan, the IPA notes that MidAmerican has used and will continue to use its generation resources whenever their cost is less than the cost of acquiring energy in the MISO market. In determining the amounts of block energy products to be procured for MidAmerican, the IPA treated the allocation of 10.86% of the capacity and energy from the identified generation resources in a manner that is analogous to a series of standard energy blocks. The set percentage of forecast fleet generation amounts for each year, month, and peak or off-peak period were subtracted from the forecast MidAmerican energy loads for the corresponding time periods to determine the energy hedge amounts for those periods. *Id.* at 49-50.

The IPA recognizes that in MidAmerican's situation, the amount of energy available varies hour-to-hour, and it does not behave exactly the same as fixed energy blocks. It concludes that the forecast supply gap for MidAmerican has load and supply uncertainty. In the IPA's opinion, one important aspect of MidAmerican's risk position is the positive correlation between the inputs, hourly load and the hourly dispatch of the generation fleet. This, it continues, reduces the uncertainty of the differential. The IPA believes that its proposed methodology with regard to MidAmerican's supply procurement is reasonable, given this correlation. The IPA maintains that the average supply gap for MidAmerican during peak hours for the 2016-2017 delivery year under the expected load forecast is estimated to be 37 MW. The average supply gap during peak hours for the 2017-2018 delivery year is 40 MW and for the 2018-2019 delivery year the supply gap is 46 MW. *Id.* at 50.

The IPA's approved 2012 Procurement Plan prescribed an average monthly peak and off-peak allocation of the LTPPAs' annual contract energy volume for each utility. The IPA's prescribed allocation covered the June 2012 through May 2015. In this Plan, the IPA proposes an extension of the monthly allocation through May 2032. The IPA states that its methodology for establishing the proposed allocations is the same one it used in the 2012 Procurement Plan. *Id.*

3. MISO and PJM Resource Adequacy Outlook and Uncertainty

The IPA is of the opinion that as a result of retail choice in Illinois, resource adequacy (the load/resource balance) is a function of determining what level of resources to purchase from which markets over time. It opines that for the Illinois market to function properly, the RTO markets and operations (*e.g.,* MISO and PJM) must provide sufficient resources to reliably satisfy the load of all customers. The IPA analyzed several outside studies of resource adequacy that are publicly available from different planning and reliability entities. The IPA formed the opinion that over the planning horizon, PJM will maintain adequate resources to meet the collective needs of customers in those regions. However, according to the IPA, MISO may be short resources starting in the 2016-2017 timeframe. *Id.* at 52.

In the IPA's view, in PJM, capacity is largely procured through PJM's capacity market, the "RPM, which was approved by the Federal Energy Regulatory Commission (the "FERC") in December 2006. The IPA defines RPM as a forward capacity auction through which generators offer capacity to serve the obligations of load-serving entities. The IPA states that the primary capacity auctions, Base Residual Auctions ("BRAs"), are held each May, three years prior to the commitment period. The commitment period is also referred to as a Delivery Year, which is from June 1 though May 31st of the following year. Also, up to three incremental auctions are held, at intervals 20, 10, and three months prior to the Delivery Year. It explains that the 1st, 2nd, and 3rd Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement. Additionally, a Conditional Incremental Auction may be conducted to secure commitments of additional capacity. *Id.* at 52.

The IPA explains that in PJM, just prior to the beginning of each Delivery Year, the Final Zonal Net Load Price is calculated, which sets the price paid by Load Serving Entities ("LSEs") for capacity procured as part of RPM. The IPA states that this price is determined based on the results of the BRA and subsequent incremental auctions for a given Delivery Year. It opines that, as the procurement of the majority of the capacity via the RPM is done during the BRA, there is little variation between the BRA clearing price and the Final Zonal Net Load Price. The IPA opines, however, that the results of the incremental Capacity Performance auctions expected in late August and early September may significantly change the net price of capacity for the 2016-2017 and 2017-2018 delivery years. *Id.* at 52-53.

In the IPA's opinion, PJM is projected to have sufficient resources to meet load plus required reserve margins for the Delivery Years 2015-2020, with projected reserve margins above the 15.7% target reserve margin. It also states that for the 2015-2016 Delivery Year, the reserve margin is approximately 10% above the target reserve margin, dropping to approximately 3% above the target reserve margin for the 2020-2021 Delivery Year. *Id.* at 53.

The IPA maintains that MISO's Resource Adequacy construct contains the Resource Adequacy Requirements (the "RAR") that require "LSEs" in the MISO region to procure sufficient planning resources to meet its anticipated peak demand, plus a Planning Reserve Margin (a "PRM"). It explains that a LSE's total resource adequacy obligation is referred to as the Planning Reserve Margin Requirement (the "PRMR"). The IPA points out that on June 11, 2012 the FERC conditionally approved MISO's proposal to enhance its RAR by establishing an annual construct based upon meeting reliability requirements on a locational basis, including the use of an annual PRA. MISO implemented the Module E-1 RAR, which became fully effective on June 1, 2013. *Id.* at 54.

The IPA is of the opinion that based upon the 2014 LTRA[10] of the North American Electric Reliability Corporation (the "NERC"), on a region-wide basis, MISO is expected to have sufficient resources to meet load plus required reserve margin for the 2015-2016 Planning Year with a reserve margin approximately 2% above the reserve margin target of 14.8%. Starting with the 2016-2017 Planning Year through the 2020-2021 Planning Year, MISO is projected to have insufficient resources to meet load plus the required reserve margin. The IPA states that the 2016-17 shortfall is approximately 2% and increases to approximately 5% in 2020-2021. According to the IPA, NERC's analysis mirrors MISO's analysis. *Id.*

The IPA posits that both NERC and MISO explain the drop in reserve margin beginning in 2016 in similar terms. It reports that the primary contributing factors driving the projected shortfall are:

- Increased retirements and suspensions due to United States Environmental Protection Agency ("EPA") regulations and market forces, such as low natural gas prices;

[10] An "LTRA" is a long term reliability assessment. Plan at 54.

- Exclusion of low certainty resources that were identified in the Resource Adequacy Survey;
- Increased exports to PJM and the removal of non-firm imports;
- Exclusion of surplus capacity in MISO South above the 1,000 MW transfer limit;
- Not enough certainty of resources planned. 91 percent of the load in the MISO footprint is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource planning and investment in resources are part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Need ("CPCN").

See, Plan at 54-55.

The IPA posits that MISO is studying ways to use existing transmission and generation to help alleviate the expected near-term shortages. One strategy, it continues, is to convert generation capacity that is currently ineligible to qualify as Planning Resources in the annual PRA. The IPA states that MISO is conducting the Unused Generation Capacity Study that seeks to identify and inform Market Participants of potential opportunities to participate in the capacity market by connecting to the grid as Network Resources. According to the IPA, preliminary results from the study indicate that approximately 806 to 938 MW of generation have the potential to become Network Resources with no required network upgrades. An additional 273 to 404 MW will require network upgrades to unlock the constrained unused generation. *Id.* at 55.

The IPA opines that the completed study will identify projects that would allow resources to qualify as Planning Resources eligible for participation in the PRA. MISO has undertaken the South to North/Central Capacity Transfer Analysis, which explores ways to improve the transfer capacity between the regions. The transfer analysis identified the full capability of the transmission system to be in the 3 to 4 GW range; an increase of 2 to 3 GW from the level of capacity that was counted from MISO South in the 2014-2015 and 2015-2016 PRAs. The IPA avers that the current assessment assumes a maximum of 1,000 MW of MISO South Region capacity is available to MISO North/Central Region. The Unused Generation Capacity Study and the South to North/Central Capacity Transfer Analysis help to inform areas where additional capacity could potentially clear and help mitigate potential resource adequacy shortfalls. *Id.*

The NERC analysis notes that although the reserve margin is projected to fall below the reserve margin target in 2016, MISO fully expects that the shortfall will change significantly once LSEs and state commissions within the footprint solidify future capacity plans. The IPA opines that the MISO capacity projection may need to be updated when more reliable data is available. *Id.*

According to the IPA, a key component is the establishment of Local Resource Zones ("LRZs") and the MISO region currently has nine Local Resource Zones. It states that Local Reliability Requirements ("LRRs") are set for each of these Zones in order to establish the minimum amount of Planning Resources needed to maintain MISO's Loss of Load Expectation within each of these zones. to the IPA states that MISO also establishes a Local Clearing Requirement for each of these zones, which is the minimum amount of Planning Resources required to be sourced within each of these zones while fully using the Capacity Import Limit ("CIL") for the LRZ. *Id.* at 56.

The IPA explains that Capacity Export Limits are also established for each Local Resource Zone. A market participant can qualify a Planning Resource and convert the Unforced Capacity of the Planning Resource into Zonal Resource Credits, which are MW units of Planning Resources that have been converted into a credit. This credit can be used to meet the Planning Reserve Margin Requirement directly through offers or self-schedules in the PRA or commitments in a Fixed Resource Adequacy Plan. *Id.* at 58.

The IPA maintains that market participants can also buy and sell Zonal Resource Credits through bilateral arrangements. MISO will impose a Capacity Deficiency Charge on an LSE that has not demonstrated that it has sufficient capacity resources to meet its Planning Reserve Margin Requirement at the close of the PRA. MISO held the third PRA in April 2015. *Id.* The IPA also notes that four complaints have been filed at FERC against MISO regarding the results of the 2015-2016 MISO PRA in Zone 4. The complaints were filed by the Illinois Attorney General, Public Citizen, Inc. Southwestern Electric Cooperative, and the Illinois Industrial Energy Consumers. *Id.* at 58 (citing FERC Docket EL15-72-000 and other FERC proceedings).

The IPA states that MISO and its Independent Market Monitor (“IMM”) claim that the 2015-2016 PRA worked as expected and the final results were not impacted by physical or economic withholding or other conduct prohibited by MISO’s tariff. According to the IPA, the review also suggests that for the 2016-2017 and 2017-2018 PRAs, Zone 4 will clear in a similar fashion to the 2015-2016 PRA, with the Zone 4 price most likely tracking the Initial Reference Price. With the IMM forecasting a $71/MW-Day Initial Reference Price for 2016-2017 and a Preliminary Initial Reference Price of $136.37/MW-Day for 2017-2018, the IPA opines that Zone 4 price may clear at close to these prices (dropping in 2016-2017 then rising again in 2017-2018).

While the PJM “BRA” for 2018-2019 has not been conducted yet due to the delayed FERC decision on PJM’s Capacity Performance filing, the IPA is of the opinion that the capacity performance incentives will most likely result in an increase in the BRA price for 2018-2019. With the MISO IMM using the opportunity cost of selling to PJM as a basis for deriving the Initial Reference Price, the IPA is also of the opinion that the Initial Reference Price for 2018-2019 will be higher. In light of the complaints and the facts surrounding the 2015-2016 PRA, the IPA expects much uncertainty in future MISO PRA Zone 4 clearing prices. In the interest of hedging price risk and maintaining rate stability for the Illinois customers, the IPA recommends hedging a portion of Ameren’s capacity market exposure for the upcoming planning years. *Id.* at 60.

4. Supply Risk

The IPA avers that procurement risk factors can be divided into three broad categories: volume, price, and hedging imperfections. It defines volume risk as the risk factors associated with identifying the volume and timing of energy delivery to meet demand requirements. It defines price risk as the risk of uncertainty in the cost of the energy and the costs associated with energy delivery in real time. Finally, it states that hedging imperfections are the result of mismatches between the types of available hedge products and the nature of customer demand. *Id.* at 61.

The IPA states that accuracy of load forecasts directly impacts volume risk. It maintains that accurate customer consumption profiles, load growth projections, and weather forecasts impact both the total energy requirement and the shape of the load curve. It opines that the risk factors that determine overall volume risk include: changes in customer load profiles and usage patterns, the uncertainties associated with load growth and short-term weather fluctuations, technology changes such as smart meters and behind the meter generation and storage, and customer switching. It views customer switching as a key factor in volume risk. The IPA avers that the opportunities for eligible customers to take service from ARES or through municipal aggregation resulted in substantial portions of the eligible retail load switching away from the utilities for non-utility retail contracts that run through the 2014-2015 procurement year. It concludes that more recently the primary uncertainty surrounding customer switching appears to be the potential for significant retail load migration back to the utilities. *Id.* at 62.

With regard to price risk, the IPA maintains that the price that Ameren and ComEd supply customers pay for electricity consists primarily of the price of energy procured in the forward and spot markets, the cost of capacity to meet resource adequacy requirements, and the cost of delivery, plus additional charges related to RPS compliance. MidAmerican customers in Illinois, it continues, pay the energy and capacity costs from the portion of the MidAmerican resources that are allocated to serving its Illinois load. The IPA states that the requirements of MidAmerican's Illinois customers that exceed this resource allocation will be obtained through the IPA's procurement process starting with the 2016 procurement year. The primary risk factors that contribute to price risk include the costs of electric energy, real-time balancing, capacity, ancillary services, transmission including congestion, and correlation with volume risk factors. *Id.*

The IPA contends that customer switching behavior impacts volume risk and, in turn, variability in utility customer volumes impacts price risks. It concludes that the blended price of utility supply may be less that the current price of an ARES or municipal aggregation offer, which can result in increased customer migration back to the utility. The IPA points out that the reverse situation can occur as well. *Id.*

The IPA maintains that hedging imperfection can contribute to supply risks through mismatches in procurement supply shape, supply delivery points and customer load locations, or the intermittent nature of renewable energy sources. It points out that the standard on-peak and off-peak block energy products procured by the IPA do not reflect hourly loads. The IPA states that these products provide constant volume and prices across a fixed number of hours, while hourly prices as well as load vary across the day and within each of the peak and off-peak periods. Because of this variation, the IPA surmises that if the average peak and off-peak monthly load is perfectly hedged, the actual hourly load will still be imperfectly hedged. *Id.*

The IPA states that ComEd and Ameren divested their generating plants to unregulated affiliates or third parties and have no contracts for unit-specific physical delivery, other than certain Qualifying Facilities under the federal Public Utilities Regulatory Policies Act contracts. It concludes that because these utilities do not purchase and take title to electricity their supply positions, other than RTO spot energy, are exclusively price hedges. *Id.* at 63.

The IPA avers that MidAmerican has retained the resources that serve its Illinois customers, most of which are located outside of Illinois. It states that MidAmerican allocates a portion of the capacity and energy from specified resources under its control for its eligible Illinois customers. Under the 2016 Procurement Plan, the IPA will procure the net requirements between MidAmerican's eligible customer retail load and the MidAmerican-controlled generation allocated to its Illinois customers. *Id.*

The IPA explains that physical electricity supply and load balancing for ComEd, Ameren, and MidAmerican are coordinated by the respective RTOs (PJM for ComEd and MISO for Ameren and MidAmerican). Each RTO provides day-ahead and real-time electricity markets and clearing prices, thus, generators supply their energy to the RTO, and the RTO delivers energy to LSEs, which include ComEd and Ameren. It concludes that while the RTO ensures the physical delivery of power, the cost of managing this delivery, including the cost of managing reliability risks, is passed on to the LSEs financially. *Id.*

The IPA states that each RTO charges a uniform day-ahead price for all energy scheduled in a given hour and delivery zone. To the extent that real-time demand differs from the day-ahead schedule, load is balanced by the RTO at a real-time price: if demand exceeds the day-ahead schedule, then the LSE pays the real-time price; if demand is less than the day-ahead schedule, the LSE is credited the real-time price. Both the day-ahead and the real-time prices are referred to as Locational Marginal Prices because they depend on the delivery location or zone. *Id.*

With respect to supply hedges, the IPA posits that an important category of energy supply hedges is a unit-specific supply contract. Other supply hedges are forward contracts, futures contracts, and options. It opines that not all of these types of hedges are suitable for use in the Procurement Plan, and not all may be readily available in electricity markets. Citing 220 ILCs 5/16-111.5(f), the IPA states that Illinois law requires the Procurement Administrator to be able to develop a market-based price benchmark for the process, the bidding must be competitive, and the Commission's Procurement Monitor is required to report on bidder behavior. *Id.* at 64.

According to the IPA, the most suitable hedges are those standardized products that are well-understood and widely-traded. It reasons that, if a product has liquid trading markets, or is similar to other products with liquid markets, a bidder can control its risk exposure. Availability of information on current prices and the price history of similar products help bidders provide more competitive pricing and help the Procurement Administrator produce a realistic benchmark. The IPA further states that before its 2014 Procurement Plan, it had generally restricted its hedging to the use of standard forward hedges in 50 MW increments. The IPA began using 25 MW increments and a mid-year procurement with the 2014 Plan. The IPA's recommended Plans have been stated in terms of monthly contracts, although procurement events have met some of these needs with multi-month contracts. *Id.*

The IPA has in the past purchased energy products that are not typically traded, such as the LTPPAs authorized in the 2010 Procurement Plan with new build renewable generation. These products still must be standardized in such a way that the winning bidders may be selected based on price alone and the price is subject to a market-based benchmark. It opines that markets for products which are specifically designed for its requirements, such as full requirements contracts or over-the-counter options, will likely have limited transparency. The IPA's procurement structure requires a benchmarking and approval process and thus may not be compatible with such a low level of transparency. *Id.*

The IPA posits that futures contracts at the PJM Northern Illinois Hub and the MISO Illinois Hub are traded in reasonably liquid markets, making such contracts easier to benchmark. In the IPA's view, the markets for long-dated (*i.e.* further in the future) contracts are less liquid. The IPA opines that it may be difficult or impossible to conduct the statutory RFP process for exchange-traded futures contracts. It concludes that setting a price through an RFP process structured per legislative mandates is incompatible with price-setting either in an open outcry auction or by a market-maker. It further surmises that it is unclear how the margin requirements would fit within the current regulatory framework if price movements require a utility to post margin many months in advance of delivery. The IPA states that the same concerns are even more applicable to options contracts trading which it views as even more illiquid. *Id.* at 64-65.

With regard to options, the IPA is of the opinion that options are not any more useful for hedging price risk than are forward contracts, unless one is exposed to other risks that correlate with and enhance price risk. It cites as an example loss of load accompanied with declining prices. It states that in theory, option prices are determined by the value of the option as a price hedge. If an option had additional value as a hedge against load migration risk some might consider options to be a bargain. The IPA views options as expensive when used as hedges for load migration risk. It states that the value of the option as a hedge against load migration risk is less than its value as a price hedge, but it is the value as a price hedge that determines the option's price.

The IPA avers that there are also other costs and logistical obstacles to using options:

- A large part of the volume of options on the market is traded on exchanges. However, the IPA's structured procurement process prevents it from buying options on the exchanges.
- Option contracts can be relatively illiquid, making it more difficult to assure fair pricing. If options purchased through the IPA procurement process required an affirmative decision, the utility would want to be able to show that it had acted prudently. If the utility exercised a put option, to sell the underlying hedge, it would want to be sure that decision did not make it a wholesale market participant for purposes of FERC Order 717. If the option exercise were purely financial and automatic—resulted only in a cash payment from the option holder – these concerns might not be as important, but counterparty credit would be an issue.
- The use of options is subject to regulations under the Dodd-Frank Act of 2010 (specifically Title VII). Under this Act, the trading of options (and other swaps) would be reported to a central database for clearing purposes. Trade details (price, volumes, time stamped trade confirmations, and complete audit trails) would need to be reported. In addition, trade records must be kept for 5 years after the termination of trade (either through

> exercise or expiration), and must be made available within five business days of request, adding more cost.

Id. at 65.

With respect to the tools for managing surpluses and portfolio rebalancing, the IPA states that it is required by law to include in the Plan the criteria for portfolio re-balancing in the event of significant shifts in load, citing 220 ILCS 5/16-111.5(b)(4). It points out that the utilities, not the IPA, are the owners of the forward hedges and that selling of excess supply in the forward markets may have unintended cost and accounting consequences. To that end, it states as follows:

- To date, the only rebalancing of hedge portfolios before the delivery date has been the curtailment of long-term renewable contracts due to budget restrictions. Spending on these contracts was subject to a limit related to a mandated rate cap.
- Sales of excess supply by the utilities via a reverse RFP to rebalance their supply portfolio may create a de facto "wholesale marketing function" within the utilities. The employees involved in wholesale marketing activities would be subject to the separation of functions in accordance with FERC Order 717.
- To date, the utilities have scheduled excess supply in their portfolios, or made up supply deficits in the RTOs' day-ahead markets, with residual balancing occurring in the RTOs' real-time markets. This has been the dominant mode of portfolio rebalancing.
- The IPA could conceivably issue an RFP to purchase derivative products, such as put options on forward hedges, which would have a similar risk reduction effect to selling forward contracts. This may avoid legal and contractual difficulties associated with selling forward hedge contracts. This approach would also require the utilities to ensure that they had regulatory approval to exercise the options after purchasing them, and the employees who exercise the options could become classified as part of a "marketing function." The IPA does not envision entering into derivative contracts for rebalancing purposes.

Id. at 66.

The IPA also states that it could conduct more than one procurement event in a year, if the rebalancing required is to increase the supply under contract. It points out that it conducted two procurements for 2014, and in 2015, after conducting a Spring procurement, it is planning a second procurement in September 2015. The IPA avers that the volumes for that procurement have been adjusted in this manner. *Id.*

According to the IPA, the Purchased Electricity Adjustment ("PEA") functions as a financial balancing mechanism to assure that electricity supply charges match supply costs over time. The balance is reviewed monthly and the charge rate is adjusted accordingly. It states that the PEA can be a debit or credit to address the difference between the revenue collected from customers and the cost of electricity supplied to these same customers in a given period. It further states that the supply costs are tracked, and the PEA is adjusted, for each customer group. The PEA is applicable to the purchased electricity costs of Ameren and ComEd; MidAmerican's charge for purchased electricity is set by the ICC under a separate cost recovery process. *Id.* The IPA opines that the PEA provides some guidance as to the amount by which the complete set of risk factors caused the cost of energy supply to differ from the estimate, in other words, the impact of risk. It states that while Ameren's PEAs have been generally negative, ComEd's have been more positive and more volatile. It continues to state that ComEd has voluntarily limited its PEA to move between +0.5 cents/kWh and -0.5 cents/kWh. *Id.* at 67.

The IPA further states that in April 2014 the Commission approved an adjustment to ComEd's PEA that allows the accumulated balance of deferrals from the computation of the PEA each June to be rolled into the base default service rate for the next year and the associated balance to be reset to zero. It avers that ComEd's PEA increased from a credit to a charge for two months in the Spring of 2015 due to how the Commission instructed ComEd to recover customer care costs from eligible retail customers in ComEd's last rate case. *Id.*

It posits that in July of 2014 the magnitude of the Ameren negative PEAs increased significantly. The IPA understands that this change was largely the result of the Ameren supply portfolio's long position resulting from the increase in municipal aggregation switching, with that long position settling favorably to customers within the MISO balancing markets. According to the IPA, this drove an over-collection from eligible retail customers during the previous Winter and subsequent return of those proceeds to the remaining eligible retail customers. The negative values of the Ameren PEAs have subsequently been much smaller as portfolio volumes have become better matched with actual load. *Id.*

The IPA avers that, historically, the utilities, pursuant to plans developed by the IPA, have used fixed-price, fixed-quantity forward energy contracts and financial hedges such as the LTPPAs, along with RTO load balancing services, to serve load. Energy deliveries have been coordinated by the RTOs and the IPA has arranged a portfolio of long-term contracts and standard forward hedges. These forward hedges were procured in multiples of 50 MW during the earlier procurements and in 25 MW blocks since 2014. Ancillary services have been purchased from the RTO spot markets. Also, the utilities have used Auction Revenue Rights to mitigate transmission congestion cost. *Id.* at 68.

It further states that forward hedges were procured on a "laddered" basis. The IPA originally sought to hedge 35% of energy requirements on a three-year-ahead basis, another 35% on a two-year-ahead basis, and the remainder on a year-ahead basis. Before 2014, procurements were on an annual basis and conducted in April or May, rather than on a more frequent or ratable basis. In the 2013 Procurement Plan however, the IPA stated that it was considering a change in hedging from 100%/70%/35% of the expected load to 75%/50%/25%. Because there were no procurements in 2013, that hedging strategy was not formally adopted or implemented.

In the 2014 Procurement Plan, the IPA proposed a modification to the 75%/50%/25% strategy. It averred that the procurement goal for a mid-April procurement event should be to hedge 106% of the expected load forecast for June-October. These months would be close to the procurement date and no benefit was seen in deferring 25% of the procurement to the spot market. On the other hand, the IPA continues, because of the correlation between load and price, and because prices in the hours of high usage are more than 100% of the time-weighted average price, a $1/MWh movement in the monthly average price translates into an increase of $1.06/MWh in the average portfolio cost (the load-weighted average price). Thus, the IPA continued to recommend hedging up to only 75% of the expected load for November-May of the prompt delivery year in the April procurement, and recommended a second procurement in September to bring the hedged volume to 100%. *Id.*

In the 2015 Procurement Plan, the IPA adopted some minor changes from the 2014 Plan. The hedge ratios for the April procurement event were adjusted to 100% of the expected forecast for off-peak hours for June through October delivery in the current year and for on-peak hours for June, September, and October delivery in the current year. The hedge ratio was left at 106% only for the on-peak hours of July and August. The target hedge ratios for delivery in subsequent years were adjusted to 50% for all months of the following year for the September procurement event, 37.5% for all months of the following year for the April event, 25% for all months of the second year out for the September event, and 12.5% for all months of the second year out for the April event. *Id.*

The IPA states that for the 2016 Procurement Plan, other than moving October from the April procurement to the Fall procurement, no substantial changes to the strategy are proposed, but consideration is given to adjusting the cumulative hedge ratios for various delivery months, effective at the next to last scheduled event prior to delivery. It avers that the procurement schedule balances procurement overhead costs, price risk, and load uncertainty. If the amounts to be hedged in any year are small, it continues, it could decide to avoid the procurement overhead and not schedule a procurement event (as in 2013). The IPA has not used options, unit specific contracts (except for the LTPPAs and the FutureGen agreement), or other forms of hedging in the past. In addition, it has not used forward sales or put options to rebalance its portfolio. *Id.* at 68-69.

According to the IPA, an objective of the procurement schedule is to maximize stability of the resulting rate for service to eligible retail customers while minimizing cost. If purchases were distributed close to evenly over 5 or 6 events in a 2 to 3 year period, the resulting average price of the portfolio of contracts for any delivery month would reflect an average of any long-term price trend over the procurement period. The inclusion of several, evenly weighted procurement dates would also smooth out day-to-day volatility in forward prices. It opines that concentrating a high percentage of purchases for some delivery months in one or two procurement events close to the beginning of the delivery period, however, increases the potential impact of day-to-day market volatility on the portfolio average price. *Id.* at 69.

The IPA expected that the volatility of portfolio price would be reduced by increasing the number of procurement events and allocating purchase targets evenly among them. However, it continues, due to the pattern of historical monthly volatilities in the forward market over the time span analyzed, the schedule of procurements prescribed in the 2015 Procurement Plan, which purchases small quantities up to 3 years prior to delivery, produces the lowest volatility of portfolio price as measured by standard deviation. It states that a review of monthly forward market volatilities does not support a strong preference for any particular months of the year as ideal or to be avoided for procurement events. This is to be expected because volatility is driven by market information, which may not have a seasonal profile. The IPA sees no reason, based on this analysis, to significantly change the energy procurement schedule from the 2015 Procurement Plan. *Id.*

The IPA used historical PJM Northern Illinois hub on peak energy forward prices for trading dates from February 1, 2011 through April 30, 2015 and delivery months from June 2014 through May 2015 to analyze the distributions of daily trade prices for individual delivery months over the trading days of each trade month. It states that reported prices begin in March 2012 for 2015 delivery months, but full monthly differentiation is not available until January 2014. Forward prices for July 2014 and August 2014 delivery rose in late 2012 and again in the first six months of 2014, with corresponding spikes in standard deviation at the beginning of those rises. Forward prices for January 2015 and February 2015 delivery rose dramatically in January 2014 and subsequent months with corresponding spikes in standard deviation. *Id.*

The IPA points out that the cost to eligible retail customers for qualified service in a given month is driven by the average price paid for blocks of on-peak and off-peak energy secured under a procurement plan. The stability of that cost is a function of the long-term trends, both predictable and random, in forward prices over the procurement period and the more random draw of the forward price on the days in which components of the portfolio are procured. The IPA performed a "backcast" analysis to study the effects of different procurement schedules for the on-peak energy component of the monthly portfolios for October 2014 through September 2015 delivery using the PJM Northern Illinois Hub forward price data. *Id.* at 73.

B. Procurement Plan Resource Choices

The primary resources included in the 2015 Procurement Plan for the forecast horizon include: (1) incremental EE; (2) energy procurement strategy; (3) balancing recommendations; and (4) demand response.

1. EE as a Supply Resource

The IPA cites Section 16-111.5B of the Act, which requires the IPA to include in its Procurement Plan:

> [A]n assessment of opportunities to expand the programs promoting energy efficiency measures that have been offered under plans approved pursuant to Section 8-103 of this Act or to implement additional cost-effective energy efficiency programs or measures.

See, 220 ILCS 5/16-111.5B. According to the IPA, it based its assessment on "an assessment of cost-effective energy efficiency programs or measures that could be included in the procurement plan" submitted to it by the utilities as part of their July 15th load forecasts. This annual assessment, the IPA avers, must include the "[i]dentification of cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act," an "[a]nalysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service," and an "[a]nalysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply." In support, the IPA cites 220 ILCS 5/16-111.5B(a)(3)(C)(D) and (E). Plan at 80.

The IPA contends that in 2011, Section 16-111.5B was enacted as part of Public Act 97-0616, the Energy Infrastructure and Modernization Act. It further states that this statute was meant to complement, enhance, and expand the utilities' existing EE program portfolios which are required by Section 8-103 of the PUA through the inclusion in the IPA's annual procurement plans of "new or expanded . . . incremental" programs that would otherwise not be included in the Section 8-103 portfolios due to Section 8-103's 2.015% rate impact cap, citing 220 ILCS 5/8-103(d). *Id.*

The IPA avers that, to identify these programs, the utilities are required to "conduct an annual solicitation process for purposes of requesting proposals from third-party vendors" to be developed "consistent with the manner in which it develops requests for proposals under plans approved pursuant to Section 8-103 of this Act, which considers input from the Agency (the IPA) and interested stakeholders," citing 220 ILCS 5/16-111.5B(a)(3). The results of that RFP process are provided to the IPA as part of each utility's assessment. Pursuant to this structure, the IPA then "shall include" in its annual plan "energy efficiency programs and measures it determines are cost-effective" and the Commission "shall approve" those programs and measures, if the Commission determines that they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of the Act. In support, the IPA cites 220 ILCS 5/16-111.5B(a)(4) and (5). *Id.*

The IPA's 2016 Procurement Plan is the fourth plan to include EE programs under Section 16-111.5B. Below is a summary of the total MWh of approved programs from each previous Procurement Plan.

Delivery Year	Ameren	ComEd
2013 – 2014 (Approved in 2013 Plan)	**70,834**	**118,515**
2014 – 2015 (Approved in 2014 Plan)	**65,680**	**430,609**
2015 – 2016	**169,442**	**830,008**
Approved in 2014 Plan	-	547,904
Approved in 2015 Plan	169,442	282,104
Moved from 8-103	*88,203*	*247,648*
Third-Party RFP	*81,239*	*34,456*
2016 – 2017	**239,813**	**984,052**
Approved in 2014 Plan	**-**	611,958
Approved in 2015 Plan	169,690	284,641
Moved from 8-103	*93,569*	*241,541*
Third-Party RFP	*76,121*	*43,100*
Proposed in 2016 Plan	**70,123**	**87,453**

The IPA points out that previous years' Plans have also featured contract offerings for more than a single delivery year. For instance, it continues, for programs included in the 2014 Plan, ComEd allowed for contracts for the upcoming three delivery years (2014-15, 2015-16, 2016-17), resulting in the "projected savings" values for future years shown in the table. *Id.* at 81.

The IPA's 2015 Procurement Plan included the approval of eight expanded or new programs for Ameren and ten for ComEd. The IPA maintains that one significant aspect of the 2015 Plan's program portfolio was the inclusion of residential lighting and behavioral programs. In separate proceedings, the Commission ordered these programs to be moved from the Section 8-103 EE portfolio of programs to the Section 16-111.5B process, thus allowing for a different portfolio of programs under Section 8-103 and causing an expansion of the budget and savings associated with the Section 16-111.5B programs, citing Commission Dockets 13-0498 and 13-0495. Also, for the 2014 Plan, ComEd significantly increased the size of its Section 8-103 Small Business Direct Install program via the Section 16-111.5B process, thus growing its overall Section 16-111.5B portfolio. *Id.* at 82.

The IPA states that its 2014 and 2015 Procurement Plans also discussed additional policy issues arising under Section 16-111.5B. For instance, the 2014 Plan included discussion of feedback mechanisms, transition year program expansion, DCEO participation, and consideration of all third-party bids. In approving that Plan, the Commission's most significant decisions were determining that DCEO is not a "utility" for the purposes of the Section 16-111.5B filings, and approving a methodology for determining whether third-party EE programs duplicate existing programs. *Id.*

In its 2015 Plan, the IPA proposed procuring a new super-peak EE block product as a supply resource. While the Commission declined to approve this proposal as a stand-alone procurement strategy, it did approve the IPA's alternative approach of allowing for modification of the solicitation of third-party programs under Section 16-111.5B to take into account the value of avoiding peak energy consumption. The IPA posits that the 2015 Plan also requested the approval of consensus language taken from 2014 workshops and raised issues regarding stakeholder participation in "duplicative" bid determinations for Commission consideration. *Id.*

The IPA states that in its Final Order approving the 2015 Procurement Plan, the Commission concluded that workshops should be conducted for the purpose of informed development of the RFPs. The Commission determined that those workshops should consider whether an additional RFP for EE programs will be necessary, the duration of any such programs, whether the Illinois Technical Resource Manual (the "IL-TRM") should govern these types of programs, and how such programs should be evaluated. In support, the IPA cites the final Order in Docket No. 14-0588 (Order of December 17, 2014) at 224.

The IPA maintains that while consensus was not reached among stakeholders on all issues, the workshops did result in changes made to Ameren's and ComEd's RFPs. According to the IPA, it also allowed for the review of bid submissions using hourly energy values. Those changes also reflected consideration of interested stakeholders' comments. *Id.* at 83.

One contested issue on which consensus was not reached, the IPA continues, was the appropriate contract length for Section 16-111.5B programs evaluated using hourly load profiles. During workshops, some parties argued that the nature of programs available and vendors willing to participate would be limited by shorter contracts, especially the one-year contracts being offered through the utilities' RFPs seeking programs for the 2016 Plan. While only one-year contracts were offered by the utilities for programs solicited in early 2016, and while longer-term contracts may promote broader participation and offer for new and innovative program types, the IPA tentatively understands that ComEd and Ameren will be offering contracts up to 3 years in length for Section 16-111.5B programs solicited for the 2017 Plan, including peak-hour oriented EE programs. *Id.*

The IPA avers that Section 16-111.5B of the Act requires it to include incremental "energy efficiency programs and measures it determines are cost-effective," citing 220 ILCS 5/16-111.5B(a)(4). It points out that under Section 16-111.5B, "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act," meaning "that the measures satisfy the total resource cost test." Section 1-10 of the IPA Act defines the "total resource cost test" as follows:

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

See, 20 ILCS 53855/1-10.

The IPA contends that since its introduction into the law in 2007, this definition has left many stakeholders grappling with questions around what costs and benefits should be included in cost-effectiveness determinations and how to appropriately quantify them. In general, the IPA explains, advocates for increased EE seek a more robust accounting of benefits and less for costs, increasing the number/scale of programs which have a TRC above 1.0, while those in favor of less spending on EE seek the inclusion of more or higher costs, and less for benefits, having the opposite effect.

The Stakeholder Advisory Group (“SAG”) established a TRC Test Subcommittee and led a series of workshops over from January-September. According to the IPA, while participants were not able to reach agreement on all issues, some consensus items did emerge from the workshops. Plan at 83-85.

With regard to marginal line losses, the IPA states that the line losses avoided by EE measures are among the “avoided electric utility costs” included in a TRC calculation. It continues to explain that line losses occur as electricity is delivered from power plants to end users, and EE measures reduce these losses as less electricity is delivered than otherwise would be in the absence of such measures. The IPA states that line losses may be calculated in two ways: average line losses, which are a measured and published figure; or marginal line losses, which are generally determined by using actual system information and more detailed calculations. It avers that in Docket No. 14-0588, the Natural Resources Defense Council argued that because line losses grow exponentially with load and are most pronounced during peak hours, marginal line loss calculations are better able to account for line losses as a square of the load. *Id.* at 85.

The IPA posits that while ComEd has historically used marginal line losses in its TRC tests, Ameren has historically incorporated average line losses in its TRC calculations. Through the TRC subcommittee workshop process, Ameren agreed that for 2016 Plan program submissions, it would show an annual marginal distribution loss that is 1.65 times the average distribution loss and apply this ratio to its average distribution losses to arrive at estimated marginal line losses. The IPA concludes that Ameren's TRC calculations for the 2016 Plan thus reflect marginal line losses. *Id.*

Regarding Demand Reduction Induced Price Effects("DRIPE"), the IPA explains that market energy prices are driven in large part by load levels, and reducing electric loads should lead to a reduction in market prices. It opines that EE programs and measures reduce consumption and, as a consequence, reduce electric loads. In turn, these load reductions should lead to price reductions in generation rates paid by electricity consumers which are independent of direct savings from installation of the EE measures themselves. *Id.* at 86.

The IPA recalls that the TRC Test Subcommittee began addressing DRIPE in January 2015 and discussions remained ongoing when IPA submitted its Plan. Several presentations were made to the TRC Subcommittee including those by Commission Staff, NorthBridge, and Resource Insight, all of which are available on the SAG website. The TRC subcommittee was provided with three reports on DRIPE. The subcommittee also heard commentary from, and asked questions of, technical experts offered by each side of the DRIPE debate. The TRC subcommittee also reviewed information on other states' practices. Despite all parties' best efforts, no consensus on the impact of DRIPE was reached. However, the IPA states that neither ComEd nor Ameren included DRIPE benefits in its assessment of EE programs and measures offered for the 2016 Plan. *Id.*

The IPA states that some parties argue that some less obvious benefits of EE programs may be accounted for in the TRC, even if they are not directly related to the supply of energy and are envisioned by law to be incorporated through language directing the inclusion of "other quantifiable societal benefits." Non-energy benefits ("NEBs"), it maintains, may incorporate several different categories of benefits from EE programs:

- Environmental adders, not including carbon dioxide savings
- Water – Resource benefit
- Societal Impacts – health, safety, comfort, building durability, etc.
- O&M cost avoidance
- Economic – Job creation
- Participant Perspective – water and sewer savings, fewer shutoffs, fewer calls to the utility, fewer reconnects, property value benefits, fewer fires, reduced moving costs, fewer illnesses and lost days from work or school, net benefits for comfort and noise, and net benefits for additional hardship.

Id. at 86-87.

According to the IPA, the TRC Test Subcommittee was considering which non-energy benefits should be included in the Illinois TRC calculation, how they should be quantified, and whether they should—or could—be quantified by program/measure type. A review of other state practices showed that some state electric efficiency programs use varying costs for non-energy benefits ranging from 10 to 30 percent. It states that no consensus was reached on the appropriate treatment of non-energy benefits for the 2016 Plan, but at the July 21, 2015 TRC Test Subcommittee meeting, a SAG Subcommittee reached agreement that the annual TRM update process would be an appropriate venue to consider measure-specific proposals to address this matter. *Id.* at 87.

Regarding the inclusion of administrative costs in the TRC, while the utilities are beginning to take steps to track administrative costs by program, program-specific administrative cost information for the 2016 Plan has not yet been developed. As a result, the IPA continued, some estimation of administrative costs must once again be applied. In addressing this issue, one proposed solution raised by the TRC Test Subcommittee identified the following categories of administrative costs:

> **Category 1: EM&V** – will add to each IPA program (3%). Utility will take 3% from each program selected, lump together.
>
> **Category 2: Program Management** – (3-4%) Utility will take program-specific and will be allocated to programs in screening. Other management administrative costs, invoicing, etc. will be allocated based on program budget.
>
> **Category 3: Increase in other Admin: Marketing, General Admin, other non-assignable** – Approximately 4% will be allocated to IPA programs based on program budgets. Non-assignable (RFP, regulatory approval, legal, potential studies, etc.) will be allocated across the portfolio. Utilities will track these costs. There was no-consensus on whether to include these costs when screening IPA programs.

The TRC Test Subcommittee discussed the idea that the utilities could screen both with 7% and 11% blanket administrative cost rates and report those numbers to the IPA for program review. The programs actually submitted to the IPA for review featured utility administrative cost screenings using different, and slightly higher, values. *Id.* at 87-88.

The IPA additionally states that consensus was reached in the EE Workshops recommending for Commission approval the following:

> **2.** Coordination of EE Programs
>
> - The utilities should include cost-effective expansions of the Section 8-103 EE programs in the annual EE assessment they submit to the IPA, unless Section 8-103 EE programs are already expected to achieve the maximum achievable cost-effective savings.
> - An “expansion” of a Section 8-103 EE program per Section 16-111.5B is not strictly defined and could include expanding the EE program in such a way as to facilitate tracking of the Section 16-111.5B portion of the expanded EE program.
> - Expansion of DCEO’s Section 8-103 EE programs would need to be shown to be cost-effective per Section 16-111.5B requirements.
> - Sections 8-103 and 16-111.5B EE portfolios can be kept separately.
> - Sections 8-103 and 16-111.5B EE budgets shall be kept separately.
> - EE program expansions would be expanded in such a way as to facilitate utility tracking of the original Section 8-103 portion and the Section 16-111.5B portion of the expanded EE program.

- Savings from the Section 8-103 portion of an expanded EE program would count toward achievement of a utility's Section 8-103 savings goal.
- Savings from the Section 16-111.5B portion of an expanded EE program would count toward achievement of a utility's Section 16-111.5B savings goal, not the Section 8-103 savings goal.
- For general reporting purposes, it would be appropriate to report each Section's EE goals, achieved savings, budgets, and impact on EE rider surcharge to show the impact of the utilities' EE portfolios across the state, both individually and collectively, so that progress can be tracked separately for each EE portfolio.

3. Procurement of EE Programs

- Multi-year EE procurement is allowed in the context of the annual EE procurement plan proceeding.
- Utilities should include all bids in their EE assessments submitted to the IPA.
- Utilities should include bid reviews in their EE assessments submitted to the IPA.
- Utilities should have flexibility to structure Section 16-111.5B EE contracts in a manner which best balances the potentially competing objectives of making the procurement process attractive to as many bidders as possible and providing confidence that the savings which are proposed/bid will actually be delivered.
- To the extent that parties are concerned with EE replacing power purchase needs under Section 16-111.5B, it would be appropriate for the IPA and procurement administrator, in consultation with the utilities and/or evaluators, to estimate the amount that the Section 16-111.5B EE programs reduce the IPA's need to procure supply, to serve as a check on the utilities' original estimate required by Section 16-111.5B(a)(3)(G), and to provide useful information to customers.
- In general, the IL-TRM should be used for Section 16-111.5B EE programs.
- There may be special circumstances where deviation from the IL-TRM may be appropriate; the utility/vendor should have the option to make the case for the special circumstance. However, the IL-TRM values must also be provided for comparison purposes.
- Evaluation of the Section 16-111.5B EE programs should be performed by the Section 8-103 EE program evaluators.
- Evaluation of Sections 8-103 and 16-111.5B EE programs should be coordinated.
- Evaluation sampling, *e.g.,* net-to-gross ("NTG") could occur on an expanded EE program-level basis, or could be based on each component

of the expanded EE program (the Section 8-103 portion and the Section 16-111.5B portion of the expanded EE program), depending on the specific circumstance.

- There must be a balance in the evaluation of Section 16-111.5B EE programs between the degree of evaluation and the size of the program, wherein larger programs justify more complete evaluations.
- Expenditures on evaluation should be capped for the Section 16-111.5B EE programs as they are for the Section 8-103 EE programs.
- Section 16-111.5B EE evaluation reports should be provided to the Commission in a public docket, either reconciliation proceeding or savings case.
- Ex-post cost-effectiveness analysis should be performed for the Section 16-111.5B EE programs.
- Ex-post cost-effectiveness analysis should be performed using actual participation and the best available information (e.g., updated NTG).
- Under the pay for performance contract, the Commission could authorize on a program basis, a maximum energy savings achieved and spending cap.
- Prudence accountability exists in a docketed proceeding but no docketed proceeding for savings goals is required per Section 16-111.5B.

4. EE Program Management

- Funds approved pursuant to Section 16-111.5B could not be spent on EE programs that were not approved in a Commission procurement plan case.
- The Commission may authorize, on a program basis, an expected spending level and the spending level cap.

5. Cost-Effectiveness of EE Programs and Measures

- The TRC test should be calculated at the program or measure level.
- Cost-ineffective programs should be dropped during the procurement plan proceeding.
- Section 16-111.5B (a)(3)(D) can be interpreted as the Utility Cost Test.
- Section 16-111.5B (a)(3)(D) should be calculated for each program.
- Section 16-111.5B (a)(3)(E) can be interpreted as the TRC Test.
- The Commission should determine how the additional information provided pursuant to Section 16-111.5B (a)(3)(D)-(E) should be used (i.e., litigate).

Consensus items from the 2014 Section 16-111.5B workshops recommended for Commission approval are described below.

6. Deeming and Evaluation for Future Section 16-111.5B EE Programs

Deeming should be permitted for the Section 16-111.5B EE programs just as it is for the Section 8-103 EE programs. Annual updates to the deemed IL-TRM for EE and NTG ratio values should occur for these Section 16-111.5B programs. As a result, reasonable changes to the vendors' savings goals and/or cost structure are permitted during contract negotiations based in part on these updates to the IL-TRM and NTG. Multi-year contracts should be constructed to re-negotiate savings calculations based on annual IL-TRM and NTG updates and should leave open the possibility for utilities to update savings calculations and contract terms based in part on IL-TRM updates or errata and NTG updates.

The IL-TRM Policies adopted in Docket No. 13-0077 should apply for the Section 16-111.5B EE programs (*e.g.,* applicability and effective dates for updated versions of the IL-TRM should be consistent for both Section 16-111.5B and Section 8-103 EE programs). Prospective application of standard measure-level savings values from the updated IL-TRM and NTG values recommended by the evaluator that are available before the start of a program year should be deemed for one program year. Ex-post evaluation results for gross savings calculations should be applied retrospectively for custom measures, behavioral measures, and for EE measures with uncertain savings, which is consistent with the approach used for EE measures under the Section 8-103 EE programs.

See, Plan at 83-92.

7. Responsible Entity

The utilities have primary responsibility for prudently administering the contracts with the vendors approved by the Commission for the Section 16-111.5B EE programs.

8. Policy or Clarity on Status of Bid Accepted into IPA Procurement Plan and Approved by the Commission and Flexibility

Once the Commission approves the procurement of EE pursuant to Section 16-111.5B(a)(5) of the PUA, the utilities and approved vendors should move forward in negotiating the exact terms of the contract based on the terms of the RFP and the bid itself (and that are "not significantly different" from the initial bid), with the clarification that negotiation around other details of the contract/scope of work/implementation plan still might need to occur depending on a variety of factors (*e.g.*, lessons learned since bid submittal, updates to the IL-TRM and NTG, changes in the market, desire to add new measures).

The utilities should use reasonable and prudent judgment in negotiating the exact terms of the contract after Commission approval and should rely upon the best available information and ensure that any modifications continue to result in a cost-effective EE program. Negotiations may result in reasonable adjustments to savings goals for the EE program in comparison to the amount proposed in the bid and reasonable and prudent modifications to the cost structure which are in line with the original design. Some degree of flexibility within an EE program should be allowed for vendors implementing EE programs under Section 16-111.5B. Flexibility should not be allowed regarding the following: (1) measures that provide less confidence in the quality of service; (2) the addition of new EE measures with no confidence in the savings; (3) measures that duplicate or compete with other EE programs; (4) cost-ineffective EE program; or (5) whether a completely different EE program is proposed, in comparison to what was bid and approved. The utilities/IPA should share the description of the vendor's EE program included in the draft procurement plan with the vendor to help ensure the EE program is accurately characterized.

An understood process for vendors to submit program changes should be clearly conveyed to all vendors by the utilities. If a vendor decides to add (or remove) EE measures midstream, they should seek approval from the utility for such changes prior to implementing the change in order to allow for possible contract renegotiations. Vendors are allowed to receive credit for energy savings from implementing new EE measures if they have received pre-approval from the utility for adding that new EE measure. To help protect against gaming, any EE measure that has not received pre-approval from the utility or is not included in the vendor's approved proposal should not be considered for energy savings. The utility should notify the IPA, ICC, and the SAG when it has stopped negotiations with an approved Section 16-111.5B EE program vendor and a contract agreement cannot be reached, and if it has terminated a contract with an approved Section 16-111.5B EE program vendor. The utility should notify the Commission in a filing in the procurement plan case in which the EE program was approved (similar to the approach ComEd used for PY7 and the approach proposed by Ameren in Docket No. 13-0546, Order at 112; Ameren RBOE at 14). The utilities should notify the SAG and keep the IPA apprised of any expected shortfalls in savings. The utility should notify the Commission of changes made, in comparison to the approved programs.

9. Continuity for Multi-Year EE Programs

The utilities should have the capability for any of the Section 16-111.5B EE programs to be able to expand into the Section 8-103 portfolio for a given program year, at the utility's discretion, if: (1) the Section 16-111.5B savings goal for the EE program9 from the Commission Order in the procurement plan case or compliance filing/contract) is achieved and the approved budget (from Commission Order in the procurement plan docket) is exhausted; and (2) the utility has budget available in the Section 8-103 EE portfolio. The utilities should make the vendor aware of this option in advance so as to avoid program disruption.

The Commission could pre-authorize up to a 20% budget shift across program years for multi-year programs, assuming remains within total approved multi-year program budget, to allow for successful EE programs to continue operation in the early (or later) program years of the multi-year contract. In such a situation, it is assumed that the kWh savings goals and budgets would be cumulative for the number of years of the contract. The utilities should make the vendor aware of this option in advance so as to help avoid EE program disruption.

10. Evaluation Budget and Process Evaluations

Consistent with the Section 8-103 evaluation process, evaluators may conduct process evaluations where justified, to encourage improvement in the implementation of the Section 16-111.5B EE programs.

Expenditures on evaluation should be capped for the Section 16-111.5B EE programs in the same manner as they are for the Section 8-103 EE programs. Each program's evaluation budget should not be restricted to 3% of the EE program budget, but evaluation costs should be limited to 3% of the combined Section 16-111.5B EE programs' budget.

To the extent that certain third-party EE programs have innovative delivery mechanisms and the potential to achieve significant savings, either generally or from key targets, a process evaluation may be justified, where the value of this effort must be weighed against the cost of conducting such an evaluation for an EE program that is: a) not unique or innovative; b) achieves very small savings; or c) is not likely to gain traction as an ongoing EE program either in future Section 16-111.5B EE processes or as part of the Section 8-103 EE portfolio. *See,* Plan at 89-93.

The IPA requests that the Commission explicitly approve the consensus items from prior years' workshops set forth above, and requests that the Commission approve such items prospectively, expressly allowing for their application to the 2016 RFP solicitation and bid evaluation process to increase certainty for all affected parties.

11. Policy Issues Regarding EE

The IPA sought feedback from stakeholders on two items that could result in the Commission giving the IPA and utilities useful direction for the development of the 2017 Plan. The first issue was the process by which the utilities screen bids the RFP process. In its submittal, Ameren applied the screening for duplicative programs prior to the running of the TRC analysis, while ComEd did the opposite. While the IPA appreciates the time and effort required to conduct a TRC analysis, it believes that it is preferable to conduct the TRC screening on every bid that complies with the basic requirements of the RFP, and then conduct any other screening (*e.g.,* for duplicative programs) thereafter. It states that this assessment is sufficiently subjective that it should be treated differently from other RFP requirements. It avers that having a complete record of TRC analyses submitted by the utilities will aid the IPA in its review of programs for consideration for inclusion in the Plan.

Having reviewed comments from stakeholders, the IPA believes that TRC analyses should be conducted for all programs meeting the requirements of the RFP, even those for which a duplicative determination is made. As not all parties may agree with the utility's duplicative determination, and as the process approved by the Commission in Docket No. 13-0546 for making duplicative determinations calls on the IPA to make its own independent assessment of whether a program is duplicative (which may be different than the utility's determination), the IPA believes that TRC screenings for such programs need to be conducted. It requests that the Commission direct the utilities to apply TRC screenings for all bids compliant with the basic requirements of the RFP. *Id.* at 93.

The second issue concerned how Section 16-111.5B programs may be used to "expand" a portfolio of Section 8-103 programs that have not yet been approved by the Commission. The IPA states that for the 2017 Procurement Plan to be developed during the Summer of 2016, incorporating information from utility assessments submitted to the IPA on July 15, 2016, this issue will be front and center: the utilities will be filing their next set of three-year plans in the Fall of 2016 and therefore there will not be a set of existing Section 8-103 programs against which the incremental programs would be considered. It concludes that consequently, the 2016 Plan and its comment period is the ideal opportunity for this discussion. *Id.* at 94.

The IPA believes that an approach that will guarantee the inclusion of third-party bids for multi-year programs (three-years, or perhaps even longer) would be desirable. If strong third-party bids are received next year, they could have an opportunity to be included with fewer constraints on the screening out of duplicative programs. Ultimately, the IPA surmises that, by allowing the competitive market to suggest a broad universe of cost-effective programs through the Section 16-111.5B RFP process, the opportunities to grow the EE sector in Illinois will be expanded, leading to additional job creation and benefits for customers. *Id.*

a. Ameren EE Plan

The IPA believes that Ameren's submission meets the requirements of Section 16-111.5B(a)(1)-(3) and that the programs identified as "cost-effective" should be approved pursuant to Section 16-111.5B(a)(5). It states that, in conjunction with the bid analysis conducted by Ameren and stakeholders, Ameren and its consultant AEG also performed analysis on the bids. All documents submitted by the bidders were reviewed including the program proposal, measure information spreadsheet, and any supporting documentation. The IPA reviewed the TRC analysis provided by Ameren and, subject to a few exceptions, generally concurred with the inputs, assumptions, and methodology.

The IPA states that administrative costs were a contested issue in the litigation of the 2015 Plan, citing Docket No. 14-0588, (Order of December 17, 2014) at 224. In that case, the Commission directed the utilities to track administrative costs by program in order to aid in future determinations of the correct administrative cost assumptions. The IPA is of the opinion that the correct administrative cost adder constitutes 11.5%, and the TRC was adjusted by the IPA to reflect an 11.5% administrative adder. Plan at 94-95.

The IPA further states that Ameren adjusted the energy savings values for certain efficiency measures provided by bidders to more accurately reflect values in the IL-TRM. Ameren also adjusted certain net-to-gross ratios provided by bidders to reflect the net-to-gross ratios recommended by Ameren's independent evaluator, consistent with the process set forth in the consensus language from the Section 16-111.5B Oversight and Evaluation Responsibility Workshop that was adopted by the Commission in Docket No. 14-0588. The IPA concludes that those adjustments appear to be reasonable. *Id.* at 96.

To the IPA, under Section 16-111.5B, the term 'cost-effective' has the meaning set forth in subsection (a) of Section 8-103 of this Act, meaning that the measures satisfy the TRC Test. It is of the opinion that the TRC Test is a distinct test from the cost of supply. In its 2016 Plan submittal, Ameren suggested that two programs which pass the TRC should still be excluded because the estimated costs of such programs are not less than the prevailing cost of supply. *Id.* at 97.

The IPA disagrees with this approach. It states that Illinois law requires the inclusion of programs that the IPA determines to be "cost-effective" through application of the TRC test. Ameren based its suggestion on Section 16-111.5B(a)(3)(E), which requires the utilities to include an "analysis of how the cost of procuring additional cost-effective EE measures compares over the life of the measures to the prevailing cost of comparable supply" as part of their Section 16-111.5B submittal. According to the IPA, this requirement does not create independent grounds for the exclusion of otherwise cost-effective programs in an IPA Plan. The IPA declined to adopt Ameren's recommendation regarding the exclusion of cost-effective EE programs which exceed the "cost of supply," but pass the TRC Test required for evaluation by the law. *Id.*

The IPA concurs with the determinations made by Ameren and the SAG that the following programs meet the duplicative standard set out in previous Procurement Plans and Commission Orders. Therefore the IPA does not recommend the approval of the programs in the table below.

Sector	Program	Reason Duplicative
Residential	Direct Install – LED and Smart Strips	Duplicative with Ameren Section 8-103 Home Performance and HVAC Programs, and DCEO Section 8-103 Low Income Program
Residential	School Kits	Duplicative with Ameren Section 8-103 School Kits Program
Business	Direct Install - LED Only	Duplicative with Ameren Section 16-111.5B Small Business Direct Install Program
Business	Direct Install - Private Schools	Duplicative with Ameren Section 8-103 Standard Program and Ameren Section 16-111.5B Small Business Direct Install Program
Business	Direct Install - Geo-Targeted	Duplicative with Ameren Section 16-111.5B Small Business Direct Install Program and DCEO Section 8-103 Direct Install Program
Business	Direct Install - Whole Building	Duplicative with Ameren Section 16-111.5B Small Business Direct Install Program, Ameren Section 8-103 Standard Program, and DCEO Section 8-103 STEP Program
Business	Rural Efficiency Kits	Duplicative to Ameren 8-103 Standard Program

See, Plan at 98-99. Additionally, two programs were considered duplicative of current DCEO programs and were not included. Both programs target public buildings. The Direct Install – Public Facilities program was also considered to be potentially duplicative of the existing Small Business Direct Install program. *Id.* at 99.

Ameren's submittal includes identification of nine EE offerings for this Plan with a TRC of above 1.0, which were not determined to be "duplicative" of existing programs, and which met Ameren's requirements. The IPA opines that all nine of these programs passed the TRC test at the time of assessment, even without adjustments made to Ameren's suggested TRC.

Program	Net Savings (MWh)	Total Utility Cost	TRC (As submitted)	TRC (IPA Adjusted)
Agricultural EE	945	$380,615	1.09	1.11
Community-Based CFL Distribution	9,330	$1,178,428	2.27	2.31
Demand Based Ventilation Fan Control	5,717	$1,227,357	3.38	3.44
Electric Only Behavior Modification	8,640	$373,920	1.06	1.06
HVAC Check-Up	5,940	$1,160,182	1.35	1.38
LED Linear Lighting for Small Facilities	14,750	$3,168,882	1.16	1.19
Private HVAC Optimization	7,692	$1,135,800	1.29	1.31
Public HVAC Optimization	7,692	$1,135,800	1.29	1.31
Small Commercial Lit Signage	9,417	$2,271,599	1.31	1.34

Id. at 100. According to the IPA, the total net savings for these programs is estimated as 70,124 MWh. The programs also contribute to a peak reduction of approximately 8.3 MW. The estimated savings attributable to eligible retail customers is 26,334 MWh. *Id.*

b. Ameren Requested Determinations

The IPA states that, in its filing, Ameren made the following requests:

> The annual updates to the measure values in the TRM and NTG ratio values result in changes to the implementer's savings goals and/or the cost structures between AIC and the implementer and will be re-negotiated for the savings calculations based upon the annual IL-TRM and NTG updates for one program year.
>
> Ameren seeks express approval that it is permitted to recover costs that exceed the estimated program costs. In lieu of this express approval, it will be forced to prematurely discontinue approved programs prior to the estimated budget being expended.

See, Plan at 100. The IPA states that it does not object to Ameren's first request above, as it appears to be consistent with consensus language adopted by the Commission in Docket No. 14-0588.

With respect to Ameren's second request, the IPA notes that the consensus language previously approved by the Commission in Docket No. 13-0546 (and set forth the consensus items above) allowed for the utilities to recover reasonable and prudent costs that incidentally (3-5%) exceeded excess program costs. However, it is unclear to the IPA whether this consensus item was intended to serve as a hard cap on allowable expenditures, or merely meant to predetermine the prudence and reasonableness of expenditures which incidentally surpassed estimated costs. For purposes of the 2016 Plan, absent a showing that customers are likely to benefit from additional expenditures exceeding that "incidental" 3-5% threshold, the IPA believes that the threshold previously established in consensus language should be followed and Ameren's second item should not be adopted. *Id.*

In addition to adopting these determinations, the IPA seeks Commission approval of the incremental EE programs as described above.

c. ComEd EE Program

The IPA believes that ComEd's filing meets the requirements in Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix C-2 to the Plan should be approved pursuant to Section 16-111.5B(a)(5). The IPA states that ComEd has traditionally used marginal line losses when calculating TRCs, and that practice continued for its submittal this year. In previous years, ComEd also did not include an adder for administrative costs. The IPA states that for this Plan, ComEd included an administrative adder of 11.5%. Also, ComEd did not include DRIPE in its TRC calculations and did not include a blanket NEB adder at the portfolio or program level. ComEd instead considers some NEBs at the measure level. *Id.* at 101-102.

The IPA avers that ComEd and its stakeholder review committee determined that the following four (out of the 16 evaluated proposals) were duplicative of existing programs.

Sector	Program	Reason Duplicative
Business	Super Trade Ally	Duplicative with Section 16-111.5B Small Business Energy Services Program
Business	Linear LED	Duplicative with Section 16-111.5B Small Business Energy Services Program
Business	Integrated Energy Controls	Duplicative with Section 16-111.5B Small Business Energy Services Program
Business	Energy Dashboard	Duplicative with Section 16-111.5B Small Business Energy Services Program

See, Plan at 102.

It further states that three of the proposals directly overlapped the ComEd Small Business Energy Services program in ways that would not offer additional consumer benefits. The fourth program provided a web-based dashboard, but failed to demonstrate how it would use that dashboard to reach under-served markets and offer measures in ways that would not be duplicative of the existing program. ComEd also noted that the dashboard replicated much of the functionality of its Building Energy Analyzer dashboard that is available to business customers with AMI meters. It understands that two other programs while having some overlap more appropriately fell into the category of competing programs in which they would not detract from the existing programs and thus were included. The IPA agrees with all of those determinations. *Id.*

The IPA additionally determined that ComEd determined that the five programs which target sectors normally served by DCEO programs could be structured so as not to be duplicative of existing programs. It commented that those programs may require additional coordination between DCEO and ComEd. *Id.* at 102-103. Below is a summary of ComEd's EE Offerings:

Program	Net Savings (MWh)	Total Utility Cost	TRC
Agricultural EE	1,354	$366,613	1.64
Assisted and Senior Housing	1,319	$625,928	1.60
Community-based CFL Distribution (DCEO)	16,343	$1,240,000	4.25
Efficient Products (DCEO)	3,711	$778,179	6.24

Enhanced Building Optimization (DCEO)	12,274	$2,500,000	2.68
Lit Signage	16,236	$3,700,000	3.09
Low-income Kits (DCEO)	4,555	$1,439,246	2.01
Low-income Multi-family (DCEO)	7,239	$2,167,622	4.47
Luminaire-Level Lighting Control	19,113	$5,101,484	4.39
Monitoring-based Commissioning	3,008	$1553,800	1.67
Rural Small Biz EE Kits	1,003	$582,970	4.60

Id. at 103. The net savings is 86,155 MWh. The IPA states that these programs are forecasted to deliver 13 MW of reduction in peak procurement and the savings attributable to eligible retail customers is 35,812 MWh. The IPA agrees with this assessment and requests that the Commission approve the programs as described above.

d. MidAmerican EE Program

The IPA cites 220 ILCS 5/16-111.5(a), which provides, in pertinent part, that: "[P]rocurement plans prepared pursuant to Section 16-111.5 of this Act shall be subject to" Section 16-111.5B's "requirements." However, the IPA continues, Section 16-111.5B's compliance "requirements" include requiring that a utility submit its "most recent analysis submitted pursuant to Section 8-103A of this Act and approved by the Commission under subsection (f) of Section 8-103 of this Act" and the "[i]dentification of new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act," citing 220 ILCS 5/16-111.5(a)(3)(B) and (C).

The IPA concludes that because Section 8-103 of the Act "does not apply to an electric utility that on December 31, 2005 provided electric service to fewer than 100,000 customers in Illinois", there are no analyses developed by MidAmerican and no underlying MidAmerican energy efficiency programs under Section 8-103 to which any "new or expanded" programs could be viewed as "incremental." Thus, the IPA believes that MidAmerican's July 15, 2015 submittal meets the requirements of Section 16-111.5B. *Id.* at 104.

e. Procurement Strategy

The IPA recommends a slight refinement to the energy hedging strategy from the 2015 Plan. The slight refinement concerns the procurement for the November to May months which will now take place for October through May. It explains that the current strategy involves the procurement of hedges to meet a portion of the hedging requirements over a three-year period. The IPA opines that including October in the Fall procurement event will better align the procurement with the utilities' non-summer period. It also gives the utilities the opportunity to cover any short position in the month of October resulting from load returning to the utility, which was not anticipated in the Spring load forecast.

For example, the IPA continues, after the March 2015 load forecast was produced, the City of Chicago announced its intention to return its municipal aggregation load to ComEd. This decision produced a short position in ComEd's supply portfolio in the months of June through October. It states that had the Fall procurement event included the month of October, the short position would had been smaller. The IPA is not aware of any negative financial consequences resulting from the return of the Chicago load to ComEd; however, from a risk management perspective, it would have been preferable to have had the option of covering the month of October in the September procurement event. Below is a table illustrating the refined strategy:

Spring 2016 Procurement			**Fall 2016 Procurement**		
June 2016-May 2017 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2016-May 2017**	**Upcoming Delivery Year + 1**	**Upcoming Delivery Year + 2**
June 100% peak and off peak July and Aug. 106% peak, 100% off peak Sep. 100% peak and off peak Oct. - May 75% peak and off peak	25%	12.5%	100%	50%	25%

See, Plan at 105.

With regard to capacity hedging, the IPA notes that previous procurement plans have recommended that ComEd continue to obtain its capacity needs through the PJM capacity market. In the current plan, the IPA recommends that ComEd continue to obtain its capacity needs from the PJM capacity market.

For Ameren, the 2015 Plan recommended that for the 2015-2016 Planning Year, Ameren purchase all of its capacity requirements via MISO's PRA. This was the first year since the IPA was formed that Ameren had no forward hedging of capacity. The IPA recommends a slight change in strategy with respect to hedging capacity price risk for Ameren. The IPA maintains that the capacity prices resulting from the 2015-2016 MISO PRA cleared substantially higher for the Illinois Region (Zone 4) than in prior years. The 2015-2016 Zone 4 price of $150/MW-Day is 9 times greater than the previous Planning Year, and more than 40 times greater than the other zones. MISO's IMM is forecasting a $71/MW-Day Initial Reference Price for 2016-2017 and a Preliminary Initial Reference Price of $136.37/MW-Day for the 2017-2018 Planning Year. It surmises that it is conceivable that the Zone 4 price will clear at close to these prices, *i.e.,* dropping in 2016-2017 then rising again in 2017-2018. *Id.* at 106.

While the PJM BRA for 2018-19 has not been conducted yet, the IPA is of the opinion that the capacity performance incentives will most likely result in an increase in the BRA price for 2018-2019. With the MISO IMM using the opportunity cost of selling to

PJM as a basis for deriving the Initial Reference Price, the IPA concludes that it is safe to assume that the Initial Reference Price for 2018-2019 will be higher. The IPA expects much uncertainty in future MISO PRA Zone 4 clearing prices. In the interest of hedging price risk and maintaining rate stability for the Illinois customers, the IPA recommends hedging a portion of Ameren's capacity market exposure. *Id*.

In the IPA's view, the differences between the PJM and MISO capacity constructs indicates that a capacity hedging strategy which relies on both the MISO PRA as well as bilateral capacity procurements by the IPA, is a reasonable hedging approach for meeting Ameren's capacity needs. The IPA notes that one particularly important difference is that for the MISO PRA, the clearing prices are not known until two months prior to the beginning of the respective Planning Year, whereas in PJM the primary capacity auctions, the BRAs are forward-looking and are held three years prior to the delivery year. The IPA concludes that MISO PRA does not provide a forward price signal; it also poses potential risks to customers when prices increase abruptly and surprisingly, as was observed in the 2015-2016 PRA. *Id.*

Given the potential scheduling conflicts between the MISO PRA and a Spring IPA capacity procurement event, the IPA is of the opinion that the capacity procurement for the upcoming planning year should take place well before the MISO PRA during a Fall procurement event. It also states that suppliers know from the MISO PRA results that the potential for higher capacity prices in Zone 4 may exist, given a higher capacity clearing price in the PRA, such as what occurred in the 2015-2016 PRA. Bidders in the IPA capacity procurement event would benefit from knowing recent MISO PRA clearing prices. The IPA capacity procurements also offer flexibility, in that, the procurements provide an option and not an obligation to execute contracts. In light of the above the IPA proposes the following hedging strategy:

- For the 2016-2017 Planning Year, 50% of Ameren's capacity was procured through an RFP in September 2015 and 50% will be procured in the 2016 MISO PRA (approved in the 2015 Procurement Plan);

- For the 2017-2018 Planning Year, 25% of Ameren's capacity would be procured through an RFP in September 2015, 50% would be procured through an RFP in Fall 2016, with the remaining 25% being procured in the MISO PRA; and

- For the 2018-2019 Planning Year, 25% of Ameren's capacity will be procured through an RFP in the Fall 2016, 50% would be procured through an RFP in Fall 2017, with the remaining 25% being procured in the MISO PRA.

Id. at 107. The IPA states that it will review and analyze the results of the 2016-2017 MISO PRA and make any necessary adjustments to the recommended capacity hedging strategy in future procurement plans.

With regard to MidAmerican, it has elected to begin to procure power and energy through the IPA procurement process for the incremental amount of capacity that is not currently served, or forecasted to be served in Illinois by MidAmerican-owned Illinois jurisdictional generation. As part of that request, MidAmerican provided the IPA with its forecasted load and capability. The IPA notes that the magnitude of the proposed capacity procurements for MidAmerican is small relative to its capacity requirements. Also, the IPA continues, while the MISO PRA bidding and clearing dynamics that have been discussed for the Ameren procurement are potentially valid for Zone 3, it is unlikely that bidding behavior in this Zone will cause the level of price separation experienced in Zone 4 this year.

The delivery point for MidAmerican's capacity is Zone 3; it cleared at $3.48/MW-Day in the 2015-2016 MISO PRA. In light of this, the IPA recommends that MidAmerican obtain 100% of its forecast capacity shortfall for 2016-2017 (approximately 16.7% of its capacity requirements), 2017-2018 (approximately 17.0% of its capacity requirements) and 2018-2019 (approximately 17.6% of its capacity requirements) from the upcoming annual MISO PRA to be held in April of 2016, 2017, and 2018 respectively. It notes that MidAmerican's capacity shortfall is relatively small, and consistent with the proposed capacity procurement strategy for Ameren, the IPA is of the opinion that procuring a small percentage (16.7% to 17.6% for MidAmerican) from the PRA is a reasonable approach. *Id.* at 107-08.

Summary of Capacity Procurement for ComEd

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2018	June 2018-May 2019	June 2019-May 2020
100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions

Summary of Capacity Procurement for Ameren

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2018	June 2018-May 2019
50% RFP in Sep. 2015 50% MISO PRA	75% RFP in Fall 2016 25% MISO PRA	25% RFP in Fall 2016 50% RFP in Fall 2017 25% MISO PRA

Summary of Capacity Procurement for MidAmerican

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2018	June 2018-May 2019
100% of expected shortfall (approximately 16.7% of the capacity requirements) from MISO PRA	100% of expected shortfall (approximately 17.0% of the capacity requirements) from MISO PRA	100% of expected shortfall (approximately 17.6% of the capacity requirements) from MISO PRA

Plan at 121.

f. Demand Response Products

The IPA is mindful of the goal in Section 8-103(c) of the Act, which provides that "Electric utilities shall implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers." *See,* 220 ILCS 5/8-103(c). The IPA reports the following demand response activities from the utilities:

ComEd has the following demand response programs:

- Direct Load Control Program: ComEd's residential central air conditioning cycling program is a DLC program with 72,900 customers with a load reduction potential of 88 MW.
- Voluntary Load Reduction ("VLR") Program: VLR provides compensation based on the value of energy as determined by the real-time hourly market run by PJM. It also provides for transmission and distribution compensation based on the local conditions of the network. This portion of the portfolio has 1,171 MW of potential load reduction.
- Residential Real-Time Pricing Program: ComEd's residential customers have an option to elect an hourly, wholesale market-based rate. The program uses ComEd's Rate BESH to determine the monthly electricity bills for each participant. This program has roughly 5 MW of price response potential.
- Peak Time Savings Program: This program is required by Section 16-108.6(g) of the PUA. It is an opt-in, market-based demand response program for customers with smart meters. Under the program, customers receive bill credits for kWh usage reduction during curtailment periods. The program commences with the 2015 Planning Year. ComEd sold 48 MW of capacity from the program into the PJM capacity auction for the 2017 Planning Year and 10 MW for the Summer of 2015.

Plan at 123.

With regard to Ameren, the IPA states that Ameren has implemented a Voltage Optimization Program which includes a Conservation Voltage Reduction Program, a Real Time Pricing Program and the Power Smart Pricing Program. Also, Ameren offers real time pricing options through its tariff, and it offers a Peak Time Rebate program.

The IPA further reports that MidAmerican administers a program called “Summer Saver Program,” a residential Direct Load Control program. In addition, there is a potential for load displacement due to curtailment of customers on an interruptible rate. Based on the customer enrollment, MidAmerican estimates its potential total capacity of Demand Response at 19.5 MW. *Id.*

The IPA does not propose any procurement of demand response programs from eligible retail customers in the 2016-2017 delivery year. Under current market and regulatory conditions, the IPA believes that a new demand response procurement by the IPA could not meet the standards set forth in Section 16-111.5(b)(3) of the Act. The reason for this, the IPA understands, is the statutory requirement that demand response under this provision must come from “eligible retail customers.” Section 16-111.5B of the Act explicitly extends EE program participation to potentially “eligible retail customers” to accommodate the challenges created by customer switching. In contrast, the IPA continues, Section 16-111.5(b)(3)(ii)(A) contains no such provision, and there may simply be no feasible way to ensure that only eligible retail customers participate.

The IPA concludes that this challenge significantly reduces the likelihood that any demand response procurement would be “cost effective.” It also points out that there could be challenges in satisfying the demand-response requirements of the regional transmission organization market in which the utility’s service territory is located, and providing for customers’ participation in the stream of benefits produced by the demand-response products. The IPA is of the opinion that for customers, including both eligible retail customers and those who have switched suppliers or take hourly priced service, the Peak Time programs as offered by Ameren and ComEd create value through reduction in capacity charges. Also, the technologies used for capacity reductions have the potential to provide longer term demand response capability that could operate over more peak hours than those used for calculations of capacity obligations. *Id.*

g. Clean Coal

The IPA Act contains an aspirational goal that cost-effective clean coal resources will account for 25% of the electricity used in Illinois by January 1, 2025. *See,* 20 ILCS 3955/1-75. The IPA maintains that as a part of the goal, the Plan must also include electricity generated from clean coal facilities, citing 20 ILCS 3855/1(d)(1). While there is a broader definition of “clean coal facility” contained in the definition section of the IPA Act, the IPA posits that Section 1-75(d) describes two special cases: the “initial clean coal facility” and “electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities” (a “retrofit clean coal facility”) citing 20 ILCS 3855/1-10. Currently, the IPA is unaware of any facility meeting the definition of an “initial clean coal facility” that has announced plans to begin operations within the next five years. Plan at 123.

With regard to FutureGen, the IPA states that in Docket No. 12-0544, the Commission approved inclusion of FutureGen 2.0 as a retrofit clean coal resource starting in the 2017 delivery year. On July 22, 2014, the Illinois Appellate Court upheld the Commission's decision to require ComEd and Ameren to recover FutureGen sourcing agreement costs through a competitively-neutral retail distribution charge applicable to all utility distribution customers (including ARES customers).

However, the IPA continues, in early February 2015, the U. S. Department of Energy ("DOE") announced the suspension of federal funding for the FutureGen 2.0 project, indicating that the project had insufficient time to be completed. On May 26, 2015 the Illinois Senate adopted SR 232 which urges the DOE to continue funding FutureGen 2.0 and to extend the deadline for funding. At the time of filing, the IPA is unaware of any further changes in status of the FutureGen 2.0 project, its underlying financing, and performance under the FutureGen 2.0 sourcing agreements. *Id.*

The IPA avers that in preparation for its 2015 Plan, it was approached by a team representing Sargas, Inc. ("Sargas"), a US subsidiary of Sargas AS, a Norwegian technology company, about its plans to develop a coal-fired power plant in Mattoon, Illinois designed to burn Illinois coal with 90% post-combustion carbon capture, with captured carbon used for local enhanced oil recovery. Sargas proposed that the IPA conduct a competitive procurement for clean coal facility sourcing agreements pursuant to its authority under Section 1-75(d)(1) of the IPA Act as a means to facilitate the project's development. *Id.* at 123-24.

For reasons explained by the IPA in its 2015 Plan, the IPA declined to adopt that proposal. In approving the IPA's 2015 Plan, the Commission approved its rejection of Sargas' proposal, stating that it was "not convinced that a proposal of the type presented by Sargas was contemplated by the Illinois General Assembly or is in the public interest," citing Docket No. 14-0588, (Order of December 17, 2014) at 315.

h. Renewable Resources

The IPA contends that from 2009 through 2012, its annual electricity procurement plans included purchases of renewable energy resources sufficient to meet the Renewable Portfolio Standard ("RPS") requirements applicable to the eligible load of ComEd and Ameren. For the Plans for 2013 and 2014, the IPA and Commission determined that potential renewable energy resource procurements were limited by the potential for curtailment of existing contracts due to the rate cap on the RRBs. In 2015, the IPA procured only Solar Renewable Energy Credits ("SRECs"), and it plans to procure RECs from DG this Fall, using only previously-collected hourly ACP funds. For the 2016 Plan, in addition to any renewable energy credit procurements to meet the RPS targets and technology-specific sub-targets for Ameren and ComEd, the IPA states that it will seek to procure sufficient RECs to meet the renewable resources target for MidAmerican based on MidAmerican's total Illinois jurisdictional load. Plan at 125.

According to the IPA, MidAmerican's involvement in the 2016 Plan raises new questions about how to calculate the renewable resource target appropriate to it. As a multi-jurisdictional utility participating in the IPA's procurement planning process to meet a portion of its load requirements, the IPA maintains that MidAmerican's participation raises a previously-unaddressed question as to whether renewable energy resources procurement targets should be calculated for all of its eligible retail customer load, or only for that portion of eligible retail customer load for which the utility specifically requests procurement.

It states that Section 1-75(c)(1) of the IPA Act refers to procurement percentages applicable to "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," citing 20 ILCS 3855/1-75(c)(1). The IPA argues that, while Section 16-111.5(a) defines "eligible retail customer" by customer status that would appear to include Mid-American's entire eligible retail customer load, this same statute also expressly contemplates that Mid-American may seek procurement for only "a portion of its eligible Illinois retail customers in accordance with the applicable provisions set forth in this Section and Section 1-75 of the Illinois Power Agency Act," citing 220 ILCS 5/16-111.5(a).

The IPA commented that MidAmerican has stated that its interpretation of the governing statutory scheme is that the amount of RECs to be procured by the IPA should be determined based on the incremental amount of energy and capacity planned to be procured by the IPA to serve MidAmerican's eligible Illinois customers, rather than the load for all of its eligible customers in Illinois. In MidAmerican's viewpoint, because a small multi-jurisdictional utility may elect for the IPA to procure only a portion of the energy and capacity required for its eligible customers, the IPA would likewise procure RECs to match the amount procured through the IPA. Plan at 125.

The IPA believes that the stronger argument is that MidAmerican's renewable resource targets are determined based upon MidAmerican's "total supply to serve eligible retail customers," which are, in the IPA's view, its entire eligible retail customer load. The IPA is of the opinion that while procurement may be requested by a small, multi-jurisdictional utility for only a portion of that load, the renewable energy procurement target itself is set through the more direct language contained in Section 1-75(c)(1) of the IPA Act ("a minimum percentage of each utility's total supply to serve the load of eligible retail customers"), and that language remains controlling, regardless of whether the broader procurement is for only a portion of eligible retail customer load. Thus, the IPA's renewable energy resource procurement targets were calculated consistent with this approach. *Id*. at 125-26.

The IPA posits that, if the Commission determines that MidAmerican's renewable energy resource procurement should cover only the incremental portion of MidAmerican's eligible customer load, the quantity of RECs to be procured will be approximately 14% of the quantity that would be needed to cover the utility's total eligible customer load. It states that if, on the other hand, the amount of RECs to be procured by the IPA should be determined based on the incremental amount of energy and capacity planned to be procured by the IPA to serve MidAmerican's eligible Illinois customers, the following are the percentages of renewable energy resources required to be procured: the renewable energy resources obligation for the utilities in the 2016-2017 delivery year is 11.5% to meet the June 1, 2016 target. According to the IPA, this obligation increases by at least 1.5% each year thereafter to at least 25% by June 1, 2025. *Id.* at 126.

i. Renewable Resources Availability and Procurement

The IPA understands that the obligation of each electric utility, which is, the amount of renewable energy resources that have to be procured to meet these statutory minimums—"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," citing 20 ILCS 3855/1-75(c)(1) Under this standard, the IPA continues, if a procurement of RECs is scheduled to take place in Spring of 2016 for delivery in the 2016-2017 delivery year, the most recently completed year is the 2014-2015 delivery year, as the 2015-2016 delivery year would not have ended prior to the procurement. The IPA reasons that as a result, customer switching taking place in the Fall of 2015 may not manifest itself in significant changes to renewable energy procurement targets until procurements take place in the Spring of 2017 for the 2017-2018 delivery year. The IPA opines that this switching will be reflected in the actual 2015-2016 delivery year load. It also states that Section 1-75(c) of the IPA Act includes targets for specific resource types: 75% wind, 6% (by June 1, 2015 and thereafter) photovoltaics ("PV") and 1% (by June 1, 2015 and thereafter) DG which can be included within the PV and wind requirements, citing 20 ILCS 3855/1-75(c)(1).

The IPA points out that the spending cap on the available RRB is defined as follows:

> 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.

Plan at 126-27; *see also* 20 ILCS 3855/1-75(c)(2)(E). The IPA states that the estimated renewable resource volumes and dollar budgets available for use by each utility and the assumptions that provide the basis for these estimates reflect the utilities' expected load forecasts as recommended by the IPA to be adopted. If the Commission were to adopt a different load forecast, the analysis which follows would have to be revised accordingly. Plan at 127.

For the upcoming 2016-17 delivery year, the IPA is of the opinion that existing resources under contract for Ameren and ComEd are not sufficient to meet solar PV and DG sub-targets, and MidAmerican is short for overall renewable energy resource compliance, wind, solar PV, and DG, due to not having previously participated in the IPA procurement process. The IPA continues to state that ComEd is short RECs for overall renewable energy resource compliance, but procuring its required solar PV volume would be sufficient to fill that gap. To achieve statutory compliance, the IPA recommends a Spring 2016 procurement of RECs to meet each utility's requirements, other than to meet the DG sub-targets, for the 2016-2017 delivery year. It states that the quantities to be procured will be based upon the "Remaining Targets," as calculated from the updated March 2016 load forecasts Those quantities will be limited to the funds available in the RRB, as reported at that time. The IPA asserts that should consensus on the March 2016 load forecasts be needed and not be reached, the quantities of RECs to be procured for the 2016-2017 delivery year will be based upon the "Remaining Target" rows of Tabs 8-1, 8-2 and 8-3 of the Plan. To the extent practicable, it maintains, the structure, process and contracts for the procurement will be based upon those used for the SREC procurement conducted by the IPA in 2015. *Id.* at 127.

According to the IPA, Section 1-75(c) of the IPA Act also requires the utilities to acquire RECs from DG devices amounting to at least 1% of each utilities total RECs target. Depending on the results of the planned Fall 2015 DG procurement, the IPA proposes to schedule at least one DG procurement in 2016 to meet the utilities' remaining 2016-2017 delivery year DG REC targets. *Id.*

The IPA posits that 20 ILCS 3855/1-75(c)(1) requires the procurement of DG in contracts of at least five years. It concludes that, due to continued volatility in the available RRB at present stemming from customer switching, in the past, new multi-year contracts were entered into using funds collected from eligible retail customers carrying a significant risk of future curtailments, and the resolution of competing curtailment provisions between distinct sets of long-term contracts. As a result, the IPA does not recommend use of the RRB for Ameren or ComEd for contracts that are more than one year in length or extending beyond the 2016-2017 delivery year. For Ameren and ComEd, the IPA opines that this may unfortunately limit the use of RRB funds to meeting the technical requirements of the utilities' RPS mandates, rather than achieving broader policy goals such as fostering the development of new renewable resources in Illinois. *Id.* at 128.

With regard to MidAmerican, the IPA states that because MidAmerican's service territory does not feature the same load volume volatility created by customer switching, and because MidAmerican is not already a party to long-term contracts for renewable energy resources, the risk of needing to curtail contracts longer than one year appears to be very small. It believes that the use of the RRB would be appropriate for contracts with MidAmerican extending beyond the delivery year. *Id.*

The IPA notes that Section 1-56(i) of the IPA Act required the development of a supplemental photovoltaic ("SPV") procurement plan for the procurement of RECs from PV systems. The IPA's initial SPV procurement was held in June 2015 with two additional SPV procurements planned for November 2015 and March 2016. As these RECs are purchased by the IPA out of the Renewable Energy Resources Fund ("RERF") and not by the utilities, the IPA concludes that the SRECs procured under the SPV plan do not count toward the utilities' DG RECs or SPV renewable energy credit targets. *Id.*

j. Current Utility Renewable Resource Supply and Procurement

With respect to Ameren, the IPA avers that Ameren's current renewable resource contracts will cover its total renewables targets for the 2016-2017 delivery year. If no additional purchases of renewable energy resources are made, the IPA states that Ameren will fall short of meeting its RPS requirements in the 2017-2018 delivery year by 6%. In the 2018-2019, 2019-2020 and 2020-2021 delivery years, the shortfall for total renewables is projected to reach 41%, 47% and 51%, respectively. The IPA maintains that Ameren is projected to exceed the wind sub-target for the 2016-2017 and the 2017-2018 delivery years. With no additional purchases being made, Ameren is projected to fall short of the wind sub-target by 22%, 29% and 35% in the 2018-2019, 2019-2020, and 2020-2021 delivery years, respectively. Assuming that no additional purchases of PV and DG are made, Ameren is projected to fall short of the PV and DG goals in each delivery year. The IPA points out that Ameren is projected to have RRB funds with which to purchase renewables. *Id.* at 128-29.

Ameren Existing RPS Contracts vs. RPS Requirements

Delivery Year		Total Renewables	Wind	Photo-voltaic s	Distributed Generation
2016-2017	Target (MWh)	776,681	582,510	46,601	7.767
	Purchased MWh	1,029,245	976,851	12,394	0
	Remaining Target (MWh)	--	--	34,207	7,767
2017-2018	Target (MWh)	907,169	680,377	54,430	9,072
	Purchased MWh	854,396	848,338	6,058	0
	Remaining Target (MWh)	52,773	--	48,372	9,072
2018-2019	Target (MWh)	1,013,368	760,026	60,802	10,134
	Purchased MWh	600,000	596,571	3,429	0
	Remaining Target (MWh)	413,368	163,455	57,373	10,134
2019-2020	Target (MWh)	1,122,680	842,010	67,361	11,227
	Purchased MWh	600,000	596,571	3,429	0
	Remaining Target (MWh)	522,680	245,439	63,932	11,227
2020-2021	Target (MWh)	1,233,082	924,812	73,985	12,331
	Purchased MWh	600,000	596,571	3,429	0
	Remaining Target (MWh)	633,082	328,241	70,556	12,331

Id. at 129.

The IPA further states that on April 16, 2015, it held a procurement for SPV RECs pursuant to the Plan that was approved by the Commission in Docket No. 14-0588. A total of 30,212 of these credits were acquired to meet Ameren's procurement target for the 2015-16 delivery year. No credits were procured for subsequent delivery years. However, it states that a procurement event for up to 6,518 DG RECs/year is planned for the Fall of 2015; as required by Section 1-75(c) of the IPA Act, this DG procurement will feature five-year contracts. *Id.*

With regard to ComEd, the IPA posits that ComEd's forecast indicates that for the 2016-2017 delivery year, total renewables are 67,960 RECs short of the target, while enough renewables have been procured to meet its wind targets. It projects that in subsequent delivery years, ComEd is forecasted to fall short of its total renewables target by 35% in 2017-2018, 56% in 2018-2019, 63% in 2019-2020, and 67% in 2020-2021. The IPA further states that ComEd is also forecasted to fall short of the PV and DG targets in each of the five delivery years considered in this Plan and to fall short of the wind target in the 2017-2018 delivery year and beyond. As with Ameren, the IPA continues, ComEd is also projected to have RRB funds with which to purchase renewables.

ComEd Existing RPS Contracts vs. RPS Requirements

Delivery Year		Total Renewables	Wind	Photo-voltaics	Distributed Generation
2016-2017	Target (MWh)	1,629,357	1,222,018	97,761	16,294
	Purchased MWh	1,561,397	1,340,016	27,895	0
	Remaining Target (MWh)	67,960	--	69,866	16,294
2017-2018	Target (MWh)	2,360,934	1,770,700	141,656	23,609
	Purchased MWh	1,533,198	1,233,838	27,887	0
	Remaining Target (MWh)	827,736	536,862	113,769	23,609
2018-2019	Target (MWh)	2,878,296	2,158,722	172,698	28,783
	Purchased MWh	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	1,616,571	924,884	144,811	28,783
2019-2020	Target (MWh)	3,444,117	2,583,087	206,647	34,441
	Purchased MWh	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	2,182,392	1,349,249	178,760	34,441
2020-2021	Target (MWh)	3,789,473	2,842,105	227,368	37,895
	Purchased MWh	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	2,527,748	1,608,267	199,481	37,895

Id.

The IPA avers that on April 16, 2015, it held a PV SREC procurement pursuant to the procurement plan approved by the Commission in Docket No. 14-0588. According to the IPA, a total of 49,700 of these credits were acquired to meet ComEd's procurement target for the 2015-16 delivery year but, none of these credits were procured for subsequent delivery years. A procurement event for up to 13,194 DG RECs/year is planned for the Fall of 2015; as required by Section 1-75(c) of the IPA Act, this procurement will feature five-year contracts. *Id.* at 129-30.

Finally, concerning MidAmerican, the IPA maintains that MidAmerican does not currently have any existing purchased RECs to meet these targets. If the IPA is directed to procure RECs based on only MidAmerican's incremental load in Illinois, then the REC quantities required would be approximately 14% of the quantities shown in the table below:

MidAmerican Existing RPS Contracts vs. RPS Requirements

Delivery Year		Total Renewables	Wind	Photo-voltaics	Distributed Generation
2016-2017	Target (MWh)	220,418	165,313	13,225	2,204
	Purchased MWh	0	0	0	0
	Remaining Target (MWh)	220,418	165,313	13,225	2,204
2017-2018	Target (MWh)	258,864	194,148	15,532	2,589
	Purchased MWh	0	0	0	0
	Remaining Target (MWh)	258,864	194,148	15,532	2,589
2018-2019	Target (MWh)	289,334	217,000	17,360	2,893
	Purchased MWh	0	0	0	0
	Remaining Target (MWh)	289,334	217,000	17,360	2,893
2019-2020	Target (MWh)	320,477	240,358	19,229	3,205
	Purchased MWh	0	0	0	0
	Remaining Target (MWh)	320,477	240,358	19,229	3,205
2020-2021	Target (MWh)	351,859	263,894	21,112	3,519
	Purchased MWh	0	0	0	0
	Remaining Target (MWh)	351,859	263,894	21,112	3,519

Id. at 130-31.

In 2010, pursuant to an IPA procurement, ComEd and Ameren entered 20-year LTPPAs from a series of wind and PV facilities. In past proceedings, the IPA has sought express authorization for those contracts to be "curtailed," (a mandated reduction in the amount which need be purchased under the contract) should the payments required under the contract exceed the expected RRB. It is of the opinion that a curtailment of these contracts could be triggered by customers switching to alternative suppliers and consequently load shifting away from the utilities, thus reducing the available budget. *Id.* at 131.

The IPA further states that Section 1-75(c)(2) of the IPA Act requires the IPA to reduce the amount of renewable energy resources to be procured for any particular year in order to keep the "estimated" net increase in charges to eligible retail customers below the statutory 2.015% rate impact cap. For the 2013-2014 and 2014-15 delivery years, the IPA continues, in an effort to keep the cost of renewable energy resources below the statutory rate impact cap, the Commission pre-approved the curtailment of the LTPPAs based on the information contained in subsequent updated load forecasts. It points out that curtailment has been required of ComEd's LTPPAs, but, curtailment has not yet been required for the Ameren's contracts. Curtailments were not required in the 2015-2016 delivery year and, based on the load forecasts supplied by the utilities, are not currently anticipated over the five-year forecast horizon of the 2016 Plan. *Id.*

The IPA posits that for the 2016-2017 delivery year, the ComEd load forecast has grown significantly based largely on a significant number of municipalities, most notably the City of Chicago, suspending their municipal aggregation programs and returning to utility supplied service. For Ameren, it continues, the load forecast has grown only modestly. The remaining RRB is a function of the amount of eligible utility load, which has increased relative to last year's load forecasts, and existing purchases, which slowed in recent years to account for the impact of municipal aggregation. The IPA forecasts that the delivery year RRBs will exceed the contractual cost for RECs already procured in each delivery year. It concludes that both Ameren and ComEd have sufficient funds available in each of the five delivery years covered by this plan. MidAmerican does not hold any LTPPAs.

Available RRB Funds and Forecast Reductions (Curtailments) of LTPPAs for Ameren

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	LTPPA Quantity Reduction (%)
2016-2017	10,403,861	12,617,481	2,213,620	0.0%
2017-2018	9,412,155	12,668,038	3,255,883	0.0%
2018-2019	8,000,000	12,721,183	4,721,183	0.0%
2019-2020	7,999,000	12,768,585	4,769,585	0.0%
2020-2021	7,753,000	12,768,585	5,015,585	0.0%

Available RRB Funds and Forecast Reductions (Curtailments) of LTPPAs for ComEd

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	LTPPA Quantity Reduction (%)
2016-2017	23,502,192	37,550,843	14,048,651	0.0%
2017-2018	23,803,641	40,720,222	16,916,581	0.0%
2018-2019	23,438,590	40,963,118	17,524,528	0.0%
2019-2020	23,566,909	41,254,513	17,687,604	0.0%
2020-2021	23,178,932	41,280,076	18,101,144	0.0%

Id. at 132.

According to the IPA, the contracted REC costs for the 2016-17 delivery year for Ameren and ComEd are respectively 82% and 63% of the current estimates of their 2016-17 RPS budget caps. It opines that those budgets depend on eligible retail load. Thus, the IPA continues, it appears that as long as ComEd's March 2016 forecast for 2016-2017 load is close to 63% of its July 2015 forecast value, and as long as Ameren's March 2016 forecast for 2016-2017 load is close to 82% of its July 2015 forecast value, neither utility will have to curtail its LTPPAs. Under the two utilities' low load forecast scenarios, the IPA surmises that ComEd would not have to curtail its LTPPAs; however, Ameren forecasts that the RRB would be exceeded and a partial curtailment of LTPPAs would be needed. *Id.*

The IPA still recommends that a final determination should be based upon the March 2016 load forecasts. In the event that curtailments are required, the IPA recommends that the methodology adopted in the Commission Order on Rehearing of the 2014 Plan be employed for the calculation of REC prices for curtailed RECs. It will address a potential curtailment through continuing to purchase curtailed RECs at the imputed REC prices from the 2010 contracts, using the RERF. *Id.*

Turning to MidAmerican, the IPA states that if it is directed to procure RECs based on only MidAmerican's incremental load in Illinois, then calculation of the available budget raises a similar issue regarding applicability of only MidAmerican's incremental load to determining the RRB. Should the Commission determine that the budget must be calculated based on 2.015% against only the portion of eligible retail customer load, for which the IPA is preparing its procurement plan, the available budget would be approximately 14% of the quantities shown in the table below:

Available RRB Funds for MidAmerican

Delivery Year	Delivery Year RPS Budget ($)	Available RPS Funds ($)
2016-2017	2,477,311	2,477,311
2017-2018	2,486,717	2,486,717
2018-2019	2,496,201	2,496,201
2019-2020	2,507,235	2,507,235
2020-2021	2,518,768	2,518,768

Id. at 132-33.

The IPA points out that Ameren and ComEd also collect ACPs on behalf of customers taking hourly service from the utility. It states that, unlike similar funds paid by the ARES into the RERF which are held and administered by the IPA, utility hourly customer ACP funds are held by the utilities. It further states that each utility has disclosed the amount of hourly customer ACP funds being held as of May 31, 2015. For Ameren, the balance is $10,040,276; for ComEd, the balance is $19,039,957. *Id.*

The IPA avers that the IPA Act requires that ACP funds from utility hourly customers must be used to "increase [the utility's] 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 ACP rate or rates in the prior year ending May 31," citing 20 ILCS 3855/1-75(c)(1). Starting with the 2013-2014 delivery year, it continues, the Commission approved the use of hourly ACP funds to purchase RECs from any curtailed LTPPAs, and the IPA recommends a continuation of that policy. Plan at 132-33.

The IPA explains that prior procurements for the utilities fell short of statutory DG sub-targets. It opines that using the already collected and otherwise unspent hourly ACP funds to allow Ameren and ComEd to meet their DG sub-targets would be appropriate to further an aspect of the utilities' RPS obligations. It also states that as contracts for DG resources must be no less than five years in length, entering into five-year contracts using existing ACP funds already collected from hourly customers eliminates the load migration risk present with the RRB, from which long-term contracts have been subject to curtailments in the past, while ensuring that there are no impacts on customer rates. Although DG systems were eligible to participate in the IPA's prior renewable energy resource procurements, the Fall 2015 procurement specifically targeting DG resources is the first of its kind conducted by the IPA. *Id.*

The IPA created a DG procurement model for a Fall 2015 procurement based on its traditional procurement process involving the block procurement of RECs with competitive bids selected on the basis of price. The IPA is proposing the model as implemented for the 2015 procurement as the starting point for a 2016 procurement of DG RECs. The IPA states that nothing in the law governing this DG procurement distinguishes between “new” or “existing” systems. It contends that its sole requirement regarding the system completion date is that all participating DG systems must successfully begin delivery of RECs generated in the 2016-2017 delivery year. Contracts will be for the five delivery years starting with 2016-2017 delivery year. *Id*. at 134.

The IPA recognizes that, given the limited amount of DG currently in Illinois, this approach’s success hinges on the ability of the Illinois DG market both to self-organize and to grow. It concludes that therefore, it will allow bids to contain DG systems of all qualifying sizes and resource types, with systems to be no larger than 2,000 kW. The technology types which are eligible to participate are defined by the IPA Act, which include DG powered by wind, solar thermal energy, PV cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams. The IPA explains that benchmarks used by the Procurement Administrator to evaluate bids may depend on system size and/or technology. Additionally, bids that meet or beat the benchmarks will be evaluated first on the basis of price, and then on the basis of achieving a 50-50 balance of RECs procured from each of the two categories of systems.

The IPA’s planned DG renewable resource procurement will use hourly ACP funds for Ameren and ComEd. It will use the RRB for MidAmerican. Also, only hourly ACP funds that have been collected as of May 31, 2016 and not allocated to the purchase of either DG RECs from the five-year 2015 DG procurement contracts or curtailed RECs for the 2016-2017 delivery year may be used. The IPA will procure DG RECs until funds are fully allocated or the utilities’ DG goals are met, whichever comes first. The products to be procured are RECs from DG systems that are interconnected with Ameren, ComEd, MidAmerican, a municipal utility in Illinois, or a rural electric cooperative in Illinois. DG systems need not be in the service territory of the utility purchasing the RECs. *Id.*

The IPA’s approach will be to procure DG RECs through a single procurement event in a competitive bid process in the early Summer of 2016 with two categories of systems participating. The first category is for systems under 25 kW, the second for systems between 25 kW and 2 MW. The IPA states that bids must be at least one megawatt in size, but may feature a number of DG systems of all qualifying sizes and resource types. Also, the bidder must identify the specific system(s) that will provide the RECs; “speculative bidding” of RECs from systems not specifically identified will not be permitted. Evidence regarding the systems may include, but is not limited to, letters of intent, signed contracts, interconnection or net metering applications, local permits, etc. *Id.* at 134-35.

According to the IPA, Section 1-75(c)(1) of the IPA Act requires that aggregators “aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity.” Consistent with this provision, the IPA continues, the first block of DG systems bid by each bidder must be at least one megawatt in size offered at a single blended price per REC. The IPA continues to state that subsequent blocks of DG systems must be bid at higher prices and must be at least 100 kW. Bidders may not designate different REC prices for the RECs generated from a single DG system or for RECs associated with a given block.

It opines that while block prices may differ, each bidder's resulting REC contract with the purchasing utility will be at a single blended price, encompassing all successful bids which have been assigned to that utility. Also, a pre-determined capacity factor for each eligible technology will be used to calculate an annual number of RECs for each block to be delivered in each year of the contract, except the first. The bid for a block may include a different number of RECs for the first year of the contract. For the 2016-2017 delivery year, RECs from any month in the delivery year will be eligible for delivery. *Id.* at 135.

The IPA states that it must endeavor to ensure that, to the extent available, half of the total DG RECs that it procures are from "devices of less than 25 kilowatts in nameplate capacity. Section 16-111.5(e) of the PUA requires that the IPA's procurement must be conducted through selecting competing bids "solely on the basis of price." It believes these requirements can be properly balanced by procuring on the basis of price within each category, (<25kW, and 25kW to 2 MW) while ensuring that the winning bid size remains at least one megawatt. If the target is met under the budget and one category is less than 50% of the target, then the next most competitive bid in that category would be selected and would replace DG RECs from a block bid in the other category (to the extent such a bid is available). The IPA concludes that, while sub-25kW systems selected by the evaluation are the lowest-priced systems in that category, a sub-25kW system can be selected ahead of an above-25kW system with a lower price, but only if that selection is required to reach the target 50% of DG RECs from sub-25kW systems. It points out that the marginal bidder in the evaluation of bids could receive a contract that includes a portion of RECs from a particular block bid and the bidder will have the option of whether to accept the contract. *Id.*

The IPA states that the Procurement Administrator may use its discretion in assigning bids (including prorated shares of bids) to each utility to accommodate the fact that the proration of the total volume of selected bids that would be allocated to each utility's procurement target may not be evenly divided due to the size of the winning bids, and each utility's available budget. It continues to state that each system included in the blocks under a contract awarded in this procurement must begin accumulating metered deliveries of renewable energy prior to the end of the 2016-2017 delivery year, May 31, 2017. *Id.*

Within two days after a procurement event featuring sealed, binding commitment bidding with bids selected on the basis of price, reports on the procurement event must be submitted by the Procurement Administrator and the Commission's Procurement Monitor to the Commission for review. These reports must contain bidding results, a recommendation for the rejection or acceptance of bids, and the assignment of winning bids to each utility. The Commission will then issue a decision on whether to accept or reject the procurement results within 2 days after receiving the reports. Within 3 days after the Commission's decision, the utility shall enter into binding contractual arrangements with the winning suppliers using the standard form contracts. *Id.*

The IPA then maintains that contracts under the DG procurements are between winning bidders and Ameren, ComEd, or MidAmerican; the IPA is not a party as it is for the procurements of SRECs conducted pursuant to the SPV Plan. Contracts will provide payment for RECs generated over five delivery years, starting with the delivery year that commences on June 1, 2016. The IPA explains that utility contracts will not feature payments prior to REC delivery, such as pre-payment at the execution of a contract or when a system becomes energized. The contract may be transferred or assigned consistent with the terms specified within each utility's contract. *Id.* at 136.

According to the IPA, it is required by law to recover the cost of conducting this procurement through bidder fees and to develop "standard credit terms and instruments." For this procurement, those are as follows:

- All bidders will pay a $500 non-refundable bid participation fee.
- Bidders will provide security (in the form of a letter of credit for the benefit of the IPA) of $8/REC as part of the bidder registration process. Bidders whose bids are not selected will have their letter of credit returned.
- Winning bidders will be assessed a Supplier Fee that reflects the balance of the cost of conducting the procurement less the total of the bid participation fees. Winning bidders will also have seven days after the approval of the procurement results by the Commission to pay the Supplier Fee due to the IPA.
- The IPA will cancel a winning bidder's letter of credit upon the bidder demonstrating to the IPA that each specific project has begun delivery of RECs from the 2016-2017 delivery year to the applicable utilities.
- Any system that is not successfully developed will forfeit the amount under the letter of credit for those RECs.

The IPA states further that, in addition to the credit requirements described above, the REC delivery contract with the utility may also include an ongoing performance assurance credit requirement. *Id.*

Regarding aggregators, the IPA maintains that Section 1-75(c)(1) of the IPA Act requires that aggregators "aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity." The IPA will allow for "self-aggregation" from system owners, so long as those bids are at least one megawatt. The IPA states that given the number of systems required to constitute a full megawatt, meeting a one megawatt threshold may be challenging for aggregators organizing bids of smaller systems. It adds that any participating system would both need to: 1) have RECs available for procurement (*i.e.,* not already under contract) and be willing to transfer available RECs; and 2) have the knowledge and understanding necessary to participate through an aggregator in an IPA procurement event. *Id.*

For the 2016 Procurement Plan the IPA proposes to hold the DG procurement earlier in the year, ideally, in the early Summer of 2016. It understands that the planning and development process for the procurement should be faster than it was in 2015 because the procurement can build off matters that were developed in 2015. The IPA states that further, the earlier procurement event will give project developers more time in 2016 to develop projects that can take advantage of the federal solar investment tax credit which is expected to expire at the end of 2016. The IPA will allow for the contract delivery of all RECs generated during the 2016-17 delivery year from winning bidders, and not only those RECs generated after the execution of contracts, as the procurement event may occur after the start of the 2016-2017 delivery year. *Id.* at 137.

Concerning the RERF, the IPA states that the RERF balance as of September 28, 2015 is $116,573,040.73. The total amount received in the IPA's RERF is attributable to ARES' ACP payments, less the cost of RECs purchased by the IPA, expenses related to the SPV process, and a $98 million transfer to the Illinois General Revenue Fund pursuant to Public Act 99-0002. *Id.*

The IPA states that Section 1-56(i) of the IPA Act required the IPA to develop a SPV procurement plan, which is required to spend up to $30 million on RECs from PV resources using the RERF. Its SPV procurement plan was approved by the Commission in Docket No. 14-0651. The first procurement event under that plan was held in June 2015. The IPA opines that, while the SPV procurement plan does not direct the IPA to utilize the full RERF balance (which will increase as ARESs make future compliance payments), it is an important first step forward in allowing those funds to be used for their intended purpose. *Id.* at 137-38.

k. Procurement Process Design

The IPA points out that the Procurement Administrator conducts the competitive procurement events on behalf of the IPA. The costs of the Procurement Administrator incurred by the IPA are recovered from the bidders and suppliers that participate in the competitive solicitations, through both Bid Participation Fees and Supplier Fees which are assessed by the IPA. It further states that the "eligible retail customers" for each of the participating utilities ultimately incur these costs. As required by the PUA, it continues, the IPA and the Procurement Administrator review the procurement process each year in order to identify potential improvements. *Id.* at 139.

The IPA points out that Section 16-111.5(e) of the Act specifies that the procurement process must include the following components:

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

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

(2) Standard contract forms and credit terms and instruments

> *The procurement administrator, in consultation with the utilities, the Commission, and other interested parties and subject to Commission*

oversight, shall develop and provide standard contract forms for the supplier contracts that meet generally accepted industry practices. Standard credit terms and instruments that meet generally accepted industry practices shall be similarly developed. . . . The terms of the contracts shall not be subject to negotiation by winning bidders, and the bidders must agree to the terms of the contract in advance. . . .

(3) Establishment of a market-based price benchmark

As part of the development of the procurement process, the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor, shall establish benchmarks for evaluating the final prices in the contracts for each of the products that will be procured through the procurement process. The benchmarks shall be based on price data for similar products for the same delivery period and same delivery hub, or other delivery hubs after adjusting for that difference. . . .

(4) Request for proposals competitive procurement process

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

(5) A plan for implementing contingencies

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

Id. at 139-40.

The IPA has implemented changes regarding the development of standard contract forms and credit terms and instruments in order to achieve process efficiency improvements designed to lower the overall costs to ratepayers. It believes that the forms have now become largely standardized and should remain acceptable to future potential bidders.

The IPA states that markets are dynamic and periodic reviews of contract terms is necessary to ensure proper protection for the utilities, utility customers and suppliers. It recommends that the last used forms, namely the energy, capacity and RPS contracts used in the 2015 procurement events should be the starting point for the contracts used in the energy, capacity, SREC, and DG REC procurements associated with the instant Plan. The IPA also recommends that the IPA, Commission Staff, Procurement Administrator, Procurement Monitor, and utilities undertake a joint review of such contracts in order to identify what terms, if any, need to be modified. *Id.* at 140-41.

Concerning recovery of procurement expenses, the IPA states that Section 1-75(h) of the IPA Act states that, "[t]he Agency shall assess fees to each bidder to recover the costs incurred in connection with a competitive procurement process." Additionally in April, 2014 the IPA adopted new administrative rules regarding fee assessments that codify past practices including defining “bidders” and “suppliers” in procurement events as well as the process for determining those fees. In support, it cites 20 ILCS 3855/1-75(h) and 83 Ill. Adm. Code 1200.110 and 1200.220.

The IPA has historically recovered the cost of procurement events through two types of fees, which are: a “Bid Participation Fee”, which is a flat fee paid by all bidders as a condition of qualification; and “Supplier Fees”, which are paid only by the winning bidders as a fee per block won at the conclusion of the procurement event. The IPA avers that, for the last several procurements, the Bid Participation Fee has been nominal ($500), which means that the bulk of the cost of the procurement event, which typically are several hundred thousand dollars, are recovered from winning bidders through Supplier Fees. The IPA identified two risks regarding its ability to recover costs:

1. If not all the blocks are procured (and no additional procurement event is held), the IPA will not recover the full cost of the procurement through the combination of the Bid Participation Fees and the Supplier Fees. The Supplier Fees are collected from the winning bidders, based on the recommended blocks approved by the Commission; the Supplier Fees from the blocks that are not procured are thus not collected.
2. Suppliers may not necessarily pay the supplier fees on time or pay them at all. Suppliers that have approved bids proceed to the contract execution process with the utility and will get paid under that contract whether they have paid the Supplier Fees.

Plan at 141.

The IPA states that it considered a number of approaches for addressing these risks involving two broad categories of solutions. The first is to maintain the current fee structure and use the pre-bid letter of credit provided by bidders as bid assurance collateral to ensure compliance with the payment obligation of the Supplier Fees. The second solution is to change the current fee structure to have the cost of the procurement largely paid upfront and bar suppliers that fail to pay all fees due from participation in IPA-run events for a period of time. *Id.*

The IPA recalls that, until the 2014 procurement events, the pre-bid letter of credit was strictly a credit instrument held for the benefit of the utility and its customers. The utility could draw upon the pre-bid letter of credit, if the supplier failed to complete the contract execution process. At that point, it continues, a utility that had filed its rates based on the winning bids would have to buy replacement supply, for which it could use funds from the pre-bid letter of credit to mitigate any default by a supplier on rates.

It states that, starting with the 2014 procurement events, the function of the pre-bid letter of credit was expanded to ensure payment of the supplier fees by adding a condition to the utility pre-bid letter of credit allowed the utility to draw, if the supplier fees were not paid by a date certain. The IPA recommends that the approach used in the 2014 and 2015 procurement events should be continued to support the procurement events recommended in this Plan. That approach is for the energy, capacity and non-DG REC contracts to maintain the condition in the utility pre-bid letter of credit allowing the utility to draw if the supplier fees are not paid by a date certain. The IPA surmises that, as was used in the 2014 and 2015 procurement events, there will also be an agreement between the IPA and the utilities regarding how funds will flow back to the IPA for payment under this circumstance. *Id.* at 142.

The IPA further recommends that procurement events should be held in the Spring through Fall of 2016 for purchase of energy blocks, capacity, SRECs, and DG RECs under the 2016 Plan. All of the components of the energy and RECs procurement process would be conducted in the Spring event, while the DG procurement would take place in the early Summer. For the Fall procurement event, for energy blocks under the Procurement Plan, certain activities would not occur as the Fall procurement event could rely on the documents or processes established for the Spring procurement event, as follows:

- The Procurement Administrator will rely on the contract and credit forms established in the Spring procurement event and suppliers would not comment anew on these documents;
- The Procurement Administrator will rely on the RFP design and updated benchmarks using the benchmark methodology established in the Spring procurement event;
- The Procurement Administrator, in consultation with each utility, IPA, Commission Staff and the Procurement Monitor, will not be prohibited from making minor changes to the contract and credit terms or minor changes to the RFP documents, including but not limited to clarifications or corrections; and
- Suppliers that participate in the Spring procurement event will have access to an abbreviated qualification and registration process if they also participate in the Fall procurement event.

The IPA recommends that the Fall procurement event should include the procurement of standard energy products for MidAmerican, Ameren and ComEd, as well as a portion of the Ameren capacity requirements, and a DG REC procurement for Ameren and ComEd. *Id.*

Finally, the IPA discusses informal hearings. It cites Section 16-111.5(o) of the PUA, which states:

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

The IPA avers that on May 22, 2015 Commission Staff posted a public notice for the informal hearing for the purpose of receiving comments regarding on the procurement process for the procurement events that were held during the Summer and Fall of 2014 and the Spring of 2015. The IPA states that the comments received in the informal hearings are available on the Commission's web site. *Id.* at 142-43.

IV. ISSUES PRESENTED

A. Uncontested Matters

1. Section 7.1.5.6 Ameren's Modifying Language Regarding Cost Overruns

Ameren requested permission to recover its costs that exceed estimated program costs, so that it need not prematurely discontinue programs before the time when the estimated budget is expended. Regarding that request, the IPA Plan states:

> With respect to Ameren's second request above pertaining to cost recovery of costs in excess of estimated program costs, the IPA notes that the consensus language previously approved by the Commission in Docket No. 13-0546. . . allowed for the utilities to recover reasonable and prudent costs that incidentally (3-5%) exceeded excess program costs. However, it is unclear to the Agency whether this consensus item was intended to serve as a hard cap on allowable expenditures, or merely meant to predetermine the prudence and reasonableness of expenditures which incidentally surpassed estimated costs. For purposes of the 2016 Plan, absent a showing by Ameren Illinois (or other parties) that customers are likely to benefit from additional expenditures exceeding that "incidental" 3-5% threshold, the IPA believes that the threshold previously established in consensus language should be followed and Ameren Illinois' second consensus item should not be adopted.

Plan at 100.

Ameren maintains that it never intended to request a license for unlimited cost overruns. Its request was meant only to reaffirm that incidental overruns would be handled consistently between Ameren's Section 5/8-103 and 5/16-111.5B portfolios. Ameren agrees with the IPA's framing of the issue, but asks that the language be modified slightly as set forth below.

> With respect to Ameren's second request above pertaining to cost recovery of costs in excess of estimated program costs, the IPA notes that the consensus language previously approved by the Commission in Docket No. 13-0546 (and set forth the consensus items above) allowed for the utilities to recover reasonable and prudent costs that incidentally (3-5%) exceeded excess program costs. . . . Ameren Illinois' request should therefore be approved as it is consistent with the consensus language.

Ameren Objections at 19-20.

The IPA did not object to this language change, and it is reasonable. The IPA shall change the language in its Plan as is set forth above.

2. Section 7.1.7 Section 8-103 Applicability to MidAmerican

The Plan concludes that "[P]rocurement plans prepared pursuant to Section 16-111.5 of this Act shall be subject to" Section 16- 111.5B's "requirements," and a procurement plan for MidAmerican would unquestionably be "prepared pursuant to Section 16-111.5." However, Section 16-111.5B's compliance "requirements" include requiring that a utility submit its "most recent analysis submitted pursuant to Section 8-103A of this Act and approved by the Commission under subsection (f) of Section 8-103 of this Act" and the "[i]dentification of new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act." As Section 8-103 of the PUA "does not apply to an electric utility that on December 31, 2005 provided electric service to fewer than 100,000 customers in Illinois" (*i.e.*, MidAmerican), there are no analyses developed by MidAmerican and no underlying MidAmerican EE programs under Section 8-103 to which any "new or expanded" programs could be viewed as "incremental." Plan at 104.

Indeed, Section 8-103(h) of the PUA provides: "This Section does not apply to an electric utility that on December 31, 2005 provided electric service to fewer than 100,000 customers in Illinois." 220 ILCS 5/8-103(h). It is not contested that MidAmerican services less than 100,000 Illinois customers. Plan, Appendix D, MEC Election to Procure Power and Energy, 1. MidAmerican asserts that because it does not fall under the scope of Section 8-103 of the PUA, many of the requirements of Section 16-111.5B are not applicable to it. It provides substantive responses and accompanying information where appropriate in regards to this assertion. The IPA believes that MidAmerican's July 15, 2015 submittal meets the requirements of Section 16-111.5B as it applies to that utility. No parties have contested this matter.

The Commission finds that MidAmerican is correct in its assertion that it does not fall under the scope of Section 8-103 of the PUA. This section of the Act explicitly provides that a utility "does not apply to an electric utility that on December 31, 2005 provided electric service to fewer than 100,000 customers in Illinois." 220 ILCS 5/8-103 (h). Since MidAmerican provided electric service to fewer than 100,000 customers in Illinois as of the effective date, this Section is not applicable to MidAmerican. Thus, the Commission finds that Section 8-103 does not apply to MidAmerican and that there are no other issues regarding this matter.

3. Miscellaneous Scrivener's Errors

The Parties made various edits and technical recommendations to the IPA Plan. The IPA has reviewed and agreed with the changes described below. No other party expressed any opposition to these changes. IPA Response at 31.

Both Ameren and ComEd suggest that the pre-approval of the March load forecast updates be subject to the consensus of the IPA, Staff, the Procurement Monitor, and the applicable utility (currently, consensus is only referenced should the load forecasts trigger a curtailment). Ameren Objections at 1-2; ComEd Objections at 3. The IPA is amenable to these suggestions and does not object to their adoption. Plan at 6.

Ameren suggests striking the phrase "as a source of supply," as used in reference to sourcing agreements with the FutureGen 2.0 facility, from the 2016 Plan. Ameren Objections at 2. The IPA is amenable to this change and does not object to its adoption. *Id.* at 48.

Staff recommends the deletion of a sentence from pages 104-105 of the Plan concerning feedback being sought on the applicability of Section 16-111.5B of the PUA to MidAmerican. Staff Objections at 14-15. This sentence appears to be inadvertently left in the filed Plan, though it was deleted from the Draft Plan, and the IPA supports its deletion. Plan at 104-105.

ComEd recommends changes to the manner in which the IPA's power procurement hedging strategy is displayed in tables 1-1 and 7-7, specifically concerning accounting for percentages already hedged via prior procurement events. ComEd Objections at 2-3. The IPA agrees and supports these changes. Table 1-1, Plan at 3 and Table 7-7, Plan at 105. ComEd also recommends a change to the savings total contained in Table 7-6 of the 2016 Plan. ComEd Objections at 8. The IPA supports this change. Plan at 103.

The Commission approves the above changes to the Plan.

B. Contested Matters

1. Plan Action Items 2 and 7: Whether any LTPPA Curtailment will be required for the 2016-2017 Delivery Year.

a. IPA Position

In the Plan, the IPA has described two recommendations regarding LTPPAs. The Renewables Suppliers discuss Action Plan items 2 and 7:

> 2. Require the utilities to provide an updated load forecast by March 15, 2016 which will be pre-approved by the ICC as part of the approval of this Plan, subject to the review of the IPA. The consensus of each utility, the IPA, the ICC Staff, and the Procurement Monitor will be required if a utility load forecast triggers the curtailment of the Long-Term Power Purchase Agreements.
>
> 7. Approve pro-rata curtailment of ComEd and/or Ameren Illinois' 2010 long-term power purchase agreements for renewable energy in the unlikely event that the updated March 2016 expected load forecast indicates that such a curtailment is necessary. This forecast will form the basis for pro-rata curtailment of long term renewable contracts assuming consensus is reached among the parties identified in Item 2 above. Otherwise, the July 2015 forecast will form the basis for curtailment. Plan at 6-7.

The IPA notes that the eligible retail customer load have been significantly affected by customer switching between utility supply and RES supply over the past several years. This reduces the quantity of renewable energy resources needed to be procured annually and the RERF budget available for their procurement. This volatility, coupled with the LTPPA entered into pursuant to the 2010 IPA Procurement Plan, is highly influential on the IPA's proposed renewable energy resource procurement approach. In the previous three plan approval dockets, the IPA has sought pre-approval from the Commission for "curtailment" of the existing long-term agreements, meaning that the utilities' financial obligations and the suppliers' delivery obligations would be "curtailed" if that was necessary to maintain compliance with the statutorily mandated rate impact cap.

At the peak of switching impacts from municipal aggregation, curtailment was required for long-term renewables contracts with ComEd, as the rate impact associated with renewable energy resource obligations was spread across too few customers (or, more accurately, too little load) in ComEd's service territory to meet existing contractual requirements. While the load forecasts submitted by the utilities for the 2016 Plan indicate that a curtailment event is unlikely, the "low" load forecast submitted by Ameren would require curtailment, and the future of customer switching in Illinois generally remains highly uncertain.

In the present proceeding, the Renewables Suppliers make several proposals regarding this process. First, they propose that the Commission need not "pre-approve" curtailment of long-term power purchase agreements given current load forecasts for the upcoming delivery year. While the IPA agrees with the Renewables Suppliers that load changes significant enough to require a curtailment are unlikely, it is not an impossible scenario, as demonstrated by Ameren's "low" load forecast. Further, the Renewables Suppliers have identified no incremental cost that would accrue through this pre-approval; as counterparties to contracts at already-determined prices and quantities that contain known curtailment provisions, they do not stand to lose financially from speculation about the possibility of a curtailment event that would be required by law, and it is unclear how they could be economically harmed. IPA Response at 23-24.

Second, the Renewables Suppliers offer two proposals through which they would assume a new role in the load forecast approval process, either through the ability to comment and/or through requiring their approval before a curtailment could be made. These changes appear designed to solve a problem that has not yet occurred, as changes to the existing load forecast and curtailment approval process are only necessary if the Commission believes that utilities' load forecasts are at risk of being manipulated so as to result in an unnecessary curtailment event.[11] The IPA does not believe it is likely that utilities are actively engaging in this type of manipulation, because the load forecasts filed in this docket are uncontested.

Further, the Renewables Suppliers forget the primary purpose of the March load forecast: updating the procurement volumes for the Spring block energy procurement. The calculations that determine if a curtailment is necessary merely flow from that purpose, and it is not in the interest of the utilities or the IPA to procure incorrect volumes of energy to meet eligible retail customer load. As the Commission has previously recognized:

> In the 2013 procurement proceeding, the Commission observed that there have been few substantive disputes regarding the underlying load forecasts of AIC or ComEd. The Commission believes this is true primarily because load forecasting is complex, the utilities have extensive experience and expertise in the area of load forecasting and the utilities have no economic incentive to develop a biased load forecast. The Commission believes actual experience has proven these observations true and AIC and ComEd have performed quite well in developing load forecasts.

[11] And even then, the IPA has offered to buy curtailed RECs using the RERF. *See,* Plan at 101-102.

Docket No. 13-0546, (Order of December 18, 2013) at 197.

Finally, the IPA points out that even if load forecasts were manipulated so as to make curtailment more likely, the existing safeguard of Staff, IPA, and Procurement Monitor approval is sufficient to prevent an unnecessary curtailment. Unlike the Renewables Suppliers, who have vested economic interests, each of these entities has an established statutory duty to ensure that statutory directives related to the procurement of both energy and renewable energy resources are met. While the IPA does appreciate that the utilities could have an interest in reducing their renewable resource obligations, there is simply no evidence that the proven process for updated load forecast approval and curtailment determination is insufficient to safeguard those interests. IPA Response at 25.

b. Renewables Suppliers Position

According to the Renewables Suppliers, the IPA Plan shows that there is a significant margin between: (i) ComEd's (and Ameren's) forecasted eligible retail customer load for the 2016-2017 Plan Year; and (ii) the levels to which the electric utilities' eligible retail customer loads would have to fall for a curtailment of purchases under the LTPPAs to be necessary in order to remain within the RPS rate caps. For ComEd, the already-contracted REC costs for the 2016-2017 Delivery Year are 63% of ComEd's estimated 2016-2017 RRB cap. The IPA Plan observes that the RRBs depend directly on eligible retail load, and therefore, so long as ComEd's March 2016 load forecast update for its 2016-2017 eligible retail customer load is close to 63% (or greater) of its July 2015 forecast value, ComEd will not need to curtail its LTPPAs. In fact, the IPA Plan notes, even under its "low" July 2015 load forecast of 2016-2017 load, ComEd would not have to curtail its LTPPAs. Renewables Suppliers Objections at 1-2.

However, despite these large margins, the IPA Plan continues to recommend (as in previous years' Plans) that the Commission, in this order, "pre-approve" curtailments of the LTPPAs if the electric utilities' March 2016 load forecast updates show curtailments to be necessary. The IPA Plan does propose that "[t]he consensus of each utility, the IPA, the ICC Staff, and the Procurement Monitor will be required if a utility load forecast triggers the curtailment of the Long-Term Power Purchase Agreements." Plan at 6. Absent such consensus, the electric utilities' July 2015 load forecasts (*i.e.*, the load forecasts presented in the IPA Plan) would continue to be used. Renewables Suppliers Objections at 2.

The Renewables Suppliers argue that in light of the significant margin between the electric utilities' load forecasts for the 2016-2017 Delivery Year and the levels of load at which LTPPA curtailments would be necessary, the Commission should direct that Plan item no. 7 in the IPA Plan be changed to provide that <u>no</u> LTPPA curtailments will be required for the 2016-2017 Delivery Year. The Renewables Suppliers claim that the Commission does not need to wait for (or even provide for) March 2016 load forecast updates, but rather can decide based on the utilities' current load forecasts provided in the IPA Plan that no LTPPA curtailments are necessary in the 2016-2017 Delivery Year.

Alternatively, if the Commission still wants to provide for March 2016 load forecast updates from the electric utilities, then Plan item no. 7 should be changed in one or both of the following ways:

First, Plan item no. 7 should be changed to provide that if an electric utility's March 2016 load forecast update indicates a need for LTPPA curtailments, then the Renewables Suppliers, other LTPPA suppliers, and other interested stakeholders, will be allowed to review the load forecast updates and submit comments to the Commission, and the Commission will then make a final determination as to the need for LTPPA curtailments. The Renewables Suppliers point out that this would eliminate the dubious practice of the Commission "pre-approving" LTPPA curtailments based on load forecasts that have not yet been produced or filed and the entities that potentially would be the most severely impacted – the LTPPA suppliers – get no opportunity to provide comments. *Id.* at 3.

The Renewables Suppliers note that they made a similar recommendation in connection with a previous year's procurement plan, and it was not adopted by the Commission. However, the circumstances here are different in that it would take *significant* changes in the electric utilities' load forecasts – particularly in ComEd's forecast – between July 2015 and March 2016 in order for the electric utilities' eligible retail customer load to fall to levels at which LTPPA curtailments would be necessary. According to the Renewables Suppliers, the March 2016 load forecast "updates" would have to be materially different from the current (July 2015) load forecasts for LTPPA curtailments to be indicated. If such significant changes in the electric utilities' load forecasts would occur in order to trigger LTPPA curtailments, and the resulting potential adverse consequences for LTPPA suppliers, the Renewables Suppliers and other LTPPA suppliers should be allowed to review and comment on the March 2016 load forecast updates before they are accepted. The Renewables Suppliers argue that the Commission should not simply "pre-approve" LTPPA curtailments, if shown to be needed by the electric utilities' as to March 2016 load forecast updates without the LTPPA suppliers and other interested parties having the opportunity to comment on the revised forecasts. *Id.* at 3-4.

To implement this proposal, each electric utility should be required to file its March 2016 load forecast update in this docket, with an explanation of the reasons for changes from the utility's July 2015 load forecast. If the filed March 2016 load forecast update indicates a need for curtailments of the electric utility's LTPPA, then interested parties should have 14 days to file comments in the docket on the updated load forecast. The Commission would then make a determination as to whether the July 2015 load forecast, the March 2016 load forecast update, or a different, modified load forecast, should be adopted for purposes of determining if curtailments of the electric utility's LTPPAs are required during the 2016-2017 Delivery Year.

The Renewables Suppliers second recommendation, either alternatively to or in addition to modification 1 above, suggests that Plan item no. 2 in the IPA Plan should be modified to provide that if an electric utility's March 2016 load forecast update indicates the need for curtailment of its LTPPAs, the consensus of the utility, the IPA, Commission Staff, the Procurement Monitor and the impacted LTPPA suppliers should be required to adopt the load forecast. The Renewables Suppliers question why one party to the LTPPAs – the electric utility – should be allowed to participate in determining if a modified (from July 2015) load forecast that triggers a curtailment should be adopted, thereby relieving the utility of a contractual commitment, while the counterparties to the LTPPAs are not allowed to participate in this determination. The Renewables Suppliers note that the LTPPA suppliers may suffer significant revenue losses as a result of the determination. *Id.* at 4.

c. ComEd Position

ComEd points out that the Renewables Suppliers advance several alternative arguments, each of which is designed to accomplish the same goal – foreclose the ability to curtail long-term power purchase agreements for renewable energy resources and RECs in the event that mass switching to retail electric suppliers would cause the rate caps to be exceeded. ComEd opposes these premature and unlawful recommendations that no curtailment be permitted to comply with the rate cap, as well as the alternative proposals, which have previously been rejected by the Commission, and urges the Commission's existing consensus process to be preserved. ComEd Response at 2.

ComEd argues that, with respect to the current planning year, no party anticipates at this time that a curtailment will be required. Even so, municipal aggregation has ushered in a very dynamic switching environment in ComEd's service territory, and the updated load forecasts required to be submitted in March 2016 will confirm whether these expectations were indeed correct. ComEd points out that the Renewables Suppliers are not content to allow this annual statutory process to take its usual course and instead ask the Commission to rush to a premature judgment now regarding the issue of curtailment by effectively eliminating the curtailment contingency in their contracts this year (even if this results in customers paying in excess of the rate cap). If this unlawful request is not granted, they propose alternative processes that are inefficient, costly, and previously rejected by the Commission. Even if these proposals were lawful, they are entirely unnecessary – the 2016 Plan again proposes to use the balance of ACPs collected on behalf of the utilities' hourly customers to purchase any curtailed RECs in an effort to mitigate the financial impacts of a curtailment if required. *Id.* at 3.

The Renewables Suppliers' primary proposal asks the Commission to preemptively order at this time that no curtailment will be authorized for the planning year. In other words, in the (unlikely) event that the March 2016 updated load forecasts demonstrated a need for curtailment, the Commission, IPA, utilities and stakeholders would be required, by order, to disregard this new information and force a smaller group of customers to pay the full costs of the Renewables Suppliers' contracts above the statutory rate cap. According to ComEd, this proposal clearly violates Section 1-75(c)(2) of the IPA Act and the curtailment provisions of the contracts, and should be rejected.

ComEd notes that the Renewables Suppliers revisit arguments they have admittedly advanced in prior years and that the Commission has already rejected. Specifically, the Renewables Suppliers propose that they be added to the consensus process the IPA has previously used to review the updated March load forecasts, and, in addition or in the alternative, the Renewables Suppliers request that the Commission permit parties to comment on the updated load forecasts culminating in another Commission determination. Yet, the Commission has already entertained arguments by the Renewables Suppliers to insert themselves in the review process of the updated March forecasts, and held that the existing process properly and fairly functions to ensure accurate and unbiased results because the participants (IPA, Procurement Monitor, Staff and the utilities) are experts in load forecasting and do not have a financial interest in the outcome of the load forecasts:

> The Commission understands that the RS is concerned with the potential impact of any updated load forecast as it has an economic interest in the potential impact on LTPPA curtailment. On the other hand, the Commission is reassured that those traditionally responsible for preparing and reviewing the updated forecast have no economic incentive to produce, or allow to be produced, a biased forecast. The Commission notes the RS request a brief period of 7 to 14 days to submit comments on the updated forecast. Based on the August 15, 2013 posting of Draft Plan by the IPA, the RS had significantly more time to review the load forecasts than it proposes to review the updated forecasts. The nature of the RS' review, comments, and recommendations regarding the load forecasts suggest to the Commission that approving the RS' proposal would serve no meaningful purpose.
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> * * * *
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> The Commission also observes that the IPA is an independent state agency created specifically to develop the Procurement Plan as well as to implement the approved Plan. While the Staff, Procurement Administrator, and Procurement Monitor participate in and oversee the IPA's activities, the IPA has responsibility for many of the procurement activities. Despite the concerns expressed by the RS, the Commission is comfortable the process it has previously used has been and will continue to be effective and successful.

Docket No. 13-0546, (Order of December 18, 2013) at 198.

ComEd argues that the fact that a curtailment may be less likely during the present planning period does not warrant a change to a Commission-approved process that emphasizes technical expertise and an unbiased review process. The primary purpose of the revised March forecasts are to purchase the correct amount of energy for customers, and the existing consensus process has proven very effective in accomplishing this goal. Indeed, customers may bear additional costs and risks if the updated forecast cannot be implemented due to an unwise and unnecessary change to the current efficient and unbiased process. For these reasons, the Renewables Suppliers' alternative arguments in this docket should be rejected. ComEd Response at 5.

d. Staff Position

Staff disagrees with the Renewables Suppliers' recommendation to alter Plan Action Item no. 7. The Commission is subject to a legislative mandate to protect ratepayers against rate increases due to renewable resource procurement in excess of those increases permitted by statute. That mandate is not diminished during the 2016-

2017 plan year by the admittedly lower probability that LTPPA curtailments will be necessary to bring about that protection. As the Commission has witnessed in previous years, circumstances can change rapidly and dramatically in the dynamic arena of retail electric choice. A significant shift among consumers away from utility supply and toward ARES supply would leave the remaining utility customers vulnerable to impermissible rate increases. If the General Assembly wanted to protect renewable suppliers (rather than ratepayers) against the impact of such load shifts, it would have included such protections in the governing statutes. Instead, the General Assembly chose to protect utility customers. Staff urges that the Renewables Suppliers' proposed change to Plan Action Item no. 7 should be rejected. Staff argues that the Renewables Suppliers' 2 alternative recommendations should also be rejected. Staff Response at 3.

Staff addresses both alternatives together, noting at the outset that the Commission has addressed the issue of load updates before. Docket No. 08-0519, (Order of January 7, 2009) at 58-60; Docket No. 09-0373, (Order of December 28, 2009) at 165-67; Docket No. 13-0546, (Order of December 18, 2014) at 196-99. Indeed, a Commission-approved process for addressing forecast updates has been in place since 2009, and the Commission rejected a similar change to the process proposed by the Renewables Suppliers in 2013. As the Commission then noted:

> The Commission also observes that the IPA is an independent state agency created specifically to develop the Procurement Plan as well as to implement the approved Plan. While the Staff, Procurement Administrator, and Procurement Monitor participate in and oversee the IPA's activities, the IPA has responsibility for many of the procurement activities. Despite the concerns expressed by the [Renewables Suppliers], the Commission is comfortable the process it has previously used has been and will continue to be effective and successful.
>
> As in previous procurement proceedings, between the IPA, Staff, and ComEd/AIC (as well as the Procurement Administrator and Monitor, should they be retained), the Commission believes that technical issues related to load forecasting will be objectively vetted and appropriately addressed. The Commission rejects the [Renewables Suppliers'] proposals.

Docket No. 13-0546, (Order of December 18, 2014 at 196-99). Staff points out that the IPA's current plan appropriately incorporates the same process that was approved by the Commission in the dockets cited above. This process allows the IPA to take into account updated load forecasts and their impact on renewable curtailments. Historically this process has worked well, and there is no reason to believe it should not continue to work well in the future.

Finally, Staff notes that, by the time the utilities submit their March updates, the Commission will have already approved the load forecasting methodologies. The purpose of the March updates is merely to update the inputs to the forecasts to reflect only any changes that may occur over the period since the forecast was presented in this docket in July. Issues about the forecast on which there can be debate, as well as the vast majority of the results, will have already been submitted, reviewed, litigated, and approved in this formal docket. Thus, by the time the Commission enters its final order, Renewables Suppliers, as well as any other interested party, will have had ample opportunity to fully vet the forecast methodologies. Consistent with past years, the purpose of the March updates is highly limited and focused and must proceed expeditiously. Staff Response at 5-6.

e. Ameren Position

Ameren states that the Renewables Suppliers' recommendations should be rejected for three reasons. The Renewables Suppliers continue to ignore the variability due to customer switching, as illustrated by the high and low forecast scenarios provided in July of 2015. If switching increases in the fall, Ameren warns that the March 2016 forecast could warrant LTPPA curtailment in the 2016 Plan year and beyond. Ameren Response at 4-5. The existing timetable for procurements do not allow for the filing of comments and a Commission order when forecast updates are available. This is the reason, Ameren states, that the IPA has sought pre-approval of March forecasts within the instant Docket. Finally, Ameren notes that consensus on the forecasts is reached among the IPA, Staff, the Procurement Monitor and the applicable utility, regardless of whether curtailment is necessary. Ameren emphasizes that these parties have no financial interest in the outcome, which is why they can remain objective. Therefore, Ameren recommends the Commission reject the Renewables Suppliers' proposals. *Id.*

f. Wind on the Wires Position

Wind on the Wires states that having the IPA, ICC Staff, the utility and the Procurement Monitor review and approve the load forecasts and approve the curtailment volumes of LTPPAs is contrary to Section 16-111.5(d)(4) and, at a minimum, deprives the party that is subject to the curtailment the ability to protect its investment through review and comment on the load forecast. The statute vests the Commission -- not the IPA, ICC Staff, the utilities or the Procurement Monitor -- with the authority to approve the load forecasts used in the procurement plan. While the Commission has in the past delegated to Staff post-docket review functions that are ministerial and within their field of expertise, Wind on the Wires states that the utilities are distinctly different than Staff. The utilities are not a statutory creation with an intended function of aiding the Commission in executing its oversight and regulatory responsibilities. Thus, the utilities should not be part of this load forecast decision making. If utilities are part of the decision making process, then the parties whose contracts are the subject of potential reduction should be allowed to participate by being granted the ability to review and comment on the Spring Load Forecast used to determine the need for and amount of reduction. Wind on the Wires would accept the Renewables Suppliers suggestion, that the affected supplier also be a member of the decision making team, in conjunction with the utility, IPA, Staff and the Procurement Monitor. Wind on the Wires Response at 4-5.

As a matter of policy, Wind on the Wires argues, parties affected by the curtailment should be afforded an opportunity to comment on the load forecasts and curtailment volumes because the decision about the load forecast affects their revenue stream. The ability to comment on the load forecasts is inherently tied to the forecasts function – forecasts are the basis for determining whether to curtail existing contracts. Given that the Spring Load Forecast plays the primary role in determining whether LTPPA contracts should be curtailed, parties affected by that curtailment should be afforded the ability to review and comment on that load forecast, similar to this Docket.

Thus, Wind on the Wires supports the two alternative proposals submitted by the Renewables Suppliers. *Id.*

g. Commission Analysis and Conclusion

The Renewables Suppliers submitted several alternative proposals to challenge how the IPA handles the March 2016 load forecast. In prior dockets, the Commission approved a process wherein the IPA, Commission Staff, the utilities and a Procurement Monitor reviewed and approved the load forecast. This includes whether curtailment will be necessary. The Commission has previously approved the IPA's request to determine whether LTPPA curtailment is necessary after the utilities have submitted their updated forecasts in March. The Renewables Suppliers have requested the Commission declare that based on the information in the record, no LTPPA curtailment will be necessary in the March 2016 load forecast. This proposal is supported by Wind on the Wires.

In the alternative, the Renewables Suppliers propose that if an electric utility's March 2016 load forecast update indicates a need for LTPPA curtailments then the Renewables Suppliers, other LTPPA suppliers, and other interested stakeholders should be allowed to review the load forecast updates and submit comments to the Commission, and the Commission will then make a final determination as to the need for LTPPA curtailments. The second proposal by Renewables Suppliers is that the Plan Action Item no. 2 in the Plan should be modified to provide that if an electric utility's March 2016 load forecast update indicates the need for curtailment of its LTPPAs, the consensus of the utility, the IPA, Commission Staff, the Procurement Monitor and the impacted LTPPA suppliers is required to adopt the load forecast. Again, Wind on the Wires supports these proposals.

The IPA, Staff, ComEd and Ameren all oppose the proposals of the Renewables Suppliers. The first proposal of the Renewables Suppliers is for the Commission to direct that Plan item no. 7 be changed to provide that no LTPPA curtailments will be required for the 2016-2017 Delivery Year. The Renewables Suppliers claim that the Commission does not need to wait for (or even provide for) March 2016 load forecast updates, but rather can decide based on the utilities' current load forecasts provided in the Plan that no LTPPA curtailments are necessary in the 2016-2017 Delivery Year. The Commission notes that the retail electric market can change quickly. There could be a large migration away from utility supply to ARESs which would lead to a shift in needed supply. That is the primary purpose of the forecasts made by the utilities in March - to update the procurement volumes for the March energy procurement. Based on the forecasts, only a moderate amount of incremental switching in the Ameren service territory would be necessary to trigger a curtailment. As previously determined by the Commission, the IPA's plan allows for taking into account updated load forecasts and the need for possible curtailment. The Commission is satisfied with this process and the Renewables Suppliers' proposal to find that no curtailment is necessary for the 2016-2017 Delivery Year is rejected.

The purpose of the March load forecast updates is to determine the final quantities needed for the energy procurement. This process allows the IPA to take into account updated load forecasts and their impact on renewable curtailments. The timetable for these procurements does not allow for the filing of updated forecasts with the Commission, the filing of comments from interested parties and a Commission determination. The Commission has previously determined that load forecasting is complex, and it takes expertise to develop an unbiased forecast. The Commission notes that the parties involved in the process, the IPA, Commission Staff, the utilities and the Procurement Monitor have no financial interest in the review process. This existing review process of the updated March forecasts ensures accurate and unbiased results because the participants are experts in load forecasting and do not have a financial interest in the outcome. Both the Renewables Suppliers and Wind on the Wires have an economic interest in the outcome of this process. The Commission finds that the process recommended by the IPA and used in the past has worked well in developing unbiased load forecasts. The proposals of the Renewables Suppliers concerning curtailment or including other interested parties to the process are rejected.

The Renewables Suppliers take exception to the ALJPO's rejection of the Renewables Suppliers' proposal that the utilities should file a revised March load forecast in this docket; interested parties should have the opportunity to file comments, and the Commission should decide based on the revised forecast and the comments whether the revised forecast should be adopted for purposes of the Plan for the upcoming year beginning June 1. Renewables Suppliers Br.on Exceptions at 2. The Renewables Suppliers claim that the current process does not comply with the statute because the Commission is not involved in the final decision. The Renewables Suppliers also claim that this process deprives them of equity and due process considerations because they do not have an opportunity to submit comments on revised forecasts that may impact their financial interests. *Id* at 2-3.

Staff recommends that the Commission reject the arguments of the Renewables Suppliers. Staff points out that Plan Action Items 2 and 7 do not conflict with the PUA. Staff Reply Br. on Exceptions at 4-5. 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 benefit of price stability." 220 ILCS 5/16-11.5 (d)(4). Staff argues that the word "forecast" in Section 16-111.5(d)(4) refers to the mathematical models and methods used to derive forecasted quantities. *Id* at 5. According to Staff, the Commission has approved the use of updated load forecasts to address the potential for significant shifts in load, beginning with the first IPA procurement plan. *Id* at 5. With respect to the Renewables Suppliers' equity and due process arguments, Staff points out that the Plan is consistent with the PUA and the Plan incorporates the same process that was approved by the Commission in prior dockets. *Id* at 6. Staff states that by the time the utilities submit their March updates, the Commission will have already approved the load forecasting methodologies. Issues concerning the forecast on which there can be a debate, as well as the vast majority of the results, will have already been submitted, reviewed, litigated and approved in this formal docket. By the time the Commission enters its final order, any interested party will have had an opportunity to respond to the forecast methodologies. *Id* at 6.

Ameren agrees that the ALJPO is correct in rejecting the position of the Renewables Suppliers. Ameren Reply Br. on Exceptions at 2. Ameren points out that the Commission has previously, on multiple occasions, determined that the process with the current parties, the IPA, Staff, the utilities and the Procurement Monitor has worked well. This is because the parties involved have no financial incentive to achieve any other outcome other than compliance with the Act. *Id* at 2-3. Ameren supports the conclusion reached by the ALJPO and hopes that it will be clear that this matter has been addressed on numerous occasions in prior Plan proceedings and it should be closed for future proceedings. *Id* at 3-4.

ComEd also recommends rejecting the position of the Renewables Suppliers on this issue. ComEd states that the Commission has previously held that the existing process properly and fairly functions to ensure accurate and unbiased results because the participants are experts in load forecasting and have no financial interest in the outcome. ComEd Reply Br. on Exceptions at 4. ComEd states that the Commission should adopt the ALJPO's conclusion on this issue.

The IPA points out that the Renewables Suppliers continue to argue that they must be involved in the process of approving any load forecasts used for the IPA's Spring procurement, a position that has been argued and rejected on several occasions. IPA Reply Br. on Exceptions at 10. The IPA states that the additional comments and process as recommended by the Renewables Suppliers would only be necessary if the process was subject to manipulation. *Id* at 11. According to the IPA, the existing process is clearly consistent with Section 16-111.5 (d) (4). Any party could have commented on the load forecasts that were filed in this docket and no comments were filed. *Id* at 11. The IPA claims that both past practice and the plain language of the law indicate that there is no need to adopt the process proposed by the Renewable Suppliers. *Id* at 12.

The Commission agrees with the IPA, Staff, ComEd and Ameren that the current process has worked well and has led to favorable results in the procurement process. There is no reason to change the conclusion on this issue. The Commission finds that the position of the Renewables Suppliers has been previously litigated and decided in an action that resulted in a final judgement on the merits involving the same parties or their privies. Docket No. 13-0546, (Order of December 18, 2014 at 196-99). The Commission finds that the Renewables Suppliers are Collaterally Estopped from presenting this argument in future procurement dockets. Collateral Estoppel prevents the re-litigation of issues decided in earlier proceedings. Commonwealth Edison Company v. Illinois Commerce Commission, *et.al.*, 2014 IL. App. (1st) 130302 at par.53.

2. Section 7.1.2.1 Whether the Plan Should be Modified to Ensure that the Utilities Offer Multi-Year Contracts in 2017.

a. IPA Position

In the Plan, the IPA states that an issue upon which consensus was not reached was the length of time for Section 16-111.5B program contracts that use hourly load profiles. During workshops, some parties argued that the nature of programs available, and vendors willing to participate, would be limited by shorter contracts, especially the one-year contracts that are being offered through the utilities' RFPs seeking programs for the 2016 Plan. While only one-year contracts were offered by the utilities for programs solicited in early 2016, the IPA tentatively understands that ComEd and Ameren will be offering contracts up to three years in length for Section 16-111.5B programs solicited for inclusion in the 2017 Plan (including peak-hour oriented EE programs). Plan at 85.

The IPA argues that, contrary to Ameren's suggestion that the RFP for the 2017 Plan has not even been discussed or developed yet, during Commission-mandated workshops concerning the IPA's EE as an Supply Resource alternative proposal from the 2015 Plan, the utilities indicated that the 2017 Plan RFP would be an appropriate time for multi-year contracts to once again be offered, given how multi-year contracts at that point in time would coincide with the Section 8-103 planning cycle. In an effort to "fully capture the potential for all achievable cost-effective savings," the IPA requests that the Commission order the utilities to offer the option of contracts of at least three years in length as part of their Section 16-111.5B RFPs for the 2017 Plans. Given the statements in Ameren's Objections and its concurrent arguments to withdraw other consensus commitments, the IPA concludes that there is simply no other way to ensure that this prior commitment will be observed. IPA Response to Objections at 17.

b. Ameren Position

Ameren cites the IPA Plan, which makes certain statements to the effect that the utilities will be offering multi-year contracts, (up to three years in length) to include Section 5/16-111.5B programs in the 2017 IPA Plan. Ameren states that there has been no decision on what will happen in the 2017 IPA Plan at this time. Ameren proposed several small modifications to the Plan in its attachment to its Objections, with the goal of restoring the more conditional language that was included in the draft IPA Plan. Ameren Objections at 2-3.

c. Commission Analysis and Conclusion

The IPA's request is reasonable and it is adopted. Longer contracts can promote broader participation and better results. The Commission agrees with the IPA that contracts of at least three years in length may "fully capture the potential for all achievable cost savings." While Ameren proposes edits to the Plan, it is not clear that Ameren disagrees with the IPA's request and rationale. The utilities should offer the option of contracts of at least three years in duration as part of their Section 16-111.5B RFPs for their 2017 Plans. The Commission rejects Ameren's proposed language, as it seems to add little and it could override the possibility of longer contracts.

Ameren argues that the length of these contracts should be no longer than three years. Ameren reasons that Section 16-111.5B contracts are required by law to be new or expanded programs that are incremental to Section 8-103 of the Act, citing 220 ILCS 5/16-111.5B(3)(C). Ameren Br. on Exceptions at 1-3. The IPA has no objection to limiting multi-year contracts to three years in duration. IPA Reply Br. on Exceptions at 7.

This request is reasonable and it is approved. Multi-year contracts in the 2017 Plan are limited to three years in duration.

3. Section 7.1.3 Whether the Plan Should Include 2013 Consensus Items in this Section.

a. IPA Position

Section 7.1.3 of the Plan is entitled "Prior Year Consensus Items." It contains an extensive list of matters that were agreed upon by parties in workshops in previous years. Plan at 89-94.

The IPA contends that including previous years' consensus items from Commission-ordered workshops in the 2016 Plan might appear awkward. It reasons that if these items were previously agreed upon and approved by the Commission, there is no need to approve them again. According to the IPA, in the RFP development process for soliciting third party EE programs for the 2016 Plan, Ameren informed the IPA and Staff that it did not consider itself bound by prior years' Commission-approved consensus items, as such items were approved only in prior plan proceedings. IPA Response at 14.

The IPA opines that this approach risks rendering Commission approval of consensus language entirely superfluous, as consensus issues may concern steps that already were taken for that year's Plan. It avers that because Section 16-111.5B leaves many implementation details open for interpretation, consensus around the law's implementation is essential to developing firm expectations for all stakeholders. The IPA, with the assistance of Staff's comments on the draft Plan, thus compiled prior years' consensus items and has specifically requested that they be approved once again for prospective application. The IPA contends that at no point does Ameren actually indicate which items specifically are "stale" and how they are "contradictory." *Id.* at 14-15.

b. Ameren Position

Ameren argues that the 2013 consensus items should be stricken from the Plan. It states that they are contradictory to some of the 2014 consensus items. Ameren also contends that these matters are "stale." Ameren Objections at 3.

According to Ameren, the IPA has selectively identified only a few of the consensus positions reached in 2013. Also, Ameren maintains that the IPA gives "no regard" to the current landscape of EE policy development. Ameren Reply at 4. It further states that there is "no disagreement that the IPA's list of consensus positions reflects positions on EE policy that were developed two years ago. *Id.* at 5.

c. Staff Position

Staff disagrees with Ameren. Staff states that it proposed a specific list of consensus items from prior years' workshops for inclusion in the Plan here that specifically removed the 2013 consensus items that contradicted the 2014 consensus items. It states that, while Ameren generally asserts that some of the 2013 consensus items in the Plan are contradictory to 2014 consensus items, Ameren does not identify any such alleged contradictions. Staff avers that to its knowledge, no such contradictions exist. Staff Response at 6.

Staff additionally argues that the Commission should reject Ameren's argument that the 2013 consensus items are stale and should not apply with respect to the current IPA Plan cycle. Staff maintains that there is no reason to reject them simply because parties reached consensus on these issues in 2013. To do otherwise, Staff continues, would require parties to revisit every consensus issue every year, which is a costly and time-consuming approach to addressing IPA Plans. Staff also states that Ameren fails to identify specific consensus items that are stale and should no longer apply, and Staff is aware of none. *Id.* at 7.

Staff agrees with Ameren's statement that "[t]here are significant changes and discussions occurring between parties with respect to future development, planning, implementation and evaluation of energy efficiency in Illinois," citing Ameren's Objections at 3. It is for this reason, Staff continues, that the Plan should include an explicit list of consensus items in its drafts and plan submissions. Staff opines that this allows parties to identify and provide support for the removal of any consensus items they believe are obsolete or no longer applicable. In such cases, the Commission should be clear that the burden is on parties to support their proposals with reference to relevant changes in circumstances that support removal of prior consensus items. Staff contends that this is a far more efficient way to respond to changing circumstances than Ameren's proposal to reject all prior consensus items and begin anew on every item every year.

Staff also takes issue with Ameren's intimation that any consensus items included in the IPA Plan should apply only with respect to the current IPA Plan cycle and should not apply going forward. Staff states that Ameren's proposal appears to imply that consensus items included in particular year's plan filing could not apply to processes and procedures regarding 2017-2018 delivery year, rendering many of the consensus items irrelevant and/or meaningless. Staff concludes that Ameren's proposal should therefore be rejected. Staff Response at 8.

d. Commission Analysis and Conclusion

To begin, Ameren provides this Commission with no information as to what 2013 consensus items are stale or contradictory and no statement as to why some 2013 items are contradictory. Thus, this Commission has no information upon which it can assess Ameren's argument.

Additionally Staff states that it reviewed the list of consensus items, and it removed the items that were contradicted by later workshop consensus items. While Ameren argues that the IPA has selectively identified only a few of the 2013 consensus positions, in fact, Staff's averment that it removed the items that were contradicted in later workshops establishes that this assertion is not correct. Also, as Staff and the IPA point out, inclusion of consensus items in a Plan is useful, it provides guidelines to vendors and the utilities. The Commission therefore declines to require the IPA to amend its Plan in the manner that Ameren requests.

In order to reduce any potential confusion on this issue, Staff recommends adding the following language: "Accordingly, the Commission hereby approves and adopts the 2013 and 2014 consensus items as requested in the Plan and as is set forth in Section III.B.2-III.B.10 of this Order and the Commission otherwise approves the IPA's applicability request pertaining to those provisions." Staff Br. on Exceptions at 3-4. Staff's request is reasonable and it is hereby approved.

Ameren withdrew its objection to consensus items based on its perception that some conflict with each other. Ameren Br. on Exceptions at 4.

Ameren and Staff point out that the SAG is actively discussing the future development, implementation and evaluation of energy efficiency programs in Illinois. *See, e.g.,* Staff Reply Br. on Exceptions at 8-9. They suggest the addition of the following language: "The Commission clarifies that adoption of the 2013 and 2014 consensus items in the Plan is not intended to prevent evolving energy efficiency policy discussions from occurring through the SAG. The Commission encourages the SAG to review the 2013 and 2014 consensus items adopted in the Plan to help identify any items which should be removed from future Plans due to staleness." This request is reasonable and it is hereby adopted.

4. Section 7.1.4 Whether Ameren Should be Required to Conduct TRC Test Analyses for Programs that are Determined to Duplicate Existing Programs.

a. IPA Position

The Plan states that Ameren screened for duplicative programs before it ran the TRC Test analysis, while ComEd did the opposite. The IPA believes that it is preferable to conduct this screening on every bid that complies with the basic requirements of the RFP, and conduct any other screening thereafter. It asserts that the TRC Test assessment is sufficiently subjective so that it should be treated differently from other RFP requirements. The IPA contends that having a complete record of the utilities' TRC Test results will aid in its review of programs for inclusion in the Plan. Plan at 93.

The IPA believes that TRC Test analyses should be conducted for all programs meeting the requirements of the RFP, even those for which a determination that it duplicates another program is made. It points out that not all parties may agree with the utility's determination as to whether an EE program duplicates another EE program. Also, the process approved by the Commission in Docket No. 13-0546 for making duplicative determinations calls on the IPA to make its own independent assessment as to whether a program is indeed duplicative, which may be different than the utility's determination. The IPA requested that the Commission direct the utilities to apply this type of screening for all bids which are compliant with the basic RFP requirements.

The IPA states that the Commission-approved process for determining whether a proposed Section 16-111.5B program is "duplicative" of an existing program and thus should not be approved consists of the following steps:

- First, the utilities receive and review the third-party RFP results, and determine which bids are, in the utility's estimation, duplicative or competing.

- Next, in the annual July 15 assessment submitted to the IPA, the utility may exclude programs which it has determined are duplicative or competing from the estimated savings calculation (and the associated adjustments to the load forecast).

- In preparing its annual procurement plan, the IPA independently reviews all of the bids submitted by the utilities and it determines which bids the IPA believes are duplicative or competing.

- After the Plan has been filed, the parties to the Procurement Plan approval litigation, including the IPA, may opine regarding whether a particular program is duplicative or competing, and the Commission will make the final determination.

IPA Response at 13.

The IPA opines that the approach offered by Ameren could work if the utility's initial determination was final, but it is not final. It further explains that the approach offered by Ameren also could work, if the IPA conducted its own TRC Test analysis, but it does not; the IPA depends on the utilities for initial screenings, with the IPA then testing assumptions and conducting sensitivity analyses based on utility submittals. *Id.* at 13-14.

The IPA avers that the inherent problem with not conducting a TRC Test calculation for programs that are deemed to be duplicative by the utilities is that the IPA and Commission are required to conduct an independent analysis and determine whether an EE program duplicates an existing program. Should the IPA or the Commission arrive at a different conclusion than that of the utilities as to whether a program is duplicative, the IPA continues, neither will have the information necessary for determining whether to include the program without a test result. It concludes that only by conducting this calculation up front is this problem avoided. *Id.* at 14.

b. Ameren Position

Ameren asks the Commission to reject the IPA's suggestion that the utilities should be required to perform a TRC analysis on all programs meeting the requirements of the RFP, including bids that were initially found to duplicate preexisting programs. According to Ameren, performing this complicated analysis would be a waste of resources which the statute does not require and which cannot produce information that is reliable enough to be useful. Ameren Objections at 8.

Ameren states that this year it received 32 bids, 10 for residential customers and 22 for business customers. Four bids withdrew or were never completed, leaving twenty-eight for review. Ameren, working collaboratively with a group of interested stakeholders, reviewed those 28 bids to determine whether they were compliant with the RFP, including whether any were duplicative of Section 8-103 programs or other preexisting programs. Ameren states that all parties agree that eleven bids were duplicative and thus did not comply with the RFP instructions. And, because they were non-compliant, Ameren did not put the duplicative bids through the TRC Test. *Id.* at 4.

Ameren argues that the IPA's recommendation needlessly increases costs and is inherently contradictory, impractical, and contrary to the terms of the Act. Ameren states that it is not disputed that performing the TRC analysis on a bid requires a substantial investment of time and resources, citing the Plan at 93. In Ameren's view, this analysis is not as simple as plugging a set of known inputs into a calculator and getting a result. Instead, according to Ameren, the TRC analysis requires review by Ameren and other stakeholders, as well as a detailed and complicated analysis by an expert consultant.

Ameren further avers that many of the inputs needed for this analysis come from the bidder, which must be reviewed for reliability, accuracy and completeness. It maintains that if there is a problem with the information provided by the bidder, Ameren and its consultant must request additional information and, if it is received, must begin the review process anew. Additionally, Ameren states that sometimes, the bidder challenges the TRC analysis or the assumptions that it has made, further complicating the process. It concludes that this time and effort should be spent on bids that comply with the RFP's requirements; ratepayers should not be required to spend additional funds analyzing non-compliant, duplicative bids. *Id.* at 4-5.

Ameren is also of the opinion that the IPA's requested directive is inherently contradictory because, while the IPA acknowledges that the duplicative programs at issue were not compliant with the RFP, it also states that TRC analysis should be run on duplicative programs anyway, citing the Plan at 93. However, according to Ameren, determining whether a bid seeks to duplicate savings, and is therefore out of compliance with the RFP, is not difficult. Ameren points out that its RFP provides that "In an effort to avoid market conflict and confusion, as well as [to] efficiently and cost-effectively capture incremental savings contemplated by the Act, bidder's proposed programs should not be duplicative of programs currently offered in the Ameren or DCEO energy efficiency portfolios." However, Ameren continues, bidders who went ahead and submitted duplicative programs anyway did not comply with the RFP, just like bidders who provided incomplete or inaccurate submissions did not comply with the RFP. Ameren Objections at 6-7.

Ameren additionally argues that TRC results are only as good as the underlying information upon which this analysis is run. It points out that a bidder who cannot follow simple instructions, or who exhibits a fundamental lack of awareness of the programs that are already ongoing in this State, sends a strong message that its underlying data and assumptions may not be reliable. Ameren is of the opinion that therefore, bidders who have not complied with the RFP, including those who bid on duplicative programs, should be screened out early in the process, so that additional resources are not expended on them. *Id.* at 7.

Ameren further contends that the IPA did not provide details regarding how such analysis would or could be helpful. According to Ameren, TRC values are typically calculated for a specific program under the assumption that the program is the sole program designed to achieve the estimated savings. It avers that when a person runs TRC values on duplicative programs without regard to the fact that the two programs would be run together, the results are not reliable. This is so, it continues, because the results would not account for the increased costs needed to account for a program that competes with another program, or any double-counted savings and/or quantifiable societal benefits. It concludes that, if a TRC value cannot reliably be calculated, it is not a useful tool.

Ameren also maintains that screening out programs first because they are duplicative is supported by the Act itself, which directs utilities to use the RFP process to identify "new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103," citing 220 ILCS 5/5/16-111.5B (a)(3)(C). It maintains that programs which merely duplicate (as opposed to expand) Section 8-103 savings are obviously not "incremental" to programs producing the same savings, and programs that merely duplicate existing Section 5/16-111.5B savings are not "new or expanded" EE programs or measures. It concludes that because duplicative programs do not meet the statutory standard, they are not to be included in a utility's assessment of a program. *Id.* at 8.

According to Ameren, the IPA's Response summarizes the way the Procurement Plan development process worked several years ago. At that time, a utility independently reviewed third-party RFP results and determined which programs were duplicative and competing. A utility could exclude those programs from estimated savings calculations, but would include those programs in its submittals so that the IPA could then make its own separate assessment of the duplicative/competing question. The IPA would then make a separate determination based on the information provided by the utility. Ameren Reply at 17-18.

Ameren asserts that the problem with the IPA's position is that the process changed this year. After last year's IPA Plan docket, 14-0588, Ameren worked with interested stakeholders in the bid review process, and specifically included them in the early-stage duplicative program review process. The RFP results were reviewed by Staff and other interested stakeholders, including the IPA. After this review, Ameren continues, all parties, including the IPA, reached a unanimous conclusion regarding which programs duplicated utility-run programs. *Id.* at 18.

Ameren concludes that based on the old process, the IPA states that it needs TRC Test information in case it determines, after its review of the bids, that a program is not duplicative. But, Ameren continues, if the IPA and the utility are reviewing the bids at the same time and arriving at the duplicative program determination together, as they will be unless the process changes, the IPA's concern is a non-issue. However, Ameren would have no objection to simply removing this issue from the Plan altogether as suggested by Staff, as it can be resolved in a future proceeding, if necessary. *Id.* at 18-19.

c. Staff Position

Staff takes the position that while Ameren raises several valid concerns, the Commission need not and should not address Ameren's recommendation at this time. It states that because the 2016/2017 delivery year represents the end of the utilities' current Section 8-103 three-year EE plan cycle, there currently are no Commission-approved EE programs or measures for the Section 8-103 2017/2018 delivery year. Thus, Staff continues, none of the programs that will be submitted to utilities and the IPA as a result of next year's Section 16-111.5B RFPs will, when they are submitted, duplicate existing approved Section 8-103 EE programs for the 2017/2018 delivery year. Staff Response at 9.

Staff also maintains that the Commission should give parties additional time to consider and work toward resolution of this issue as it concerns IPA Plans for 2018 and beyond. In Staff's opinion, Ameren raises valid concerns concerning the performance of such analysis. However, Staff states that Ameren's arguments are premised significantly upon the assumption that determinations regarding whether programs are duplicative is "not difficult." Staff points out that this may not always be the case. In fact, Staff continues, disputes concerning whether a program was duplicative versus competing occurred in the last procurement proceeding, Docket No. 14-0588. *Id.* at 10.

Staff posits that in its 2014 IPA Plan Order, the Commission addressed the process for drawing distinctions between duplicative programs and competing programs at length. It adopted formal standards to aid stakeholders and potential bidders to identify and distinguish between the two, citing Docket No. 13-0546, (Order of December 18, 2013) at 148-49. In Staff's opinion, the necessity for such guidance indicates that such determinations can be difficult. While Staff agrees with Ameren's goal to eliminate needless analyses, it states that the Commission should not adopt a process that does not require utilities to conduct TRC analyses when parties have reasonable disagreements as to whether a program duplicates an existing EE program. Staff Response at 10-11.

d. Commission Analysis and Conclusion

Both the IPA and Ameren have valid points. The IPA is concerned with having enough information up front regarding an EE program and Ameren is concerned with the time and expense involved in conducting TRC analyses of bids made by entities that do not follow the directions on Ameren's RFP form. Staff rightly states that the 2016-2017 delivery year is the end of the current Section 8-103 three-year EE plan cycle, and therefore, it is not possible to duplicate a Section 8-103 EE plan for the 2017/2018 delivery year. It is possible, although it seems unlikely, to duplicate another Section 16-111.5B program.

At this time, the Commission agrees with Ameren in that it should not be required to conduct a TRC analysis on bids when they have been found to duplicate existing EE plans. Therefore, the IPA shall strike the language in its Plan that requires the utilities to do so.

It may be possible to find some common ground between the IPA's position and Ameren's by exploring the topic in workshops conducted by the SAG. Perhaps additional information would be helpful up front, without the necessity of a full TRC analysis. Or, it may be possible that some parts of the TRC analysis could be conducted preliminarily, without the necessity of a full TRC analysis. Other ways may bridge the gap between Ameren's position and the IPA's. Exactly what information the IPA needs up front should be discussed in SAG workshops and hopefully resolved therein.

The Commission acknowledges Ameren's argument that because the process has changed, this issue may be moot. However, the IPA is of the opinion that it needs more information, and how to address the information it needs is best left to discussions at the SAG workshops. On that point, the Commission agrees with the IPA.

On Exceptions, the AG takes issue with the language in the Commission's Analysis and Conclusion immediately above. The AG reasons that permitting utilities to circumvent TRC analysis leaves the IPA without the critical TRC cost analysis it relies upon to independently assess all of the utility's findings and recommendations as to what should be included in a Plan. It points out that the IPA retains independent authority to determine whether a program is competing or duplicative. Because the IPA relies upon the utilities to conduct TRC analyses, the importance of a utility submitting a TRC analysis cannot be understated. AG Br. on Exceptions at 10-12.

The IPA argues that the language in the Commission's Analysis and Conclusion immediately above is erroneous. The IPA avers that while the Commission-directed process for making a determination as to whether a program is duplicative does not specifically address TRC calculations, it does require utilities to provide the IPA with all of the underlying documents for the IPA's review. It contends that requiring TRC analyses for all programs is consistent with the spirit of this requirement. The IPA states that absent a TRC analysis, it would not know whether it should include a program that a utility has designated as duplicative in a Plan. IPA Br. on Exceptions at 4-5. ELPC concurs with the AG and the IPA that the TRC test is crucial and the IPA needs this information. ELPC Reply Br. on Exceptions at 5.

No party has stated what in a TRC analysis is critical for the IPA's independent assessment as to whether an EE program is duplicative. It is more logical, at this time, to ensure via SAG workshops that the parties are on the "same page" as to what information the IPA needs to determine whether that information can be tendered without a formal TRC analysis, and then, if need be in the future, revisit this issue with concrete information. The Commission therefore declines to make a change to the language above.

On Exceptions, Ameren points out that the issue here involves not whether Ameren determines whether a program is duplicative; rather, here, the programs in question were determined to be duplicative by the Natural Resources Defense Council, ELPC, the Department of Commerce and Economic Opportunity, Ameren, and Commission Staff. It maintains that, in last year's procurement plan proceeding, Docket No. 14-0588, parties requested more stakeholder involvement in the bid review process and the Commission agreed. ICC Docket No. 14-0588, Final Order of December 17, 2014, at 225. Ameren then incorporated the various stakeholders, including the IPA, into the review process. In other words, Ameren continues, the IPA had already reviewed the programs in question by July 15, 2015, which was when Ameren made its submittal to the IPA. Also, at that time, the IPA had already determined, along with other stakeholders, that these programs were duplicative. Ameren Reply Br. on Exceptions at 5-7.

The Commission notes that Ameren's averments are indicia that the correct course of action is not to require TRC analysis of programs that are determined to be duplicative. Instead, as is set forth above, a more useful course of action is to determine exactly what information the IPA would need through SAG workshops.

Ameren further takes issue with the IPA's statement regarding the directive to provide it with all of the underlying documents regarding an EE program bid. It asserts that providing the underlying documents is not at all the same as conducting a TRC analysis. Ameren concludes that the IPA's logic linking the two is faulty. *Id.* at 8. This statement further indicates that workshops clarifying the terms involved and addressing the issue are needed.

5. Section 7.1.4 Whether to Require the SAG to Address How Section 16-111.5B Programs can be Used to Expand Section 8-103 EE Programs that have not yet been Approved by the Commission.

a. IPA Position

In the Plan, the IPA states that for the 2017 Procurement Plan to be developed during the summer of 2016, the utilities will be filing their next set of Section 8-103 EE three-year plans for the Fall of 2016, and therefore, there will not be a set of existing (and approved) Section 8-103 programs against which the Section 16.111.5B programs would be considered. The IPA observed that, at the Staff-led workshops conducted in 2013, the issue of multiyear programs was extensively discussed, including how that would relate to the three-year planning cycle of the Section 8-103 EE programs. It avers that no clear resolution was reached and the 2014 Plan stated that "[i]n anticipation of the this triennial issue, a legislative change to either Section 16-111.5B or 8-103 would likely be necessary to create a mechanism for utilities to seek expansion of Section 8-103 programs through the Section 16-111.5B process, rather than seeking approval for new programs only when an 8-103 three year plan is awaiting Commission approval." However, no such legislative change has been enacted. Plan at 93-94.

The IPA believes that an approach that will guarantee the inclusion of third-party bids for multi-year programs (three-years, or perhaps even longer) would be desirable. It opines that, if strong third-party bids are received next year, they could have an opportunity to be included with fewer (or no) constraints regarding the screening out of duplicative programs. The IPA notes that, while the Commission rejected the AG's "proposed expansion" of expected-to-be core Section 8-103 programs in Docket No. 13-0546, the Commission did approve the inclusion of third-party programs in ComEd's Section 16-111.5B submittal and it approved programs for a term of three years. The IPA believes that, by allowing the competitive market to suggest a broad universe of cost-effective programs through the Section 16-111.5B RFP process, and not simply excluding promising programs on the basis of any potential disconnect with a not-yet-finalized Section 8-103 portfolio, the opportunities to grow the EE sector here will be expanded. The IPA opines that this will lead to additional job creation and benefits for customers.

While the IPA appreciates ComEd's suggestion that stakeholders address this issue through the SAG, it is of the opinion that if the Commission fails to further address this issue in the present proceeding, there will be little for stakeholders to discuss. It acknowledges that expanded Section 8-103 programs would not be permissible as part of the 2017 Plan. Instead, the IPA states that it raised this issue for discussion in an attempt to forge a path forward that avoids an "unfortunate situation." The IPA seeks to balance the two competing requirements that programs must be "incremental" to those approved under Section 8-103, but also that the plans should fully capture the potential for all achievable cost-effective savings. A more balanced approach, it continues, could feature the Commission making clear to participating utilities and stakeholders that stipulations or conditional Commission approval of expanded programs (dependent on final rulings on the Section 8-103 portfolio) may be allowed for the 2017 Plan approval proceeding, and the IPA invites further feedback on this approach in Reply Briefs. IPA Response at 15-16.

The IPA clarifies that, in Docket No. 13-0546, the Commission approved the inclusion of numerous third-party programs in the IPA's 2014 Plan, (including multi-year contracts) even though the Section 8-103 plans had not yet been finalized, citing the 2014 Plan at 87, 89. Also, while ComEd states that the Commission will enter its Order approving the next set of Section 8-103 plans in early 2018, Section 8-103 requires those plans to be filed by September 1, 2016 with an Order approving the new plans entered in early 2017. IPA Response at 16-17.

b. ComEd Position

ComEd avers that while this is not an issue for the 2016 Plan, the IPA has suggested that it will be an issue for the 2017 Plan because the Section 8-103 EE programs under Section 8-103 that will be in effect for the 2017 Plan's delivery year will not be approved until early 2018, a month or two after the 2017 Plan is approved. It maintains that the 2016 Plan seems to suggest that the Commission could approve "expanded" Section 8-103 programs under Section 16-111.5B, even if the Section 8-103 plan and its programs are not yet approved. ComEd Objections at 3.

ComEd argues that Section 16-111.5B does not permit proposals for EE programs or measures without reference to the underlying "baseline" programs approved under Section 8-103. According to ComEd, Section 16-111.5B is limited to "new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act… " citing 220 ILCS 5/16-111.5B (a)(3)(C). ComEd explains that programs or measures proposed under Section 16-111.5B cannot be considered in isolation, but rather are subject to review and approval, in light of their relation to measures and programs already approved by the Commission as part of a Section 8-103 EE plan.

ComEd avers that the utilities' current Section 8-103 plans extend only through May 31, 2017, and the EE programs and measures to be offered beginning on June 1, 2017 will not be known until the Commission enters its order approving the next triennial Section 8-103 plan in early 2018. ComEd concludes that, because the Commission has already decided the issue and the General Assembly has not amended Section 16-111.5B, the 2016 Plan should be revised to conform to, rather than contradict, past Commission decisions, and encourage stakeholders to address this issue through the SAG. *Id.* at 3-5.

c. Ameren Position

Ameren agrees with ComEd. It opines that Section 16-111.5B does not permit consideration of EE bids without reference to an underlying or baseline set of Section 8-

103 programs. According to Ameren, eliciting multi-year bids that would flow into the next planning cycle is not "appropriate." Ameren Objections at 8-9.

d. Commission Analysis and Conclusion

The parties do not define what is meant by "expansion" of Section 8-103 programs. It appears that Section 16-111.5B limits what can be offered to those programs that do not duplicate programs provided pursuant to Section 8-103. However, that does not mean, that a program related to an existing Section 8-103 program, but which does not duplicate it, would contravene Section 16-111.5B.

The Commission notes that, according to the IPA, if the Commission does not require workshop discussion on this issue, such discussion will not occur. The best course of action, with regard to planning, duplication, and many other related topics, would be to address these topics at workshops conducted by the SAG. Therefore, the SAG shall convene workshops to address this specific issue.

On Exceptions, ComEd avers that the term "expansion" can be found in the IPA Act, which limits the types of energy efficiency programs to "new or expanded" cost effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of the Act, citing 220 ILCS 5/16-111.5B(a)(3)(C). In other words, ComEd continues, programs or measures pursuant to Section 16-111.5B must be considered alongside the Section 8-103 portfolio. ComEd Br. on Exceptions at 2. ComEd, however, does not take issue with the conclusion above finding that the SAG workshops are the best forums addressing this issue currently. ComEd points out that the IPA has mentioned the concepts of stipulations or conditional approval, which could be explored more fully where all interested energy efficiency stakeholders are participating in SAG workshops. *Id.* at 2, 3.

Also on Exceptions, the IPA states that a program expansion constitutes taking a Section 8-103 program whose reach and budget is limited by the statutory rate impact cap in Section 8-103(d)(5) and expanding it to fully capture the potential for all achievable cost-effective savings through inclusion in an IPA procurement plan. The IPA points out that, as new Section 8-103 portfolios will not yet have been approved by next July's utility submittal deadline, this creates the timing issue identified in the Plan. IPA Br. on Exceptions at 7-9. The IPA does not take issue with the conclusion above finding that the SAG workshops are the best forums addressing this issue currently. *Id.* at 9.

Staff and the IPA suggest the addition of the following clarifying language:

The Commission recognizes the challenges of "expansion" of Section 8-103 programs when the portfolio for such programs has not yet been approved. This creates a natural tension: while unapproved programs cannot easily be "expanded," the law calls for IPA plans to fully capture the potential for all achievable cost-effective savings, which presumably includes expanded Section 8-103 programs.

In recognition of this challenge, the Commission directs the SAG to address this topic at workshops. These workshops should demonstrate a genuine commitment to resolving this problem, consistent with the goal of capturing all achievable energy savings. It should also consider solutions such as the conditional approval of Section 8-103 program expansions in the IPA's 2017 Plan and potential contractual mechanisms to accommodate the uncertainty that is present when there is an unapproved Section 8-103 portfolio.

This request is reasonable and it is approved.

6. Section 7.1.5.2 Whether Ameren's Adder to its TRC Analysis for Administrative Costs in EE Programs Adequately States what its Actual Administrative Costs Are.

a. IPA Position

The Plan states that Ameren used a blanket administrative cost adder of 13.58% to all EE programs, and it provided only rudimentary information on how that 13.58% figure was reached. In its submittal to the IPA, Ameren explained the costs as: "3.5% for Evaluation, Measurement & Verification activities ("EM&V"), 5% for program implementation oversight; a portion of the costs to conduct the potential study (estimated at $1.5 million), 3% for education and awareness activities as well as planning, assessment and tracking of the programs, as required under Section 5/16-111.5B." Plan at 95-96.

The IPA posits that Ameren's administrative costs was a contested issue in the litigation of the 2015 Plan. In response to arguments that Ameren's blanket administrative adder of 14% was both inflated and inadequately justified, the Commission directed the utilities "to track administrative costs by program in order to aid in future determinations of appropriate administrative cost assumptions," citing Docket No. 14-0588, (Order of December 17, 2014) at 224. In light of this directive, the IPA believes that including fixed, non-incremental, non-program-specific costs in the TRC calculation such as those for Ameren's potential study, is inconsistent with the direction taken by the Commission in Docket No. 14-0588. If costs from Ameren's potential study are removed, the administrative cost adder would then constitute 11.5%, which is, according to the IPA, the same amount reported by ComEd in its submittals. The TRC as adjusted by the IPA in the Plan reflects an 11.5% administrative adder.

In its Response to Ameren's Objections, the IPA states that resolution of this issue has no impact on what costs may actually be incurred by the utilities going forward or whether such costs are reasonable or recoverable. It states that its determination was solely about what administrative costs are inputs in a TRC Test for determining whether a proposed program has a benefit-to-cost ratio of greater than 1.0. IPA Response at 10-11.

The IPA notes that the only adjustment made to Ameren's administrative cost TRC adder was to remove a single category of non-administrative costs from that adder. In its submittal, the IPA continues, Ameren provided several administrative costs as percentages (adding to 11.5%) and the cost of its potential study as a dollar amount ($1.5 million). According to the IPA, Ameren did not explain how it arrived at an overall percentage of 13.58% It avers that costs which are fit for inclusion in a TRC test include actual implementation costs, plus "costs to administer, delivery, and evaluate" programs, citing 20 ILCS 3855/1-10. It further maintains that the requirement that Ameren submit a new potential study every three years does not involve the implementation, administration, delivery, or evaluation of a program. Rather, according to the IPA, it is a stand alone requirement in Section 16-111.5B (a)(3)(A) that must be completed, even if no programs are administered. IPA Response at 11.

The IPA continues to state that its adjustment (from 13.58% to 11.5%) to Ameren's administrative costs was not motivated by an effort to create equivalency between Ameren and ComEd. Equivalency as a result of that adjustment is merely a coincidence or, a function of the percentages disclosed by the utilities in submittals. Unlike ComEd, the IPA continues, Ameren layered on an additional $1.5 million as a non-administrative cost for the development of its potential study. It concludes that this adjustment was necessary to maintain consistency with the Commission's prior directive and the law. *Id.* at 12.

b. Ameren Position

Ameren takes issue with the IPA Plan on this conclusion. According to Ameren, the IPA's criticisms are not based in fact. Ameren states that it is using the same figures that it has used for years, which the Commission has consistently approved. Last year, Ameren continues, was the first time that any party questioned Ameren's administrative adder, and the Commission resolved the issue by ordering Ameren to "track administrative costs by program in order to aid in future determinations of appropriate administrative cost assumptions to use in the TRC analysis of the Section 16-111.5B programs," citing Docket No. 14-0588, (Order of December 18, 2014) at 160, 224.

Ameren maintains that it has begun to track those costs, as ordered, and its tracking efforts to date show that the administrative adder which it has applied every single year, including this year, is approximately correct. If that changes, so that, a year of tracking administrative costs at the program level shows that Ameren's estimate is incorrect, then Ameren will use the correct figure in future IPA Plan submittals. Ameren is of the opinion that when its approach is contrasted with the IPA's administrative adder, the reduction should clearly be rejected. Ameren Objections at 9-10.

Ameren also argues that the IPA ignores the practical effects of cutting its administrative budget. It avers that despite the fact that the IPA picks the programs and the Commission approves them, the responsibility to contract with bidders falls on the utility. Also, it continues, the implementation of programs and measures adopted pursuant to Section 5/16-111.5B requires time and effort to administer and assist. In order to avoid, or at least minimize, difficulties in administering such programs, Ameren has hired a third-party firm to provide assistance to Ameren with day-to-day implementation, and to provide it with information regarding the performance of the providers. Ameren states that the third-party service comprises about 4.5-6% of the IPA program budgets, and it accounts for the same portion of the 13.58% administrative adder. This arrangement, it states, was made clear in its RFP, which was reviewed and approved by the IPA. In other words, according to Ameren, if the cost of the potential study was not included in its administrative adder, Ameren would not recover that cost. *Id.* at 11.

Ameren further argues that the idea that the percentage of total program costs assigned to ComEd's and Ameren's administrative costs should be the same is unsupported and misleading. According to Ameren, this is because ComEd runs much larger Section 5/16-111.5B programs than Ameren. For example, it continues, last year's Plan process resulted in a two-year budget of approximately $103 million for ComEd and $76 million for Ameren, despite the fact that the two utilities were running a similar number of programs. It contends that, even if it and ComEd have the exact same administrative costs, those administrative costs would make up a larger percentage of Ameren's total program costs than they do of ComEd's total program costs. It posits that ComEd's service area includes dense, urban areas with approximately 10 million residents. Ameren's service territory covers a much smaller customer base which is spread out over a much larger geographical space. It concludes that the challenges of marketing, administering and monitoring EE programs in the two service territories are different, and the IPA's conclusion should be rejected. *Id.* at 11-12.

In its Reply, Ameren states that when determining the cost-effectiveness of the programs, the administrative costs involved in planning assessment and tracking of the Plan, which are not reflected in the program bids themselves, must be considered. It contends that the issue here is not about recoverability of those costs. Rather, Ameren avers, the issue is whether the fixed costs in question will be charged to the customers and fairly allocated to the programs in an EE portfolio. It continues to state that no party disputes that the cost of the potential study is a cost incurred for the purpose of complying with 16-111.5B. Additionally, it continues, no party disputes that the cost of the potential study, like other portfolio-level costs, will be recovered through Rider EDR. It maintains that the only dispute here is whether the cost at issue should be considered when calculating the cost effectiveness of EE programs that are proposed to be included in the Plan. Ameren Reply at 9, 10.

Ameren further contends that the TRC Test compares the cost of a program, including those costs that might be allocated across the programs but not considered by the bidders themselves to the program benefits, which results in a determination of whether the benefits outweigh the costs. According to Ameren, ignoring costs that were not included in the bids when they benefit all of the programs would only set up the TRC Test to produce overstated results. *Id.* at 23.

c. Staff Position

Staff notes that the IPA only omitted the costs of Ameren's potential study. Staff also states that, in the Order in Docket No. 14-0588, the Commission did require the tracking of administrative costs; however, it did not explicitly state what administrative costs should be included in TRC analyses in the future. Staff Response at 11-12.

Staff further disagrees with Ameren's argument that the IPA is cutting its administrative budget. Staff avers that the IPA proposal does not suggest that Ameren should not recover the costs in question. Rather, Staff states, the IPA merely argues that costs which are not incremental to any particular program should not be included in that program's costs for purposes of TRC calculation. Staff is of the opinion that these costs are portfolio costs, and as such, they can be included in the rate impact analysis. *Id.* at 12-13.

Staff states that Ameren will incur the cost of the potential study whether Ameren does ten, thirty or no EE programs. It opines that fixed costs that do not change with the number of programs undertaken are useful only for assessing the overall cost of Ameren's

IPA portfolio. That is, if the sum of the incremental benefit of all of Ameren's IPA programs is not large enough to offset the fixed costs for the programs, then Ameren's IPA portfolio as a whole is producing net losses for customers. *Id.* at 13.

Staff agrees with Ameren's assertion that there is no reason to presume that Ameren's administrative cost adder should be the same as that for ComEd. However, Staff maintains that this has no bearing on whether fixed costs that are not incremental to any particular program should be included in the program-level TRC analysis. Staff concludes that the IPA is correct in stating that the fixed cost at issue here, which is not incremental to any program, should not be included in Ameren's TRC analysis. *Id.* at 14.

d. ComEd Position

ComEd states that it is unclear what Staff means by "rate impact analysis." Also, according to ComEd, the Commission is otherwise made aware of, and able to review, these costs every year through the utilities' annual reconciliation filings. ComEd Reply at 3-4.

e. Commission Analysis and Conclusion

The Commission agrees with Staff and the IPA. Ameren's potential study is not a cost which was incurred in administering any particular program. As Staff has pointed out, including costs in a TRC Test analysis of a particular program that do not involve that specific program skews the test results. Additionally, while Ameren has argued that the IPA is cutting its administrative budget, the IPA and Staff have demonstrated that this is not correct. The Commission agrees with Ameren and Staffthat the percentage of Ameren's administrative costs may very well differ from that incurred by ComEd.

It seems that even after the Commission ordered the utilities to track their administrative costs in Docket No. 14-0588, the utilities are not clear as to what administrative costs should be tracked, and, as ComEd has noted, it is unclear what Staff proposes with respect to additional reporting and whether it is needed. These topics should be thoroughly addressed and determined with specificity in workshops conducted by the SAG.

On Exceptions, Ameren asserts that the extra costs in the 13.58% adder contains an (unspecified) amount for planning, assessment and tracking of the programs, as well as a portion of the costs to conduct the potential study. Ameren Br. on Exceptions at 7. Ameren states that it recognizes that this issue was inadvertently made more complicated by its submittal to the IPA. *Id.* Additionally, according to Ameren, the cost of the potential study was not the only cost that the IPA cut from Ameren's administrative adder. *Id.* at 8.

The problem with this argument is that Staff and the IPA are of the opinion that the cost of the potential study was the only cost that the IPA cut from Ameren's administrative adder. (*See* above). Also, Ameren has failed to quantify the amount it incurred for planning, assessment and tracking of the programs. This lack of clarity about basic facts may have been avoided if Ameren had provided the IPA with more than just rudimentary information, which it apparently did not do. The Commission declines to alter the conclusion above, as Ameren has failed to demonstrate that it is not correct.

7. Section 7.1.5.3 Whether to Exclude Two of Ameren's EE Programs from the Plan When Ameren Asserts that the Cost of these Programs Exceeds the Cost of Electric Supply

a. IPA Position

Citing 220 ILCS 5/16-111.5B(b), the Plan states that the requisite "cost effectiveness" therein has the same meaning as that set forth in Section 8-103(a) of the Public Utilities Act, which requires a measure to satisfy the TRC Test. In the Plan, the IPA concludes that, if an EE program satisfies the TRC Test, it does not matter if an EE program exceeds the cost of supply. It therefore rejects Ameren's argument that two of its EE programs that pass the TRC Test but exceed the cost of supply should be excluded from the Plan. Plan at 96-97.

Ameren had based its argument on 220 ILCS 5/16.111.5B(a)(3)(E), which requires utilities to include an analysis of how the cost of procuring additional cost-effective EE measures compares over the life of the measures to the prevailing cost of comparable electric supply. The IPA concludes that this requirement does not create independent grounds to exclude otherwise cost effective EE programs in an IPA Plan. The IPA points out that Ameren's argument is inconsistent with the consensus approach developed in 2013 workshops.

The IPA cites Commission Docket No. 14-0588, and states that in that proceeding, the Commission faced arguments from the Natural Resources Defense Council and the Attorney General seeking adjustments to the cost and benefit inputs to the TRC Test. In response to those arguments, and acknowledging even that it had seen such arguments in prior proceedings and was "intrigued" by the supporting logic, the Commission determined that "a significant problem with procurement proceedings is the expedited schedule combined with a relatively large number of contested issues and parties" that "makes it difficult for the Commission to deal with complex economic issues," citing Docket No. 14-0588, (Order of December 17, 2014) at 224. According to the IPA, in that case, the Commission held that "procurement proceedings are not the ideal forum for considering complex economic issues" and it directed parties to attempt to reach consensus through a collaborative workshop process. IPA Response at 5.

The IPA argues that here, Ameren is asking the Commission to approve not merely adjustments to inputs, but to approve an entirely new test. It points out that there has been no vetting of this issue in prior proceedings, and little, if any, prior review of this new test by other key stakeholders, some of which may not be participating in this proceeding. It states that Ameren's initial submission simply contained a declaratory statement that two programs failed their cost of supply test with no substantiating information. If known adjustments to inputs are too complex for a 90-day Commission proceeding, it continues, the introduction of an unseen and not vetted test is "inappropriate" for approval in this proceeding. *Id.* at 6.

The IPA avers that Ameren's approach is also flawed as a matter of policy. It states that Ameren's cited "cost of supply" test does not include transmission and distribution costs, despite, allegedly, the fact that such costs are being avoided by the adoption of EE measures. It also maintains that the "cost of supply" assumes a uniform cost for all customers based on the cost to eligible retail customers, while Section 16-

111.5B programs are available to all retail customers. Under this methodology, the IPA concludes that customers of ARESs who may have higher supply costs are treated with a cost of supply that is suited only to those customers taking service from the utility. *Id.*

The IPA points out that the dollar amounts of the costs described by Ameren in its Objections are for the entire portfolio of programs, not the specific programs addressed in Ameren's Objection. It concludes that this focus on the entire portfolio magnifies the extent of the issue in an attempt to change the subject. *Id.* at 7.

In response to Staff's Objections, the IPA states that it is confused by Staff's rationale. Initially, Staff agreed with the IPA that Ameren's analysis of whether particular programs' costs exceed the cost of the supply does not comport with the consensus reached in prior years, that Section 111.5B(a)(3)(E) of the PUA can be interpreted as the TRC Test, citing Staff Objections at 4. In the IPA's view, Staff ignores Section 16-111.5B and its established interpretation to focus instead on the cost impacts on ratepayers, without any corresponding discussion of benefits. *Id.*

The IPA recognizes that expanding EE programs can have bill impacts on customers. However, it concludes that inherent in the statutorily-mandated TRC screening process is a required determination that expected benefits exceed those costs. It acknowledges that, unlike Section 8-103 of the Act, Section 16-111.5B does not contain a rate impact cap allowing for a strict limitation of costs. Instead, according to the IPA, the law directs the Commission to include those programs that are necessary to "fully capture the potential for all achievable cost-effective savings, to the extent practicable" in IPA procurement plans, citing 220 ILCS 16-111.5B(a)(5).

The IPA argues that Section 16-111.5B of the Act directs the Commission to include those programs that are necessary to "fully capture the potential for all achievable cost-effective savings, to the extent practicable" in IPA procurement plans, citing 220 ILCS 16-111.5B (a)(5)). The word "practicable," it continues, means "capable of being put into practice or of being done or accomplished," citing Merriam-Webster.com. According to the IPA, it is notable that the drafters of Section 16-111.5B did not include a more restrictive condition, and sought instead for cost-effective programs that are "capable" of "being done or accomplished" to be included in IPA Plans. It states that cost-effectiveness is the balancing of costs against benefits, and not merely the cost that is used to evaluate a program's inclusion in a plan. It reasons that circumventing that approach as suggested by Ameren and Staff is inconsistent with the balance that is carefully struck by Illinois law and previously observed in each prior Commission docket. IPA Response at 10.

b. Ameren Position

Ameren recommends excluding two of its EE programs, an electric-only behavior modification program and an agricultural EE program. Ameren believes that those programs would cost customers more than simply procuring electric supply at the prevailing cost. Ameren Objections at 13. According to Ameren, the Act directs the Commission to approve EE to the extent practicable, citing Section 16-111.5B(a)(5). It posits that there are limiting principles, such as the fact that duplicative programs should not be included in the final Plan, regardless of whether they pass the TRC Test.

Unlike its Section 8-103 portfolio, Ameren continues, where costs are recovered from all rate classes, the costs at issue are born only by residential and small business rate classes. Ameren maintains that the impact on those customers is significant. Before 2013, (the time when the IPA began accepting EE programs as an alternative to supply) the average annual EE charges were approximately $20 for residential customers and $61 for small businesses. However, Ameren states, for the year in question, the annual cost of electric EE for both Section 8-103 and through a procurement plan, will exceed $55 for residential customers and $175 for small businesses. Ameren Objections at 14-15.

Ameren is of the opinion that there are practical limits on EE procurement. It avers that the decision to use the prevailing cost of comparable supply as a reference point is based upon the language in the statute. Ameren posits that Section 16-111.5(a)(3)(E) provides that an electric utility shall include in its assessment: "Analysis of how the cost of procuring cost-effective EE measures compares over the life of the measures to the prevailing cost of supply," citing 220 ILCS 5/16-111.5(a)(3)(E).

Ameren contends that Section 16-111.5B and that in Section 16-111.B5 (a)(3)(E) (cited above) address two different issues. According to Ameren, the Act provides that only cost effective EE programs should be included a utility's assessment of an EE program. However, it continues, the Act also provides that a comparison to the prevailing cost of comparable supply should only be run on programs that have already been determined to be cost effective. Ameren Objections at 15-16.

Ameren further argues that the IPA's position does not make sense. This is true, it continues, because the Act provides that the Commission should only approve cost effective measures "to the extent practicable." *See,* 220 ILCS 5/16-111.5B(a)(5). It cites Section 16-111.5B(d)(4), which provides that the Commission shall approve the procurement plan only "if the Commission determines that it will ensure adequate, reliable, affordable efficient and environmentally sustainable electric service at the lowest cost over time." At a certain point, Ameren continues, all parties must ask themselves when a given year's EE procurement has grown large and expensive enough. Ameren states that bill impacts matter. It reasons that, if procuring EE would be more expensive than procuring supply (not distribution or transmission) at the prevailing cost of supply, the Commission should use its limiting powers accordingly. *Id.* at 16-17. Thus, it proposes that the Commission should rely on its "indisputable power" to impose practical limitations on Section 6-111.5B EE programs. Ameren Response at 7-8.

Ameren maintains that Merriam-Webster defines "practicable" to mean "capable of being put into practice or of being done or accomplished: feasible," citing merriam-webster.com: "Feasible," it continues, means something different than the IPA intends. "Feasible," as defined by Oxford, means "[p]ossible to do easily or conveniently," citing oxforddictionaries.com. It concludes that reliance on dictionary definitions, without selective revision, does not support a finding that the legislature intended, when it used the word "practicable," to mean that every cost-effective program must be pursued regardless of the practical implications. Ameren Reply at 14.

Ameren believes that "supply," as used in Section 16-111.5B, means the sort of comparable supply that is procured by the IPA, citing Section 16-111.5B(a)(3)(G), as it instructs utilities to include in their submittals, "[f]or each expanded or new program, the estimated amount that the program may reduce the agency's need to procure supply." Ameren states that the IPA only procures supply for "eligible retail customers," citing 220 ILCS 5/16-111.5. It concludes that therefore, when Subsection 16-111.5B (a)(3)(E) instructs the utilities to include a comparison of the cost of a measure or program to the "cost of supply," it instructs a utility to compare the program to the cost of supply for eligible retail customers. Ameren Reply at 16.

In response to the IPA's statement regarding Ameren's use of the total bill impact on customers from the costs of the entire Section 16-111.5B EE portfolio, Ameren states that its use of total bill impacts was to illustrate the need to set practical limits on this year's Section 16-111.5B EE procurement. It posits that ratepayers' bills are impacted by *all* EE procured by the IPA and implemented by a utility. Ameren reasons that customers do not see program-level cost breakdowns. It understands that Section 16-111.5B EE programs in its Illinois' service territory in 2016 will have a substantially larger bill impact than they have in years past, and that bill impact could be moderated by excluding a pair of programs for which the cost exceeds the cost of comparable supply. *Id.* at 16-17.

c. Staff Position

Staff points out that while Section 16-111.5(B)(b) of the Act requires all programs or measures that are included in a procurement plan to be cost-effective, using the TRC Test, this statute sets forth a number of additional analyses to include with the utilities' EE assessment. Staff gleans from this fact that the TRC Test is merely the minimum requirement in deciding whether programs or measures should be approved as part of the Plan. Staff Objections at 4.

Staff is of the opinion that the Commission should be mindful of the analysis provided by Ameren concerning the "significant burden" imposed upon small businesses and residential ratepayers with the approval of each additional EE program. Given the impact of significant increases in EE costs to these customers, Staff reasons that information other than the results from the TRC Test should be considered by the Commission when determining which EE programs or measures should be approved as part of a Plan. Citing Ameren's figures, Staff states that removal of those two programs would result in a decrease in costs to ratepayers of $754,535. *Id.* at 4-6.

While Staff does not agree with Ameren's cost of supply analysis in terms of it being in alignment with Section 16-111.5B(a)(3)(e) of the Act, Staff does believe that it provides another "data point" for Commission consideration. Staff therefore supports Ameren's recommendation that the Commission should not approve the two less competitively priced EE programs as part of the Plan. Staff also states that, if the Commission rejects these two costlier programs, it will send a clear signal to bidders that they should put forth competitive pricing in next year's RFP process, which is beneficial to ratepayers. *Id.* at 6.

Staff opines that Section 16-111.5B(a)(5) does not require all cost effective EE programs and measures to be included in a procurement plan. According to Staff, that section of the statute only states that EE programs and measures must be included in the procurement plan "if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of this Act," citing 220 ILCS 5/16-111.5B(a)(5) Staff states that the more relevant law is Section 16-111.5B(a)(4) of the PUA, which states:

> The Illinois Power Agency shall include in the procurement plan prepared pursuant to paragraph (2) of subsection (d) of Section 16-111.5 of this Act energy efficiency programs and measures it determines are cost-effective and the associated annual energy savings goal included in the annual solicitation process and assessment submitted pursuant to paragraph (3) of this subsection (a).

See, 220 ILCS5/16-111.5B(a)(4). Staff points out that the word "all" does not appear in that statute. Staff Reply at 7-8. Staff argues that the statute merely requires EE programs and measures included in a plan to be cost effective. In terms of formal logic, Staff reasons that cost effectiveness is a necessary, but not a sufficient, condition for inclusion in a Plan. *Id.* at 8.

With respect to the IPA's argument that Section 16-111.5B does not contain a rate impact cap and therefore there is no basis to exclude cost effective EE programs and measures, Staff contends that the IPA does not consider that, not only must EE programs and measures be cost effective, but for the Commission to approve a Plan, the IPA must demonstrate that including the EE programs and measures in a procurement plan will contribute to the objectives set forth in Section 16-111.5(d)(4) of the Act. This statute, Staff continues, requires a showing that the proposed procurement will "ensure adequate, reliable, efficient, and environmentally sustainable electric service at the lowest cost over time, taking into account any benefits of price stability," citing 220 ILCS 5/16-111.5(d)(4). Staff maintains that including in a procurement plan programs and measures that would cost Ameren customers more than procuring the supply does not meet this standard. Staff Reply at 8-9.

Staff further avers that a utility that is analyzing whether programs and measures exceed the cost of supply is not subjecting the programs and measures to a new test. Rather, according to Staff, this analysis is a component of a thorough determination of whether including the programs and measures in the Plan meets the long-established standard set forth in Section 16-111.5(d)(4) of the Act. *Id.* at 9.

d. Commission Analysis and Conclusion

At issue is the propriety and the legality of including two EE programs in the Plan that are more expensive than the supply of electricity. The word "efficiency" is "the ability to do something or produce something without wasting materials, time, or energy: the quality or degree of being efficient." Merriam-Webster.com. It is not "efficient" to procure a source of energy that is more expensive than supply, as such procurement, without other benefits (and none have been raised here), is wasteful. Additionally, as Staff and Ameren point out, the cost of EE procurement is directly borne by ratepayers.

The Commission further agrees with Ameren's statutory construction in that the phrase "to the extent practicable" in 220 ILCS 5/16-111.5B(a)(5) gives this Commission the authority to set practical limits on the procurement of EE. If the General Assembly had intended to require all EE plans that passed the TRC Test to be included in an IPA Plan, it would not have used any qualifier at all. The phrase "to the extent practicable" is a qualifying phrase that allows this Commission to exercise judgment and flexibility.

This Commission is further mindful of the fact that ratepayers should not bear the costs of EE programs that are expensive, when no party has pointed to some other benefit to these programs. Further the SAG has determined that cost-inefficient programs should be eliminated. *See*, Plan at 88. Finally, as Staff has pointed out, rejection of these two programs should send a signal that in the future, EE programs should be competitively priced. The IPA shall exclude these two programs from its Plan.

On Exceptions, Staff opines that a utility analyzing whether programs and measures exceed the cost of supply is not subjecting the programs and measures to a new test. Rather, Staff continues, this analysis is a component of a thorough determination as to whether including the programs and measures in the Plan meets the standard set forth in Section 16-111/5(d)(4) of the Act, which requires a showing that the program will "ensure adequate, reliable, efficient, and environmentally sustainable electric service at the lowest cost over time, taking into account any benefits of price stability." Staff also avers that, as is reflected in the TRC results in the Plan and reproduced in the IPA's Brief on Exceptions, the two programs at issue barely passed the TRC test and have the lowest TRC ratios out of all of the programs in the Plan for Ameren. Staff Reply Br. on Exceptions at 12-13, 14.

On Exceptions, Ameren takes issue with the IPA's argument that Ameren has proposed something new or calamitous. Ameren avers that it provided its comparison in its July 2015 submittal to the IPA, and it also provided the IPA with information documenting the cost of the programs and the cost to procure power. Ameren Reply Br. on Exceptions at 14. Ameren and Staff, it continues, have proposed that a plain reading of the Act calls for considerations other than cost-effectiveness, and the Commission has the discretion to limit the procurement of cost effective EE, including programs whose costs exceed the cost of supply. *Id.* at 16.

Citing 20 ILCS 3855/1-5(A), Ameren further posits that, while the IPA dismisses bill impacts upon consumers as irrelevant, it should not be so quick to do so, given its statutory obligation to "develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time." It concludes that the significant bill impact upon its customers, due to the growth of energy efficiency in this state, is a good reason to exercise the Commission's limiting authority, particularly since the two programs at issue would cost more to procure than comparable supply. *Id.* at 19.

The ELPC concurs with the IPA's and the AG's arguments that only the TRC test should be used to determine whether a program is cost effective. The ELPC concurs with the arguments made by the IPA and the AG to the effect that as long as a program is not competing with, or duplicative of, a Section 8-103 program, it should be included in the IPA's annual plan. ELPC Reply Br. on Exceptions at 6.

The AG contends that the Commission's conclusion is erroneous. Citing several sections in 220 ILCS 5/16-111.5B, the AG argues that the term "cost-effective" means satisfying the TRC test. The AG concurs with the IPA's conclusion that analysis of "how the cost of procuring additional cost effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply" does not establish an independent ground for excluding energy efficiency programs that pass the TRC test. AG Br. on Exceptions at 3, 4.

To the AG, the language above construing the phrase "to the extent practicable" in 220 ILCS 5/16-111.5B(a)(5) misreads the statute by applying that phrase to specific energy efficiency programs, rather than to the goal of capturing all achievable cost-effective savings within the meaning of 220 ILCS 5/16-111.5B(a)(5). It reasons that this Commission cannot simply supplant the TRC test with the utility's assessment of the cost of supply. *Id.* at 6.

The AG further states that how the cost of supply calculation was conducted has clear implications regarding a utility's determination that the cost of an energy efficiency program exceeds the cost of electric supply. The AG continues that the record does not reveal how Ameren calculated the cost of supply. *Id.* at 7.

The AG is correct in asserting that the record does not reveal how Ameren calculated the cost of supply. The AG is correct when stating that how the cost of supply is determined is important; however, in ruling that Ameren's programs at issue should not be included in the Plan, this Commission is not suggesting that a utility can merely aver that an energy efficiency program exceeds the cost of supply and this Commission will concur with that assertion. Rather, because the IPA did not earlier dispute the correctness of Ameren's assertion that these programs cost more than electricity, and there was no evidence to suggest that Ameren was incorrect in its conclusion, the language above, in effect, found that these programs exceed the cost of electricity. In the future parties should present their method for calculating the cost of supply when asserting that an energy efficiency program exceeds that cost.

In addition, the AG does not take into account that Section 16-111.5B(a)(2)(D) provides that utilities are charged with providing, among other things:

> Analysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service.

220 ILCS 5/16-111.5B(a)(2). The only reduction in the cost of electric service that would take place with energy efficiency programs that are more expensive than electricity would be to shift the cost of electricity onto the purchase of energy efficiency, at a greater price. Procurement of such energy efficiency programs seems to contravene the spirit, if not the letter, of this portion of the statute.

For the first time on Exceptions, the IPA asserts that without comprehensive scrutiny, it is not possible to know whether Ameren's test here is indeed the "cost of supply." The IPA also cites 220 ILCS 5/8-103(a), which requires investment in cost-effective energy efficiency and demand response measures that avoid or delay the need for new generation, transmission and distribution infrastructure." The IPA reasons that it is avoided electric utility costs, and not merely supply costs, which the law requires to be used to evaluate the efficacy of an energy efficiency program. IPA Br. on Exceptions at 12-14.

The IPA further states that the term “energy efficiency” is defined by statute as follows:

> “Energy efficiency” means measures that reduce the amount of electricity or natural gas required to achieve a given end use. “Energy efficiency” also includes measures that reduce the total Btus of electricity and natural gas needed to meet the end use or uses.

20 ILCS 3855/1-10. Because this term was defined by statute, the IPA contends that use of the dictionary definition of “efficiency” above was erroneous. *Id.* at 14.

The IPA also disagrees with the conclusion above finding these two programs to be expensive. It argues that whatever the expense of these programs, their benefits exceed the costs. *Id.* at 17-19. While the IPA did argue previously that Ameren is creating a new test, it did not question Ameren’s ultimate conclusion that the cost of these programs exceeds the cost of supply, except to point out that Ameren’s new test did not include the cost of transmission and like costs. The IPA offered no facts establishing that the cost of transmission, etc. would change the outcome that the cost of these two programs exceeds the cost of electric supply. It has therefore waived its right to challenge the validity of Ameren’s determination at this late stage in the proceeding. *Franciscan Communities v.Hamer,* 2012 IL App (2d) 110431 at par. 19.

The Commission does not see a contradiction between the dictionary definition of efficiency, as it is used above, and the statutory definition of energy efficiency. While energy efficiency is aimed at reducing the use of energy, little benefit is really achieved on that level, if the cost of avoiding the use of energy exceeds the cost of energy, which is how the dictionary definition of “efficiency” was used above. This argument does not aid the IPA.

The Commission notes that the IPA’s lack of concern for the expense involved in procuring an EE program could encourage EE providers to furnish services without diligence or even regard to the expenses involved in providing such services. The ruling above helps to assure that ratepayers are not saddled with unnecessary expenses from these programs.

8. Section 7.1.5.4 Whether to Exclude Programs that Duplicate Existing DCEO Programs

a. IPA Position

In the Plan, the IPA included two programs, due to start on June 1, 2016, which duplicate DCEO programs. Use of these two programs is conditional upon the fact that DCEO, an Illinois State agency, may not have the funding to run its programs, and it is not known whether it will have the funding to run these programs. Therefore, these two programs would only be included if the DCEO programs were not available. Plan at 99.

While the IPA shares Ameren’s concern about not approving programs that are deemed to be “duplicative,” the IPA believes that this approach risks statutory non-compliance. The IPA cites Section 16-111.5B of the Act, and opines that only conditional approval of these two programs allows for the satisfaction of the standards in that statute. It argues that, if DCEO programs go unfunded and these “duplicative” programs are not conditionally approved, then the “programs and measures included in the procurement plan" will not "fully capture the potential for all achievable cost-effective savings," within the meaning of that statute. The IPA states that, if DCEO does receive funding, the conditional programs will not be funded and there is no risk of operating "duplicative" programs. IPA Response at 15.

The IPA appreciates that time and effort is required to proceed from merely having a bid coming to contractual terms with a bidder prior to the start of a program. As a result, the IPA would not object to conditional approval having an end date, under which this approval would become granted, and at that point in time the utilities would be instructed to move forward with making contractual arrangements with bidders, only if DCEO funding is not clearly secured by the end of the window of time for rehearing of the Final Order approving the Plan here. *Id.*

b. Ameren Position

Ameren contends that these duplicative programs should not be included, conditionally or otherwise. It states that the IPA openly acknowledges that it cannot state whether the programs in question will be new or expanded programs incremental to DCEO's efforts pursuant to Section 5/8-103, or if they will remain duplicative. It reasons that the Commission cannot make a finding that the statutory threshold for inclusion is met for these two programs; it makes no difference whether the threshold might be met at some time in the future. Ameren Objections at 18.

Ameren also avers that there is no reliable TRC analysis for these programs because it is not yet known whether the programs will ultimately be duplicating savings. It further is concerned that, as a practical matter, the IPA's proposal would be extremely difficult to administer. It states that coming to terms with IPA bidders takes significant time and it requires a determination by a set period of time (here, by the end of this proceeding) that the programs have been approved for implementation. It opines that a "conditional approval," which only becomes effective if and when the Illinois legislature decides to take action, would make it "nearly impossible" to come to terms with bidders and then have them implement these programs in a manner that is timely enough to produce the proposed estimated savings. *Id.* at 18-19.

c. Commission Analysis and Conclusion

The IPA's modification of its original proposal is reasonable, and it shall be adopted. That is, if the status of the DCEO programs is not known by the window time for requesting rehearing herein has expired, the conditional programs will be approved.

Ameren acknowledges that it performed TRC analyses of these programs but states that this analysis is not accurate because it is not yet known whether the programs will ultimately be duplicating savings. *See,* Ameren Objections at 19, fn. 8. Yet, the fact that it performed a TRC analysis of these programs is indicia that they meet the statutory standards. Ameren provides this Commission with no information indicating that its TRC analysis is extremely unreliable. The Commission acknowledges that Ameren's TRC analysis may not have been totally accurate; however, Ameren has given this Commission no indication that its TRC analysis is anything more than slightly unreliable.

This conclusion is not meant to suggest that a full TRC analysis is not necessary for EE programs. Rather, it is an acknowledgment that the current status of DCEO's programs is precarious and the IPA has found a way, albeit a less than perfect one, to deal with that situation.

On Exceptions, the IPA avers that the time frame deadline for the conditionally-approved alternatives to DCEO programs should be May 1, 2016. The IPA reasons that using this later date would allow all parties to proceed with the best possible information, while providing sufficient time for adjustments. IPA Reply Brief on Exceptions at 9-10. This request is reasonable and it is approved.

9. Section 7.1.6.4 Whether to Exclude Programs that ComEd has Determined are "Performance Risk" Programs from the Plan.

a. IPA Position

In the Plan, the IPA states that ComEd identified six programs that it considered to be "performance risks" based upon the review of ComEd, the Stakeholder Review Committee, and DCEO, where applicable. ComEd stated that one of those programs did not pass the TRC Test, and one was determined to be duplicative of another program. Of the remaining four programs, ComEd expressed concerns that the sales cycle for the applicable products in two of the bids is very slow and complex. Another program expands on an existing program which has not currently expended its budget, and the third program may rely on lists of customers receiving LIHEAP[12] for marketing, and those lists are not available, due to confidentiality provisions. Plan at 103-104.

ComEd does not, however, recommend excluding such programs from the IPA's Plan or disapproval by the Commission. The IPA agrees. Similar to the argument made regarding Ameren's costly EE programs, the IPA contends that pursuant to Section 16-111.5B, "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act," meaning "that the measures satisfy the total resource cost test." The IPA cites this language to mean that once a measure or plan passes the TRC Test, it is the obligation of the IPA to place it in the Plan. *Id.*

The IPA further reasons that the "pay for performance" nature of Section 16-111.5B contracts should insulate ratepayers from paying for programs that cannot achieve their expected savings. It continues to state that if the risk of non-performance rested with ratepayers or on the administering utility, then qualitative program factors would need to be considered to protect those parties' interests. It concludes that under a pay for performance arrangement, the risk of underperformance rests with the winning bidders, and any flawed program design will simply manifest itself in less payment for less performance. *Id.*

The IPA views Staff's position on this issue to be problematic. According to the IPA, Staff proposes that, any program labeled by ComEd as having a "performance risk" simply should be considered to have failed the TRC Test, and therefore should not be included in a utility's EE programs. While the TRC test is a mathematical calculation that requires quantifiable inputs in order to determine a numerical ratio, the IPA is of the opinion that Staff offers no supporting analysis for why a program's costs suddenly exceed benefits, or how the magnitude of any given program's specific performance risk has changed the test result. Instead, according to the IPA, Staff states that such

[12] LIHEAP is Low Income Energy Assistance Program.

programs should not be included because they are not cost-effective, once reasonable TRC input assumptions are used. The IPA points out that Staff does not state what those reasonable TRC input adjustments actually are. IPA Response at 8-9.

The IPA takes issue with Staff's logic that cost-effectiveness is merely the minimum requirement in deciding whether the programs or measures should be approved. According to the IPA, the law requires that approved IPA procurement plans "fully capture the potential for all achievable cost-effective savings, to the extent practicable," and not only certain programs that are both cost-effective and otherwise attractive to Staff or others, citing 220 ILCS 5/16-111.5(a)(5). The IPA maintains that if cost-effective programs are arbitrarily cut because they have failed to meet Staff's or some other stakeholder's subjective determinations, all achievable cost-effective savings will not be fully captured. The IPA also believes that Staff does not explain how this new qualitative designation could be consistently and fairly applied. IPA Response at 9. However, the IPA concurs with ComEd that this would have a chilling effect on third-party EE programs in Illinois, and it would frustrate the statutory requirement that IPA procurement plans "fully capture the potential for all achievable cost-effective savings.'" *Id.* at 10.

The IPA points out that ComEd does not object to including these programs in the 2016 Plan. It states, however, that while in the world of regulatory theory, it would be nice to insulate ratepayers from any and all risks, some businesses will inevitably fail, and pay for performance contracts are a well-established, reasonable, and pragmatic way to minimize ratepayer exposure to performance risk. Instead of throwing out these programs as advocated by Staff, the IPA believes that the approval of programs by the Commission here should provide participating utilities with firm confidence to move forward in contracting with the bidders. *Id.*

The IPA states that it is sensitive to the concerns raised by ComEd in its Response; it agrees that a single vendor's insolvency does not demonstrate a malfunctioning process. It opines that the existing process of vetting vendors and programs is comprehensive and it demonstrates a genuine commitment to soliciting and valuing stakeholder input. The IPA maintains that the existing pay-for-performance contract structure may not completely insulate ratepayers from all potential contingencies, instead, it generally demonstrates a fair balancing of competing goals. It argues that steps taken to eliminate all risk, such as those contemplated in Staff's Objections, would upset this balance and cause more harm than good. The IPA believes that the Commission should not hastily order the utilities to make changes to a contract structure that has generally worked effectively. It, however, agrees with ComEd that workshops are the appropriate forum for addressing performance risk concerns and what steps can be taken to mitigate these risks. IPA Reply at 6-7.

b. Staff Position

In Staff's opinion, the IPA is not required to recommend approval of all cost-effective programs in its annual procurement plans. Staff argues that IPA is legally required to ensure that the programs or measures included in the plan must be cost effective, citing 220 ILCS 5/16-111.5B(a)(4). However, in Staff's opinion, this does not mean that the IPA is legally required to recommend for approval all cost effective programs or measures. Staff Objections at 6-7.

Staff points out that a cost-effective program which duplicates a utility's Section 8-103 EE program may be excluded for sound reasons, citing the Order from the 2014 Plan... Docket No. 13-0546 (Order of December 18, 2013) at 148-49. Staff reasons that, for the programs and measures included in the procurement plans, the law requires that they fully capture the potential for "all achievable cost-effective savings, to the extent practicable," citing 220 ILCS 5/16-111.5B(a)(5). This language, Staff continues, gives the IPA discretion when determining what EE programs to include in a procurement plan. Staff Objections at 7-8.

Staff contends that the reference in Section 16-111.5B(a)(5) of the Act to "all achievable cost-effective savings, to the extent practicable" requires a Plan to provide electric service at the "lowest total cost over time." Staff additionally cites Section 16-111.5B(a)(3), and states that, while all the programs or measures included in a Plan must be cost-effective using the TRC Test, the fact that the statute sets forth a number of additional analyses to include with the utilities' EE assessments means that information other than the results from that test must be considered by the IPA and the Commission when determining which programs or measures should be approved as part of the Plan. In Staff's opinion, whether an EE plan passes the TRC Test is only the minimum requirement in deciding whether a program or measure should be approved. *Id.* at 9.

Staff quotes the Plan which states that "[i]f risk of non-performance rested with ratepayers or the administering utility, then qualitative program factors would need to be considered to protect those parties' interests." Plan at 103. Staff believes that it serves the public interest to use qualitative program factors when analyzing third-party bids in order to protect parties' interests. Staff notes that use of qualitative program factors in analyzing bids is reasonable and consistent with the approach currently used by the utilities in conducting the RFP process for the Section 8-103 EE programs. In Staff's view, there is no logical reason for performing a less comprehensive review of Section 16-111.5B bids, in comparison to the review of Section 8-103 bids, especially given the fact that Section 8-103 has a spending cap and Section 16-111.5B does not. Staff Objections at 9-10.

The Plan also states that "under a pay for performance arrangement, the IPA understands risk of underperformance to rest with the winning bidders, and flawed program design will simply manifest itself in less payment for less performance." Plan at 103. The problem with this statement, according to Staff, is that the pay-for-performance model that was relied upon in the past did not insulate ratepayers and utilities from financial risk. Staff states that this is due in part to large upfront payments being made to vendors without any demonstration of performance. Also, it is primarily up to the utilities and the IPA to true up performance shortfalls after the end of the program year. Staff refers to testimony in the currently pending ComEd EE reconciliation docket, where a Section 16-111.5B third-party vendor became insolvent and did not perform, forcing ratepayers and/or the utility to cover the loss of approximately $390,000, citing Docket No. 14-0567, ComEd Ex. 3.0 at 3; Staff Objections at 10.

In Staff's opinion, the IPA and the Commission should consider qualitative program factors when analyzing and evaluating whether to accept bids for Section 16-111.5B programs. Staff states that, to protect ratepayers, such adjustments should be made through the RFP process next year. Staff recommends that the Commission direct Ameren and ComEd to adjust RFP development in a manner that ensures that winning bidders are not significantly compensated before they demonstrate achieved savings, while still providing the utilities with flexibility in determining the best way to accomplish these goals through the development of the RFPs. *Id.* at 10-11.

Staff states that some of what is characterized as qualitative factors may be better accounted for within TRC analyses. For example, Staff continues, if a program design is infeasible, the expected benefits from the program should be reduced or eliminated for purposes of the TRC analysis. With respect to the current programs identified as performance risks, Staff believes the "performance risk" programs should not have been included in the IPA's Plan because they are not cost-effective, once reasonable TRC input assumptions are used. *Id.* at 12.

According to Staff, ComEd and stakeholders did not adjust the TRC Test inputs to reflect reasonable input assumptions based on the identified performance risk of such programs. Staff continues to state that the IPA made no adjustments to ComEd's analysis of these programs. One reason noted in the Plan is that the IPA does not have access to ComEd's software and it therefore could not perform any revised cost-effectiveness analysis of ComEd's programs, citing the Plan at 101. In Staff's view, ComEd should not rely solely on the information provided by vendors when performing the TRC Test analysis of the bids when it is aware of adjustments that would better reflect reality and reasonable inputs. *Id.* at 12.

Staff avers that ComEd's TRC assumptions that do not pertain to the amount of first year savings are unreasonable. As an example, Staff points to the measure life values for one of the performance risk programs. Staff contends that when Ameren performed the TRC analysis of the same program, it followed up with the vendor and learned that the original measure life length in the bid was incorrect and adjusted its TRC analysis accordingly. *Id.* at 13.

Staff recommends that the Commission reject four of the six performance risk EE programs that were included in the Plan. Also, according to Staff, the Commission should direct ComEd to make adjustments to its TRC analysis of bids to reflect reasonable assumptions, consistent with the approach used by Ameren. *Id.* at 10-11. Staff additionally recommends that the Commission direct ComEd and Ameren to take all reasonable steps to make adjustments to their TRC analysis of bids to reflect reasonable assumptions, consistent with the approach used by Ameren. *Id.* at 13.

According to Staff, ComEd does not intend to change the contracting process to reduce performance risk, and therefore, the Commission should order ComEd to do so. Staff states that the utilities should consider structuring contracts so that payments are made only after they verify that energy saving products have been delivered to customers and/or after energy savings have been achieved. Staff further opines that the utilities also should consider holdbacks dependent upon the evaluated results, as well as requiring performance bonds to guarantee against failure of a third-party vendor to meet its performance obligations. Staff maintains that ComEd and Ameren should evaluate their quality assurance/quality control processes to ensure that third-party vendors providing IPA EE programs are not subject to less oversight than are the Section 8-103 of the PUA EE programs. *Id.* at 16.

Staff further acknowledges that withholding payments from vendors until after evaluations are completed would dramatically reduce the amount of EE offerings. Staff states, however, that this is the reason it has suggested alternatives. Staff encourages the utilities to draw upon their experience and knowledge with managing such contracts to identify and explore other alternatives. According to Staff, ComEd stated that it would manage third-party contracts to reduce performance risk, if its own shareholder's funds were at risk, as opposed to the funds of ratepayers. This statement, Staff avers, should give the Commission pause in adopting any language that directly or indirectly implies that the utilities bear no financial risk with respect to the management of their third-party EE contracts. *Id.* at 17.

c. ComEd Position

ComEd generally agrees with the IPA's summary of the pay for performance contract structure, however, it comments on the IPA's statement in the Plan that the utilities plan to make adjustments in RFP development to help ensure that any winning bidders may not be significantly compensated before they demonstrate achieved savings. According to ComEd, this statement requires further clarification and consideration. ComEd Objections at 6, citing Plan at 103.

ComEd opines that withholding payment to EE vendors could substantially shrink, if not shut down, these programs. ComEd explains that in its Plan Year 6 reconciliation docket, Staff has proposed two disallowances totaling nearly $390,000 regarding two programs administered by third-party vendor Project Porchlight Inc., citing Docket No. 14-0567, Staff Exs. 1.0 and 2.0. According to ComEd, these EE programs were reviewed by Staff, Intervenors, and the Commission in Docket Nos. 12-0544 and 13-0546 and no one objected to the programs. Also, the Commission approved the programs, and the final orders in those cases required that ComEd move forward with funding these third-party programs. *Id.* at 6-7.

ComEd further states that, because Project Porchlight did not deliver the promised energy savings, the pay for performance contract required Project Porchlight to return its start-up costs to ComEd which ComEd had paid to Project Porchlight during the course of Plan Year 6. However, Project Porchlight became insolvent early in Plan Year 7. Therefore, Project Porchlight was unable to perform its contractual duties and return the funds it owed. ComEd avers that Staff has apparently taken the position that the insolvency of Project Porchlight should result in the disallowance of costs of the Project Porchlight-administered programs, citing Docket No. 14-0567, Staff Exs. 1.0 and 2.0.

ComEd contends that Staff has also proposed that vendors should not be paid until after the independent evaluator verifies the energy savings for the vendors' programs. ComEd opines that this proposal appears to form the basis, in part, for the

Plan's observation that the utilities intend to revise their contracts to specify that they will withhold payment until energy savings are verified.[13] ComEd Objections at 7.

ComEd argues that Staff's disallowance, if adopted, would require utilities to refrain from paying vendors until final evaluation results are known. It maintains that, if utilities were to be blamed for events beyond their control regarding implementing Section 16-111.5B programs and complying with Commission orders entered thereunder, they will be forced to manage this risk by withholding vendor payment as proposed by Staff and the 2016 Plan. *Id.* at 7-8.

ComEd is of the opinion that the impact of withholding payment cannot be underestimated. It maintains that implementing Staff's and the 2016 Plan's proposal could effectively dismantle the third-party administered EE programs under Section 16-111.5B. It also argues that discontinuing payment of start-up costs and any in-progress payment to third-party vendors means that each vendor would be required to "front" all of its start-up and implementation costs for at least 15 months and then wait months or years for completion of the final evaluation process before receiving any payment. ComEd expects that, by making this process so costly for third-party vendors, this approach would dramatically reduce participation in bidding through the IPA process, and thereby reduce EE offerings and savings. *Id.* at 8.

d. Ameren Position

Ameren supports Staff's conclusion that the IPA is not required to include all cost-effective programs in the Plan. It argues that the Commission is not required to approve every program that is cost-effective, as, according to Ameren, the Act undeniably provides the Commission the basis to set "practical" limits on the procurement of EE in an IPA Procurement Plan, citing 220 ILCS 5/16-111.5B(a)(5). Ameren Response at 9.

e. Commission Analysis and Conclusion

ComEd and the IPA are of the opinion that the "pay for performance" nature of Section 16-111.5B contracts insulates ratepayers from paying for programs that cannot achieve expected savings. Staff argues that the "pay for performance" nature of these contracts is not in fact insulating ratepayers from paying for programs that do not achieve expected savings. Staff also pointed out that the programs at issue here are not scrutinized in the same manner that the Section 8-103 EE programs vendors are scrutinized. It seems to be a simple matter to require the same level of scrutiny for Section 16-111.5B contracts as that which is imposed for Section 8-103 contracts. The utilities are directed to develop a plan to implement use of the same scrutiny for Section 16-111.5B contracts as that for Section 8-103 contracts through workshops conducted by the SAG. However, the Commission rejects Staff's proposals to require the utilities to withhold payment and to disallow under-performing programs, as the workshops should

[13] In this vein, ComEd included substantive changes to the Plan in an Appendix to its Objections. (*See,* ComEd Objections, Appendix A at 105). However, ComEd did not present any discussion in its Objections as to why this Commission should consider these proposed substantive changes to the Plan. Therefore, this language, as well as Staff's response to this language, (*See,* Staff's Response at 14-15) were not considered.

address issues that will help insulate ratepayers from paying for programs that cannot achieve expected savings.

Additionally, Staff states that in contrast to the analysis performed by Ameren, ComEd relies solely on information supplied by vendors when conducting TRC analysis and it does not perform an independent analysis of EE programs. ComEd has given this Commission no reason for its failure to do so. ComEd is directed to conduct future TRC analyses in the manner in which Ameren performs this analysis.

As for Staff's recommendation to reject the four EE programs included in the Plan that were identified as "performance risks," the Commission declines to do so at this time. Not enough information was provided for the Commission to make an informed decision in this regard. In fact, Staff did not state which four programs of the six performance risk programs should be rejected. The Commission also did not consider matters in another Commission proceeding, Docket No. 14-0567. Issues presented in that proceeding will be resolved in that case.

On Exceptions, Staff argues that ComEd's TRC test results for the four of six performance risk programs included in the IPA plan are erroneous. (Only four of the six were included in the Plan). Staff Brief on Exceptions at 5. Staff reasons that the language above does not adequately address how approving these programs satisfies the legal requirement that approval of programs must represent "achievable" cost effective savings, citing 220 ILCS 5/16-111.5B(a)(5). According to Staff, there is no evidence here which demonstrates that the savings goals assumed for the performance risk programs are achievable.

Staff did not raise this issue earlier;therefore, it has waived its right to do so now. *Franciscan Communities,* 2012 IL App (2d) 110431 at par. 19. It is true that, in earlier briefs, Staff contested the propriety of the manner in which ComEd amasses information for TRC testing. However, Staff's requested relief was to require ComEd to make reasonable adjustments to its TRC analysis of bids consistent with the approach used by Ameren. This was addressed above.

Staff did not previously argue that ComEd's TRC analysis was so faulty that it does not demonstrate that the savings goals for these programs are achievable. It does so for the first time in its Brief on Exceptions. Despite the fact that this issue is waived, ComEd should be required to make adjustments to its TRC analyses of these four programs in a manner that is consistent with Ameren's methodology.

On Exceptions, ComEd argues that it already subjects its Section 16-111.5B contracts to the same scrutiny that it applies to Section 8-103 contracts and also that it engages in an in-depth analysis of the proposals it receives through the RFP process. According to ComEd, Staff's allegations that utilities scrutinize vendor contracts differently under the two statutes was refuted. ComEd does not state where in the record this claim was refuted. Instead, it cites a previous energy efficiency proceeding, Docket No. 13-0529, (Final Order of June 11, 2014) at 14, in which, a ComEd witness was quoted as stating that ComEd used the same cost control procedures that it applies to the rest of its energy efficiency portfolio. ComEd Br. on Exceptions at 6-7.

ComEd also contends that in its Response it explained that it had constructed an inclusive RFP process that ensures that such submissions are subjected to follow-up enquiry and utility analysis, as well as analysis from key stakeholders. Additionally, ComEd states that it is not clear what Ameren's process is or how it differs from that of ComEd. *Id.* at 8.

The Commission notes that what occurred in a previous energy efficiency proceeding, without more, does not establish what occurs now. Other than this one sentence, ComEd provides no facts to establish that it subjects the two types of contracts to the same scrutiny. *See,* ComEd Response at 9. Additionally, if ComEd is truly subjecting its Section 16-111.5B contracts to the same scrutiny applied to Section 8-103 contracts, then it should be a simple matter for it to comply with the language above. This argument lacks validity.

This issue should be discussed at the SAG workshops. There, how the two utilities proceed regarding RFPs for EE plans can be discussed, compared and perhaps even improved through communication of ideas. The Commission declines to alter the language above at this time, except to note that SAG workshops are needed on this issue.

10. Section 8 Whether ELPC's and the Renewables Suppliers' Request that the IPA Expand or add its REC Procurements in 2016 Should be Granted.

a. IPA Position

According to the IPA, Section 1-75(c) of the IPA Act (20 ILCS 3855/1-75(c)) contains the state's RPS. The RPS sets forth the obligations of the utilities for renewable energy resource procurement. Renewable energy resources may be either RECs, which constitute certificates representing the environmental attributes of electricity generated from renewable energy generation, <u>or</u> both RECs and the corresponding electricity itself. 20 ILCS 3855/1-10. An increasing portion of the load requirements of eligible retail customers (*i.e.,* residential and small commercial customers taking supply service from the utility, and not from an alternative supplier) must be met through the procurement of renewable energy resources. 20 ILCS 3855/1-75(c)(1). For the upcoming 2016-2017 delivery year, that amount is 11.5%, increasing 1.5% for each delivery year thereafter until 2025. Section 1-75(c)(2)(e) also specifies the methodology for determining the maximum amount that may be spent on renewable energy resource procurement pursuant to this section: a 2.015% rate impact cap based upon the greater of 2007 or 2011 electric rates. Plan at 125.

The IPA states that because this section concerns only eligible retail customer load, both the renewable energy resource procurement targets (the actual quantity of renewable energy resources required to be procured by statute) and the budget available for such procurements (sometimes referred to as the RRB)[14] are impacted by customer switching between utility service and alternative supplier service. There has been an increase in customers receiving electric supply from alternative suppliers over the last few years due to a wave of municipalities adopting municipal aggregation resolutions and

[14] Unlike the IPA-administered RERF (*See,* 20 ILCS 3855/1-56), this constitutes a maximum spend allowance and is not made up of funds already collected from ratepayers.

entering into opt-out municipal aggregation contracts. This reduces both the quantity of resources needed to be procured and the budget available for their procurement.[15] *Id.* at 19-20.

IPA claims that this volatility, coupled with existing 20-year bundled agreements for energy and RECs (commonly known as the LTPPAs) entered into pursuant to the 2010 IPA Procurement Plan, drives the IPA's proposed renewable energy resource procurement approach. In the previous three plan approval dockets, the IPA has sought pre-approval from the Commission for "curtailment" of the existing long-term agreements, meaning that the utilities' financial obligations and the suppliers' delivery obligations would be "curtailed" if necessary to maintain compliance with the statutorily mandated rate impact cap. At the peak of switching impacts from municipal aggregation, curtailment was required for long-term renewables contracts with ComEd, as the rate impact associated with renewable energy resource obligations was spread across too few customers (or, more accurately, too little load) in ComEd's service territory to meet existing contractual requirements. While the load forecasts submitted by the utilities for the 2016 Plan indicate that a curtailment event is unlikely, the "low" load forecast submitted by Ameren would require curtailment, and the future of customer switching in Illinois generally remains highly uncertain. *Id.* at 20.

For these reasons, the IPA continues to propose only one-year contracts to meet only the upcoming delivery year targets using the renewable energy resources budget.[16] Neither the IPA nor any other party knows whether future budgets may be sufficient to cover new multi-year contracts, something further complicated by the Renewables Suppliers' proposal that existing long-term agreements operate as senior to new agreements should curtailment be required. The IPA opines that layering any additional longer-term obligations atop existing long-term agreements that already risk being curtailed due to volatile and uncertain budgets would be highly unadvisable. Even if potential suppliers were willing to assume that heightened curtailment risk and participate in such a procurement event, risk premiums associated with those bids could frustrate the IPA's statutory duty to "ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at <u>the lowest total cost over time</u>, taking into account any benefits of price stability." 20 ILCS 3855/1-5(A). The Commission acknowledged that very risk in the 2015 Procurement Order:

> As the IPA correctly points out, it has competing statutory obligations to encourage the development of new solar facilities while assuring that it does so at a reasonable cost. Staff also correctly notes that there many ways in which government encourages the development of solar facilities. The

[15] For customers taking service from an alternative supplier, the supplier is responsible for making an ACP for no less than 50% of its compliance obligation, with its payment rate determined by results from the procurement of renewable energy resources using the RRB. These ACPs are generally made in conjunction with a supplier's self-procurement of the remainder of its renewable energy resource obligation to meet compliance with state's RPS. ACPs from suppliers are deposited into the IPA-administered RERF. *See* 220 ILCS 5/16-111.5D; 20 ILCS 3855/1-56.

[16] For its DG procurement, which by law requires contracts of at least 5 years in length (*see* 20 ILCS 3855/1-75(c)(1), the IPA has eliminated this budget risk by proposing that, for ComEd and Ameren, only those dollars which have already been collected as ACPs from customers taking hourly electricity service be used.

> Commission's primary concern with the ELPC and ISEA proposal is the lack of stability in the funding source for this particular procurement and therefore the ELPC and ISEA proposal to replace the one-year SREC procurement with a longer term DG REC procurement is rejected. The Commission concludes that the IPA's proposal for a one-year SREC procurement is clearly supported by the record and should be approved.

Docket No. 14-0588, (Order of December 17, 2014) at 286. As volatility still exists in the law and energy markets, these concerns remain and longer-term contract proposals using the renewable resource budget should be rejected.

IPA points out that in arguing for longer-term contracts from the renewable resource budget, ELPC makes several statements which require clarification. First, there is no "significant surplus of available funds" associated with the RRB, as ELPC claims. IPA Response at 22, citing ELPC Objections at 2. Neither the IPA nor ELPC (nor the Commission) knows future renewable energy resource budget levels, as those levels are dependent on the size eligible retail customer load—which, in past years, has proven to be highly volatile. This supposed "surplus" has not been collected; it is simply the projected maximum which could be available to be spent given current load forecasts. IPA points out that as in past years, it will change as the retail energy markets continue to evolve, and it should be treated as merely estimates for planning purposes.

Additionally, the IPA states that it does not "currently project that it will fall significantly short" of future years' compliance targets. Claims regarding a "shortfall" by ELPC and the Renewables Suppliers are highly misleading. Tables included in the IPA's procurement plan simply show resources currently under contract relative to a future year's projected compliance goal. They say nothing of future IPA procurements stemming from future IPA procurement plans. The IPA is not projecting "falling short" of any targets; it is merely deferring decisions on how best to meet future years' targets to future years' plans, at which time it will have better information on available funding and procurement target amounts. IPA Response at 22-23, citing ELPC Objections at 2.

The IPA does not understand ELPC's request that a better balance be struck between "the risk of budget volatility related to customer switching and the risk that could result from an overly conservative procurement strategy and missed statutory goals." There has been no demonstration that IPA's proposed strategy for managing RRB volatility increases the likelihood that statutory goals will be missed. The IPA believes its strategy increases the likelihood that such goals are met, as decisions about how best to meet those goals are made closer to the delivery year with better information about procurement targets and budgets. The IPA points out that if it were to overcommit to potentially expensive five-year contracts using significant projected sums of the renewable energy resources budget as ELPC suggests, future budgets may be entirely exhausted by these new obligations while resources under contract may not be sufficient to meet statutory targets, introducing new risks that renewable energy resource targets may not be met. IPA Response at 22-23.

b. ELPC Position

According to ELPC, 2016 is a key year for solar investment. The Federal Investment Tax Credit for commercial and residential solar power installations allows projects put into service before the end of 2016 to qualify for a 30% tax credit. After December 31, 2016, the commercial tax credit drops to 10% while the residential tax credit expires. ELPC claims that from the IPA and ratepayer perspective, distributed solar resources are effectively "on sale" in 2016 as compared to RECs from distributed solar projects the IPA will need to procure in future years to meet Illinois sub-targets. Maximizing distributed solar procurements in 2016 will help Illinois meet its DG and solar sub-target goals in a more cost-effective way for Illinois ratepayers. ELPC Objections at 1-4.

ELPC points out that the IPA proposes to procure DG RECs through a single DG procurement event in the early summer of 2016, funded by the ACPs collected by ComEd and Ameren on behalf of customers taking hourly service.[17] However, due to "continued volatility" in the available RRB because of customer switching, the IPA does not propose to use any resources from the RRB for DG resources. Under current conditions and load forecasts, this will result in a significant surplus of available funds in the RRB that could have been allocated towards additional solar and DG resources. According to ELPC, the IPA currently projects that it will fall significantly short of the statutory solar and DG sub-target goals in every delivery year through the 2021 planning horizon.

ELPC respectfully recommends that the IPA allocate more of the remaining RRB funds towards an expanded DG procurement in early 2016 for each of the three utilities to close this regulatory shortfall in the most cost effective way. First, the statute clearly states that the amounts are minimums, and that "at least the following percentages shall come from distributed renewable energy resources…1% by June 1, 2015 and thereafter." This authorizes the IPA to procure more than the minimum percentage this year in order to meet its future compliance targets. Because the majority of DG resources are likely to be solar, an expanded DG procurement strategy would enable the IPA to close the compliance shortfall that is currently projected for DG, PV, and total renewables for ComEd, Ameren and MidAmerican. If the IPA invests in solar, the Illinois industry will grow, bringing with it economies of scale, skilled labor, and lower costs that will enable easier and less expensive compliance with future renewable energy targets. ELPC claims that waiting for future years simply carries more risk and more expense, and it forfeits the opportunity to leverage the federal ITC to reduce RPS compliance costs to benefit Illinois ratepayers. *Id.*

ELPC appreciates the IPA's contention that customer switching creates planning challenges for the IPA. Contracts for DG resources must be "no less than 5 years" in length, which requires some level of forecasting for future trends in customer switching and municipal aggregation. 20 ILCS 3855/1-75(c)(1). ELPC argues that while the IPA cannot predict these trends with perfect certainty, it may be able to strike a balance between the risk of budget volatility related to customer switching and the risk that could result from an overly conservative procurement strategy and missed statutory goals. ELPC states that the Plan does not describe the level of budget risk that the IPA perceives nor whether that perceived risk justifies a procurement strategy that would leave Illinois short of its statutory renewable energy targets. The imminent expiration of the federal ITC

[17] As of May 31, 2015, Ameren's hourly ACP balance is $10,040,276 and ComEd's balance is $19,039,957. *See,* Plan at 133.

creates more urgency for the IPA to carefully weigh its options in the 2016 Plan to maximize solar resource procurement while accommodating a safety margin for budget volatility. ELPC Objections at 3-4.

ELPC recommends that the Commission order the IPA to expand its planned DG procurement in order to maximize the impact of federal tax incentives and make up some of the current statutory shortfall of DG RECs in a cost effective way. ELPC suggests that the IPA consider using the RRB along with the ACP funds previously described to fund an expanded DG procurement in early 2016 to meet the IPA's full DG sub-target requirements through the 2020-2021 Delivery Year.[18] While the IPA will procure some DG RECs through its Fall 2015 procurement, the IPA will remain significantly short of the DG targets specified in the law.

The IPA revised the timing of its proposed DG procurement from fall to early summer of 2016 in order to accommodate the scheduled expiration of the investment tax credit, but the IPA and Commission should consider whether this date should be moved even earlier to provide additional time for developers to complete projects to qualify for the ITC. *Id.* at 4.

c. Ameren Position

Ameren opposes ELPC's proposal to expand DG REC procurements in 2016 using the remaining available RRB and ACP funds collected from real time priced customers. Ameren Response at 6.

Ameren points out that there are several problems with ELPC's proposal. First, uncertain switching translates into uncertain dollars associated with the RRB. Second, in the event the RRB is exceeded in the future, it is unclear how contracts would be curtailed or if remaining customers would be expected to absorb the cost and financial risk of pre-existing contracts. Third, the proposal to hedge 100% of DG sub-targets through 2020-2021 delivery year is extreme and conflicts with the IPA's reasoned approach where only 50% is proposed to be hedged for the 2017-2018 delivery year and 25% for the 2018-2019 delivery year. Finally, the DG REC procurement recently approved by the Commission resulted in only *one contract* awarded to Ameren, and this contract represents a small portion of the budget for the DG REC procurement. In addition to the hedging risk posed by the ELPC proposal, it is not clear why such an aggressive procurement and its associated administrative costs can be justified at a time when recent DG REC procurement results did not meet the budget and quantity goals. For all of these reasons, Ameren urges that the Commission reject ELPC's proposal. Ameren Response at 6-7.

d. ComEd Position

ComEd also opposes ELPC's proposal. Like Ameren, ComEd claims that this approach ignores the very real risk posed by customer switching through municipal aggregation programs. The IPA's 2016 Plan correctly considers the risks of switching and strikes the right balance between satisfying RPS requirements and mitigating the risks of future curtailments. ComEd Response at 5-6.

[18] The DG RPS requirement is 1% of the annual RPS requirement. *See,* 20 ILCS 3855/1-75(c)(1).

ComEd states that municipal aggregation has created a volatile switching environment in ComEd's service territory. Since the start of municipal aggregation programs, ComEd's service territory saw over two-thirds of its residential and small commercial customers switch to taking supply from a retail electric supplier. As a result, LTPPAs executed in 2010 had to be curtailed to ensure that the statutory rate caps were not violated. Over the past year, however, some municipalities (including the City of Chicago) have suspended their municipal aggregation programs because of recent power price movements, which has returned customers to utility supply, which demonstrates how the forecast of future funds available for renewable energy credit procurements can and does change drastically from year to year. *Id.* at 6.

ComEd argues that a substantial portion of these projected funds would disappear in the event that one or two large municipalities reestablished their municipal aggregation programs. The 2016 Plan minimizes this risk by restricting REC purchases to a single year to meet the RPS using the current year's funds. For those multi-year purchases undertaken to meet the RPS requirements, the IPA uses the known (and already collected) monies from the ACP fund. ComEd commends the IPA on this balanced, well-designed process and recommends that ELPC's proposal be rejected. *Id.* at 6-7.

e. Renewables Suppliers Position

Similar to ELPC, the Renewables Suppliers propose that the IPA should conduct a procurement event during the 2016-2017 Plan Year to procure RECs from wind and solar generation sources under short-term contracts (1 year to 5 years duration) to cover a portion of the currently projected shortfall in meeting the wind and solar RPS targets for the 2017-2018 through 2020-2021 Delivery Years. Renewables Suppliers Objections at 4-8. However, the Renewables Suppliers urge caution in the amount of the currently projected uncommitted RRB for those four Delivery Years that should be committed to pay for REC contracts entered into in procurement events conducted in 2016-2017. This is because the available RRB for an electric utility in each year is a function of its eligible retail customer load, and the electric utilities' eligible retail customer loads have been volatile and difficult to forecast in recent years. Renewables Suppliers Objections at 5-8, IPA Plan at 126-28 and 131-32. For this reason, the Renewables Suppliers recommend that the IPA conduct a procurement event or events in the 2016-2017 Plan Year to procure RECs under short-term contracts in amounts that would not exceed the following percentages of each electric utility's currently forecasted available RRB for the 2017-2018 through 2020-2021 Delivery Years:

Delivery Year 2017-2018: 30%

Delivery Year 2018-2019: 25%

Delivery Year 2019-2020: 20%

Delivery Year 2020-2021: 10%

According to the Renewables Suppliers, the objective of this cautious approach is to avoid a situation in which the electric utilities' eligible retail customer load drops sharply (due to customer migration to ARESs), the RRB for a future year(s) correspondingly shrinks, and the REC procurement contracts that have been entered into (even REC contracts with terms of 5 years or less) cannot be fulfilled but rather must be curtailed.

Similar caution is warranted in conducting any procurement event for 5-year contracts for DG RECs, as proposed by ELPC. Therefore, the Renewables Suppliers recommend the amount of DG RECs procured in 2016-2017 under 5-year contracts should be limited to only a small fraction of the electric utility's currently-projected available RRB for the upcoming five Delivery Years.

The Renewables Suppliers add that any procurement of DG RECs conducted in the 2016-2017 Plan Year to meet the DG sub-targets for future years must take into account the respective requirements for renewable energy resources from wind, solar and DG in the statutory RPS. 20 ILCS 3855/1-75(c)(1). The RPS specifies that, to the extent available, renewable energy resources from wind, solar and DG must comprise the following percentages of the total RPS requirement for the year: wind, 75%; solar, 6%; and DG, 1%. The Renewables Suppliers claim that the IPA Plan (in Tables 8-1 and 8-2 on Plan at 129-30) shows that Ameren and ComEd have projected shortfalls in meeting the RPS sub-targets for renewable energy resources from wind and solar in the 2017-2018 through 2020-2021 Delivery Years. Therefore, the Renewables Suppliers argue that any procurement events conducted during 2016-2017 for RECs to be delivered in the 2018-2019 through 2020-2021 Delivery Years must maintain a balance among wind, solar and DG that takes into account: (1) the respective statutory sub-targets for renewable energy resources from each of these sources; and (2) the currently projected shortfalls for renewable energy resources to meet the sub-targets for each resource in the 2017-2018 through 2020-2021 Delivery Years.

Finally, consistent with the Renewables Suppliers' own proposal that a procurement event or events be conducted during the 2016-2017 Plan Year for wind and SRECs under short-term (1-year to 5-year) contracts: (1) Any short-term contracts for DG RECs should specify that the REC purchases are subject to available funding under the electric utility's RRB as determined by the final approved load forecast or load forecast update for the applicable Delivery Year; and (2) any procurement event for DG RECs conducted in the 2016-2017 Plan Year should specify that deliveries and payments under the existing LTPPAs for bundled energy from renewable resources and RECs must be considered senior to the delivery of and payment for DG RECs under short-term REC contracts. Renewables Suppliers Response at 5.

f. Commission Analysis and Conclusion

ELPC recommends that the IPA should expand DG REC procurements in 2016 using available RRB and ACP funds collected from real time pricing customers. ELPC proposes using these funds to expand this procurement to enable more distributed solar procurement to occur in 2016.This way, according to ELPC, additional commercial and residential installers can take advantage of tax credits which decrease significantly after 2016. ELPC also asks the Commission to consider whether this DG procurement date should be moved earlier than Spring 2016 to provide additional time for developers to complete projects to qualify for this tax incentive.

The IPA points out that both the renewable energy procurement targets and the budget available to purchase the renewables are impacted by customers switching between utility service and alternative suppliers. If more customers take supply from ARESs, both the needed resources and the budget for the procurement are affected. The

IPA states that there is no surplus of available funds for the RRB, and it does not project that there will be a significant shortfall of future years' compliance targets. ComEd and Ameren also oppose ELPC's proposal, due to the volatility in customer switching. Ameren further points out that the recent DG procurement only resulted in one contract, and the administrative costs and efforts to run an expanded procurement do not seem to be justified.

The Commission agrees with the IPA strategy that the decisions made closer to the delivery year are more likely to meet the targets and budgets for the DG REC procurement. The Commission also agrees with ComEd and Ameren that this strategy minimizes any possible switching risk. The Commission agrees with the IPA's date of early Spring to conduct the DG REC procurement, which should allow any interested parties sufficient time to take advantage of the 2016 tax credit. Therefore, the proposal by ELPC and supported by the Renewables Suppliers to expand the DG procurement through the 2020-2021 delivery year is rejected by the Commission.

The Renewables Suppliers take exception to the ALJPO failure to adopt its proposal to the IPA plan to include an additional procurement event or events during the 2016-2017 Plan Year for the limited procurement of one to five year contracts for RECs for Delivery Years 2017-2018 through 2020-2021. Renewables Suppliers Br. on Exceptions at 6. The Renewables Suppliers claim that its position was not adequately addressed in the proposed order because its positon is different and more conservative than the ELPC proposal. The Renewables Suppliers' proposal calls for purchasing RECs under one, three and five year terms and spending only a small portion of the currently forecasted available RPS funds for each utility for the succeeding four delivery years. The Renewables Suppliers also recommend spending a lower percentage of currently forecasted available RPS Funds in each succeeding year over the four years and to expressly provide that the RECs' contracts specify that the RECs' purchases in each delivery year are subject to available funds and that existing LTPPAs will be considered senior to delivery and payment for the RECs procured under these short term REC contracts. *Id* at 9. According to the Renewables Suppliers, if its position is deemed too risky due to load shifting from the utilities, then there will not be any procurements of RECs other than one year contracts. *Id* at 10.

On Exceptions, ELPC also disagrees with the conclusion reached in the ALJPO on this issue. ELPC again points to the expiring tax credits and questions whether the IPA proposal for the DG procurement strategy is too conservative. According to ELPC, foregoing the opportunity to procure DG RECs in 2016 when tax credits are available means future procurements will be more expensive. ELPC Br. on Exceptions at 2. ELPC believes that the record supports a larger DG procurement. ELPC claims that additional resources could be allocated to DG resources while accommodating the IPA's goal to manage and minimize customer risk. *Id* at 3.

In Staff's Reply Brief on Exceptions, Staff agrees with the ALJPO in rejecting the positions of ELPC and the Renewables Suppliers. Staff argues that both parties advise the Commission to disregard the judgment of the IPA, which would place ratepayers at an elevated risk of paying more for the renewable energy resources than permitted by statute. Staff Reply Br.on Exceptions at 20. Staff also points out that both ELPC and the Renewables Suppliers ignore the other reason for rejecting this proposal:there is no risk of significantly falling short of the statute's compliance targets. *Id* at 20. Staff acknowledges that while the Federal Tax Credits are important, the Commission should adopt the sustainable long run strategy of the IPA for procurement of the DG RECs. *Id* at 21.

Ameren agrees that the ALJPO correctly rejected the recommendations of the Renewables Suppliers and ELPC for multi-year REC procurement using the RRB. In its Reply Brief on Exceptions, Ameren states that the decisions made closer to the delivery year are more likely to align with the targets and budgets for the REC procurement. Ameren Reply Br. on Exceptions at 21-22. Ameren agrees that there is no budget surplus or projected shortfall in compliance targets moving forward. Ameren also states that the uncertainty of customer switching is still a very real risk that could have a serious impact on the overall available funds in the RRB. *Id* at 22. Ameren recommends that the Commission affirm the ALJPO on this issue such that the Plan will not include any multi-year REC procurement using the RRB.

ComEd also supports the conclusion on this issue in the ALJPO. ComEd points out that the reality of customer switching could have dramatic effects on the procurement in this area. A substantial portion of these projected funds would disappear in the event that one or two large municipalities re-established their municipal aggregation programs. ComEd Reply Br. on Exceptions at 6-7. ComEd argues that the ALJPO thus correctly concludes that the IPA's 2016 Plan skillfully navigates the risks of switching and strikes the right balance between satisfying Renewable Portfolio Standard requirements and mitigating the risks of future curtailments. Id at 7.

The IPA agrees with the ALJPO's rejection of the proposal of ELPC and the Renewables Suppliers on this issue. According to the IPA, the potential curtailment of existing agreements already loom over the discussion of renewable procurements and new multi year contracts would only complicate this area. IPA Reply Br. on Exceptions at 13-14. The IPA feels that given the amount of renewable resources already under contract using renewable resource budget funds, the more responsible approach is to defer the decision when there is better information concerning available funds and procurement target amounts. *Id* at 14-15.

The Commission finds nothing new in the arguments of ELPC and the Renewables Suppliers to warrant changing the conclusion on this issue. The IPA's plan to make this determination with updated information and forecasts is better in the long run for ratepayers.

11. Section 8.1 Whether the RRB Should be used for SREC When the Total REC Target has been Exceeded for the Present Year with Existing Contracts.

a. IPA Position

In recent years, procurements for Ameren and ComEd have generally met their overall REC procurement targets. For the 2015–2016 delivery year, resources under contract from prior IPA procurements for Ameren and ComEd were sufficient to meet overall REC targets, but insufficient to meet the law's solar PV requirements. As a result, the IPA proposed and the Commission approved a 1-year SREC procurement for ComEd and Ameren to meet those shortfalls. That SREC procurement was held in the spring of 2015. Plan at 127.

Turning to the upcoming 2016-2017 delivery year, existing resources under contract for Ameren and ComEd are not sufficient to meet solar PV and DG sub-targets, and MidAmerican is short for overall renewable energy resource compliance, wind, solar PV, and DG (due to not having previously participated in the IPA procurement process). ComEd is short RECs for overall renewable energy resource compliance, but procuring its required solar PV volume would be sufficient to fill that gap. To achieve statutory compliance, the IPA recommends a spring 2016 procurement of RECs to meet each utility's requirements for the 2016-2017 delivery year. The quantities to be procured will be based upon the "Remaining Targets" as calculated from the updated March 2016 load forecasts and will be limited to the funds available in the RRB as reported at that time. Should consensus on the March 2016 load forecasts be needed and not be reached, the quantities of RECs to be procured for the 2016-2017 delivery year will be based upon the "Remaining Target" rows that year found in the Plan. To the extent practicable, the structure, process and contracts for the procurement will be based upon those used for the SREC procurement conducted by the IPA in 2015. *Id.* at 127.

In response to Ameren's argument that the procurement of one-year SRECs is not required, the IPA states that the law is clear: the renewable energy resource mix "shall" be achieved at "at least" a statutorily prescribed percentage:

> 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, 2011, *<u>at least</u>* the following percentages of the renewable energy resources used to meet these standards *<u>shall</u>* come from photovoltaics on the following schedule: 0.5% by June 1, 2012, 1.5% by June 1, 2013; 3% by June 1, 2014; and 6% by June 1, 2015 and thereafter. Of the renewable energy resources procured pursuant to this Section, *<u>at least</u>* the following percentages *<u>shall</u>* come from distributed renewable energy generation devices: 0.5% by June 1, 2013, 0.75% by June 1, 2014, and 1% by June 1, 2015 and thereafter.

20 ILCS 3855/1-75(c)(1)(emphasis added).

Assuming available funding, the IPA has a statutory obligation to meet enumerated targets for the procurement of renewable resources from PV and DG—even if overall REC targets are being met. Consistent with last year's proposal approved by the Commission in Docket No. 14-0588, the IPA has proposed PV and DG procurements to achieve compliance with these requirements. While the IPA appreciates that its proposed PV procurement involves costs for eligible retail customers, the balance between statutory renewables procurement obligations and rate impacts is defined by statute, and the proposed procurement would remain within the rate impact cap mandated by the IPA Act. *See*, 20 ILCS 3855/1-75(c)(2)(E); IPA Response at 27-28.

In arguing that such procurements are unnecessary, Ameren again references the IPA's 2013 Procurement Plan and the Commission's resulting Order. But those circumstances are simply not instructive; the IPA's 2013 Plan was developed in the midst of rapid customer switching to ARESs through hundreds of municipalities statewide suddenly entering into new opt-out municipal aggregation agreements. This unprecedented rate of switching left a cloud of uncertainty over projected budgets, including whether the RRB would be sufficient to cover existing obligations. More instructive is the relative stability present for the IPA's 2015 Plan—and as it did last year in approving that Plan, the Commission should reject Ameren's argument that the plain language of the IPA Act can be ignored and statutory renewable energy resource sub-targets need not be met. *Id.*

b. Ameren Position

Similar to last year, Ameren questions the need to satisfy REC sub-targets in a year where the total REC target has been exceeded. According to Ameren, the IPA's interpretation of Section 1-75(c)(1) would add costs to eligible retail customers, but unlike last year, such costs would be incurred at a time when upward pressure on MISO capacity prices has significantly increased overall supply costs. The Commission may deem the incremental costs of the proposed one-year SREC unnecessary. Ameren Objections at 20.

Ameren notes that this issue was previously addressed in the 2013/14 IPA Plan approved by the Commission and the Commission's Final Order summarized the IPA's position as follows:

> [O]n a total portfolio basis, there is no compelling reason to purchase additional renewable resources during the planning horizon, even though there may be dollars 'left over' to spend.

Docket No. 12-0544, (Order of December 19, 2013) at 51.

Ameren states that it is unclear whether REC sub-targets must be met in a year where the total REC target has been exceeded. Since the total REC target for 2016-2017 has been exceeded with existing contracts, the Commission should clarify, as it did in Docket No. 12-0544, whether the IPA should spend the remaining RRB for a one-year SREC procurement.

According to Ameren, the IPA's proposal would result in the expenditure of approximately $2.2 million. Based on the current forecast, provided to the IPA in July 2015, such expenditures would increase supply costs by approximately $5 per year for a typical residential customer taking fixed price supply from Ameren. Again, these costs would come at a time when eligible retail customers are already bearing the burden of a dramatic increase in MISO capacity costs. Ameren Objections at 21.

Setting aside the unnecessary cost to Ameren customers, there is little if any benefit to Illinois. Last year's one-year SREC procurement resulted in the majority of SRECs coming from states other than Illinois. More specifically, approximately 80% of the SRECs procured for Ameren came from facilities located in states other than Illinois or adjacent states. There is no reason to expect a different outcome at this time, and therefore, there is no realistic expectation that another one-year SREC procurement event will promote the development of solar projects in the state.

Ameren questions whether a procurement of one-year SRECs serves any valid purpose or is required in a year where total REC targets are exceeded. To the extent that such procurement is not required under the law, or the Commission follows similar logic to that it followed in Docket No. 12-0544, Ameren favors an approach that keeps costs as low as possible for eligible retail customers. This means the rejection of the IPA proposal for a one-year SREC procurement. *Id.* at 22-23.

c. ComEd Position

The Plan recommends "a spring 2016 procurement of RECs [SRECs] to meet each utility's [ComEd's and Ameren's] requirements for the 2016-2017 delivery year." Plan at 127. However, ComEd agrees with Ameren that this will result in utility customers paying for more RECs than the amount targeted by Section 1-75(c) of the IPA Act, 20 ILCS 3855/1-75(c). Specifically, the absence of a legal requirement to meet RPS sub-targets once the overall target has been achieved, the cost of the above-target RECs, and the cost involved in holding a REC procurement event, raise the question of why holding such a procurement makes sense for utility customers. The sub-targets are relevant when constructing the plan to meet the overall RPS target, but not after the overall goal has been achieved. ComEd Response at 10-11.

d. Commission Analysis and Conclusion

As the IPA correctly points out, the language in Section 1-75(c)(1) of the IPA Act is not permissive: "…*at least* the following percentages of the renewable energy resources used to meet these standards *shall* come from photovoltaics on the following schedule: 0.5% by June 1, 2012, 1.5% by June 1, 2013; 3% by June 1, 2014; and 6% by June 1, 2015 and thereafter…" 20 ILCS 3855/1-75(c)(1). The language does not carve out an exception to these sub-targets if the overall target of RECs is met. However, the Commission notes that the statute does clearly and unambiguously set limits to the total amount of renewable energy resources procured pursuant to the Plan. While the IPA has an obligation to meet technology-specific targets, it is also required to limit overall costs of procurement as described Section 1-75(c)(2)(E) of the IPA Act.

Where possible, clear and unambiguous terms in statutes are to be given their plain and ordinary meaning. *West Suburban Bank v. Attorneys Title Insurance Fund, Inc.*, 326 Ill. App. 3d 502, 507 (2001). Where statutory provisions are clear and unambiguous, the plain language must be given effect, without reading into the language any exceptions, limitations, or conditions the legislature did not express. *Davis v. Toshiba Machine Co.*, 186 Ill. 2d 181, 184-85 (1999). Ameren argues that the SREC procurement will lead to unnecessary costs and no clear gains, as Illinois or Illinois-adjacent suppliers have not participated in previous solar procurements. Ameren questions whether a procurement of one-year SRECs serves any valid purpose or is required in a year where total REC targets are exceeded. Regardless, the Commission finds that the plain language of Section 1-75(c)(1) requires technology-specific targets by dates certain, and the IPA's proposal to conduct a Spring SREC procurement which mimics the structure and process of the 2015 supplemental procurement and is described in the Plan at pages 127-130 is hereby adopted.

On Exception, Ameren again questions the adoption of the IPA's position for procurement of SRECs pursuant to Section 1-75(c)(1) of the IPA Act. Ameren points out that the Commission in the 2013-2014 procurement determined that there was no compelling reason to purchase additional renewable resources during the planning horizon, even though there may be money to spend. Ameren's Br. on Exceptions at 13.

Ameren also points out that the ALJPO does not address that the sub-target requirements for the Distributed Generation RECs have not been satisfied by the prior IPA procurements. Ameren further claims that under the IPA's plan, the renewable sub-targets are required under the law, but only to the extent they line up with the IPA procurement design strategies. Ameren's Br. on Exceptions at 13-14.

The IPA points out, as adopted in the ALJPO, the plain language of Section 1-75(c) (1) requires technology-specific targets by a date certain. IPA Reply Br. on Exceptions at 15.The IPA argues that the plain language of the statute requires it to meet targets for the procurement of renewable resources from photovoltaics and distributed generation even if the overall REC targets are being met. The IPA responds to Ameren's argument about the 2013 Plan by stating that the 2013 Plan was being developedat a time when there was rapid customer switching due to municipal aggregation. *Id* at 16. According to the IPA that will not be the case this year. The IPA finds that the current environment clearly features budgets that will allow for one year renewable energy resource procurement. *Id* at 16-17. Finally, the IPA states that the challenges with meeting distributed generation procurement requirements are from the IPA adhering to the statute and not the IPA's design strategies as claimed by Ameren. *Id* at 17.

ELPC also supports the conclusions of the Proposed Order. ELPC Reply Br. on Exceptions at 2-3. ELPC points out that the plain language of the statute requires that a specified target percentage of RECs shall come form solar and distributed renewable energy devices each year. *Id* at 2-3. ELPC recommends that the Commission reject the position of Ameren on this issue.

The Commission agrees with the IPA and ELPC. The plain language of the statute requires that a percentage of the renewable energy resources shall come from photovoltaics. The Commission notes that the IPA shall limit additional procurement of photovoltaic renewable energy resources, if necessary, pursuant to 20 ILCS 3855/1-75(c)(2)(E). Ameren has not provided adequate reasoning to change the conclusion reached above on this issue.

12. Section 8.1.3 Whether MidAmerican's Renewable Energy Resources should be Calculated for all of its Eligible Retail Load or Only for the Portion of Its Customer Load for which it has Requested Procurement

a. IPA Position

The Plan states that MidAmerican's involvement in the Plan raises new questions about how to calculate the appropriate renewable resource target. As a small multi-jurisdictional utility participating in the IPA's procurement planning process to meet a portion of its load requirements, the Plan states that MidAmerican's participation raises a previously unaddressed question as to whether renewable energy resources procurement targets should be calculated for all of its eligible retail customer load, or only for that portion of eligible retail customer load for which the utility specifically requests procurement. The IPA opines that Section 1-75(c)(1) of the IPA Act references procurement percentages applicable to "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." While Section 16-111.5(a) defines "eligible retail customer" by customer status that would appear to include MidAmerican's entire eligible retail customer load, this same section also expressly contemplates that MidAmerican may seek procurement for only "a portion of its eligible Illinois retail customers in accordance with the applicable provisions set forth in this Section and Section 1-75 of the Illinois Power Agency Act," citing 220 ILCS 5/16-111.5(a). Plan at 125-26.

The IPA disagrees with MidAmerican's contention that its renewable energy resources procurement target should be based only on that portion of its eligible retail customer load for which the IPA is planning procurement. It argues that where two statutes are in conflict, an interpretation that allows both to stand is favored, if possible *See*, *McNamee v. Federated Equipment & Supply Co.*, 181 Ill.2d 415, 427 (1998). The IPA believes that the two sections of law at issue, Section 16.111.5 of the Act and Section 1-75(c)(1) of the IPA Act, may be read harmoniously under the IPA's reading of the law. IPA Response at 28.

The IPA notes that a small multi-jurisdictional utility may elect to participate in the IPA's procurement process for only a portion of its Illinois load, as MidAmerican has done. The IPA explains that upon that election, whether for all or a portion of its load, MidAmerican becomes a participating utility subject to the requirements of Section 1-75 of the IPA Act:

> A small multi-jurisdictional electric utility that on December 31, 2005 served less than 100,000 customers in Illinois may elect to procure power and energy for all or a portion of its eligible Illinois retail customers in accordance with the applicable provisions set forth in this Section and Section 1-75 of the Illinois Power Agency Act.

See, 220 ILCS 5/16-111.5(a)).

Section 1-75(c) of the IPA Act requires that procurement plans also must include cost-effective renewable energy resources. The IPA explains that upon making that election, MidAmerican is now governed by the "applicable provisions" of Section 1-75(c) which provides in part:

> 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.

See, 20 ILCS 3855/1-75(c)(1).

The IPA cites Section 16-111.5(a) of the PUA, which defines "eligible retail customers" as follows:

> [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.

220 ILCS 5/16-111.5(a).

Under the IPA's approach, Section 16-111.5B is the universe of customers used to calculate the renewables procurement target. The IPA states that one could argue that this creates a disconnect, as the renewables procurement target is based on a different universe of load than the load for which the IPA is conducting block energy procurements (which may only be "a portion" of the above). However, in the IPA's view, a policy under which a participating utility must meet certain renewable requirements as a condition of participation in the IPA's procurement may simply be a function of design. The IPA explains that the two sections may not be inconsistent or in conflict; they may simply be understood to address different things. IPA Response at 29-30.

The IPA argues that, even if these two provisions could only be viewed as competing, the more specific language for calculating the renewables target found in Section 1-75(c)(1) should apply. It asserts that where one of two provisions is general and designed to apply to cases generally, and the other is particular, the particular provision should prevail, citing *Bowes v. City of Chicago*, 3 Ill.2d 175, 205 (1954). The IPA explains that the question is how MidAmerican's renewable resource procurement target should be calculated. It notes that while Section 16-111.5(a) contains general provisions around procurement planning process participation, Section 1-75(c) directly and specifically addresses how procurement targets are to be calculated as a "minimum percentage of each utility's total supply to serve the load of eligible retail customers," citing 20 ILCS 3855/1-75(c)(1). The IPA concludes that as this is the more specific and direct language, it should govern the calculation of MidAmerican's renewable resource procurement targets. IPA Response at 29-30.

b. Staff Position

Staff asserts that the Commission should reject MidAmerican's argument that the renewable resources targets procured through the IPA's Plan for MidAmerican should be based on just a portion of MidAmerican's eligible retail load. The IPA Act provides that renewables resources shall be based upon the total supply needed by the utility to serve its eligible retail customers. Staff contends that MidAmerican's position is not supported by the plain language of the IPA Act and the PUA. According to Staff, MidAmerican reads an exception into the IPA Act and PUA that the legislature did not include when it amended the IPA Act and PUA in 2011 through Public Act 097-0325. Both Staff and the IPA agree that the IPA Act and the PUA require that the renewable resources targets for MidAmerican must be based upon total supply to serve its Illinois retail customers and not just a portion of MidAmerican's eligible retail load. Staff Response at 18.

Staff maintains that, pursuant to Section 16-111.5(b) of the PUA, MidAmerican requested that the IPA prepare a procurement plan for power and energy for MidAmerican for just a portion of its total Illinois retail load. Staff contends that in addition to procuring power and energy, subsection (c) of Section 1-75 of the IPA Act requires that procurement plans also must include cost-effective renewable energy resources. *Id.*

Staff states that the Plan provides for the procurement of renewable resource targets for MidAmerican based upon its "total supply to serve eligible retail customers" and not upon just a portion of its Illinois load. Staff explains that when interpreting a statute, the primary objective is to ascertain and give effect to the intent of the legislature, citing *Metro Utility Co. v. Illinois Commerce Commission*, 262 Ill. App. 3d 266, 274 (1994). Staff argues that the best indication of legislative intent is the statutory language itself. Clear and unambiguous terms, Staff continues, are to be given their plain and ordinary meaning, citing *West Suburban Bank v. Attorneys Title Insurance Fund, Inc.*, 326 Ill. App. 3d 502, 507 (2001). Staff also notes that where statutory provisions are clear and unambiguous, the plain language must be given effect, without reading into the language any exceptions, limitations, or conditions the legislature did not express, citing *Davis v. Toshiba Machine Co.*, 186 Ill. 2d 181, 184-85 (1999).

Staff asserts that MidAmerican erroneously reads an exception into the IPA Act and PUA. Staff explains that in 2011, through an amendment to the IPA Act and PUA, the legislature allowed small multi-jurisdictional utilities that on December 31, 2005, served less than 100,000 customers in Illinois to request the IPA to prepare a procurement plan for their Illinois jurisdictional load. Staff avers that, prior to the enactment of Public Act 097-0325, the IPA developed procurement plans only for electric utilities that on December 31, 2005 provided service to at least 100,000 customers in Illinois (*i.e.,* ComEd and Ameren).

Staff comments that MidAmerican serves less than 100,000 customers. Staff notes that Public Act 097-0325 made four changes to the IPA Act and six changes to the PUA in connection with allowing small multi-jurisdictional electric utilities to have the option to have the IPA develop procurement plans for them. Staff asserts that, if the legislature had intended for the IPA procurement Plans for a small multi-jurisdictional electric utility to include renewables based upon only a portion of the load that is being procured for a utility, (and not the utility's total load), then the legislature would have made a change to the law to provide for that exception when it amended the IPA Act and PUA in 2011. Staff Response at 20.

Staff notes that the legislature made ten changes in total to the IPA Act and PUA related to the 2011 amendment, allowing small multi-jurisdictional electric utilities to have the option to have the IPA develop procurement plans for them.

Staff explains that, when the legislature amended the IPA Act and PUA to allow small multi-jurisdictional utilities to request a procurement plan for their Illinois jurisdictional load, it made extensive changes to the IPA Act and PUA. It contends that the legislature did not change Section 1-75(c) of the IPA Act, which provides that the percentage of renewables is based upon the utility's total supply to serve the load of its eligible retail customers. Also, the legislature did not change the definition of "eligible retail customers" in Section 16-111.5(a) of the PUA. Staff contends that the legislature made no changes to the IPA Act and PUA which would create an exception that the renewables percentage for small multi-jurisdictional utilities would be based upon just a portion of a utility's eligible retail load. *Id.* at 20-22.

c. MidAmerican Position

MidAmerican points out that the IPA specifically noted that the statute is unclear as to "whether renewable energy resources procurement should be calculated for all of MidAmerican's eligible retail customer load, or only for that portion of eligible retail customer load for which the utility specifically requests procurement." MidAmerican states that the Plan includes a resource mix where "MidAmerican's renewable resource targets are determined based upon MidAmerican's "total supply to serve eligible retail customers." It notes that the IPA's Draft Plan also recognized there are multiple interpretations and the IPA invited further comment. MidAmerican Objections at 3.

MidAmerican points to Staff's argument that the statute was clear and that the procurement of renewable resource targets for MidAmerican should be based upon MidAmerican's "total supply to serve eligible retail customers." MidAmerican claims that, therefore, there is an unresolved issue for the Commission to consider regarding MidAmerican's renewable resource mix. MidAmerican objects to the inclusion of a procurement amount for RECs, which includes a REC amount based on MidAmerican's entire Illinois jurisdictional load in the 2016 Procurement Plan. *Id.* at 3-4.

MidAmerican acknowledges that the IPA concludes Section 16-111.5(a) defines "eligible retail customers" to include MidAmerican's entire Illinois jurisdictional load for the purposes of determining the renewable resources when read in conjunction with Section 1-75(c) of the IPA Act. MidAmerican asserts that the IPA also concludes that it need only procure a portion of MidAmerican's jurisdictional load as outlined in Section 16-111.5(b). MidAmerican contends that its "eligible retail customers" only include a portion of its Illinois load being procured by the IPA. It argues that Section 16-111.5 must be read in its entirety and any renewable resource target must be based on the portion of the Illinois jurisdictional load being procured by the IPA.

MidAmerican maintains that the legislature provided an exception in Section 16-111.5(a) and (b) of the Act and the 2016 Procurement Plan reflects that intent by including only a "portion" of MidAmerican's eligible retail load and not MidAmerican's "total" Illinois retail load. It contends that Illinois courts have also held that "[w]here the statutory language is ambiguous and the legislative history is not determinative, this court must attempt to resolve the conflict by reference to the entire statute," citing *Business and Prof. People for the Pub. Interest v. Illinois Commerce Comm'n.*, 146 Ill. 2d 175, 208, 585 N.E.2d 1032, 1045 (1991). MidAmerican contends that Sections 16-111.5(a) and (b) must be read together to ascertain the exception to the "eligible retail customer" carved out for small multi-jurisdictional utilities. Section 16-111.5(a) and (b) read in part:

> (a) An electric utility that on December 31, 2005 served at least 100,000 customers in Illinois shall procure power and energy for its eligible retail customers in accordance with the applicable provisions set forth in Section 1-75 of the Illinois Power Agency Act and this Section. <u>A small multi-jurisdictional electric utility that on December 31, 2005 served less than 100,000 customers in Illinois may elect to procure power and energy for all or a portion of its eligible Illinois retail customers in accordance with the applicable provisions set forth in this Section and Section 1-75 of the Illinois Power Agency Act.</u> This Section shall not apply to a small multi-jurisdictional

> utility until such time as a small multi-jurisdictional utility requests the Illinois Power Agency to prepare a procurement plan for its eligible retail customers. "Eligible retail customers" for the purposes of this Section means those retail customers that purchase power and energy from the electric utility under fixed-price bundled service tariffs, other than those retail customers whose service is declared or deemed competitive under Section 16-113 and those other customer groups specified in this Section, including self-generating customers, customers electing hourly pricing, or those customers who are otherwise ineligible for fixed-price bundled tariff service. Those customers that are excluded from the definition of "eligible retail customers" shall not be included in the procurement plan load requirements, and the utility shall procure any supply requirements, including capacity, ancillary services, and hourly priced energy, in the applicable markets as needed to serve those customers, provided that the utility may include in its procurement plan load requirements for the load that is associated with those retail customers whose service has been declared or deemed competitive pursuant to Section 16-113 of this Act to the extent that those customers are purchasing power and energy during one of the transition periods identified in subsection (b) of Section 16-113 of this Act.
>
> (b) A procurement plan shall be prepared for each electric utility consistent with the applicable requirements of the Illinois Power Agency Act and this Section. For purposes of this Section, Illinois electric utilities that are affiliated by virtue of a common parent company are considered to be a single electric utility. <u>Small multi-jurisdictional utilities may request a procurement plan for a portion of or all of its Illinois load.</u> Each procurement plan shall analyze the projected balance of supply and demand for eligible retail customers over a 5-year period with the first planning year beginning on June 1 of the year following the year in which the plan is filed. . .

See, 220 ILCS 16-111.5(a) and (b) (*emphasis added).*

MidAmerican asserts that subsections 16-111.5(a) and (b) both carve out an exception for MidAmerican's eligible retail load so that only a portion of its total eligible retail customer load represented as the "net" or "differential" between MidAmerican's eligible retail customer load in Illinois and MidAmerican-owned generation allocated to Illinois customers, is served through the IPA's procurement planning process. The 2016 Plan includes the incremental amount of capacity and energy that is not currently served or forecasted to be served in Illinois by MidAmerican-owned Illinois jurisdictional generation. MidAmerican reasons that the Plan does not include the "total supply" to serve eligible retail customers. It concludes that the Plan only includes the incremental amount of energy and capacity that is not serviced or forecast to be served in Illinois by MidAmerican-owned jurisdictional generation. Thus, the quantity of RECs procured should only be proportionate to the portion of the "total supply" procured for MidAmerican's jurisdictional eligible retail customers that is included in the Plan. MidAmerican surmises that the quantity of RECs procured for it should exclude the amount of Illinois-jurisdictional load supplied by MidAmerican owned generation. MidAmerican Objections at 5-7.

d. Commission Analysis and Conclusion

The issue here is one of statutory interpretation. MidAmerican disagrees with Staff and the IPA about whether the renewable resources targets procured are determined based on all of MidAmerican's Illinois customers or just a percentage of customers for MidAmerican in the 2016 Plan. The IPA, Staff and MidAmerican all make reasonable points on how the statutes in question should be interpreted. MidAmerican advocates that the quantity of RECs procured should only be based upon that portion of the "total supply" procured for MidAmerican's jurisdictional eligible retail customers that is included in the Plan and should exclude the amount of Illinois-jurisdictional load that is supplied by MidAmerican owned generation. The IPA and Staff advocate that based on the plain language of the statutes, the Commission should find the IPA Act and the PUA require that the renewable resources targets procured through the Plan for MidAmerican should be based upon total supply to serve MidAmerican's Illinois retail customers. and not just a portion of MidAmerican's eligible retail customers' load. In this case, the statutes in question leave room for ambiguity.

When interpreting a statute, the primary objective is to ascertain and give effect to the intent of the legislature. *Metro Utility Co. v. Ill. Commerce Comm'n*, 262 Ill. App. 3d 266, 274 (1994). The best indication of legislative intent is the statutory language itself. *Id*. Clear and unambiguous terms are to be given their plain and ordinary meaning. *West Suburban Bank v. Attorneys Title Insurance Fund*, 326 Ill. App. 3d 502, 507 (2001). Where statutory provisions are clear and unambiguous, the plain language must be given effect, without reading into the language any exceptions, limitations, or conditions the legislature did not express. *Davis v. Toshiba Machine Co.*, 186 Ill. 2d 181, 184-85 (1999). Illinois courts have found where two statutes are allegedly in conflict, an interpretation that allows both to stand is favored, if possible. *See, McNamee v. Federated Equipment & Supply Co.*, 181 Ill.2d 415, 427 (1998). Where one of two provisions is general and designed to apply to cases generally, and the other is particular and relates to only one subject, the particular provision should prevail. *Bowes v. City of Chicago*, 3 Ill.2d 175, 205 (1954)).

MidAmerican argues that Section 16-111.5(a) and (b) of the PUA must be read together to ascertain the exception to the "eligible retail customer" carved out for small multi-jurisdictional utilities. It asserts that these parts of the PUA provide an exception for MidAmerican's eligible retail load so that only a portion of MidAmerican's total eligible retail customer load represented as the "net" or "differential" between MidAmerican's eligible retail customer load in Illinois and MidAmerican owned generation allocated to Illinois customers. The IPA and Staff argue that MidAmerican erroneously reads an exception into the IPA Act and PUA. The IPA contends that even if the two provisions could only be viewed as competing, the more specific language for calculating the renewables targets found in Section 1-75(c)(1) should apply. It asserts that while Section 16-111.5(a) contains general provisions around procurement planning process participation, Section 1-75(c) directly and specifically addresses how procurement targets are to be calculated and should be applied. The IPA and Staff contend that as this is the more specific and direct language, it should be understood to govern the calculation of MidAmerican's renewable resource procurement targets.

In analyzing these arguments, where one of two provisions is general and designed to apply to cases generally, and the other is particular and relates to only one subject, the particular provision should prevail. *Bowes*, 3 Ill.2d 1 at 205. Further, where two statutes are allegedly in conflict, an interpretation that allows both to stand is favored, if possible. *McNamee*, 181 Ill.2d at 427. MidAmerican is correct in arguing Section 16-111.5(a) and (b) of the IPA Act must be read together to determine the exception to the "eligible retail customer" carved out for small multi-jurisdictional utilities. The IPA's and Staff's argument that Section 1-75(c) of the IPA Act should apply to this issue is misguided because it fails to look at the statute in its entirety. In this case, the reasonable approach is to examine the entire statute so the greatest level of deference to legislative intent can prevail.

Further, prior to the enactment of Public Act 097-0325, the IPA developed procurement plans <u>only</u> for electric utilities that on December 31, 2005 provided service to at least 100,000 customers in Illinois (*i.e.*, ComEd and Ameren). MidAmerican serves less than 100,000 customers in Illinois. Plan, Appendix D, at 1. Staff asserts that if the legislature had intended for the IPA procurement plans for a small multi-jurisdictional electric utility to include renewables based upon a portion of the load that is being procured for that utility, and not the utility's total load, then the legislature would have made a change to the law to provide for that exception, when it amended the IPA Act and PUA in 2011.

MidAmerican disagrees and argues the legislature did provide an exception in Section 16-111.5(a) and (b) of the PUA and the 2016 Procurement Plan reflects that intent by including only a "portion" of MidAmerican's eligible retail load and not MidAmerican's "total" Illinois retail load. It explains that the Plan includes the incremental amount of capacity and energy that is not currently served or forecast to be served in Illinois by MidAmerican-owned Illinois jurisdictional generation. It states, consequently, that the 2016 Plan does not include the "total supply" to serve eligible retail customers. MidAmerican contends that the Plan only includes the incremental amount of energy and capacity that is not serviced or forecast to be served in Illinois by MidAmerican-owned jurisdictional generation.

The primary objective of statutory interpretation is to ascertain and give effect to the intent of the legislature and the best indication of legislative intent is the statutory language itself. *Metro Utility Co.*, 262 Ill. App. 3d at 274. Here, the statutory language provided in Section 16-111.5(a) and (b) of the PUA reflects including only a "portion" of MidAmerican's eligible retail load and not MidAmerican's "total" Illinois retail load, is what the legislature intended to do, if it is read in its entirety. In this case, it is likely unreasonable to determine that the intent of the legislature would be to create unnecessary hardship for MidAmerican to participate in the 2016 Procurement Plan.

The Commission finds the statutes should be interpreted such that the renewable resources targets should only relate to that portion of the "total supply" procured for MidAmerican's jurisdictional eligible retail customers that is included in the 2016 Procurement Plan pursuant to Section 16.111.5 of the PUA and Section 1-75(c) of the

IPA Act. Thus, the statutes should be interpreted by reading them in their entirety, as MidAmerican argues. The IPA shall amend the Plan accordingly.

On Exceptions, Staff argues that if the legislature had intended for the IPA procurement plans regarding small multi-jurisdictional utilities to include renewables based only upon a portion of the load that the IPA procures for that utility, it would have made a change to the law to provide for that exception. Staff Br. on Exceptions at 12-13. However, Staff ignores the fact that the language above, in effect, construes the phrase "total supply" in Section 1-75(c) of the IPA Act to mean the totality of supply procured by the IPA. Staff's argument is not on point.

Also on Exceptions, Staff argues that the IPA did not state how it calculated the portion of IPA-procured load at 14 %. Staff offers several methodologies that Staff feels should be in a final Order. Staff Br. on Exceptions at 17-18. Staff offers one methodology which appears to be uncontroversial, which is:

$$R = \frac{\text{Forecasted energy consumption-Forecasted non-IPA energy supply}}{\text{Forecasted energy consumption}}$$

<u>(Adjusted for consistent treatment of energy losses). Staff further recommends that the Commission authorize an adjustment to the maximum spending limit using that same ratio. *Id.* at 18.</u>

<u>However, Staff did not challenge the IPA's methodology earlier in this proceeding. It has, therefore, acquiesced to the correctness of that methodology. In the future, the IPA shall provide evidence as to how it arrived at MidAmerican's percentage and it shall use the formula above.</u>

On Exceptions, the IPA takes issue with use of the phrase "unnecessary hardship" above. It states that MidAmerican would simply be placed on a level playing field with ComEd and Ameren, which are required to meet renewable energy resource procurement targets for their entire eligible retail customer load. The incremental costs, the IPA continues, still could not rise beyond the 2.015% rate impact cap in Section 1-75(c)(2)(E) of the IPA Act and MidAmerican would face no financial hardship through the collection of fees from its customers, which would cover the cost of renewable energy. IPA Br. on Exceptions at 21.

However, the IPA is not correct in asserting that MidAmerican would be placed in the same position as Ameren and ComEd. According to the IPA, only 14% of MidAmerican's Illinois load would be procured by the IPA. Yet, it would be required to meet the targets for its entire Illinois customer load. That is not the situation for Ameren or ComEd.

The Commission acknowledges that MidAmerican would face no financial hardship if 100% of its Illinois load were the base line for the renewable procurement targets. This is true because, in that situation, the costs would be passed on to MidAmerican's customers. However, the IPA has given this Commission no reason to burden MidAmerican's customers with this extra expense. And that is the "unnecessary hardship" that is referred to above. The Commission does not find the IPA's arguments to be persuasive.

,MidAmerican avers that the Proposed Order's language above correctly concluded that subsections 16-111.5(a) and (b) must be read together to ascertain the exception to the "eligible retail customer" carved out for small multi-jurisdictional utilities. To interpret otherwise, it continues, renders the legislative intent for MidAmerican to procure power for only a portion of its eligible Illinois customers meaningless. MidAmerican Reply Br, on Exceptions at 2-3.

MidAmerican further argues that applying the renewable target percentage to only the portion of its load procured by the IPA will avoid unneeded excess procurement, the cost of which is born by its customers. It additionally disagrees with the IPA's statement that there would be no hardship because MidAmerican would be placed on a level playing field with ComEd and Ameren, if MidAmerican were required to procure renewables based upon 100% of its Illinois load. MidAmerican avers that comparing it to ComEd and Ameren is wrong, given that ComEd and Ameren have different statutory requirements. The IPA further points out that the 2.015% rate cap is a protective threshold to limit rate shock. It argues that, therefore, this figure is not a correct basis to set a renewable target. *Id.* at 4, 5.

MidAmerican is correct to point out thatit has different statutory requirements than Ameren and ComEd. The Commission further concurs with MidAmerican's averment that, when construing the statutory schemes at issue, one must consider both 220 ILCS 5/16-111.5(a) and (b).

Finally, MidAmerican responds to Staff's request, made for the first time on Exceptions, for clarification as to how its portion of the renewables budget should be calculated. It points out that these questions were addressed in its Comments which were filed with the IPA on September 14, 2015. In those Comments, MidAmerican requested changes to pages 125-26 of the Draft Plan to reflect requirements based only upon its requested procurement through the IPA. *See,* MidAmerican Reply Br. on Exceptions at 6-8.

It states that those changes, set forth in its Brief, are based upon underlying calculations that exclude projected sales of excess supply to the Midwest Independent System Operator, as Staff had proposed. MidAmerican states that its calculations are similar to those proposed by Staff, but MidAmerican's figures are in MWh values, not ratios. MidAmerican asks the Commission to direct the IPA to amend the Plan in accordance with the information it provided to the IPA in its September 14, 2015 Comments. *Id.* at 7, 8.

The Commission concludes that MidAmerican's request to require the IPA to amend the Plan in accordance with the information that MidAmerican supplied to the IPA on September 14, 2015, and which is contained in its Reply Brief on Exceptions, is reasonable and it is approved. The Commission notes that the methodology for those calculations is in MidAmerican's Reply Brief on Exceptions and it is similar to what Staff has urged this Commission to follow, which is set forth above.

13. Section 8.4 Whether the IPA should be the Contractual Counterparty with Suppliers to the Planned DG Procurement, and not the Utilities Themselves; Whether the bids or the Resulting Contracts should be Required to be at Least 1 Megawatt in Size for the DG Procurement.

a. IPA Position

After analysis and review of comments from stakeholders and additional consideration (including coordination, where possible, with the SPV procurement plan) during the development of the 2015 Plan, the IPA settled on a DG procurement model for a fall 2015 procurement. This model was based on the IPA's traditional procurement process involving the block procurement of RECs with competitive bids selected on the basis of price. As the IPA was proposing a DG procurement to meet DG sub-targets, and not simply a solar PV REC procurement, the IPA also believed that this model left it best able to accommodate RECs from generating technologies beyond solar PV. IPA Plan at 134.

The IPA is proposing the 2015 model as the starting point for a 2016 procurement of DG RECs. Unlike with the IPA's SPV procurement under Section 1-56(i) of the IPA Act, nothing in the law governing this DG procurement distinguishes between "new" or "existing" systems. As a result, the IPA's sole requirement regarding the system completion date is that all participating DG systems must successfully begin delivery of RECs generated in the 2016-2017 delivery year. Contracts will be for the five delivery years starting with 2016-2017 delivery year. *Id.*

The IPA recognizes that given the limited amount of DG currently in Illinois, this approach's success hinges on the ability of the Illinois DG market both to self-organize and to grow. Therefore, the IPA will allow bids to contain DG systems of all qualifying sizes and resource types. Systems must be no larger than 2,000 kW. The technology types eligible to participate are defined by the IPA Act and include DG "powered by wind, solar thermal energy, PV cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams." 20 ILCS 3855/1-10. Benchmarks used by the Procurement Administrator to evaluate bids may depend on system size and/or technology. Bids that meet or exceed the benchmarks will be evaluated first on the basis of price and then on the basis of achieving a 50-50 balance of RECs procured from each of the two categories of systems, namely systems below 25 kW and systems of 25-2,000 kW in size, while maintaining winning bid sizes at a one megawatt threshold. *Id*.

The IPA's planned DG renewable resource procurement will use hourly ACP funds for Ameren and ComEd, and use the RRB for MidAmerican. Only hourly ACP funds that have been collected as of May 31, 2016 and not allocated to the purchase of either DG RECs from the five-year 2015 DG procurement contracts or curtailed RECs for the 2016-2017 delivery year may be used. The IPA will procure DG RECs until funds are fully allocated or the utilities' DG goals are met, whichever comes first. The products to be procured are RECs from DG systems that are interconnected with Ameren, ComEd, MidAmerican, a municipal utility in Illinois, or a rural electric cooperative in Illinois. DG systems need not be in the service territory of the utility purchasing the RECs. *Id*.

The IPA goes on to state that Ameren suggests that the IPA become the contractual counterparty with suppliers to the planned DG procurement, and not the utilities themselves. This issue was discussed extensively in Docket No. 14-0588, and is plainly inconsistent with state law. "[A]dministrative bodies…are creatures of statute and possess no general or common law powers. Any power or authority claimed by an administrative agency must find its source within the provisions of the statute by which the agency was created." *Vuagniaux v. Dept. of Professional Regulation*, 208 Ill.2d 173, 187-188 (2003).

Like all State agencies, the IPA only has those powers specifically granted to it by law, and it cannot simply assume new contractual obligations without corresponding authority which allows for it to enter into such obligations. Section 1-56(i) of the IPA Act, which enables the IPA to conduct the supplemental solar REC procurements and which Ameren would seek to expand through its approach, only allows the IPA to enter into contracts for up to a designated amount ($30 million) from a designated source (the RERF) for the purchase of a designated project (RECs from solar PV systems). *See,* 20 ILCS 3855/1-56(i). Nothing in Section 1-56(i) of the IPA Act, or elsewhere in the IPA Act or the PUA, empowers the IPA to enter into additional contracts as a counterparty using ACPs previously collected from Ameren's real-time pricing customers, or to purchase additional RECs from any funding source other than the RERF. IPA Response at 25.

The IPA points out that the requirements of Section 1-75(c) of the IPA Act, including the DG sub-targets, apply to the participating utilities themselves (who are then required to "retire all renewable energy credits used to comply" with those standards 20 ILCS 1-75(c)(4)), with the IPA acting as an independent agency developing procurement plans and conducting procurement events to ensure that compliance. More specifically, the very ACP funds in question are to be used for the "purchase of renewable energy resources to be procured by the electric utility." 20 ILCS 3855/1-75(c)(5) (emphasis added). These are the roles carefully spelled out under the law for each entity, and having the IPA serve as the resulting contractual counterparty would plainly run afoul of those requirements. IPA Response at 25-27.

The IPA also disagrees with ComEd's suggested modifications to the IPA's DG procurement approach which would require that resulting contracts, as opposed to the bids themselves, be at least one megawatt in size. The relevant language of the IPA Act states as follows:

> In order to minimize the administrative burden on contracting entities, the Agency shall solicit the use of third-party organizations to aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity. These third-party organizations shall administer contracts with individual distributed renewable energy generation device owners.

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

The IPA believes that because the one megawatt threshold applies to the aggregation of renewable energy, it is intended to apply to the Agency's solicitation and bidding process, and that the reference to a one megawatt "bid" be maintained in the 2016 Plan. IPA Response at 25-26.

In its reply to responses, the IPA points out that ELPC also objects to ComEd's recommendation that bids for DG procurement be at least one megawatt for each product size. Ameren now supports ComEd's proposal. The IPA agrees with ELPC and strongly disagrees with ComEd and Ameren. The IPA avers that if the parties are seriously focused on meeting the statutory goals of Section 1-75(c), proposals should be focused on how to make this one megawatt aggregation requirement more manageable, not unnecessarily tightened beyond what is statutorily mandated. Assuming the average residential rooftop PV installation is 5 kW in size, assembling a one megawatt bid requires 200 such installations.

Requiring that hundreds of small DG systems be organized as a threshold to participation could effectively foreclose small system participation in the IPA's DG procurement, frustrating the IPA Act's requirement that "half of the renewable energy resources… shall come from devices of less than 25 kilowatts in the nameplate capacity." 20 ILCS 3855/1-75(c)(1). Further, according to the IPA such a requirement could drive up the resulting prices by shifting competitive bidding, inconsistent with the PUA's requirement that an approved IPA Procurement Plan achieve "the lowest total cost over time, taking into account any benefit of price stability." 220 ILCS 5/16-111.5(d)(4). The one megawatt bid threshold presents a significant barrier to participation for potential bidders, and further tightening of that requirement by making it applicable to system size categories is unjustified and counter productive. IPA Reply at 11-12.

b. Ameren Position

Ameren points out that the IPA recommends a procurement of DG RECs using renewable funds previously collected from Ameren's real-time pricing customers. These funds are currently held by Ameren in a liability account. The IPA proposes a procurement term of five years with a solicitation date in early summer 2016. Ameren Response at 7.

Ameren recommends that any Commission approved DG REC procurement in the IPA Plan should recognize that the IPA is also pursuing supplemental solar REC procurements using the RERF. Under these procurements, the IPA will act as the contractual counterparty with suppliers and not the Utilities.

The proposed DG REC procurement associated with the IPA Plan would benefit all interested parties by stipulating that the IPA is the contractual counterparty with suppliers and not Ameren. Doing so would streamline the procurement process and the administration of resulting contracts. To compensate the IPA for DG REC expenses under its contracts, Ameren and the IPA would enter into a supplemental agreement whereby Ameren would use prior collections from real time pricing customers to reimburse the IPA for contractual expenditures.

ComEd proposes limited revisions designed to clarify the meaning of certain terms or concepts. ComEd recommends that a safeguard be added to avoid placing an undue burden on utilities associated with managing contracts involving prorated shares and no more than one contract between aggregators and utility may be below one megawatt because of proration. Ameren supports ComEd's proposal and the reasons put forth for its approval. *Id.* at 7.

c. ComEd Position

ComEd proposes limited revisions designed to clarify the meaning of certain terms or concepts. Of particular importance is ComEd's recommendation that a safeguard be added to avoid placing an undue burden on utilities associated with managing contracts involving prorated shares. As proposed in Appendix A, no more than one contract between the aggregators and utility may be below one megawatt because of proration. ComEd Objections at 8.

In its Objections, ComEd proposed revisions to the 2016 Plan to clarify that the contracts utilities execute with aggregators must be at least one megawatt in size, but the overall contract can include both renewable energy credit product sizes specified in Section 1-75(c) (*i.e.*, (less than 25 kW and 25 kW to 2 megawatts). ComEd Objections at 8; App. A at 137. ComEd's proposed change would also permit one contract with the aggregators to be below 1 megawatt to accommodate any balancing the IPA may need to undertake between the utilities. *Id.* ComEd offered these proposals in conformance with Section 1-75(c) of the IPA Act, which provides that "to minimize the administrative burden on contracting entities, the Agency shall solicit the use of third-party organizations to aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity." 20 ILCS 3855/1-75(c)(1). Moreover, these "organizations shall administer contracts with individual distributed renewable energy generation device owners." *Id*.

ComEd notes that the IPA recommends a procurement term of five years for DG RECs in early summer of 2016 using renewable funds previously collected from real time pricing customers. Plan at 13. These funds are currently held separately by each utility (ComEd and Ameren) in a liability account. ComEd Response at 11.

Because the IPA is also pursuing supplemental SREC procurements using the RERF and will act as the contractual counterparty with suppliers, Ameren's Objections recommend that the IPA (rather than utilities) should also act as the contractual counterparty with suppliers in the DG REC procurement proposal in the IPA Plan. ComEd agrees with Ameren's recommendation that doing so would streamline the procurement process and the administration of resulting contracts. *Id.*

ComEd also agrees with Ameren that in order to compensate the IPA for DG REC expenses under its contracts, each utility (Ameren and ComEd) would enter into a supplemental agreement with the IPA whereby each utility would use prior collections from real time pricing customers to reimburse the IPA for contractual expenditures.

ComEd claims that ELPC appears to have misinterpreted ComEd's proposed revisions regarding minimum contract size and pricing. Rather than requiring bidders to submit *bids* of at least one megawatt in size for each REC product size (<25 kW and 25 kW to 2 megawatts), ComEd's suggested change is that aggregator *contracts* be for at least one megawatt in size. The contracts can contain both REC product sizes (less than

25 kW and 25 kW to 2 megawatts), but would include a single blended price for REC products less than 25 kW and a single blended price for REC products 25 kW to 2 megawatts. Having one price for all REC product sizes under contract, as the 2016 Plan proposed, can create inequity between the parties to the contract because the price for REC products less than 25 kW is likely to be greater than the price for REC products 25 kW to 2 megawatts. ComEd Reply at 12.

For example, assume the IPA awards a contract with a single blended price of $150 per REC based on the expectation that 50% of the RECs delivered would be less than 25 kW at a price of $200 per REC and 50% of the RECs delivered would be between 25 kW to 2 megawatts at a price of $100 per REC. If the actual deliveries under the contract were 30% from the less than 25 kW product size and 70% from the 25 kW to 2 megawatt product size, then customers would be paying more to the aggregator than the effective value of the RECs received (*i.e.*, paying an average of $150 per REC for an average value of $130 per REC). The reverse could happen as well, with the winning aggregator being underpaid under a single blended price for all REC product sizes, which would leave the aggregator with too little in collected funds to pay the DG systems that they have aggregated. *Id.*

To avoid these inequities and any potential gaming of bids, ComEd's proposal for a single blended price *per REC product size rather than per contract* will ensure that both parties to the contract will be treated fairly.

ComEd next responds to the IPA suggestion that the 1 megawatt threshold apply only to the IPA's solicitation and bidding process, and should not extend to the contracts executed between utilities and aggregators. The IPA's view, however, contradicts the statutory mandate to avoid burdensome contract administration. "[T]o minimize the administrative burden on contracting entities, the Agency shall solicit the use of third-party organizations to aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity." 20 ILCS 3855/1-75(c)(1). Moreover, these "organizations shall administer contracts with individual distributed renewable energy generation device owners." *Id*. Put simply, these provisions clearly direct the IPA to undertake measures that ensure utilities will not have to administer numerous small contracts. ComEd Reply at 13.

The Commission also addressed this matter in the 2015 Plan proceeding, and approved the requirement that contracts must be no less than 1 megawatt in size:

> Additionally, the IPA proposes that aggregators may contract with system owners at different REC price points and systems may be selected at different price points, but with a single blended average REC price for an aggregator's contract with ComEd. The IPA suggests this may better balance the need to promote small system participation while alleviating administrative burdens on the utilities.
>
> *In its Reply, ComEd states assuming this means that the contract between the aggregator and utility reflects a minimum of 1 MW for a single price (derived from "blending"), ComEd says this is the position it advocated in its Objections*

> *and Response. ComEd says the aggregator construct facilitates small contract amounts and varying prices between aggregators and suppliers. It appears to the Commission that the IPA and ComEd are now in agreement on this issue; and the Commission hereby approves that agreement for purposes of this Plan.*

Docket No. 14-0588, (Order of December 17, 2014) at 288 (emphasis added).

ComEd claims the wisdom of consistently applying the statutory and Commission-approved 1 megawatt threshold to bids and contracts can be demonstrated through a brief example. While a number of aggregators may submit bids of 1 megawatt to the IPA, the bids may contain many projects that are unacceptable due to price or technical reasons, resulting in a contract that is merely a fraction of 1 megawatt. As a result, the IPA's proposal would lead to utilities having to execute multiple small contracts, each of which is well under 1 megawatt. This result thus does not "minimize the administrative burden on *contracting entities*", as required by the IPA Act. 20 ILCS 3855/1-75(c) (1).

Consistent with ComEd's Objections, Section 1-75(c)(1) and the Commission's prior order, the Commission should again confirm that the minimum contract size for DG RECs is 1 megawatt. *Id* at 15.

d. ELPC Position

ELPC notes that ComEd includes only one paragraph related to renewable resources in its Objections, stating only that it has proposed "limited revisions" to the contracting terms "designed to clarify the meaning of certain terms of concepts." However, the "limited revisions" that ComEd has proposed to Section 8.4.1 (Procurement Process) of the IPA's Plan are not merely "clarifications." Instead, the proposal to require bidders to submit bids of at least one megawatt in size *for each REC product size* (<25 kW and 25 kW to 2 megawatt) departs from the Commission's resolution of this issue last year and would create very significant challenges for the procurement of DG RECs from small (<25 kW) systems. As the IPA's Final 2015 Plan states, "[b]ids must be at least one megawatt in size, but may feature a number of DG systems <u>of all qualifying sizes and resource types</u>." Docket No. 14-0588, (Order of December 17, 2014) at 106 (emphasis added). There is no requirement that bids must be segregated by "each REC product size," as ComEd suggests, nor is there good reason to do so. In fact, ELPC is aware of several project developers that have expressed significant concern about their ability to assemble the requisite number of <25 kW projects in order to meet a 1 megawatt bidding threshold from small projects alone. The Commission should reject ComEd's proposed "clarifying" amendments to Section 8.4.1 of the Plan. ELPC Response at 4-5.

e. Commission Analysis and Conclusion

The IPA recommends a procurement of DG RECs using renewable funds previously collected from Ameren and ComEd real-time pricing customers. Ameren suggests that the IPA become the contractual counterparty with suppliers to the planned DG procurement and not the utilities themselves. This proposal is supported by ComEd. The IPA is allowed to enter into contracts under Section 1-56(i) of the IPA Act because the source of those funds, namely the RERF is under the control of the IPA. The DG procurement takes place using funds collected from real-time pricing customers of the utilities. The Commission agrees with the IPA that Section 1-75(c)(5) of the IPA Act specifically states that these funds are to be used for the "purchase of renewable energy sources to be procured by the electric utility." 20 ILCS 3855/1-75(c)(5). As the IPA points out, there is nothing in the IPA Act or the PUA that would authorize the IPA to enter into these contracts. The proposal of Ameren and supported by ComEd is rejected.

ComEd is also asking that the Commission revise the IPA's DG procurement to indicate that contracts utilities execute with aggregators must be at least 1 megawatt in size. According to the IPA, this would make it more difficult for smaller DG systems to be included in the process. The Commission wants to encourage development in this area, not make it more restrictive. Section 1-75(c)(1) requires half of the renewable resources must come from devices of less than 25 kilowatts in the named capacity. 20 ILCS 355/1-75(c)(1). The Commission agrees with the IPA and ELPC and rejects the proposal of ComEd.

On Exceptions, ComEd stated that it will not contest the ALJPO's conclusion that the IPA will not be the contracting counterparty in the distributed generation procurement. ComEd Br. on Exceptions at 12. ComEd also argues that the Proposed Order ignores the statutory threshold of 1 MW and thus incorrectly rejects a required minimum contract size of 1 MW and that the Proposed Order overlooks the proposal that the contracts include a single blended price for renewable energy credit products less than 25 kilowatts and a single blended price for renewable energy credit products 25 kW to 2 MW. *Id* at 12.

On Exceptions, Ameren continues to argue that the IPA should be the contracting party for the DG REC procurement rather than the utilities. Ameren Br. on Exceptions at 16. According to Ameren, there are administrative costs associated with having a different DG REC procurement process using RERF and those using ACPs. Ameren points out that these costs would be borne by ratepayers and these costs could be streamlined or avoided if both DG REC procurements were run through the IPA. *Id* at 16.

In its Reply Brief on Exceptions, Ameren supports the language put forth by ComEd to include the statutory 1 MW threshold requirement for DG RECS and that DG REC contracts include a blended price for each product size. Ameren Reply Br. on Exceptions at 23.

In its Reply Brief on Exceptions, ELPC agrees with the ALJPO's conclusion rejecting Ameren's proposal that the IPA become the contracting party for the procurement of DC RECs using ACPs. ELPC Reply Br. on Exceptions at 3. ELPC points out that this position would be inconsistent with Section 1-75 (c) of the IPA Act. *Id* at 3-4. ELPC argues that many developers would have trouble financing contracts that include an Illinois state agency as a counterparty. *Id* at 4. ELPC also supports the conclusion of the ALJPO that the 1 MW requirement applies to the IPA's solicitation and bidding process, but does not lock the counterparties into a minimum size contract. *Id* at 4.

The IPA in its Reply Brief on Exceptions states that the position of ComEd believing that the minimum threshold of 1 MW applies to the resulting contract rather than the bids themselves is inconsistent with Section 1-75 (c)(1) of the IPA Act. The IPA feels that the requirement should apply to the bid and not the contract. In the IPA procurement, it is the bids that are solicited not the contracts. IPA Reply Br. on Exceptions at 18. The IPA points out that the contracts are only executed after the solicitation of bids, aggregation process and the Commission approval of the procurement results. *Id* at 18. According to the IPA, this process still significantly minimizes the administrative burden by requiring 1 MW bids. *Id* at 18.

The IPA does support the proposal of ComEd that executed contracts feature a single blended price per product size and believes that this may further reduce the administrative burden on the utilities. *Id* at 19. The IPA agrees with ComEd that this type of single price per product may limit any incentive for gaming between product categories. *Id* at 19.

The Commission does not agree with the utilities' interpretation concerning the 1 MW threshold. It seems more logical that the process would apply the 1 MW threshold on the bids and not the contracts themselves. The relevant part of the statute requires third party organizations to aggregate distributed renewable energy into groups of no less than one MW in installed capacity and not into contracts of one MW capacity. *See* 200 ILCS 3855/1-75 (c)(1). Therefore, the position of ComEd and Ameren concerning the size of the contracts will not be adopted.

There does not seem to be any opposition to the proposal of ComEd requiring a blended rate based on product size. Therefore, the following language proposed by ComEd will be adopted. "<u>The Commission approves ComEd's uncontested proposal that the contracts include a single blended price for each product size category (*i.e.,* less than 25 kW and 25 kW to 2 MW).</u>"

14. Section 8.5 Whether the IPA Should use the RERF to Procure Additional DG RECs.

a. IPA Position

The RERF balance as of September 28, 2015 equals $116,573,040.73, the total amount received in the IPA's RERF attributable to ARESs' ACP payments less the cost of RECs purchased by the IPA, expenses related to the SPV procurement process, and a $98 million transfer to the Illinois General Revenue Fund pursuant to Public Act 99-0002. Prior to 2015, the Commission found that it did not have jurisdiction over the RERF, and as a result the IPA did not seek approval for procurement using the RERF in previous plan years. Docket No. 12-0544, (Order of December 19, 2012) at 112-14.

Section 1-56(i) of the IPA Act required the IPA to develop a SPV procurement plan to spend up to $30 million on RECs from PV resources using the RERF. The IPA's SPV procurement plan was approved by the Commission in Docket No. 14-0651. The first procurement event under that plan was held in June 2015 and successfully allocated the full $5 million budget for that event. While the SPV procurement plan does not direct the IPA to utilize the full RERF balance (which will increase as ARESs make future compliance payments), it is an important first step forward in allowing those funds to be used for their intended purpose. The IPA hopes that future legislative changes will enable the IPA to use the remaining fund balance to further the RERF's purposes. Plan at 137.

In response to the ELPC proposal, the IPA states that as it develops its plans for any use of the RERF, it will provide opportunities for stakeholders to provide input and comment on the most efficient and appropriate use of the RERF and potential coordination with procurements approved in this proceeding. However, as the Commission held in Docket No. 12-0544 and as ELPC itself acknowledges, "it is clear the Commission has no authority over disbursements from the RERF collected on behalf of ARES customers." Docket No. 12-0544, (Order of December 19, 2012) at 113. The IPA strongly believes that a Commission Order approving its Plan should concern only those matters over which the Commission has jurisdiction, and that it would be inappropriate for the Commission to offer recommendations on planned disbursements from that fund. IPA Response at 30-31.

b. ELPC Position

ELPC states that in addition to the RRB and hourly ACPs, the IPA also holds funds in the RERF to procure renewable energy resources pursuant to Section 1-56 of the IPA Act. The IPA has interpreted language in Section 1-56 to limit the use of the RERF to years in which the IPA can conduct a procurement "in conjunction with" a procurement for electric utilities. While this has effectively limited the use of the RERF in prior years, the fact that the IPA is planning a renewable resources procurement for electric utilities in 2016 means that it can also tap the RERF for additional renewable resources this year.

ELPC again point to the expiration of the federal ITC as the reason the IPA should maximize the use of the RERF to procure additional distributed solar resources early in 2016. ELPC claims it would be prudent to maximize the impact of these payments by accelerating DG procurements, particularly as the General Assembly has swept unused RERF funds in the past and could do so again in the future if they are not used for their statutory purpose. The IPA should consider the use of a one-time payment for a future five-year stream of DG RECs in order to minimize any risk of future RERF sweeps impacting existing contracts with suppliers. ELPC acknowledges that the ICC does not have direct jurisdiction over the use of the RERF, but requests that the ICC recommend that the IPA coordinate its use of RERF funds with its traditional procurement plan in order to provide greater transparency to the industry and stakeholders. ELPC Objections at 4.

c. Renewables Suppliers Position

The Renewables Suppliers point out that ELPC recommends that the IPA should signal its intent to use funds accumulated in the IPA RERF to procure additional DG SRECs. ELPC Objections at 5. ELPC acknowledges, and the Renewables Suppliers agree that the Commission does not have authority to direct the IPA as to how it will spend the funds accumulated in the RERF. Renewables Suppliers Objections at 9.

The Renewables Suppliers agree generally with ELPC that the IPA should act during 2016-2017 to purchase RECs, using available funds in the RERF, in conjunction with one or more procurements for electric utilities, in order to avoid or minimize the risk of those funds being "borrowed" by the General Revenue Fund to be used for other State budgetary purposes. Indeed, the fact that Section 1-56(c) of the IPA Act (as the IPA has interpreted it) requires the IPA to make procurements using the RERF only "in conjunction with" a procurement for electric utilities is a compelling reason why the IPA Plan should include REC procurements for the electric utilities during the 2016-2017 Plan Year, as recommended by both the Renewables Suppliers and ELPC. However, as with ELPC's proposal for an electric utility procurement event(s) for DG RECs, any procurement conducted by the IPA during 2016-2017 using funds in the RERF should follow the sub-targets specified in Section 1-56(b) of the IPA Act: 75% from wind, 6% from solar, and 1% from DG resources.

The Renewables Suppliers argue that the Commission should recommend to the IPA that: (1) during the 2016-2017 Plan Year, the IPA should conduct procurements for RECs, using funds in the RERF, in conjunction with procurement events for the electric utilities; and (2) any such procurements using the RERF should, in the aggregate, procure RECs from wind, solar and DG resources in approximately the percentages stated in Section 1-56(b), specifically, 75% from wind resources, 6% from PV resources, and 1% from DG resources. Renewables Suppliers Response at 6.

d. Wind on the Wires Position

Wind on the Wires agrees with ELPC that the IPA should signal its intended use of the RERF, however, it points out that the IPA Act directs the use of RERF money to resources beyond distributed solar and the IPA should follow those directives. Wind on the Wires Response at 1-2.

Wind on the Wires states that Section 1-56(b) of the IPA Act provides guidance on how the RERF money is to be administered. Under this section at least 75% of the renewable energy resources purchased with funds in the RERF shall come from wind generation. This section also indicates that at least 6% of the resources procured using the RERF shall come from PV. 5 ILCS 3855/1-56(b). The statute qualifies these amounts as being floors -- using “at least” language -- therefore Wind on the Wires recommends IPA propose a portfolio of products that are not overly weighted toward DG but ensures that the minimums are met for all of the technologies listed within Section 1-56(b) of the IPA Act. *Id.* at 2.

Resources in the RERF have already been used to procure PV and distributed PV generation. Money from the RERF has been tapped once before, pursuant to Public Act 98-0672. That amendment provided for a one-time $30 million supplemental procurement of new PV resources. The IPA developed a plan to meet the directive of P.A. 98-0672 through as many as four procurement events to be held between June 2015 and early 2017, which was modified and approved by the Commission in Docket No 14-0651. *Id.*

Of the $116,573,040.73 in the RERF, the one-time supplemental procurement of PV resources earmarks $30 million for use. That leaves approximately $86 million for use as prescribed by Section 1-56(b).

The IPA is proposing to procure wind resources RECs for MidAmerican. The procurement price of those RECs can serve as the benchmark for wind resource RECs procured using the RERF.

Thus, Wind on the Wires encourages the IPA to indicate that it intends to use those funds in compliance with Section 1-56(b) by purchasing a diverse portfolio of products that ensue the floors will be achieved, and to develop a procurement timeline for the wind, solar and DG markets.

e. Commission Analysis and Conclusion

The IPA holds funds in the RERF to procure renewable energy resources pursuant to Section 1-56 of the IPA Act. The IPA indicates that it would be inappropriate for the Commission to offer recommendations on planned disbursement from the RERF collected on behalf of ARES customers. When the IPA develops its plan to use these funds, stakeholders will have an opportunity to provide input and comments on the best way to use these funds. The Commission agrees with the IPA and declines to make any recommendation concerning the IPA's use of these funds.

In its Brief on Exceptions, the Renewables Suppliers acknowledge that the Commission does not have the authority to direct the IPA as to how to spend the funds accumulated in the RERF. However, the Renewables Suppliers see no reason why the Commission should not use its expertise to make recommendations to the IPA for the use of these funds. Renewables Suppliers Br. on Exceptions at 12. The Renewables Suppliers point to the Commission Order in Docket 12-0544, where the Commission was troubled with the IPA's interpretation of Section 1-56(c) of the IPA Act. *Id* at 12.

The IPA responds in its Reply Brief on Exceptions that in Docket 12-0544, the Commission acknowledged that it does not have jurisdiction over the disbursement from the RERF collected on behalf of the ARES customers. IPA Reply Br. on Exceptions at 22. The IPA points out that Section 16-111.5 of the PUA provides for the annual procurement plans and it details how the IPA will conduct procurements to meet the load requirements of eligible retail customers. Procurements using the RERF are not used to meet the load requirements of eligible retail customers. *Id* at 23*.*

The Commission is not persuaded by the arguments of the Renewals Suppliers and agrees with the IPA that the Commission does not have jurisdiction over the use of RERF.

V. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having reviewed the entire record, is of the opinion and finds that:

(1) Commonwealth Edison Company, Ameren Illinois Company and MidAmerican Energy Company are 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 PUA and an "electric utility" as defined in Section 16-102 of the PUA;

(2) the Commission has jurisdiction over the parties hereto and the subject matter hereof;

(3) the recital of fact and conclusions of law in the prefatory portion of this Order are supported by the record and are hereby adopted as findings of fact and conclusions of law;

(4) the load forecast for Ameren Illinois Company attached to the Illinois Power Agency 's September 28, 2015 petition should be approved; the load forecast for Commonwealth Edison Company attached to the Illinois Power Agency 's September 28, 2015 petition should be approved; the load

forecast, as amended herein for MidAmerican Energy Company should be approved;

(5) subject to the modifications adopted in the prefatory portion of this Order, including such 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; and

(6) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that subject to the modifications adopted in the prefatory portion of this Order, the Plan filed by the Illinois Power Agency pursuant to Section 16-111.5 of the Public Utilities Act is hereby approved, as are the load forecasts found appropriate above.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to 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 16th day of December, 2015.

(SIGNED) BRIEN SHEAHAN

Chairman