2015

ILLINOIS
POWER AGENCY

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Director

[ELECTRICITY PROCUREMENT PLAN]

Prepared in accordance with the Illinois Power Agency and Illinois Public Utilities Acts

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Illinois Power Agency

2015 Electricity Procurement Plan

Prepared in accordance with the

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Illinois Power Agency

2015 Electricity Procurement Plan

1 Executive Summary

This is the seventh electricity and renewable resource procurement plan (the "Plan," "Procurement Plan," or "2015 Procurement Plan") prepared by the Illinois Power Agency ("IPA" or "Agency") under the authority granted to it under the Illinois Power Agency Act ("IPA Act") and as further regulated by the Illinois Public Utilities Act ("PUA"). Chapter 2 of this plan describes the specific legislative authority and requirements to be included in any such plan including from previous orders of the Illinois Commerce Commission ("Commission" or "ICC").

The Plan addresses the provision of electricity and renewable resource supply for the "eligible retail customers" of Ameren Illinois Company ("Ameren") and Commonwealth Edison ("ComEd") as defined in Section 16-111.5(a) of the PUA, who generally are residential and small commercial fixed price customers who have not chosen service from an alternate supplier. The Plan considers a 5-year planning horizon that begins with the 2015-2016 delivery year and lasts through the 2019-2020 delivery year.

The 2014 Procurement Plan was approved by the Commission in Docket No. 13-0546.[1] That plan recommended a return to the procurement of electricity after no procurement was conducted in 2013, and a number of refinements to the procurement process including an updated hedging strategy, smaller procurement blocks and a second procurement in September, 2014. It was the second plan that included incremental energy efficiency programs as mandated by Section 16-111.5B of the PUA.

The Plan recommends a continuation of the procurement strategy for electricity adopted for 2014 (Chapter 7). This conclusion is based on the IPA's analysis of the load forecast scenarios (Chapter 3), the position of the supply portfolio (Chapter 4), and the IPA's analysis of the risks associated with serving electric load and various factors of power procurement (Chapter 6). That analysis of risks carefully examines the concept of the Agency procuring full requirements products, rather than the IPA's traditional approach of procuring standard blocks of power. Once again, the IPA concludes that a full requirements approach in lieu of standard blocks does not best serve the interests of the eligible retail customers that the IPA is directed by the General Assembly to serve. The Plan includes a proposal to conduct a fall procurement event for energy efficiency as a supply resource for delivery starting in the summer of 2016 (Chapter 7). The Plan also recommends a procurement of Solar Renewable Energy Credits ("SRECs") and Renewable Energy Credits ("RECs") from distributed generation resources (Chapter 8).

1.1 Power Procurement Strategy

The Plan proposes to continue using the risk management and procurement strategy that the IPA has historically utilized: hedging load by procuring on and off-peak blocks of forward energy in a three-year laddered approach. While the IPA again this year investigated alternative strategies, such as full requirement contracts and use of options, the IPA believes the continuation of its previous (tested) risk management strategy is the most prudent, most reasonable, and the most likely to meet its statutorily mandated objective to "[d]evelop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[2]

The proposed hedging strategy, in the short term, is designed to manage the risk of load uncertainty resulting from the possibility of large blocks of load returning to the utilities because of municipalities choosing not to continue their aggregation programs. As described in detail in Chapter 7, based on the analysis of the costs of procurement in Chapter 6 and supply shortfalls identified in Chapter 4, the IPA recommends continuation of

[1] While the 2014 Procurement Plan was approved in the Final Order in Docket No. 13-0546 on December 18, 2013, the Renewables Suppliers were granted a rehearing on issues related to the curtailment of long-term power purchase agreements for renewable resources and the Order on Rehearing was approved on June 17, 2014.
[2] 20 ILCS 3855/1-20(a)(1).

the procurement approach adopted in 2014 for use in the procurement of power for delivery year 2015-2016 and beyond. The IPA also recommends procurement of energy in blocks of 25MW, consistent with the 2014 Plan. The risk management strategy will continue to bifurcate the first delivery year into two periods with different hedging levels—with the summer fully hedged at the time of the April procurement event, and the balance of the year 75% hedged. The IPA recommends that the Commission pre-approve a supplemental September procurement event, which would bring the hedging level for the balance of the first delivery year to the fully hedged level, based on factors intended to ensure that the benefits outweigh the costs.

The Agency also recommends the procurement of energy efficiency as a supply resource in fall 2015 for delivery starting in June 2016. This proposed procurement is intended to reduce the overall cost of procuring supply for eligible retail customers.

The IPA continues to recommend that capacity, ancillary services, load balancing services, and transmission services be purchased, as they are now, by Ameren from the MISO marketplace and by ComEd from PJM's.

1.2 Renewable Energy Resources

The load forecasts supplied by the utilities on July 15, 2014 indicate that existing renewable energy resources under contract do not meet or exceed the Renewable Portfolio Standard obligations for solar resources or distributed generation for eligible retail customers. Accordingly, the IPA recommends conducting procurement events for solar RECs using the renewable resources budget and for distributed generation RECs using hourly ACP funds. Those proposals are discussed in more detail in Chapter 8.

While it is highly unlikely that the statutorily mandated rate caps for the renewable resources budget will be exceeded in the 2015-16 delivery year for either utility, the IPA recommends that the Commission pre-approve a curtailment of the long-term power purchase agreements that were entered into as part of the 2010 procurement should the utility load forecast updates in Spring 2015 indicate that a curtailment is necessary. This is a similar approval process as was adopted in last year's plan. Unlike last year, given that the IPA is planning a procurement of DG resources using hourly ACP funds, the IPA does not recommend the use of Alternative Compliance Payments collected from customers on hourly pricing to purchase curtailed RECs (in the unlikely event that the load forecast updates in Spring 2015 show that the rate caps will be exceeded and that the long-term power purchase agreements must be curtailed). Instead, while not subject to ICC jurisdiction, the IPA would plan to use funds from the Renewable Energy Resources Fund to purchase remaining curtailed RECs.

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

Table 1-1: Summary of Hedging Strategy

April 2015 Procurement			September 2015 Procurement
June 2015-May 2016 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	November 2015-May 2016
106% (June-Oct.) 75% (Nov.-May)	50%	25%	100%

Table 1-2: Summary of Procurement Plan Recommendations Based on July 15, 2014 Utility Load Forecast (quantities to be adjusted based on the March 2015 load forecast):

	Delivery Year	Energy	Capacity	Renewable Resources	Ancillary Services
AMEREN	2015-16	Up to 875MW forecasted requirement (April Procurement) Up to 275 MW additional forecasted requirement (September Procurement)	Direct purchase from MISO capacity market	One-year SRECs procurement up to 30.2 GWh Five-year DG REC procurement up to 6.5 GWh No RPS procurement for other resources, target exceeded	Will be purchased from MISO
AMEREN	2016-17	Up to 400MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG)	Will be purchased from MISO
AMEREN	2017-18	Up to 275MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: shortage of 85GWh, revisit next year	Will be purchased from MISO
AMEREN	2018-19	No energy procurement required	Direct purchase from MISO capacity market	No RPS procurement: shortage of 447GWh, revisit next year	Will be purchased from MISO
AMEREN	2019-20	No energy procurement required	Direct purchase from MISO capacity market	No RPS procurement: shortage of 553GWh, revisit next year	Will be purchased from MISO
COMED	**Delivery Year**	**Energy**	**Capacity**	**Renewable Resources**	**Ancillary Services**
COMED	2015-16	Up to 1,950MW forecasted requirement (April Procurement) Up to 550MW additional forecasted requirement (September Procurement)	Direct purchase from PJM capacity market	One-year SRECs procurement up to 49.8 GWh Five- year DG REC procurement up to 13.2 GWh. No RPS procurement for other resources, target exceeded	Will be purchased from PJM
COMED	2016-17	Up to 750MW forecasted requirement (April Procurement)	Direct purchase from PJM capacity market	No RPS procurement: shortage of 120GWh, revisit next year	Will be purchased from PJM
COMED	2017-18	Up to 375 MW forecasted requirement (April Procurement)	Direct purchase from PJM capacity market	No RPS procurement: shortage of 428GWh, revisit next year	Will be purchased from PJM
COMED	2018-19	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: shortage of 888GWh, revisit next year	Will be purchased from PJM
COMED	2019-20	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: shortage of 1,124GWh, revisit next year	Will be purchased from PJM

1.3 Energy Efficiency as a Supply Resource

After examining the concept of energy efficiency as a supply resource in the draft 2014 Procurement Plan, and after conducting a workshop and receiving written comments early in 2014, the IPA is proposing a procurement of energy efficiency as a supply resource. The proposal is for the procurement for "super-peak" summer weekday blocks, as discussed in more detail in Section 7.1. To work through potential challenges and allow the market to properly organize, the Agency is proposing that the procurement be held in late 2015, for delivery starting in 2016, and to ensure that the procurement is structured to lower the overall supply portfolio cost.

1.4 Incremental Energy Efficiency

This plan is the third year of inclusion of incremental energy efficiency programs pursuant to Section 16-111.5B of the Public Utilities Act. The IPA recommends inclusion of the programs submitted by the utilities that have passed the Total Resource Cost and have not been determined to be duplicative of other programs as discussed in Section 7.2. The IPA further recommends the approval of the consensus items from the Staff-led workshops held earlier this year.

1.5 The Action Plan

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

1. Approve the base case load forecasts of ComEd and Ameren as submitted in July 2014.
2. Require the utilities to provide an updated March 13, 2015 forecast which will be pre-approved by the ICC in this docket subject to the March 2015 consensus of each utility, the IPA and the ICC Staff, and the Procurement Monitor.
3. Approve two energy procurement events. The first scheduled for April 2015, the second scheduled for September 2015. The energy amounts to be procured in April will be determined by the IPA based on the updated March 2015 load forecast and in accordance with the hedging levels stated in this Plan and as ultimately approved by the ICC in this docket. The September procurement is subject to a July 2015 load forecast indicating a hedging shortfall exists in the November through May period of the prompt delivery year and a determination by the IPA that the estimated risk management benefit exceeds the cost of the procurement event and also subject to other conditions as may be specified by the Commission.
4. Require the utilities to expand the July 2015 forecast to include the November 2015 to May 2016 period. The addition of the November 2015 through May 2016 forecast will be used solely in determining the quantity of energy to be solicited, if applicable, in the September 2015 procurement event and will have no bearing on renewable curtailment decisions, if any.
5. Approve continued procurement by ComEd and Ameren of capacity, network transmission service and ancillary services from their respective RTO for the 2015-2016 delivery year.
6. Approve pro-rata curtailment of ComEd and Ameren's Long-Term Power Purchase Agreements for renewable energy in the unlikely event that the updated March 2015 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 2014 forecast will form the basis for curtailment.
7. Approve a one-year procurement of SRECs to allow the utilities to meet their RPS requirement.
8. Approve a procurement of distributed generation RECs using already collected hourly ACP funds.
9. Approve a fall 2015 procurement of energy efficiency as a supply resource to lower the overall cost of supply starting in 2016.
10. Approve the consensus items from the ICC staff-led workshops on Section 16-111.5B.

11. Approve Section 16-111.5B incremental energy efficiency programs.
12. Approve the recommendations to improve the procurement event process including updating the processes to ensure that the IPA recovers the cost of holding procurement events.

The Illinois Power Agency respectfully submits this draft Procurement Plan for public comment, which the IPA believes is compliant with all applicable law. The IPA intends to file with the Commission and requests Commission approval of the Plan as contained herein and summarized above.

2 Legislative/Regulatory Requirements of the Plan

This section of the 2015 Procurement Plan describes the legislative and regulatory requirements applicable to the Agency's annual Procurement Plan. This includes compliance with previous Commission Orders. A Regulatory Compliance Index, Appendix A, provides a complete cross-index of regulatory/legislative requirements and the specific sections of this plan that address each requirement identified.

2.1 IPA Authority

The Illinois Power Agency ("IPA", or "Agency") was established in 2007 by Public Act 95-0481 in order to ensure that ratepayers, specifically customers in service classes that have not been declared competitive and who take service from the utility's bundled rate ("eligible retail customers"),[3] benefit from retail and wholesale competition. The objective of the Act was to improve the process to procure electricity for those customers.[4] In creating the IPA, the General Assembly found that Illinois citizens should be provided "adequate, reliable, affordable, efficient, and environmentally-sustainable electric service at the lowest, total cost over time, taking into account benefits of price stability."[5] The General Assembly also stated "investment in energy efficiency and demand-response measures, and to support development of clean coal technologies and renewable resources" as additional goals.[6]

Each year, the IPA must develop a "power procurement plan" and conduct a competitive procurement process to procure supply resources as identified in the final procurement plan, as approved pursuant to Section 16-111.5 of the Public Utilities Act ("PUA").[7] The purpose of the power procurement plan is to secure the electricity commodity and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company ("ComEd") and Ameren Illinois Company ("Ameren").[8] The Illinois Power Agency Act ("IPA Act") directs that the procurement plan be developed and the competitive procurement process be conducted by "experts or expert consulting firms," respectively known as the "Procurement Planning Consultant" and "Procurement Administrator."[9] The Illinois Commerce Commission ("Commission") is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[10]

2.2 Procurement Plan Development and Approval Process

Although the procurement planning process is ongoing, incorporating stakeholder input and lessons from past proceedings, the formal statutory timeline for this 2015 Procurement Plan began on July 15, 2014. On that date, each Illinois utility that procures electricity through the IPA submitted load forecasts to the Agency. These forecasts – which form the backbone of the Procurement Plan and which are covered in sections 3.2 and 3.3 in greater detail – cover a five-year planning horizon and include hourly data representing high, low, and expected scenarios for the load of the eligible retail customers. Prior to the receipt of these forecasts, the IPA held informal workshops on full requirements products, distributed generation, and energy efficiency as

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[3] 220 ILCS 5/16-111.5(a).
[4] 20 ILCS 3855/1-5(2); 3855 /1-5(3); 3855/1-5(4).
[5] 20 ILCS 3855/1-5(1).
[6] 20 ILCS 3855/1-5(4).
[7] 20 ILCS 3855/1-20(a)(2), 3855/1-75(a).
[8] Docket 11-0660, Final Order dated December 21, 2011 at 1. Although the IPA must create a procurement plan for ComEd and Ameren, the IPA must also create a procurement plan for MidAmerican Energy Company if MidAmerican elects to opt into the IPA procurement process. (See 20 ILCS 3855/1-20(a)(1).) MidAmerican has not made such an election at this time.
[9] 20 ILCS 3855/1-75(a)(1), 3855/1-75(a)(2).
[10] 220 ILCS 5/16-111.5(b), (c)(2).

a supply resource. The IPA then solicited and received feedback on specific questions after each workshop, and has used the input received from stakeholders in the preparation of this Plan.[11]

Next, the IPA prepared this draft Procurement Plan. On August 15, the Plan was made available for public review and comment. The Public Utilities Act provides for a 30-day comment period starting on the day the IPA releases its draft plan. Because the 30th day will be on a Sunday, the comment period for this plan will close on Monday September 15, 2014. During the 30-day comment period, the IPA must hold at least one public hearing within each utility's service area for the purpose of receiving public comment on the procurement plan; those public hearings are set for September 3 and 10, 2014 in Chicago and Springfield, respectively. Within fourteen days following the end of the 30-day review period (*i.e.*, no later than September 29, 2014), the IPA will file a revised Procurement Plan with the Commission for approval. Objections must be filed with the Commission within five days after the filing of the Plan;[12] typically, the Administrative Law Judge sets the dates for Responses and Replies to Objections by Ruling shortly after the docket opens. The Commission must enter an order confirming or modifying the Plan within 90 days after it is filed by the IPA, which this year will be Sunday, December 28, 2014 (leading to a Monday, December 29, 2014 deadline). The current ICC calendar indicates the last scheduled meeting prior to that deadline is on Tuesday, December 23, 2014.

The Commission approves the Procurement Plan, including the load 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."[13]

2.3 Procurement Plan Requirements

At its core, the Procurement Plan consists of three pieces: (1) a forecast of how much energy (and in some cases capacity) is required by eligible retail customers; (2) the supply currently under contract; and (3) what type and how much supply must be procured to meet load requirements and all other legal requirements (such as renewable/clean coal purchase requirements or mandates from previous Commission Orders). To that end, the Procurement Plan must contain an hourly load analysis, which 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.[14] In addition, the Procurement Plan must analyze the impact of demand side and renewable energy initiatives, including the impact of demand response programs and energy efficiency programs, both current and projected.[15] Based on that hourly load analysis, the Procurement Plan must detail the IPA's plan for meeting the expected load requirements that will not be met through preexisting contracts,[16] and in doing so must:

- Define the different Illinois retail customer classes for which supply is being purchased, and include monthly forecasted system supply requirements, including expected minimum, maximum, and average values for the planning period.[17]
- Include the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year that, separately or in combination, will meet the portion of the load requirements not met through pre-existing contracts.[18] 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,

[11] The questions and responses from stakeholders are available on the IPA website at: www2.illinois.gov/ipa/Pages/Plans_Under_Development.aspx.
[12] 220 ILCS 5/16-111.5(d)(3).
[13] 220 ILCS 5/16-111.5(d)(4).
[14] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).
[15] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).
[16] 220 ILCS 5/16-111.5(b)(3).
[17] 220 ILCS 5/16-111.5(b)(i), 220 ILCS 5/16-111.5(b)(iii).
[18] 220 ILCS 5/16-111.5(b)(3)(iv).

monthly capacity, annual capacity, peak load capacity obligations, capacity purchase plan, and ancillary services.

- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[19]
- Assess the price risk, load uncertainty, and other factors associated with the proposed portfolio measures, including, to the extent possible, the following factors: contract terms; time frames for security products or services; fuel costs; weather patterns; transmission costs; market conditions; and the governmental regulatory environment.[20] For those portfolio measures that are identified as having significant price risk, the Plan shall identify alternatives to those measures.
- For load requirements included in the Plan, the Plan should include 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. [21]
- Include renewable resource and demand-response products, as discussed below.

2.4 Standard Product Procurement and Load-Following Products

As noted in Section 2.3, the IPA Act provides examples of "standard products."[22] Reading Subsection 16-111.5(b)(3)(vi) in conjunction with Subsection 16-111.5(e) and the ICC's Order approving the IPA's 2014 Procurement Plan,[23] the IPA understands that the definition of "standard product" also to include wholesale load-following products (including potentially full requirements products) so long as the product definition is standardized such that bids may be judged solely on price.[24]

2.5 Renewable Portfolio Standard

The General Assembly has acknowledged the importance of including cost-effective renewable resources in a diverse electricity portfolio.[25] "Renewable energy resources" is defined in the Illinois Power Agency Act, and means (1) energy and its associated renewable energy credit or (2) credits alone from qualifying sources such as wind, solar thermal energy, photovoltaic cells and panels, biodiesel, and others as identified in the IPA Act.[26] A minimum percentage of each utility's total supply to serve the load of eligible retail customers shall be generated from cost-effective renewable energy resources; by June 1, 2015, at least 10% of each utility's total supply should be generated from renewable energy resources.[27] For the current (2015) Procurement Plan, to the extent cost-effective resources are available, the IPA is directed to procure at least 75% of the renewable energy resources from wind generation, 6% from photovoltaics, and 1% from distributed

[19] 220 ILCS 5/16-111.5(b)(3)(v).
[20] 220 ILCS 5/16-111.5(b)(3)(vi).
[21] 220 ILCS 5/16-111.5(b)(4).
[22] 220 ILCS 5/16-111.5(b)(3)(vi).
[23] While not adopting ICEA's full requirements proposal, the Commission's Final Order approving the IPA's 2014 Plan made clear that wholesale load-following products, including full requirements products, may qualify as a "standard product." See Docket No. 13-0546, Final Order dated December 18, 2013 at 94 ("the Commission agrees with Staff and the IPA that full requirements products should be considered a 'standard product' under Section 16-111.5").
[24] *See, e.g.*, 220 ILCS 5/16-111.5(e)(2) (requiring development of standardized "contract forms and credit terms" for a procurement); 16-111.5(e)(3)-(4) (creation of a price-based benchmark and selection of bids "on the basis of price"); Docket No. 09-0373, Final Order dated December 28, 2009 at 115-116 (Commission approval of long-term renewable resource PPA project selection based on price alone).
[25] 20 ILCS 3855/1-5(5), 1-5(6).
[26] 20 ILCS 3855/1-10. See also Docket No. 10-0563, Final Order dated December 21, 2010 at 83 ("Section 1-10 defines 'renewable energy resources' as either energy and its associated renewable energy credit or renewable energy credits from renewable energy, such as wind or solar thermal energy. As noted in Section 1-10 a REC is a renewable energy resource and therefore fully meets the requirement of Section 1-20 of the IPA Act requiring the procurement of renewable energy.")
[27] 20 ILCS 3855/1-75(c)(1).

renewable energy generation devices.[28] Renewable energy resources procured from distributed generation devices to meet this requirement may also count towards the required percentages for wind and solar photovoltaics.[29] In other words, if the IPA procures 1% distributed renewable energy that is solar-generated, that 1% also counts toward the 6% solar guideline, leaving 5% solar to be procured from other sources.

The IPA Act defines "cost-effective" in two ways: first, for different renewable resources, the Procurement Administrator creates a "market benchmark" against which all bids are measured. Second, and in addition to the market benchmarks, the total cost of renewable energy resources procured for any single year shall be reduced by an amount necessary to limit the annual estimated average net increase due to the costs of these resources to no more than the greater of:

- 2.015% of the amount paid per kilowatt-hour by eligible retail customers during the year ending May 31, 2007; or
- The incremental amount per kilowatt-hour paid for these resources in 2011.[30]

These values are now fixed, and the greater of the two is 0.18054 ¢/kWh for Ameren and 0.18917 ¢/kWh for ComEd.

Cost-effective renewable energy resources are subject to geographic restrictions; the IPA must first procure from resources located in Illinois or in states that adjoin Illinois.[31] If cost-effective renewable energy resources are not available in Illinois or adjoining states, the IPA must seek cost-effective renewable energy resources from "elsewhere."[32]

In the docket approving the IPA's 2014 Procurement Plan, the Commission pre-authorized a curtailment of long-term renewable PPAs, pursuant to the language of the contract. The Commission ordered that if a March 2014 load forecast showed that the eligible retail customer rate cap would be exceeded under the expected load forecast, the long-term renewable PPAs would be curtailed *pro rata* in order to reduce volumes to a level that would not exceed the rate cap under the expected load forecast.[33]

In addition to funds from eligible retail customers, alternative compliance payments collected by the utility from the utility's customers taking service under the utility's hourly pricing tariff "increase [IPA] spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year."[34] In addressing curtailed RECs from long-term PPAs in the docket approving the 2014 Plan, the Commission authorized these funds to be spent on RECs from long-term renewable PPA holders that could not be purchased by eligible retail customers due to Commission-authorized curtailments necessitated by the statutory 2.015% rate impact cap.[35]

Based on the expected case load forecasts and associated data provided to the IPA by the utilities on July 15, 2014, the IPA believes that it is unlikely that the curtailment of the long-term renewable PPAs will be necessary to avoid exceeding the annual estimated average net rate increase mentioned above during the five-year planning horizon of this plan.

2.6 Distributed Generation Resources Standard

Effective beginning in the 2013 Procurement Plan, a distributed generation resource requirement was added by the General Assembly. Procurement of renewable energy resources from distributed renewable energy

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[28] Id.
[29] 20 ILCS 3866/1-75(c)(1).
[30] 20 ILCS 3855/1-75(c)(2)(E).
[31] 20 ILCS 3855/1-75(c)(3).
[32] Id.
[33] See Docket No. 13-0546, Final Order dated December 18, 2014 at 49-56 (authorization of curtailment if necessitated by rate impact cap was not a disputed issue).
[34] 20 ILCS 3855/1-75(c)(5).
[35] Docket No. 13-0546, Order on Rehearing dated June 17, 2014 at 54.

generation devices is to be conducted on an annual basis through multi-year contracts of no less than five years, and shall consist solely of renewable energy credits.[36]

A generation source is considered a "distributed renewable energy generation device" under the IPA Act if it is:

- Powered by wind, solar thermal energy, photovoltaic 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;
- Interconnected at the distribution system level of either an electric utility, alternative retail electric supplier, municipal utility, or a rural electric cooperative;
- Located on the customer side of the customer's electric meter and is primarily used to offset that customer's electricity load; and is
- Limited in nameplate capacity to no more than 2,000 kW.[37]

To the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25 kW in nameplate capacity.[38]

In the Commission proceeding to approve the 2012 Electricity Procurement Plan, the Illinois Power Agency committed to holding workshops in the spring of 2012 to assist with the development of a future distributed generation renewable resource procurement (at that time, no such procurement was planned).[39] The IPA held workshops in 2012 on February 24th and Aril 2nd. This year, the IPA also held a workshop on June 12th. In the workshops, the IPA discussed best practices for meeting the obligations of the distributed generation portfolio requirement with stakeholders. Meeting materials are available on the IPA website.[40]

Public Act 98-0672, signed into law with an effective date of June 30, 2014, creates new subsection 1-56(i) of the IPA Act requiring the Illinois Power Agency to conduct a supplemental procurement of renewable energy credits from solar photovoltaics ("SRECs") using up to $30 million from the Renewable Energy Resources Fund.[41]

Under new subsection 1-56(i), the IPA has 90 days from the effective date of the Act to develop a plan for the procurement of SRECs from photovoltaic systems – including contracts of at least 5 years in length from distributed generation systems.[42] The law provides that, to the extent available, at least half of the distributed generation SRECs must come from systems of less than 25 kw of nameplate capacity.[43]

As of the publishing of its draft 2015 Procurement Plan, the Agency is still working to determine many of the key details and features associated with its Section 1-56(i) supplemental procurement plan. A public workshop was held on August 7, 2014 to receive feedback from interested stakeholders and to address issues and challenges associated with a successful procurement. The Agency's draft Supplemental Procurement Plan is due to be posted for public comment on September 29, 2014, with comments due to be received by October 14, 2014. A revised plan will then be filed with the Illinois Commerce Commission on or before October 28, 2014, with the Commission then having 90 days for review and approval.[44]

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[36] 20 ILCS 3855/1-75(c)(1).
[37] 20 ILCS 3855/1-10.
[38] 20 ILCS 3855/1-56(b).
[39] Docket No. 11-0660, Final Order dated December 21, 2011 at 117.
[40] http://www2.illinois.gov/ipa/Pages/CurrentEvents.aspx.
[41] http://ilga.gov/legislation/publicacts/fulltext.asp?Name=098-0672
[42] 20 ILCS 3855/1-56(i)(1)
[43] Id.
[44] 20 ILCS 3855/1-56(i)(2)

To the extent practicable, the IPA believes it would be desirable to have a uniform purchasing program, and the Agency expects to spend some portion of the 1-56(i) funds on procuring SRECs from distributed generation systems. In Section 8.3 below, the IPA proposes to procure certain additional distributed generation resources using funds collected from customers taking hourly electric service to allow the utilities to meet their mandated distributed generation goals. Despite the differences in governing law—which could become manifest in distinct procurement structures—the IPA does see value in coordinating as many aspects of this procurement with the Section 1-56(i) procurement as possible, particularly the development of product definitions and credit requirements.

2.7 Energy Efficiency Resources

Section 16-111.5B of the PUA outlines requirements related to including new or expanded cost-effective energy efficiency programs in the Procurement Plan. The Procurement Plan must include an assessment of opportunities to expand programs under the utilities' existing Commission-approved energy efficiency plans or to implement additional cost-effective energy efficiency programs or measures.[45] To assist in this effort, the utilities are required to provide, along with their load forecasts, an assessment of cost-effective energy efficiency programs or measures that could be included in the Procurement Plan. Both Ameren and ComEd have provided this information, which is included in the Appendices to this Procurement Plan along with their load forecast information. This information includes an analysis of new or expanded programs that demonstrates their cost-effectiveness as defined in the PUA, and information sufficient to demonstrate the impacts of the assessed incremental programs on the overall cost to the utility of providing electric service, including how the cost of procuring these measures compares over the life of the measures to the prevailing costs of comparable supply, along with estimated supply quantity reductions should the IPA recommend to include them in the proposed resource portfolio. Programs come from two sources: expansion of existing utility programs authorized by the Commission pursuant to Section 8-103 of the Public Utilities Act, or new programs bid pursuant to a request for proposals undertaken annually by the utilities.

The PUA requires the Agency to include in its Procurement Plan energy efficiency programs and measures that it determines are cost-effective; the utilities are directed to factor in the associated energy savings to the load forecast. If the Commission approves the procurement of this additional efficiency, it shall reduce the amount of power to be procured under the Procurement Plan and shall direct the utility to undertake the procurement of the efficiency resources. For purposes of meeting this statutory requirement, "cost-effective" means that the assessed measures pass the total resource cost test as defined in the IPA Act:[46]

> *"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 or supply resources. In calculating avoided costs of power and energy that an electric utility would otherwise have had to acquire, reasonable estimates shall be*

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[45] See 5 ILCS 220/16-111.5B(a)(2). Additionally, pursuant to Section 16-111.5B(a)(1), the Agency's analysis required under Section 16-111.5(b)(2) must provide "the impact of energy efficiency building codes or appliance standards, both current and projected." This information is contained in Appendices B and C.

[46] See 5 ILCS 220/16-111.5B(b) ("For purposes of this Section, the term 'energy efficiency' shall have the meaning set forth in Section 1-10 of the Illinois Power Agency Act, and the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act.); 5 ILCS 220/8-103(a) ("As used in this Section, 'cost-effective' means that the measures satisfy the total resource cost test.").

> *included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases.*[47]

In response to the Commission's directive in its approval of the 2013 Procurement Plan, ICC Staff held a series of workshops leading to the consensus resolution of open issues associated with successfully implementing Section 16-111.5B's provisions. After additional open issues were identified in the development and approval of the 2014 Plan, the Commission again requested ICC Staff hold workshops. Consensus was reached over a set of additional open issues this summer; further discussion of the 2014 workshops is included in Section 2.9 below, and the IPA requests the Commission approve the consensus items from the workshops described in that Section.

2.8 Demand Response Products

The IPA may include cost-effective demand response products in its Procurement Plan. The Procurement Plan must include the particular "mix of cost-effective, demand-response products for which contracts will be executed during the next year, to meet the expected load requirements that will not be met through preexisting contracts."[48] Under the PUA, cost-effective demand-response measures may be procured whenever the cost is lower than procuring comparable capacity products, if the product and company offering the product meet minimum standards.[49] Specifically:

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;
- The products must at least satisfy the demand-response requirements of the regional transmission organization market in which the utility's service territory is located, including, but not limited to, any applicable capacity or dispatch requirements;[50]
- The products must provide for customers' participation in the stream of benefits produced by the demand-response products;
- The provider must have a plan for the reimbursement of the utility for any costs incurred as a result of the failure of the provider to perform its obligations;[51]; and
- Demand-response measures included in the plan shall meet the same credit requirements as apply to suppliers of capacity in the applicable regional transmission organization market.[52]

Public Act 97-0616, the Energy Infrastructure Modernization Act ("EIMA"), required ComEd and Ameren to file tariffs instituting an opt-in market-based peak time rebate ("PTR") program with the Commission within 60 days after the Commission has approved the utility's AMI Plan.[53] ComEd's PTR program was provisionally approved in Docket No. 12-0484 and Ameren's PTR program was likewise provisionally approved in Docket No. 13-0105.[54] These programs are discussed further in Section 7.5, where demand response resource choices are examined.

2.9 Clean Coal Portfolio Standard

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.[55] As a part of the goal, the Plan must also include electricity

[47] 20 ILCS 3855/1-10.
[48] 220 ILCS 5/16-111.5(b)(3)(ii).
[49] 220 ILCS 5/16-111.5(b)(3)(ii).
[50] 220 ILCS 5/16-111.5(b)(3)(ii)(A); 16-111.5(b)(3)(ii)(B).
[51] 220 ILCS 5/16-111.5(b)(3)(ii)(C); 16-111..5(b)(3)(ii)(D).
[52] 220 ILCS 5/16-111.5(b)(3)(ii)(E).
[53] 220 ILCS 5/16-108.6(g).
[54] See Docket No. 12-0484, Interim Order dated February 21, 2013 at 32; Docket No. 13-0105, Interim Order dated January 7, 2014 at 19.
[55] 20 ILCS 3855/1-75(d).

generated from clean coal facilities.[56] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[57] Section 1-75(d) describes two special cases: the "initial clean coal facility"[58] 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 ("retrofit clean coal facility").[59] Currently, there is no facility meeting the definition of an "initial clean coal facility," that the IPA is aware of, that has announced plans to begin operations within the next five years. In Docket No. 12-0544, the Commission approved inclusion of FutureGen 2.0 as a retrofit clean coal facility starting in the 2017 delivery year; the Illinois Appellate Court recently upheld the cost recovery mechanism used in that docket's Order.[60] Additional discussion of the Clean Coal Portfolio Standard is located in Section 7.6 of the Plan.

[56] 20 ILCS 3855/1-75(d)(1).
[57] 20 ILCS 3855/1-10.
[58] Id.
[59] 20 ILCS 3855/1-75(d)(5).
[60] See Docket No. 12-0544, Final Order dated December 19, 2012 at 228-237; Docket No. 13-0034, Final Order dated June 26, 2013 ("Phase II" approving sourcing agreement as required in Docket No. 12-0544); Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2014 IL App (1st) 130544, July 22, 2014.

3 Load Forecasts

3.1 Statutory Requirements

Under Illinois law, a procurement plan must be prepared annually for each "electric utility that on December 31, 2005 served at least 100,000 customers in Illinois."[61] 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.[62]

The statute also defines the process by which the procurement plan is developed. The load forecasts themselves are developed by the utilities as stated in the statute:

> *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.*[63]

The forecasts are prepared by the utilities, but the Procurement Plan is ultimately the responsibility of the Illinois Power Agency. The Illinois Commerce Commission is required to approve the plan, including the forecasts on which it is based. Therefore, the Agency must review and evaluate the load forecasts to ensure they are sufficient for the purpose of procurement planning. This chapter contains a summary of the load forecasts for Ameren and ComEd, the Agency's evaluation of the load forecasts, and a recommendation on the forecasts that the Commission should approve for procurement planning.

Note: Throughout this report, except where noted, the retail load is taken to include an allowance for losses. In other words, it represents the volume of energy that each utility must schedule to meet the load of its eligible retail customers at the RTO level (MISO for Ameren and PJM for ComEd).

3.2 Summary of Information Provided by Ameren

In compliance with Section 16-111-5(d)(1) of the Public Utilities Act, Ameren provided the IPA with the following documents for use in preparation of this plan:

- *Ameren Illinois Company ("AIC") Load Forecast for the period June 1, 2015 – May 31, 2020* (See Appendix B)
- *Electric Energy Efficiency Compliance With 220 ILCS 5/16-111.5B.* This document also contained seven Appendices. (See Appendix B. Note, Ameren Appendix 6 [Third Party Bids] and 7 [Detailed Analysis] were marked confidential and are not included in Appendix B.)
- Spreadsheets of the expected, high, and low forecasts. Supplemental spreadsheets detailed the renewable portfolio standard targets and budgets under each scenario, capacity needs under each

[61] 220 ILCS 5/16-111.5(a).
[62] 220 ILCS 5/16-111.5(b)(1).
[63] 220 ILCS 5/16-111.5(d)(1).

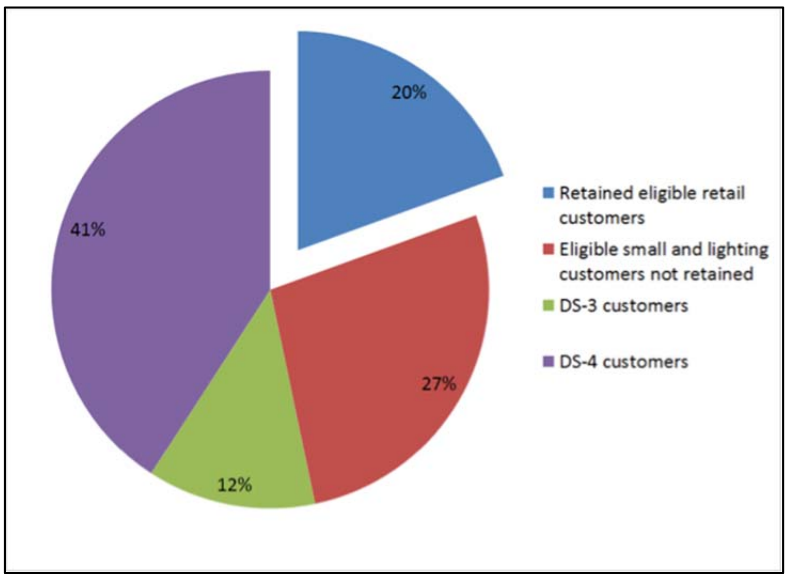
scenario, and the impact on the expected load forecast of incremental energy efficiency programs. (Summarized in Appendix D)

Ameren uses a combination of statistical and econometric modeling approaches to develop its customer class specific load forecast models. A Statistically Adjusted End-use approach is used for the residential and commercial customer classes. This approach combines the econometric model's ability to identify historic trends and project future trends with the end-use model's ability to identify factors driving customer energy use.

Industrial and public authority classes are modeled using a traditional econometric approach that correlates monthly sales, weather, seasonal variables, and economic conditions. The Lighting load class is modeled using either exponential smoothing or econometric models.

Figure 3-1 shows the annual breakdown of usage by customer class[64], and separates out the eligible from ineligible small and lighting customers.

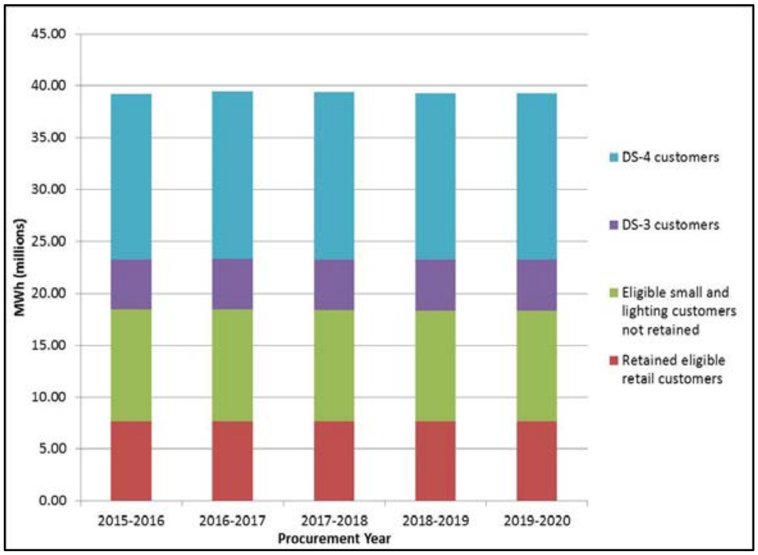
Figure 3-1: Ameren Load Breakdown, Delivery Year 2015-2016



Ameren forecasts are performed on the total Ameren delivery service load using a regression model applied to historical load and weather data. A separate analysis is performed for each customer class to account for the differing impacts of weather on the different customer classes. Figure 3-2 shows the Ameren 5-year forecast by customer group.

[64] Ameren assigns load profile classifications at the service point level and only to points of service that are metered. The classifications are as follows: DS1 – Residential, DS2 – Non-Time of Use Commercial & Industrial with demands less than 150 kW, DS3 – Time of Use Commercial & Industrial with demands between 150 kW and 1,000 kW, DS4 – Time of Use Commercial & Industrial with demands above 1,000 kW, and DS5 – Lighting. The DS3 and DS4 classes are fully competitive meaning customers in these classes must receive supply from ARES or Ameren real time pricing. Customers in the DS1, DS2 and DS5 classes are eligible to take fixed-price service from Ameren or an ARES. The percentage of the customers in these classes forecasted to take fixed-price service from Ameren are included in the "Retained eligible retail customers" category in Figure 3-1 and the percentage of those customers that are forecasted to switch to ARES are included in the "Eligible small and lighting customers not retained" category.

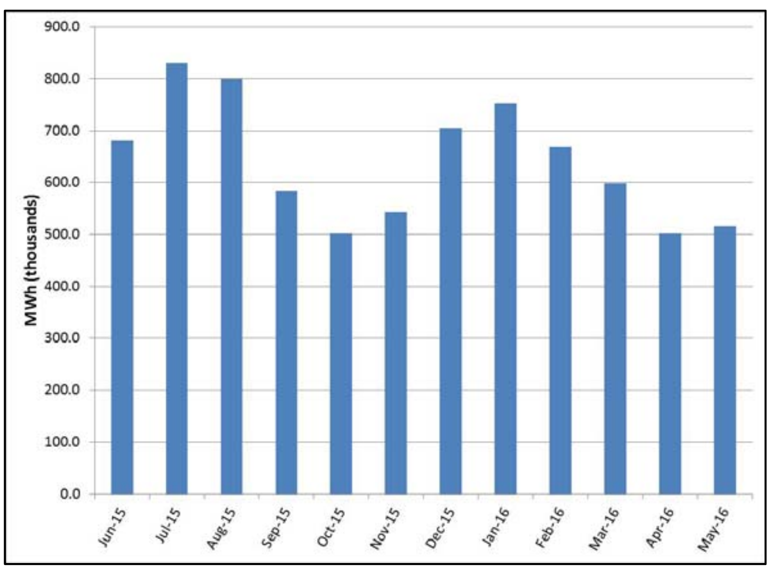
Figure 3-2: Ameren Load by Delivery Year



Ameren applies assumed "switching rates" to the total system load forecast to remove the load to be served by bundled hourly pricing (Power Smart Pricing or Rider HSS), municipal aggregation, or other Alternative Retail Electric Suppliers ("ARES"). Ameren establishes the current customer switching trend line utilizing actual switching data by customer class. Qualitative judgment is used to make adjustments. The portion of the forecast load attributed to rider HSS, municipal aggregation, and other ARES customers is subtracted from the total system load forecast. The result is the forecasted load to be supplied by Ameren.

Figure 3-3 provides a monthly breakdown of the expected or base-case forecast of Ameren's eligible retail load, that is, the load of customers who are eligible for bundled supply procured under this Procurement Plan.

Figure 3-3: Ameren Eligible Retail Load* by Month, Delivery Year 2015-2016



*Total load, prior to netting QF supply

Ameren 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, that is, the fraction for which the utility retains the supply obligation). Similarly, a low load case should represent the combination of weaker-than-expected economic growth, mild weather and an increase level of switching.

3.2.1 Macroeconomics

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 energy efficiency, by rate class.[65] Specifically, in each case, a single multiplier is defined for each of the five delivery service rate classes, and the "before switching" load forecast for every hour is multiplied by the rate class multiplier.

Table 3-1: Load Multipliers in Ameren Excursion Cases

Rate Class	Low Case	High Case
DS1	0.940	1.080
DS2	0.930	1.070
DS3	0.930	1.070
DS4	0.860	1.140
DS5	0.940	1.080

Because the excursion cases are based on the statistics of the residuals, they reflect the influence of unmodeled variables. The forecasting model appears to be dominated by technological and weather effects. The econometric variables are related to short-term decision making. Uncertainty around long-term economic growth will appear in the residuals.

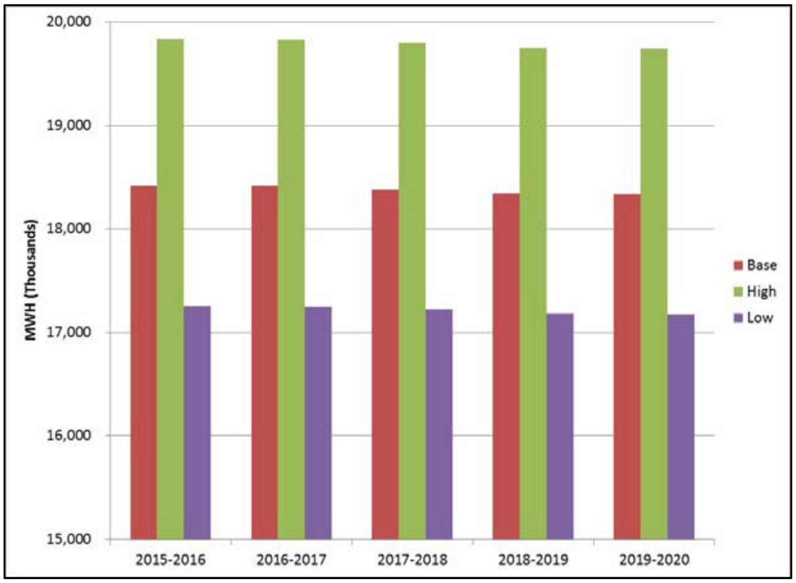
3.2.2 Weather

Ameren includes "high weather" and "low weather" in its characterization of the high and low cases. Ameren 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.

Figure 3-4 shows the base, high, and low case forecasts of Ameren's total delivery service load, assuming no switching, for the non-competitive classes DS1, DS2, and DS5. The difference between the high, low and base cases show the variation Ameren attributes to macroeconomics and weather. The low case is about 5% lower than the base case and the high case is about 9% higher than the base case.

[65] Ameren provided four forecast cases: an expected case, a high case, a low case, and a version of expected case that also included incremental energy efficiency not yet approved (cf. Section 7.1). While the IPA's analysis has in general been based on this fourth case, the high and low cases were computed without incremental energy efficiency.

Figure 3-4: Ameren Annual Load by Delivery Year



3.2.3 Switching

According to Ameren, switching, in particular municipal aggregation, is the greatest driver of load uncertainty. Switching through April 2014 has resulted in approximately 65-70% of residential and small commercial load seeking service from alternative suppliers. Ameren expects the amount of load supplied by ARES will modestly decline during the summer of 2014 and spring of 2015 based on indications from municipalities that have contracts expiring. Additionally, Ameren's current year tariff price is lower than comparable ARES prices. As such, Ameren forecasts the residential and small commercial switching rate to decline to 54% and 66%, respectively by June 2015. However, beginning in June 2015, the trend becomes less certain and therefore the Ameren base case predicts flat switching from that point throughout the planning horizon.

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 approximately 30% of residential load will see contracts under government aggregation expire. Residential and commercial switching rates under the high load scenario are forecasted to be 44% and 57%, respectively, in May 2016, 16% and 51%, respectively in May 2017, and 12% and 42%, respectively, by the end of the planning horizon.

Conversely, should future Ameren tariff price 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 will approach 73% and 75%, respectively, in May 2016, 78% and 81%, respectively in May 2017, and 87% and 91%, respectively, by the end of the planning horizon.

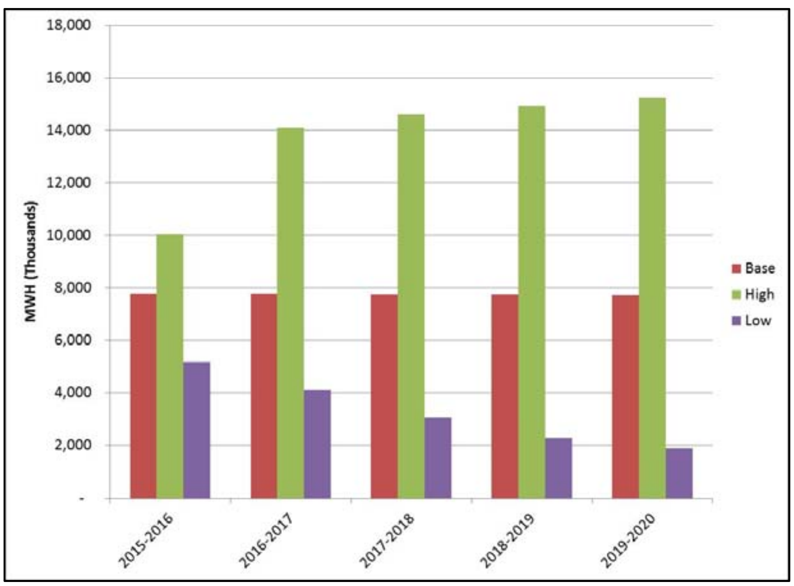
The difference in the amount of switching among the three cases is significant. Figure 3-5 shows the retention, that is, the fraction of delivery load in classes DS1, DS2 and DS5 that remains on utility service, for the base, high and low cases.

Figure 3-5: Utility Load Retention in Ameren Forecasts

As the figure shows, the difference in switching rates among the scenarios grows through the projection horizon. The difference in switching rates is the most significant factor driving the differences among the scenarios.

Figure 3-6 shows the forecasted Ameren supply obligation in each case.

Figure 3-6: Utility Supply Obligation by Delivery Year in Ameren Forecasts



3.2.4 Load Shape and Load Factor

Figure 3-7 and Figure 3-8 display the hourly profile of Ameren's supply obligation in each case (relative to the daily maximum load). Figure 3-7 illustrates a summer day and Figure 3-8 a low-load spring day. In these figures the curves are normalized so that the highest value in each is 1. There is little difference between the profiles of the high and base cases, and these are both slightly "peakier" than the low case. One calls a load shape "peaky" if there is a lot of variation in it – for example, if there is a large difference between the lowest and highest load values or, in these normalized curves, if the lowest point is well below 1. A load shape that is not peaky is one in which the load is nearly constant.

Figure 3-7: Sample Daily Load Shape, Summer 2015 in Ameren Forecasts

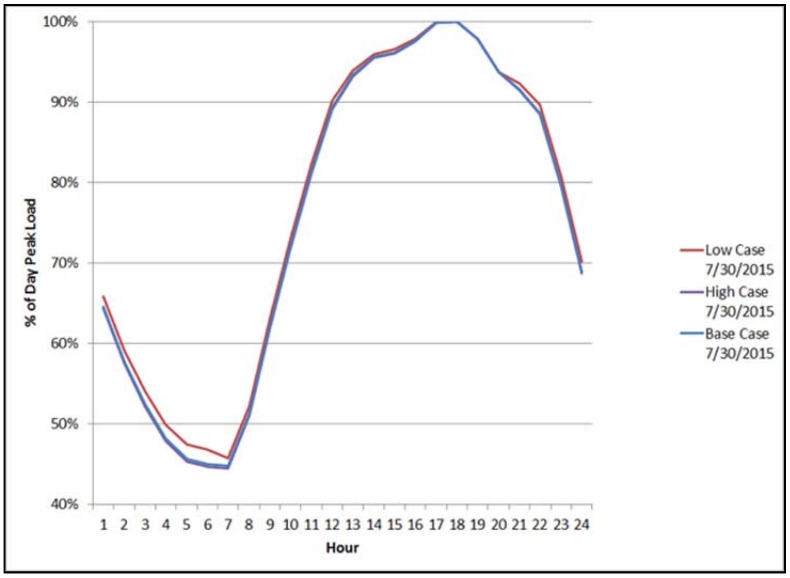
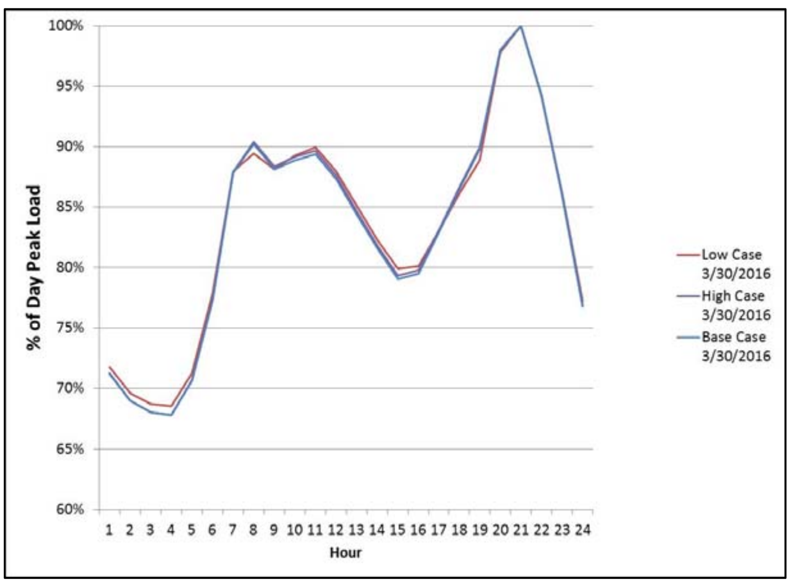


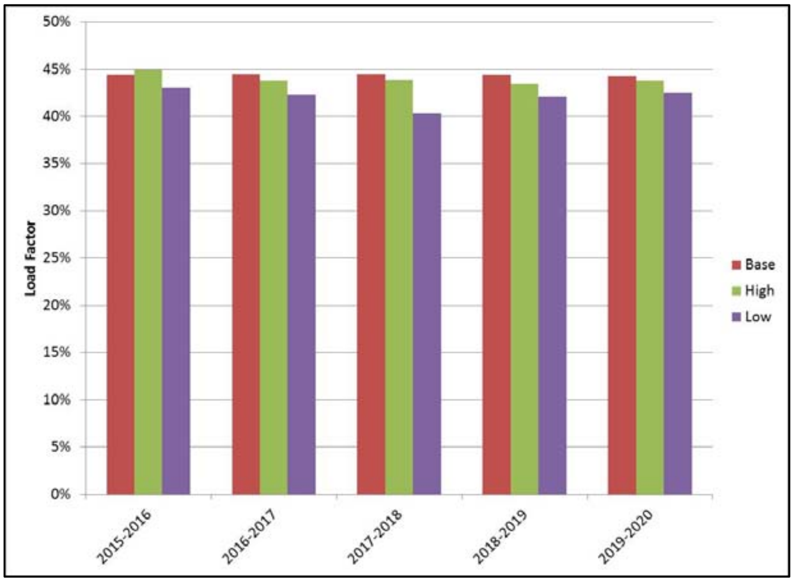
Figure 3-8: Sample Daily Load Shape, Spring 2016 in Ameren Forecasts



The peakiness of a case is usually borne out by the load factors. The load factor in any time period, such as a year, is the ratio of the average load to the maximum load. Peaky load curves have low load factors.

However, the comparison of Figure 3-9 with Figure 3-7 and Figure 3-8 does not reflect this trend: in 2015-2016 the low case is less peaky than the other cases while it has the lowest load factors. This may reflect a difference in weather assumptions between the low case and the other two cases.

Figure 3-9: Utility Load Factor by Delivery Year in Ameren Forecasts



3.3 Summary of Information Provided by ComEd

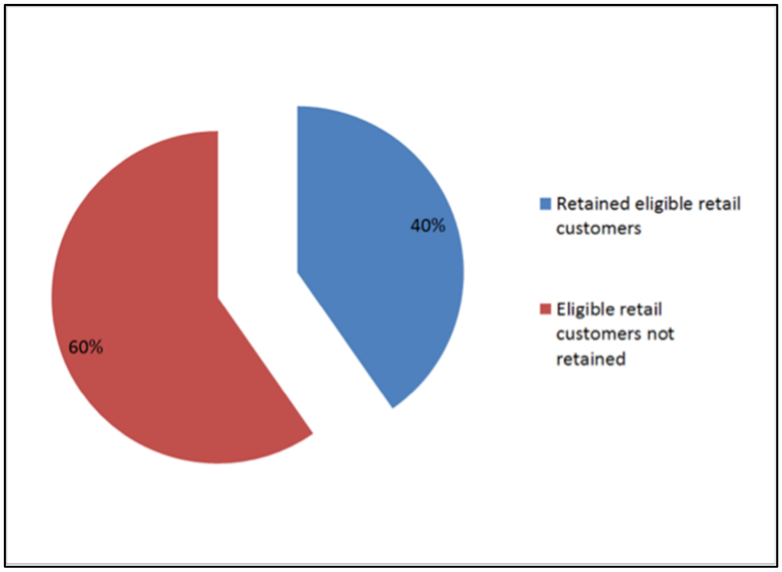
In compliance with Section 16-111-5(d)(1) of the Public Utilities Act, ComEd provided the IPA the following documents for use in preparation of this plan:

- *Load Forecast for Five-Year Planning Period June 2015 – May 2020.* This document also contained Appendices A-D. Four of the Appendices are included in the main document, while one (ComEd Appendix C) with supplemental information on Section 16-111.B incremental programs was included as four additional separate documents. (See Appendix C. Note, ComEd also provided an additional document entitled, *2014 Third Party Efficiency Program Summary of Bid Review Process* which was marked confidential and is not included in Appendix C.)
- Spreadsheets of load profiles, hourly load strips, model inputs, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix E)

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. 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 therefore cannot be eligible retail customers. Figure 3-10 shows the annual breakdown of usage by eligible and ineligible small and lighting load.

Figure 3-10: ComEd Composition of Eligible Customers Weather Normal Sales Volumes, Delivery Year 2015-2016



As noted above, ComEd provides a forecast of total usage for the entire service territory and allocates the usage to various customer classes using the models specific to each class. 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.

In determining the expected load requirements for which standard wholesale products will be procured, the ComEd forecast must be adjusted for the volume served by municipal aggregation and other ARES. The ComEd 5-year annual load forecast, shown in Figure 3-11, 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. The figure decomposes the total forecast of residential and small commercial customer load, in the same way as Figure 3-10 does for a single year.

Figure 3-11: ComEd Composition of Eligible Customers Weather Normal Sales Volumes by Delivery Year

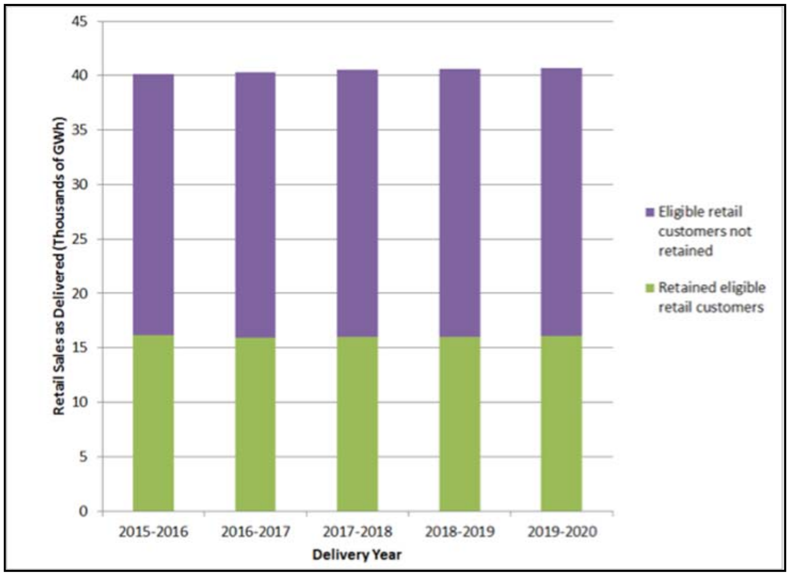
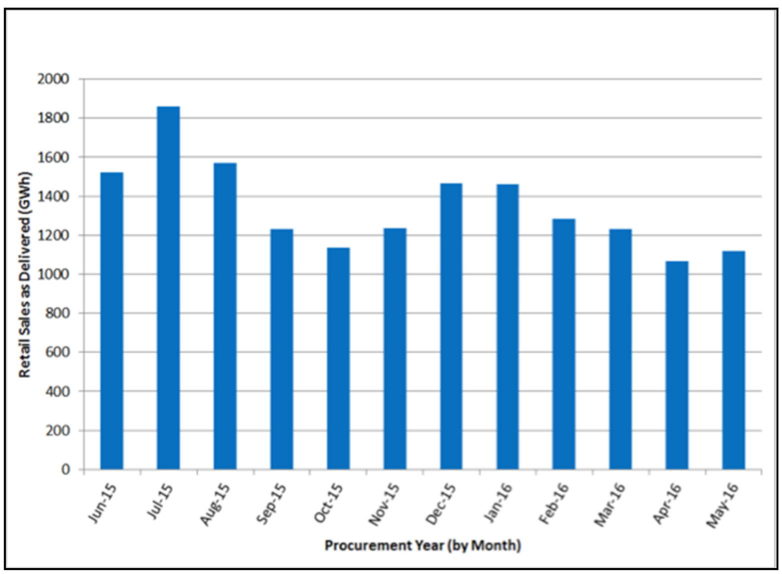


Figure 3-12 provides a monthly breakdown of the expected or base-case forecast of ComEd's eligible retail load, that is, the load of customers who are eligible for bundled supply procured under this Procurement Plan.

Figure 3-12: ComEd Eligible Load by Month, Delivery Year 2015-2016



ComEd provides a base case and two excursion cases: a low forecast and a high forecast. Each excursion case addresses three different uncertainties, simultaneously moving in the same direction: macroeconomics, weather, and switching. The combined impact of the changes in macroeconomics, weather, and switching, which are discussed in more detail below, is estimated to represent a scenario probability range between the 15th percentile for the low forecast and 85th percentile for the high scenario.

3.3.1 Macroeconomics

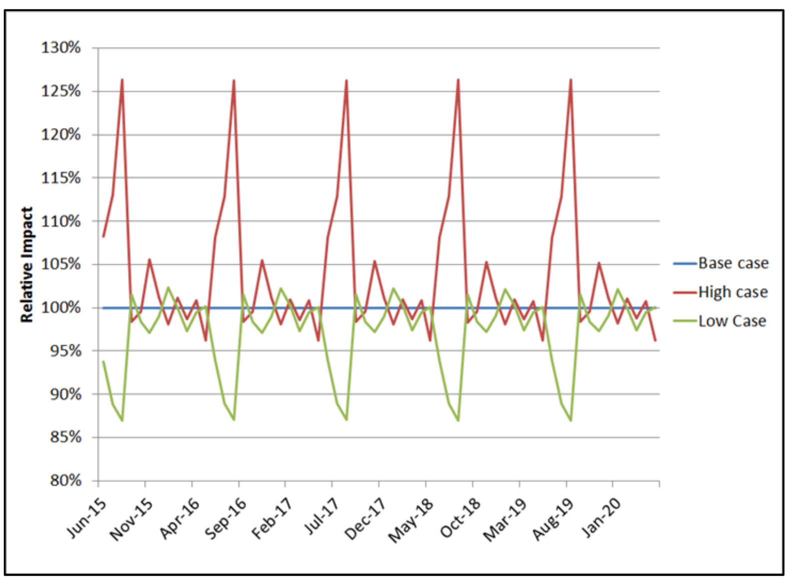
ComEd's base case load forecast is driven by a Zone Model that includes both macroeconomic variables (Gross Metropolitan Product for Chicago and other metropolitan areas within ComEd's service territory, household income) and demographics (household counts). ComEd did not use this model to define "high" and "low" cases. ComEd modified the service area load growth rates, increasing them by 2% in the high case and reducing them by 2% in the low load (because the growth rate in the expected case is below 2%, presumably this implies negative load growth in the low case throughout the projection horizon). ComEd informed the Agency that, in its assessment, the high load case is estimated to be near the bottom of the top quartile of the load growth distribution (80^{th} percentile) and the low load case is conversely near the top of the lowest quartile of the load growth distribution (20^{th} percentile).

3.3.2 Weather

ComEd includes "high weather" and "low weather" in its characterization of the high and low cases. The high weather case is based on observed temperatures in 1995, and the low weather case on observed temperatures in 2004. These years represent approximately the 90^{th} percentile and 10^{th} percentile of weather impacts on load respectively.

ComEd has not provided the specific impacts of the load growth assumption (load forecasts in the absence of switching). ComEd did provide the impacts of the weather case on residential and small commercial load, relative to the base case forecast. They are provided as percentages that summarize the hourly impacts of a finer-scale model of the effect of temperature on load. Figure 3-13 shows the impact of weather on load by month. The high and low years are not high and low in every month. There are some months, for example, where the impact of the "high weather" year is less than 1.

Figure 3-13: Weather Impacts in ComEd Forecasts

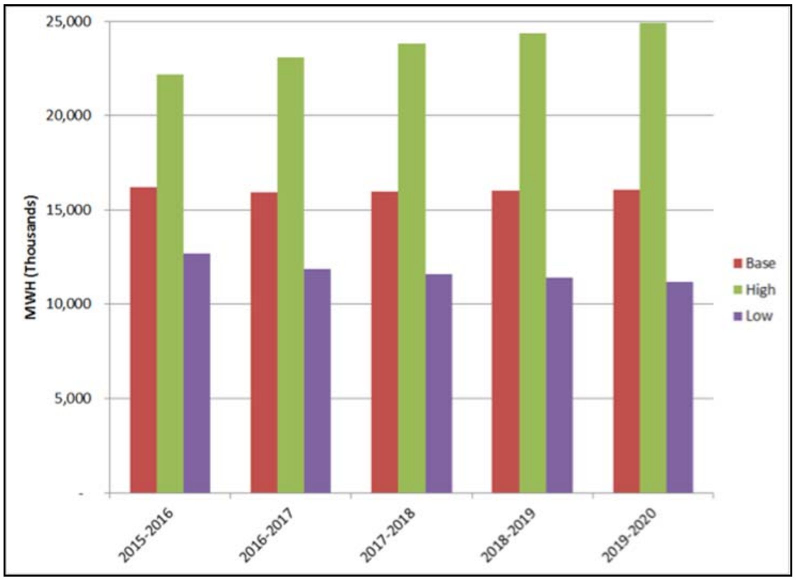


3.3.3 Switching

ComEd's high and low switching cases are moderate relative to Ameren's. The high switching (low load) case assumes residential ARES usage returns to the May 2014 level (approximately 70%) in the summer of 2015 as the communities that are opting for ComEd service renew their programs. In addition, it is assumed that small commercial switching increases slightly over the next 3 years.

The low switching (high load) case assumes additional communities opt for ComEd service beginning in June 2015 such that residential ARES usage declines from approximately 70% of total usage in May 2014 to approximately 54% in June 2017. This coincides with a 1.8 percentage point decrease in small commercial switching over the next 3 years. Figure 3-14 shows the forecasted ComEd supply obligation in each case.

Figure 3-14: Utility Supply Obligation in ComEd Forecasts



3.3.4 Load Shape and Load Factor

Figure 3-15 and Figure 3-16 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-15 illustrates a summer day, and Figure 3-16 a low-load spring day. The high case is definitely peakier on a summer day than the base case, and the low case is flatter. ComEd has not explicitly indicated QF supply in its forecast.

During the sample summer day, both the base case and low case are less peaky than the high case; and during the sample spring day, there is not a great deal of difference between the profiles of the high and base cases, but the low case is a bit peakier.

Figure 3-15: Sample Daily Load Shape, Summer 2015 in ComEd Forecasts

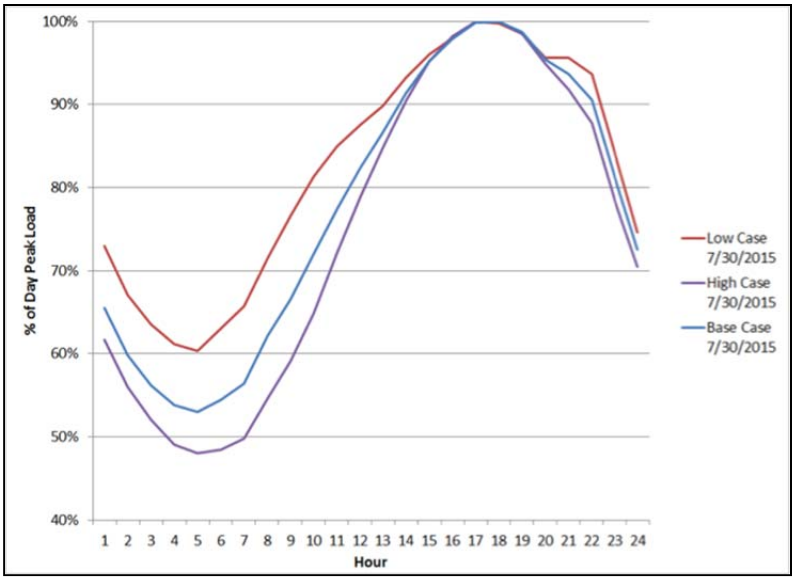
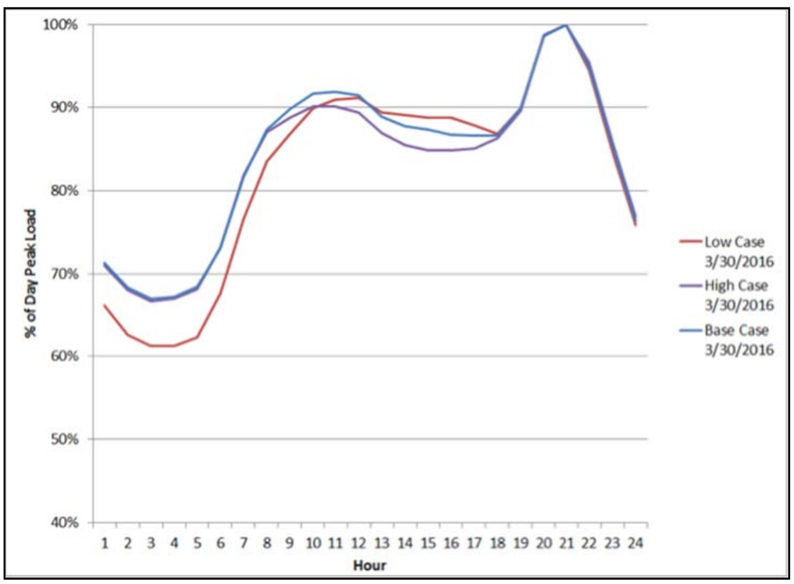
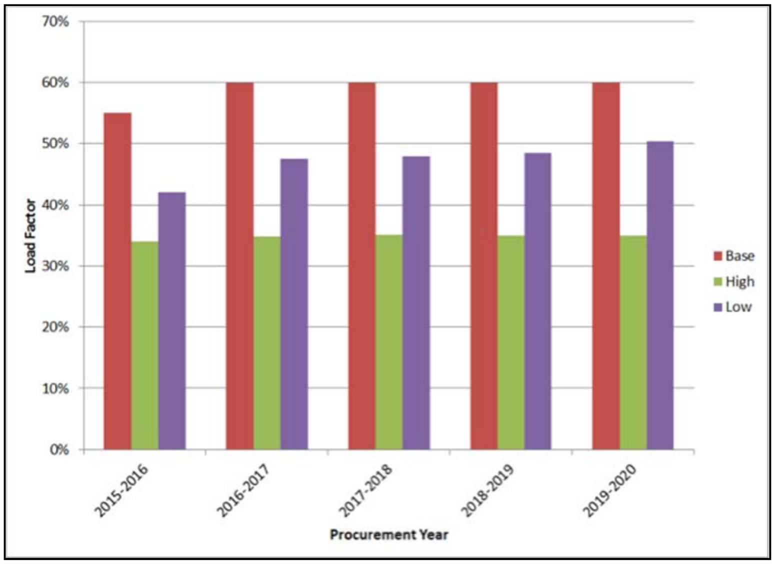


Figure 3-16: Sample Daily Load Forecast, Spring 2016 in ComEd Forecasts



The annual load factors are shown in Figure 3-17. As expected, the high load case has a lower load factor than the base case. Unexpectedly, the base case load factor is much higher than both the high-case and low-case load factors. This may indicate that the base forecast was based on an over-averaged temperature pattern (normal every day).

Figure 3-17: Utility Load Factor in ComEd



3.4 Sources of Uncertainty in the Load Forecasts

In the past, the Agency has procured or hedged power for the utilities to meet a forecast of the average hourly load in each of the on-peak and off-peak periods. The Agency 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 Agency does not purchase its entire forecast that far ahead because the forecast is itself uncertain. It is therefore important to understand the sources of uncertainty in the forecasts.

Furthermore, even if the Agency could perfectly forecast the average hourly load in each period, and perfectly hedge that forecast, it would still be exposed to power cost risk. Load varies from hour to hour. Energy in one hour is not a perfect substitute for energy in another hour because the hourly spot prices differ. A perfect hedge would cover differing amounts of load in different hours, and would have to be based on a forecast of the different hourly loads. The "expected hourly load" is not an accurate forecast of each hour's load (see Section 3.4.3). This is not an issue of uncertainty: it would be true even if the expected hourly load were a perfect forecast of the average load, and the hourly profile (the ratio of each hour's load to the average) were known with certainty. So it is treated here together with the other uncertainties.

3.4.1 Overall Load Growth

Both utilities construct their load forecasts by forecasting load for their entire delivery service area, then forecasting the load for each customer class or rate class within the service territory, and then applying multipliers to eliminate load that has switched to municipal aggregation or other ARES service. Customer groups that have been declared competitive – medium and large commercial and industrial customers – are removed entirely, as the utilities have no supply or planning obligation for them.

Ameren does not explicitly address uncertainty in load growth. In other words, they do not define "load growth scenarios" and examine the consequences of high or low load growth. They address both load and weather uncertainty by defining high and low scenarios at particular confidence levels of the model fit, that is, of the residuals of their econometric model. The high and low cases, which represent the combined and correlated impact of weather and load growth uncertainties, represent a variation of only +9% and -5%, respectively, in service area load. However, Ameren's high and low cases also include extreme customer migration uncertainty.

ComEd defines high and low load growth scenarios as 2% above or below the load growth in their base or expected case forecast. The changes in load growth are imposed upon the model rather than derived from economic scenarios so it is hard to determine how they relate to economic uncertainty. Given the stability of utility loads in recent years, differences of +/-2% in load growth should represent an appropriately representative range of uncertainty.

3.4.2 Weather

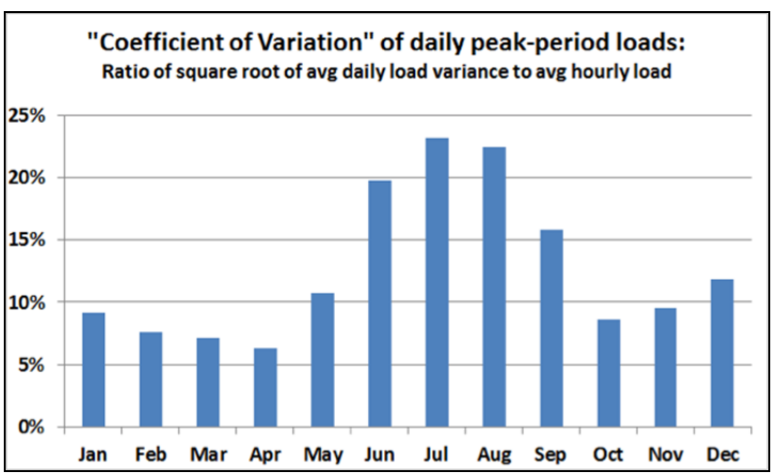
On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The discussion of high and low scenarios, sections 3.2.2 and 3.3.2, notes the way that Ameren and ComEd have incorporated weather variation into their high and low load forecasts. Ameren treats weather uncertainty together with load growth uncertainty. ComEd's forecasts are built around two sample years. Much of the impact of weather is on load variability within the year.

3.4.3 Load Profiles

As noted above, the "average hour" load forecast is not an accurate forecast of each hour's load. 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. More importantly, multiplying the average hourly load by the cost of a "strip" contract (equal delivery in each hour of the period) gives an inaccurate forecast of the cost of energy. This is because hourly energy prices are correlated with hourly loads (energy costs more when demand is high). Technically, this is referred to as a "biased" forecast, because the expected cost will predictably differ from the product of expected hourly load and expected hourly cost.

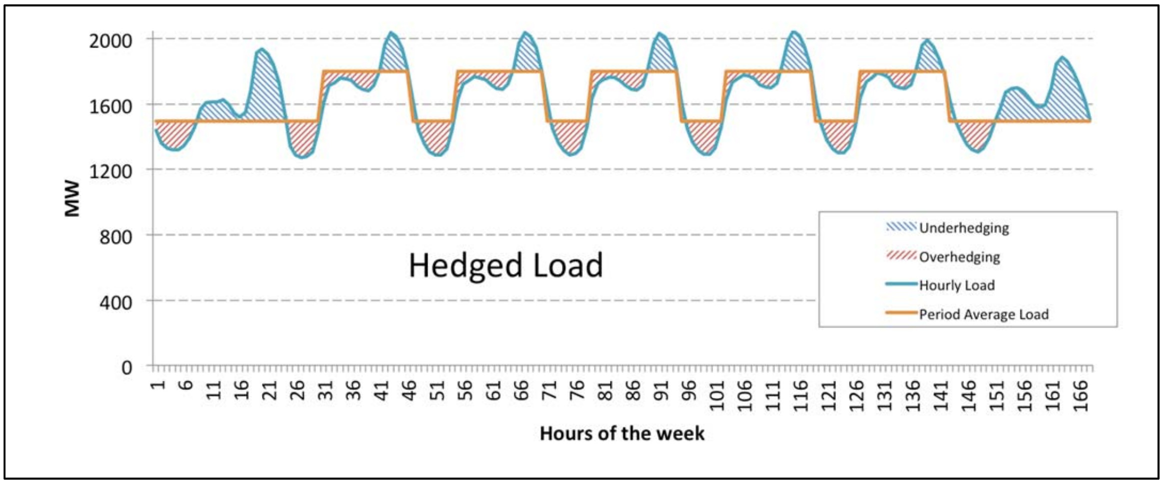
Figure 3-18 illustrates this disconnect by showing, for each month, the average historical "daily coefficient of variation" for peak period loads. This figure is based on historical ComEd loads from June 2002 through 2013, normalized to the monthly base case forecasts in the first delivery year. To calculate the daily coefficient of variation, the variances of loads within each day's peak period are averaged to produce an expected daily variance. That variance is then scaled to load by first taking the square root and then dividing by the average peak-period hourly load forecasted for the month. As the figure shows, there is significant load variation during the day in the high-priced summer months.

Figure 3-18: Coefficient of Variation of Daily Peak-Period Loads



Because of this variation, even if the average peak and off-peak monthly load is perfectly hedged, the actual hourly load will still be imperfectly hedged. In other words, if the Agency were to buy peak and off-peak hedges whose volumes equaled respectively the average peak period load and average off-peak period load, there would still be unhedged load because the actual load is usually greater or less than the average. This is illustrated in Figure 3-19 below:

Figure 3-19: Example of Over- and Under-Hedging of Hourly Load



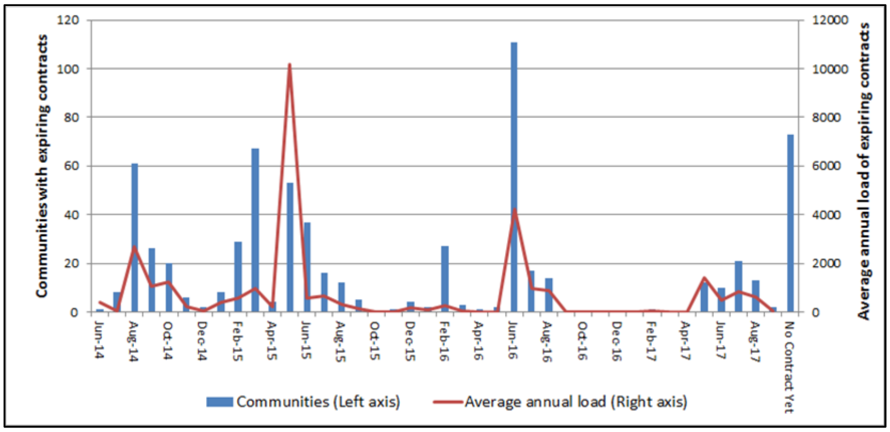
3.4.4 Municipal Aggregation

In their base cases, Ameren projects 57.7% switching by eligible retail customers by the end of the 2015-2016 delivery year and ComEd projects about 63.2%. These levels represent a decline in the switching statistics assumed in the July 2013 forecasts and are informed by lower than forecasted actual switching through April 2014 driven in part by communities deciding to suspend and/or not renew their municipal aggregation programs and return to utility service. Savings opportunities that existed prior to 2014 drove the growth in residential switching, but in 2014 these savings began to diminish.

At this point, the uncertainty around municipal aggregation and switching may be more related to the chance that utility load will increase from return to service or opt-out.

As shown in Figure 3-20, approximately half of the current supply contracts for municipal aggregation will expire in the 2014-2015 delivery year. It is possible that many of the renewal offers made by the suppliers to municipal aggregations may be “out of the money” relative to utility bundled supply prices, so there may be a considerable amount of return to utility service. This is especially true if market prices rise between now and the expiration of municipal aggregation contracts. On the other hand, switching could be higher than expected, resulting in an over-hedged position. Expanding on the hypothetical, assuming that those hedges are above market prices, the remaining load taking bundled utility service would be subject to higher bundled rates. Both Ameren and ComEd have assumed a wide range of switching fractions in their low and high scenarios (return to utility service would be represented as a decrease in the switching fraction over time).

Figure 3-20: Distribution of Municipal Aggregation Contract Expirations



3.4.5 Individual Switching

ARES offer a variety of products to customers – some of which have a similar structure to the utility bundled service, and some that vary significantly in structure. These include offers with "green" energy above the mandated RPS level, month to month variable pricing, longer-term fixed prices, options to match prices in the future, options to extended contract terms, and options to adjust prices retroactively.[66] Individual customers who choose one of these other rate structures presumably have made an affirmative choice to take on those alternative services.

Although switching from the utility to ARES by individual customers has some impact, Ameren and ComEd switching forecasts have been dominated by municipal aggregation. While the IPA recognizes that many ARES focus on individual residential switching, the IPA is not aware of a significant number of residential customers leaving default service to take ARES service outside of a municipal aggregation program. As shown in Table 3-2, this is currently the case because of the appreciable difference that currently exists between the utility price to compare[67] and representative ARES prices[68] available to eligible utility customers. It appears that, at the current time, ARES fixed price offers for a similar term to the utility price do not offer savings or benefit to individual residential customers. It is reasonable to assume that switching behavior by individual customers (other than those who chose an ARES rate that is not an "apples to apples" comparison to the utility rate) will not be a significant factor in the load forecast, except for transition to municipal aggregation, opt-out from municipal aggregation, and return from municipal aggregation.

Table 3-2: Representative ARES Fixed Price Offers (Offers without a premium renewable component) and Utility Price to Compare

Utility Territory	Utility Price to Compare (¢/kWh)	Representative ARES Price (¢/kWh)
Ameren (Zone I)	4.66	5.74
Ameren (Zone II)	4.55	5.74
Ameren (Zone III)	4.63	5.74
ComEd	7.60	8.07

[66] For more information on choices offered by ARES, see the 2014 Annual Report of the ICC Office of Retail Market Development.
[67] July 2014 utility cost to compare from http://www.pluginillinois.org/MunicipalAggregation.aspx.
[68] Representative ARES prices are an average of 12-month fixed price non-green offers from ARES available at http://www.pluginillinois.org/OffersBegin.aspx as of August 5, 2014.

3.4.6 Hourly Billed Customers

Customers who could have elected bundled utility service but take electric supply pursuant to an hourly pricing tariff are not "eligible retail customers." Therefore, 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; they appropriately considered these customers to have switched. The amount of load on hourly pricing is small and unlikely to undergo large changes that would introduce significant uncertainty into the load forecasts.

3.4.7 Energy Efficiency

Public Act 95-0481 also created a requirement for ComEd and Ameren to offer cost-effective energy efficiency and demand response measures to all customers.[69] 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 forecasts that are included with this Procurement Plan. Section 7.2 of this plan discusses the proposed incremental energy efficiency programs that have been submitted pursuant to Section 16-111.5B. These programs are reflected in the load forecasts.

3.4.8 Demand Response

As noted by the utilities in their load forecast documentation, demand response does not impact the weather-normalized load forecasts. As such, the IPA notes that they are more like supply resources. Section 7.5 of the Plan contains the IPA's discussion and recommendations for demand response resources.

3.4.9 Emerging Technologies

A number of emerging technologies were described in the 2013 Procurement Plan and two more technologies, AMI and EV, were described in the 2014 Procurement Plan. That material will not be repeated here, other than to note that in Docket No. 14-0212, the Commission approved an acceleration of ComEd's AMI deployment plan.[70] The IPA is not aware of other emerging technologies that warrant inclusion in this Plan at this time.

3.5 Recommended Load Forecasts

3.5.1 Base Cases

The IPA recommends adoption of the Ameren and ComEd base case load forecasts, which include already approved energy efficiency programs. (The IPA also recommends that the Commission approve the additional incremental energy efficiency as presented in sections 7.2.5 and 7.2.6. The March 2015 load forecasts will also reflect those newly approved programs.)

3.5.2 High and Low Excursion Cases

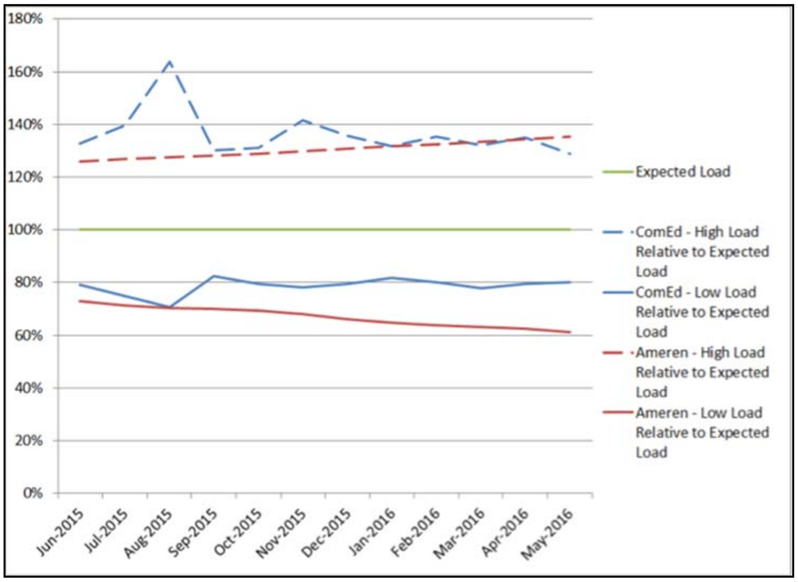
The high and low cases represent useful examples of potential load variability. Although they are primarily driven by variation in switching, Ameren correctly notes that this is the major uncertainty in its outlook. The switching variability, especially in Ameren's high and low forecasts, is extreme and thus these may be characterized as "stress cases." The Agency's procurement strategy to date has been built on hedging the average hourly load in each of the peak and off-peak sub-periods, and the high and load cases represent significant variation in those averages.

As illustrated in Figure 3-21, Ameren low and high load forecasts are on average equal to 67% and 131% of the base case forecast, respectively, during the 2015-2016 delivery. Comparatively, for the same period,

[69] See P.A. 95-0481 (Section originally codified as 220 ILCS 5/12-103).
[70] See Docket No. 12-0212, Final Order dated June 11, 2014.

ComEd's low and high load forecasts are on average equal to 78% and 137% of the base forecast, respectively. This reflects the differences in switching assumptions used by the two utilities.

Figure 3-21: Comparison of Ameren and ComEd High and Low Forecasts for Delivery Year 2015-2016



Another use of the high and low cases will be to estimate the risks of different supply strategies. A key driver of that risk is the cost of meeting unhedged load on the spot market. One of the main reasons load is unhedged is that one attempts to hedge a variable, or shaped, load with a product whose delivery is constant. The spot price at which the unhedged volumes are covered is positively correlated with load. The high and low cases are less suitable for such a risk analysis.

The high load factor of the ComEd base case forecast implies that the hourly profile of that case is not representative of a typical year. This means that the base case hourly forecast would understate the amount by which hourly loads vary from the average hourly loads in the peak and off-peak sub-periods. Using that hourly profile for a risk analysis could lead to underestimating the cost of unhedged supply.

The Ameren load scenarios have identical monthly load shapes (differing by uniform scaling factors). These shapes will not provide much information about the cost of meeting fluctuating loads, except for the information contained in the expected load shape. The expected load shape may have an overstated load factor like that of ComEd, and no other forecast case is available for comparison.

The extreme nature of Ameren's low and high load forecasts can influence the results of a probabilistic risk analysis. With almost any assignment of weights to the Ameren cases, load uncertainty will dominate price uncertainty. This does not apply to ComEd, which must be taken into account when evaluating any simulation of procurement risk.

4 Existing Resource Portfolio and Supply Gap

Prior to the 2014 Procurement Plan, the IPA purchased supply in standard 50MW on-peak, off-peak, and around-the-clock blocks. For the 2014 Procurement Plan, to more accurately match supply with load, the IPA reduced the block size to 25 MW.[71] The history of the IPA administered procurements is available on the IPA website.[72]

These purchases are driven by the supply requirements outlined in the current year procurement plan and are executed through a competitive procurement process by the IPA's Procurement Administrator. This procurement process is monitored for the Commission by the independent Procurement Monitor.

In addition to purchasing block contracts in the forward markets, Ameren and ComEd rely on the operation of their RTOs (MISO and PJM respectively) to balance their loads and consequently may incur additional costs or credits. Purchased energy blocks may not perfectly cover the load, therefore triggering the need for spot energy purchases or sales from or to the RTO.

IPA procurement plans are based on a supply strategy designed, among other things, to manage 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 for the following years.

Prior to the 2013 Procurement Plan, the first year of the 3-year procurement plan was hedged at 100% (meaning that energy contracts would fully cover the demand), while the second and third years were only hedged at 70% and 35% respectively. Based on suggestions from Commission staff, the IPA considered a revision to this strategy (for the energy products only)[73] as part of the 2013 Procurement Plan to account for declining market prices and accelerating customer switching. This proposal was to hedge the first year at 75%, while the second and third year would be hedged at 50% and 25% respectively. However, because no procurement was required, the IPA recommended that the hedging strategy be revisited in future Plans. For the 2014 Procurement Plan, this strategy was updated to include hedging at 106% of the summer months for the first delivery year, 100% for the balance of the year, 50% for the second year, and 25% for the third year. The 2014 Procurement Plan was also the first Plan in which a second procurement, taking place in the fall, was included.

Because of the lack of visibility and liquidity of the energy markets and to limit the ratepayers' exposure to unnecessary price risk and cost, the IPA has not purchased energy beyond a 3-year horizon, except in two circumstances. These include:

- A 20-year bundled REC and energy purchase (also known as the long-term power purchase agreements or "LTPPAs"), starting in June 2012, made by Ameren and ComEd in December 2010 pursuant to the Final Order in Docket No. 09-0373.
- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017. [74]

Due to the additional load coming back to the utilities, curtailment of the LTPPAs is unlikely for the 2015-2016 delivery year for both ComEd and Ameren. Section 8.2 contains additional discussion on curtailment.

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[71] IPA 2014 Procurement Plan at 93.
[72] http://www2.illinois.gov/ipa/Pages/Prior_Approved_Plans.aspx.
[73] In its 2013 Procurement Plan, the IPA recommended retaining the 100%/70%/35% hedging strategy for purposes of Ameren's capacity requirements until such time as MISO demonstrates a robust FERC-approved capacity auction.
[74] P.A. 97-0616 also mandated associated REC procurements, but these REC procurements do not impact the (energy) resource portfolio.

The discussion below explores in more detail the supply gap between the updated utility load projections described in Chapter 3 and the supply already under contract for the planning horizon. The IPA's approach to address these gaps is described in Section 7.

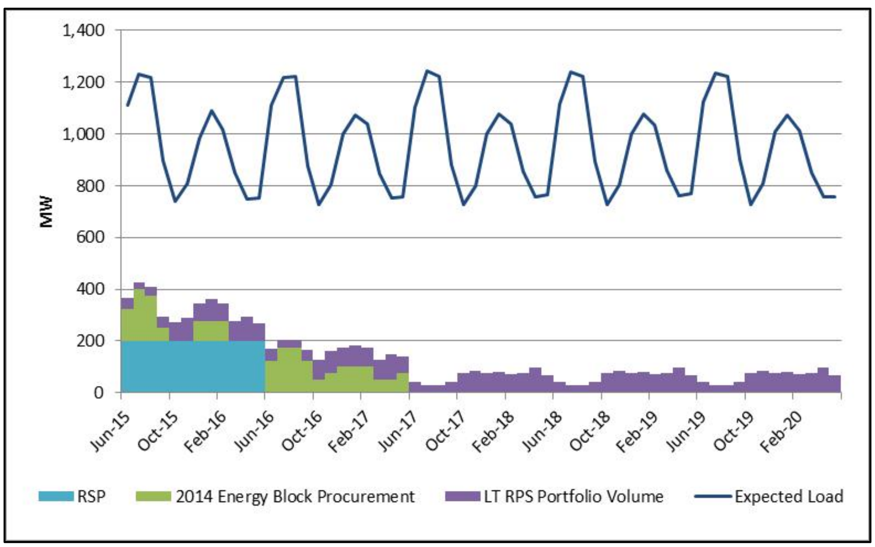
4.1 Ameren Resource Portfolio

Figure 4-1, Figure 4-2, and Figure 4-3 show the current gap in the Ameren supply portfolio for the June 2015-May 2020 planning period, using the expected, high, and low load on-peak forecast described in Section 3.2.

Ameren's existing supply portfolio, including the Rate Stability contracts and the long-term renewable resource contracts, is not sufficient to cover the projected load for the 2015-2016 delivery period. Additional energy supply will be required for the entire 5-year planning period. The main driver for this change from the previous plan is the change in load attributed to switching. On average, Ameren's load forecast produced in July 2014 for the 2015-2019 delivery period is between 64% and 90% higher than the forecast produced in July 2013 for the same delivery period (similarly, ComEd's load forecast produced in July 2014 for 2015-2019 delivery year is between 43% and 62% higher than the forecast produced in July 2013 for the same delivery period).

Quantities shown are average peak period MW for both loads and historic purchases.

Figure 4-1: Ameren's On-Peak Supply Gap - June 2015-May 2020 Period - Expected Load Forecast



Under the expected load forecast scenario, the average supply gap for peak hours of the 2015-2016 delivery period is estimated to be 615 MW.

Under the high load forecast scenario, the average supply gap for peak hours of the 2015-2016 delivery period is estimated to be 900 MW, while under the low load forecast scenario, Ameren's average supply gap for peak hours of the 2015-2016 delivery period is estimated to be 300 MW.

Figure 4-2: Ameren's On-Peak Supply Gap - June 2015-May 2020 Period - High Load Forecast

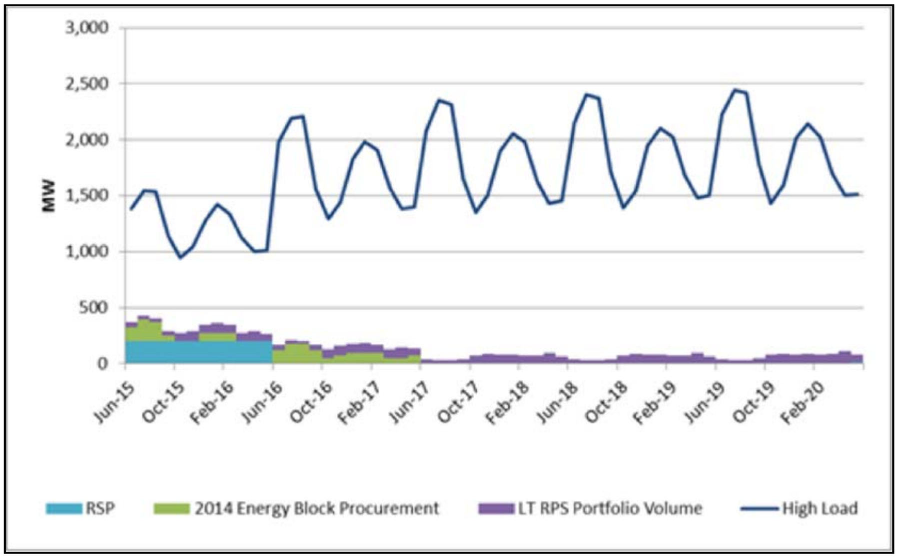
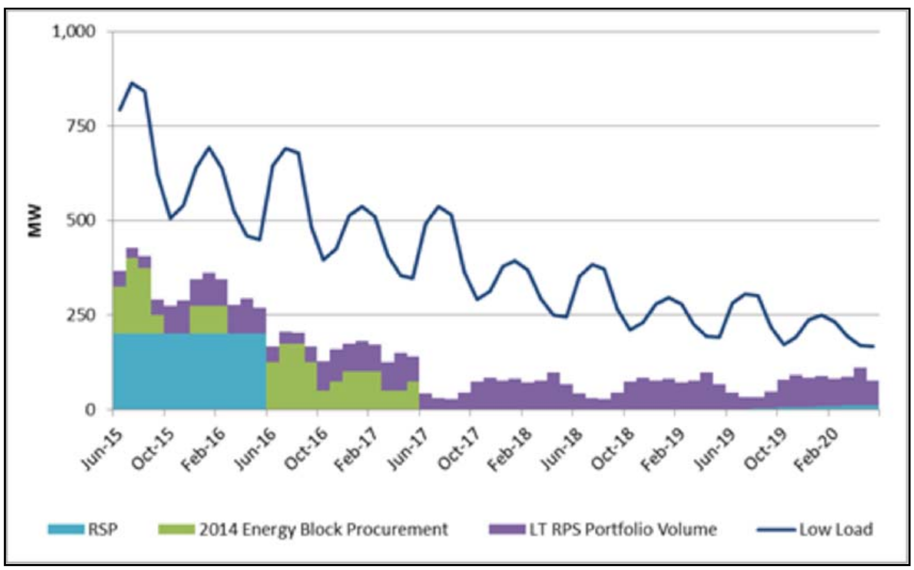


Figure 4-3: Ameren's On-Peak Supply Gap - June 2015-May 2020 Period - Low Load Forecast

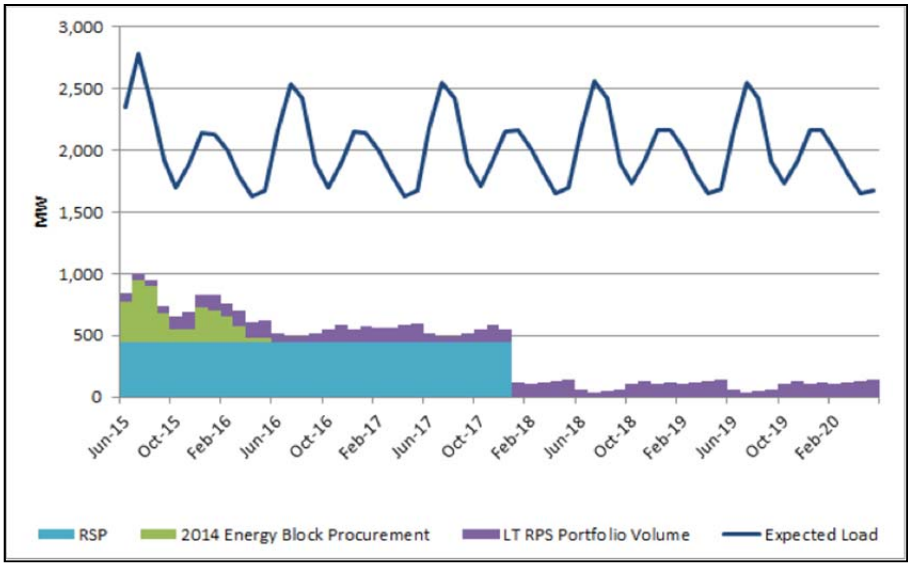


4.2 ComEd Resource Portfolio

Figure 4-4, Figure 4-5, and Figure 4-6, show the current gap in the ComEd supply portfolio for the June 2015-May 2020 planning period, using the expected, high and low load on-peak forecast described in Section 3.3.

ComEd's current energy resources will not cover load starting in June 2015. The average supply gap during peak hours for the 2015-2016 delivery year is estimated to be 1,223 MW.

Figure 4-4: ComEd's On-Peak Supply Gap - June 2015-May 2020 period - Expected Load Forecast



Under the high load forecast scenario, ComEd will be consistently short during the whole study period. The average supply gap for peak hours of the 2015-2016 delivery year is estimated at 1,966 MW. Under the low load forecast scenario, ComEd will also be consistently short on average 790 MW for the 2015-2016 delivery year.

Figure 4-5: ComEd's On-Peak Supply Gap - June 2015-May 2020 Period - High Load Forecast

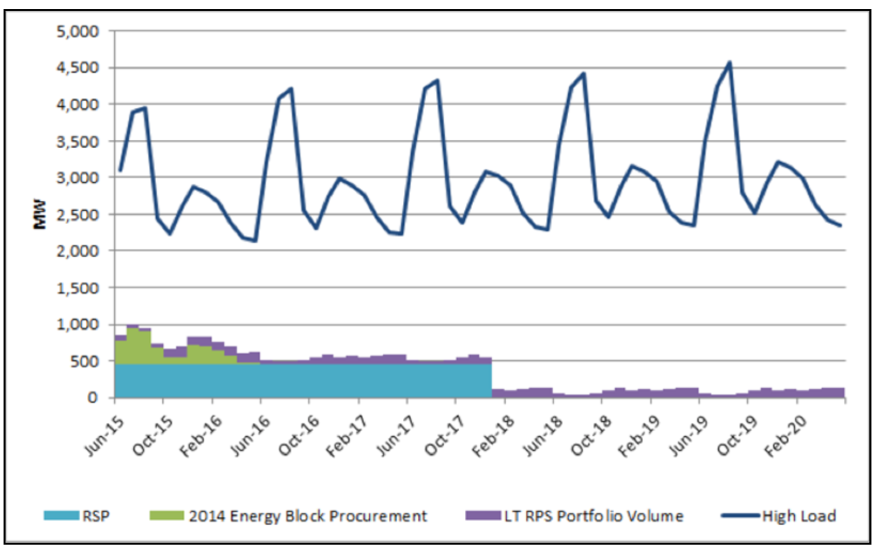
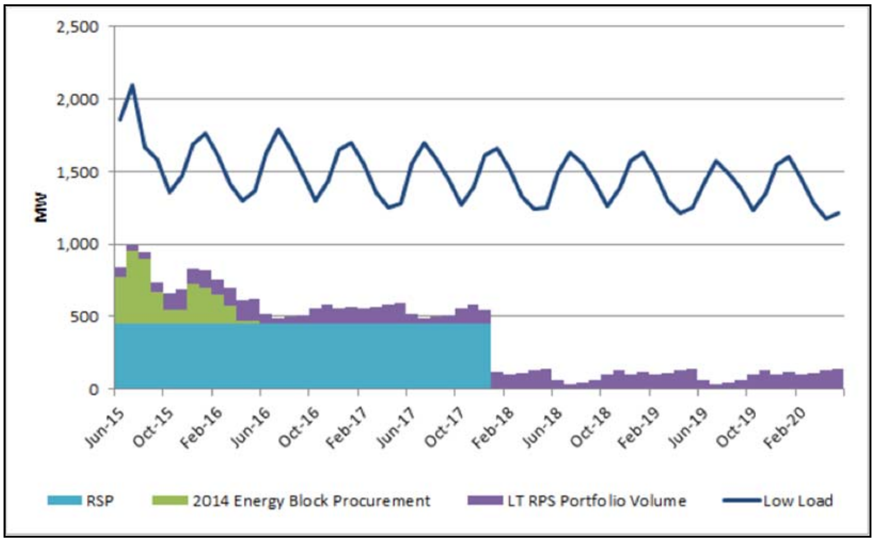


Figure 4-6: ComEd's On-Peak Supply Gap - June 2014-May 2019 Period - Low Load Forecast



5 MISO and PJM Resource Adequacy Outlook and Uncertainty

As a result of retail choice in Illinois, resource adequacy (the load/resource balance) can be viewed as a function of determining what level of resources to purchase from which markets over time. However, for the Illinois market to function properly, the RTO markets and operations (e.g., MISO and PJM) must provide sufficient resources to satisfy the load of all customers reliably. This section reviews the likely load/resource outcomes over the planning horizon to determine if the current system is likely to provide the necessary resources such that customers will be served with reliable power.

In reviewing the load/resource outcomes over the planning horizon, this section analyzes several outside studies of resource adequacy that are publicly available from different planning and reliability entities. These include:

- North American Electric Reliability Corporation ("NERC"), the entity certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards with the goal of ensuring the reliability of the American bulk power system.
- Midcontinent ISO ("MISO"), which operates the transmission grid in most of central and southern Illinois.
- PJM Interconnection ("PJM"), which operates the transmission grid in Northern Illinois.

From review of these entities' most recent documentation, it is apparent that over the planning horizon PJM will maintain adequate resources to meet the collective needs of customers in those regions. MISO may be short resources in the 2016 timeframe.

5.1 Resource Adequacy Projections

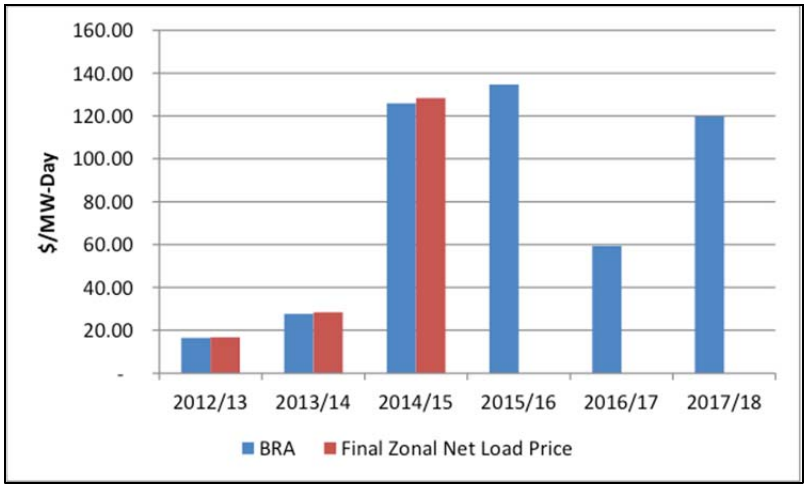
In PJM, capacity is largely procured through PJM's capacity market, Reliability Pricing Model ("RPM"), which was approved by FERC in December 2006. RPM is a forward capacity auction through which generation offers capacity to serve the obligations of load-serving entities. The primary capacity auctions, 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 ("DY").[75] In addition to the BRAs, up to three incremental auctions are held, at intervals 23, 13, and 3 months prior to the DY.[76]

Just prior to the beginning of each DY, the Final Zonal Net Load Price, which is the price paid by load serving entities for capacity procured as part of RPM in PJM, is calculated. This price is determined based on the results of the BRA and subsequent incremental auctions for a given delivery year. As the majority of the capacity procured via RPM is done so during the BRA, there is little variation between the BRA clearing price and the Final Zonal Net Load Price. As shown in Figure 5-1, the price volatility that does exist under RPM is inter-temporal across delivery years. While this volatility is large, it is not hedgeable.

[75] A DY is June 1 through May 31 of the following year.

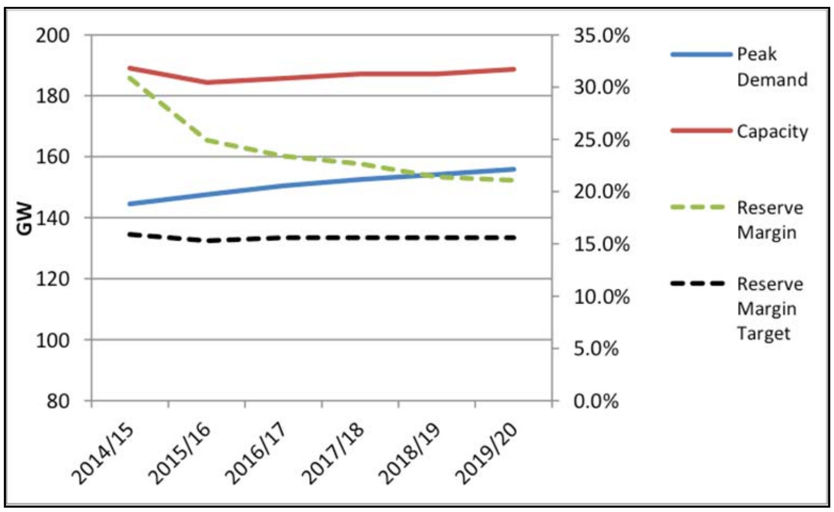
[76] To the extent the 1st and 3rd incremental auctions are not needed, they may be cancelled by PJM. The 2nd incremental auction is held to procure capacity to meet the deferred short-term resource procurement.

Figure 5-1: PJM RPM Capacity Price for Delivery Years 2012-2017[77]



As outlined in Figure 5-2, PJM is projected to have sufficient resources to meet load plus required reserve margins for the delivery years 2014-2019, with projected reserve margins averaging over 20% during this time frame. This is approximately 5% above the 15.6% target reserve margin.

Figure 5-2: PJM NERC Projected Capacity Supply and Demand for Delivery Years 2014-2019



MISO's capacity market construct, Module E, creates a framework for electric utilities and capacity resources to enter into bilateral agreements for capacity. Specifically, Module E is a resource adequacy program that requires the region's load-serving entities to procure sufficient capacity resources to meet their peak load plus target reserve margin.[78] Under Module E, a load-serving entity can procure resources to meet its resource adequacy requirements by offering or self-scheduling resources in the annual auction or by submitting a Fixed Resource Adequacy Plan ("FRAP") to demonstrate sufficient resources have already been procured. MISO held its second annual capacity auction in April 2014, with capacity prices in the majority of

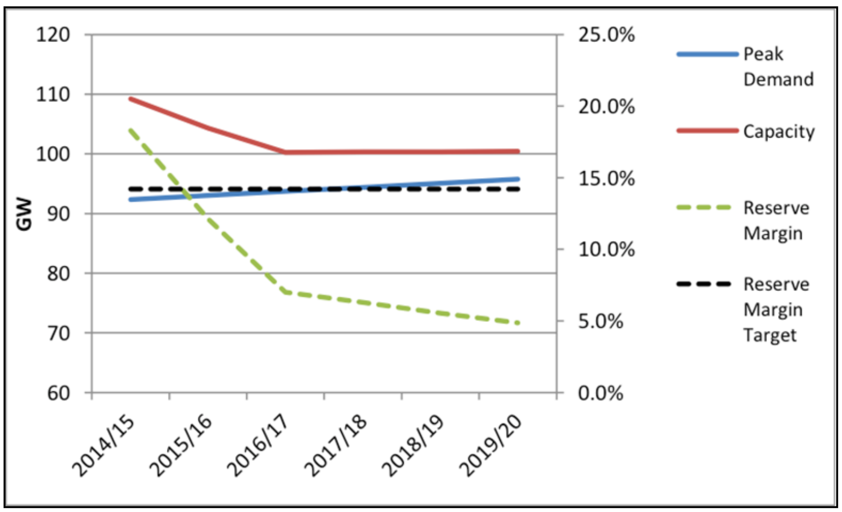
[77] 2014/15 is the latest DY for which the Final Zonal Net Load Price has been calculated. It will be calculated for future DYs as the start of the year approaches.

[78] An LSE's reliability requirement is based on either planning reserve margins (PRM) determined by MISO, based on a loss of load expectation of one day in ten years, or state-specific standards.

zones clearing up to 15 times higher than in the first auction due potentially to a tightening of the capacity reserve margin in MISO ($16.75/MW-day for the 2014/15 delivery year versus $1.05/MW-day for the 2013/14 delivery year).

As outlined in Figure 5-3, MISO is projected to be short capacity supply to meet load plus target reserve margins for the delivery years 2014-2019, with reserve margins averaging less than 10% during this period. This is approximately 4% below the 14.2% target reserve margin. The drop in reserve margin beginning in 2015 is primarily attributable to the assumed retirement of coal generation due to environmental regulations (i.e., the implementation of the Mercury and Air Toxics Standards, "MATS," in 2016) and fuel prices. However, the assumed 8 GW of coal retirements by 2016 represent a worst case scenario and likely do not fully reflect final retirements versus environmental compliance or coal-to-gas conversions decisions by these facilities. Additionally, NERC has suggested that some—if not all—of the projected shortfall by 2016 could be mitigated by future-planned additions, DSM growth,[79] additional support anticipated from the MISO South Region, and transmission upgrades. The MISO capacity projection may need to be updated when more reliable data is available.

Figure 5-3: MISO NERC Projected Capacity Supply and Demand for the Delivery Years 2014-2019



5.2 Locational Resource Adequacy Needs

The RTO-based reliability assessments examined above are important measures of resource reliability in Illinois because the Illinois electric grid operates within the control of these two RTOs. The IPA concludes that it does not need to include any extraordinary measures in the 2015 Procurement Plan to assure reliability over the planning horizon.

[79] On January 14, 2014, MISO proposed to modify Module E-1 tariff to treat Demand Response ("DR") and Energy Efficiency ("EE") resources similarly to other capacity providing resources for operational planning purposes. MISO has removed language to permit LSEs to net the effects of DR and EE resources from their coincidental peak, and instead, will credit these resources with the equivalent number of Zonal Resource Credits (ZRCs). The change is an accounting measure intended to enable MISO to better track which LSE has which DR and EE resources. This change was accepted by the FERC on March 14, 2014.

In 2013, MISO integrated Entergy into MISO creating the MISO South Region. The MISO South Region adds over 18,000 miles of transmission and approximately 30 GW of load into the MISO footprint. Generators in the MISO South Region are dispatched and bid into the MISO markets (the load/resource balance associated with the South Region is not reflected in Figure 5-3 as it has yet to be incorporated in NERC projections).

6 Managing Supply Risks

The Illinois Power Agency Act lists the priorities applicable to the IPA's portfolio design, which are "to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[80]

At the same time, the Legislature recognized that achievement of these priorities requires a careful balancing of risks and costs, when it required that the Procurement Plan include:

> *an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the following factors: contract terms, time frames for securing products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment; the proposed procurement plan shall also identify alternatives for those portfolio measures that are identified as having significant price risk.*[81]

This chapter discusses and assesses risk in the supply portfolio, as well as tools and strategies for mitigating them. Developing a strategy requires knowledge of the risk factors associated with energy procurement and delivery, and of the tools available to manage those risks. Section 6.1 lists the risk factors themselves. Section 6.2 describes types of contracts and hedges that can be used to manage supply risk. Those products may be thought of as being used to build a supply portfolio. Section 6.3 addresses the complementary issue of reducing or re-balancing the supply portfolio when needed, and the legal, regulatory and policy issues that may arise if utilities have to do so by selling previously purchased hedges over-the-counter.

Sections 6.4 through 6.6 address the cost and uncertainty impacts of these risk factors. Risk is often taken to mean the amount by which costs differ from initial estimates. Utility energy pricing in Illinois is based on estimates and cost differences are trued up after the fact through the Purchased Electricity Adjustment ("PEA").[82] Section 6.4 provides a historical summary of PEA rates as a guide to the historical impact of risk factors. Section 6.5 recapitulates a simulation study performed last year, and briefly discusses the risk of winter price spikes such as occurred in 2014. Section 6.6 focuses on full requirements contracts. Finally, Section 6.7 addresses demand management.

6.1 Risks

Procurement risk factors can be divided into three broad categories: volume, price, and hedging imperfections. Volume risk deals with risk factors associated with identifying the volume and timing of energy delivery to meet demand requirements. Price risk covers not only the uncertainty in the cost of the energy but also the costs associated with energy delivery in real time. Hedging imperfections are the result of mismatches between the types of available hedge products and the nature of customer demand.

The 2014 Procurement Plan contained a detailed description of the following risk factors, which is incorporated here by reference.

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[80] 20 ILCS 3855/1-20(a)(1).
[81] 220 ILCS 5/16-111.5(b)(3)(vi).
[82] See 220 ILCS 5/16-111.5(l). This policy is manifest through riders filed by each utility – ComEd's Rider PE (Purchased Electricity), and Ameren's Rider PER (Purchased Electricity Recovery).

6.1.1 Volume Risk

The accuracy of load forecasts directly impacts volume risk. Accurate customer consumption profiles, load growth projections, and weather forecasts impact both the total energy requirement and the shape of the load curve. Sections 3.2 and 3.3 describe the load forecasting processes undertaken by Ameren and ComEd respectively.

- Load Profiles (load shape, or the fraction of the total annual, monthly or daily usage associated with each hour)
- Load Growth Projections (impacts of economic conditions, customer in-migration, customer out-migration)
- Impacts of Weather Fluctuations
- Technology Impacts, e.g., smart metering, customer generation
- Customer Switching

6.1.2 Price Risk

The price the 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.

- Energy prices (on the unhedged portfolio, up to the day-ahead)
- Real-Time Balancing Costs (deviation between day-ahead and real-time load)
- Capacity (primarily applies to Ameren as the PJM capacity price is largely determined by the Base Residual Auction three years earlier)
- Ancillary Services
- Transmission pricing
- Congestion costs
- Correlation Between Volume and Price Risk Factors

6.1.3 Hedging Imperfections

- Procurement Supply Shape (Difference between Load Shape and the profiles of products available for procurement)
- Locational Pricing (Procurement Location versus Customer Location)
- Lack of hedges for Renewable Energy costs

6.2 Tools for Managing Supply Risk

Traditionally, a utility's electricity supply plan includes physical supply and financial hedges. Physical supply includes the power plants that the utility owns or controls, as well as transactions for physical delivery of electricity. Financial hedges are additional hedging instruments used to manage residual price risk and other risks, such as weather risk.

ComEd and Ameren divested their generating plants to unregulated affiliates or third parties. They have no contracts for unit-specific physical delivery, other than certain (Qualifying Facilities under the Public Utilities Regulatory Practices Act ("PURPA")) contracts. Their long-term renewables Power Purchase Agreements ("LTPPAs") are structured as "Contracts for Differences." As the utilities do not purchase and take title to electricity, the utilities' supply positions, other than RTO spot energy, are exclusively price hedges.

Physical electricity supply and load balancing for ComEd and Ameren are coordinated by the respective RTOs (PJM and MISO respectively). ComEd and Ameren are considered Load Serving Entities ("LSEs") by the RTOs. Each RTO provides day-ahead and real-time electricity "spot pricing." That is, generators supply their energy to the RTO, and the RTO delivers energy to LSEs and customers. 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. The risks faced by LSEs in supplying energy to customers are mostly financial. The LSE still needs to manage certain operational risks such as scheduling and settlement. There are other, non-financial risks associated with electricity retailing, such as customer billing or accounts payable risks, but those are not associated with the supply portfolio.

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; and 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 ("LMPs") because they depend on the delivery location or zone.

6.2.1 Types of Supply Hedges

The 2014 Procurement Plan contained a detailed description of a number of different types of supply hedges, listed below. One point made in that plan is that hedges available in the market are not perfect; the risks listed in Section 6.1 cannot all be hedged away except through a specially tailored "full requirements" hedge contract, whose cost may or may not be acceptable in return for that degree of risk reduction.[83]

An important category of energy supply hedges is a unit-specific supply contract. Other supply hedges are forward contracts, futures contracts, and options.

6.2.1.1 Unit-Specific Hedges

- As-available
- Baseload
- Dispatchable

6.2.1.2 Unit-Independent Hedges.

- Standard forward hedges (block contracts)
- Shaped forward hedges
- Futures contracts
- Options
- Full requirements hedges. Section 6.6.1 includes a summary of other states' experience with full requirements hedges and Section 6.6.2 addresses estimates of the cost premium associated with them. The cost premium of full requirements contracting can only be evaluated by comparison with the value of eliminating price.

[83] Even a full requirements hedge does not truly eliminate all risk. For example, if a supplier of a full requirements tranche were to default, additional procurement costs to make up the shortfall could be passed along to eligible customers.

6.2.2 Suitability of Supply Hedges

Not all of the types of hedges listed in Section 6.2.1 are suitable for use in this Procurement Plan, and not all may be readily available in electricity markets. Illinois requires that "any procurement occurring in accordance with this plan shall be competitively bid through a request for proposals process," provides a set of requirements that the procurement process must satisfy, and mandates that the results be accepted by the ICC.[84] Among the specific requirements, the Procurement Administrator must be able to develop a market price benchmark for the process; the bidding must be competitive; and the ICC's Procurement Monitor is required to report on bidder behavior.[85] The most natural evidence of competitiveness will be breadth of participation, although other evidence may be possible as well.

Hedges most suitable for use by the Agency would be those standardized products that are well-understood, and preferably widely-traded. 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. Prior to its 2014 Procurement Plan, the IPA 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 Agency's recommended plans have been stated in terms of monthly contracts, although procurement events have met some of these needs with multi-month contracts.

The IPA has in the past purchased energy products that are not typically traded, such as the long-term PPAs with new build renewable generation that were authorized in the 2010 Procurement Plan. As noted in Section 2, 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. As discussed in Section 2.4, while the ICC clarified its understanding of the definition of "standard product" in its approval of the 2014 Procurement Plan, the IPA's authority to procure other products, including shaped forward contracts and option contracts, could be subject to future litigation. Markets for products that are specifically designed for the IPA's 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 may not be compatible with such a low level of transparency.

Futures contracts at the PJM Northern Illinois Hub and the MISO Illinois Hub are traded in reasonably deep liquid markets, making such contracts easier to benchmark. The markets for long-dated (*i.e.* further in the future) contracts are less liquid, however. The Agency ought to be able to obtain competitive pricing on such contracts if it were to want to incorporate them in its portfolio. However, it may be difficult or impossible to conduct the statutory RFP process for futures contracts; for example, it is unclear how the margin requirements would fit within the current regulatory framework. The same concerns are even more applicable to options contracts, trading in which is more illiquid.

6.2.3 Options as a Hedge on Load Variability

An option gives the buyer a right but not an obligation. For example, a call option gives the buyer the right, but not the obligation, to buy a specific contract. A put option gives the buyer the right, but not the obligation, to sell a specific contract. Options are "one-way" hedges. A call option, for example, can help hedge against price increases but provides no hedge against price decreases. Options on forward or futures contracts are much less expensive than the contracts themselves, because they only convey the right to spend the money to buy the contract.

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[84] 220 ILCS 5/16-111.5(b), (e), (f).
[85] 220 ILCS 5/16-111.5(f).

Some may perceive options as attractive tools to hedge against customer migration and other forms of load fluctuations. According to option pricing theory, 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, for example, loss of load accompanied with declining prices. 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. It turns out that options are expensive when used as hedges for load migration risk. This is because if a call option on 1 MW of load has a price V, then that should be its value as a price hedge. If the 1 MW is not currently served by the utility, but may return with some probability P, then the value of this option should be only P times V which is less than its price. In other words, 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.

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. They have a particular advantage in that the trading exchange bears the counterparty default risk. However, the Agency's structured procurement process prevents the Agency's from buying options on the exchanges.
- Option contracts can be relatively illiquid, making it more difficult to assure fair pricing. If options purchased by the IPA required an affirmative exercise decision, which most likely they would, the utilities would seek regulatory comfort on their exercise decision-making before agreeing to use options. For example, if an exercise decision were dependent on the utility's load forecast or view of municipal aggregation, the utility would want to be able to show 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. This would add to either the purchase cost or the ownership cost of options.

6.3 Tools for Managing Surpluses and Portfolio Rebalancing

The Illinois Power Agency Act specifies that the Procurement Plan "shall include … the criteria for portfolio re-balancing in the event of significant shifts in load."[86] It is therefore appropriate to consider what tools are available to conduct such rebalancing, keeping in mind that the utilities, not the Agency, are the owners of the forward hedges and that selling of excess supply in the forward markets may have unintended cost and accounting consequences.

1. To date, the only rebalancing of hedge portfolios prior to 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.
2. Sales of excess supply by the utilities in the wholesale market to rebalance their supply portfolio may create a de facto "wholesale marketing function" within the utilities. The employees involved in

[86] 220 ILCS 5/16-111.5(b)(4).

wholesale marketing activities would be subject to the separation of functions in accordance to FERC Order 717.[87]

3. For the last few years, the utilities have scheduled excess supply in their portfolios, or made up supply deficits, in the RTOs' day-ahead markets. This has been the dominant mode of portfolio rebalancing.
4. As an alternative form of rebalancing, the Agency could conduct "reverse RFP" procurement events, in which the bids are to buy rather than sell forward hedges. The Agency does not believe that has the authority to "conduct competitive procurement processes" under 20 ILCS 3855/1-20(a)(2) to sell excess supply.
5. The Agency 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 forwards. This may avoid legal and contractual difficulties associated with selling forward hedge contracts. This approach would also require the utilities to ensure they had regulatory approval to exercise the options after purchasing them, and the employees who exercise the option could become classified as part of a "marketing function." The Agency does not envision entering into derivative contracts for rebalancing purposes.
6. The Agency could conduct more than one procurement event in a year if the rebalancing required is to increase the supply under contract. This is what the IPA proposed for 2014 (and again proposes in this Plan) and it is scheduled to conduct a second procurement event on September 22, 2014. The volumes for that procurement were updated based upon load forecast supplied by the utilities in July 2014 and reflect increased volumes to be procured compared to the March 2014 forecasts.

6.4 Purchased Electricity Adjustment Overview

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. The PEA can be a debit or credit to address the difference between the revenue collected from customers and the cost of electricity supplied to these same customers in a given period. The supply costs are tracked, and the PEA adjusted, for each customer group.

The 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. Figure 6-1 shows how the PEAs have changed over the last three years. While Ameren's PEAs have been generally negative, ComEd's have been more often than not positive, and have had more volatility. ComEd has voluntarily limited its PEA to move between +0.5 cents/ kWh and -0.5 cents/kWh, and the figure shows that ComEd's PEA has oscillated between those limits.

In April 2014, the Commission approved an adjustment to ComEd's PEA that allows the accumulated balance of deferrals associated with 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.

To additionally reduce PEA volatility, ComEd is investigating "unbundling" ComEd's supply charge into energy, capacity, and transmission charges. ComEd stated the following in its responses to questions asked by the IPA after the June workshop on full requirements products:

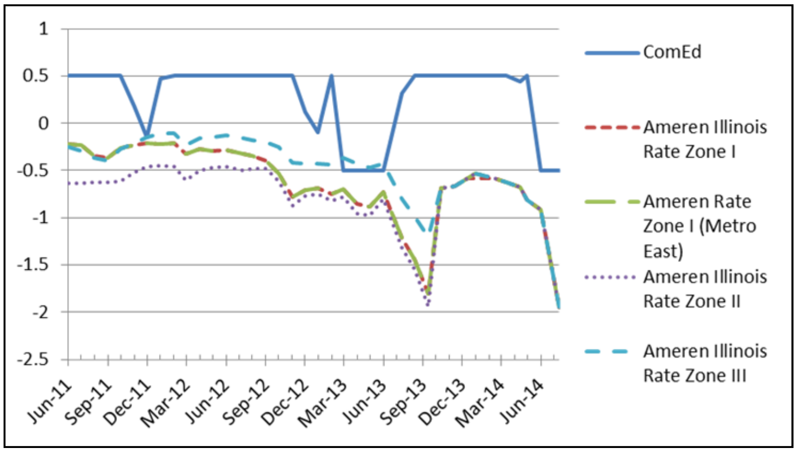
> *By aligning our rates with the fixed nature of these costs, ComEd could significantly reduce the volatility of under/over recovered energy costs. This reduced volatility may make it possible for ComEd to forgo the monthly PEA adjustments that currently impact ComEd's fixed price customers and instead just roll any*

[87] 125 FERC ¶ 61,064, Oct. 16, 2008.

accumulated credit or debit balance into rates when reset each June (although there would likely need to be a provision to reinstate such monthly true-ups in extreme circumstances).[88]

In July 2014, the value of Ameren PEAs decreased significantly. The IPA understands this decrease is likely the result of Ameren over-collection during the past winter and its PEAs represented the return of these proceeds to customers.

Figure 6-1: Purchased Electricity Adjustments in Cents/kWh, June 2011 – June 2014



The current IPA hedging strategy, including the planned September procurements for ComEd and Ameren, combined with ComEd's implemented and under consideration improvements to its PEA methodology, should result in reduced volatility in the PEA for the coming years. This reduction in PEA variation will provide the clarity that many ARES have sought by allowing for an easier comparison between the utility rate and potential offers by ARES.

6.5 Estimating Supply Risks in the IPA's Historic Approach to Portfolio Management

6.5.1 Historic Strategies of the IPA

The utilities, pursuant to plans developed by the IPA, have historically used fixed-price, fixed-quantity forward energy contracts and financial hedges (such as the LTPPAs), along with RTO load balancing services to serve load. In other words, energy delivery has been coordinated by the RTOs and the Agency has arranged a portfolio of long-term contracts and standard forward hedges, in multiples of 50 MW (and in 2014, 25 MW), for each utility. Ancillary services have been purchased from the RTO spot markets. The utilities have used Financial Transmission Rights and Auction Revenue Rights to mitigate transmission congestion risk.

Forward hedges have been procured on a "laddered" basis. The Agency 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. Prior to 2014, procurements had been annual, in April or May, rather than on a more frequent or ratable basis. For example, in the spring of 2010, the Agency procured forward hedge volumes (in 50MW increments) as close as possible to 35% of the monthly average peak and off-peak load forecasts for the 2012-2013 delivery year. In the Spring of 2011, the Agency procured forward hedge volumes (in 50MW increments) to bring the total volume as close as possible to 70% of then-current monthly

[88] See "ComEd Comments" at 2 from Full Requirements Products Request for Comments available at www2.illinois.gov/ipa/Pages/Plans_Under_Development.aspx.

average peak and off-peak load forecasts for the 2012-2013 delivery year. And in the Spring of 2012, the Agency procured forward hedge volumes (in 50MW increments) to bring the total volume as close as possible to 100% of then-current monthly average peak and off-peak load forecasts for the 2012-2013 delivery year. In the 2013 Procurement Plan, the Agency indicated it was considering a change in hedging from 100%/70%/35% of the expected load to 75%/50%/25%. There were no procurements in 2013 so 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. The Agency suggested 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, 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 more than $1/MWh in the average portfolio cost (the load-weighted average price) – in fact, approximately $1.06. The Agency continued to recommend hedging up to only 75% of the expected load for November-May of the prompt delivery year in the April procurement, but also recommended a supplemental procurement in September to bring the hedged volume to 100%.

The procurement schedule balances procurement overhead costs, price risk, and load uncertainty. If the amounts to be hedged in any year are small, the Agency could decide to avoid the procurement overhead and not schedule a procurement event (as in 2013). The Agency has not used options, unit specific contracts (except for the LTPPAs), or other forms of hedging in the past. In addition the Agency has not used forward sales or put options to rebalance its portfolio.

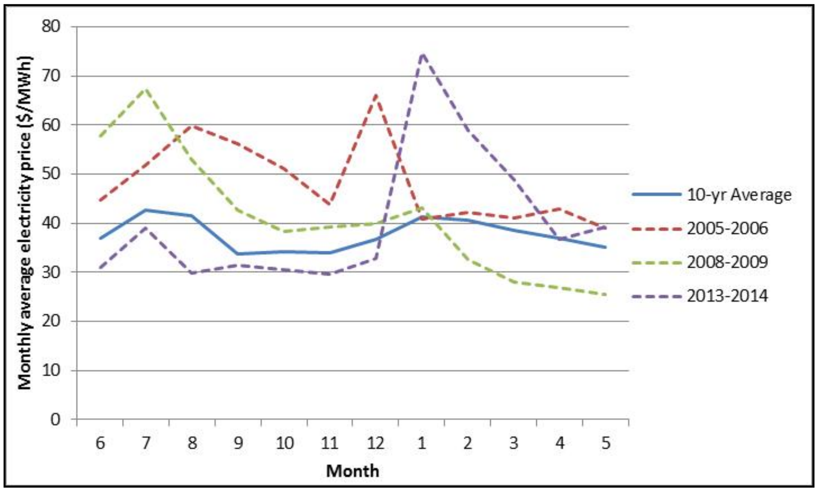
6.5.2 Measuring the Cost and Uncertainty Impacts of Risk Factors

Section 6.1 enumerated a number of risks in power procurement, most of which have been mitigated by the Agency's historic procurement strategy. In the 2014 Procurement Plan, the IPA described its use of a Monte Carlo model to evaluate the potential cost and uncertainty impacts of various risks. The Agency also used this model to estimate the added cost of full requirements contracts.

The risk study in the 2014 Procurement Plan led to a change in procurement strategy motivated by shaping risk. Shaping represents the impact of the correlation of load and price, both of which vary during the period of time hedged by a standard product. Shaping risk magnifies price exposure and it is desirable to reduce such risk. In fact, the IPA hedges the July through October position to 106% of expected average load.

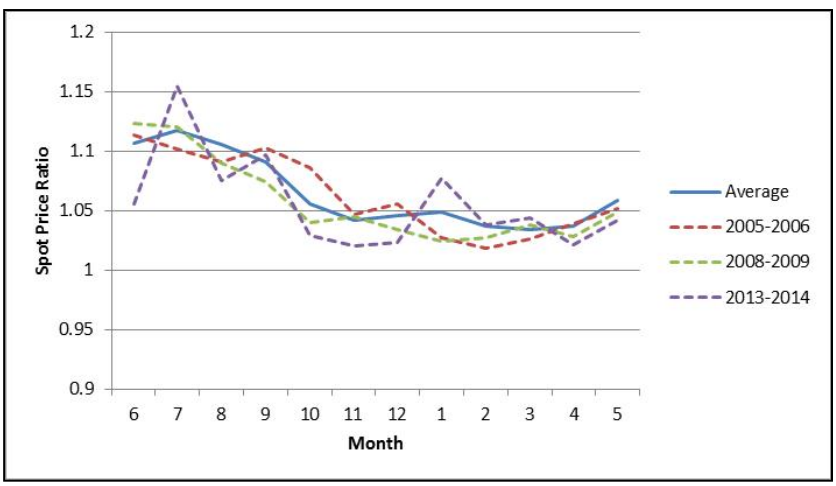
The polar vortex event of 2014 demonstrated that, in rare events, that there can be unexpected levels of price risk in the winter, and that price excursions can have short-term causes that cannot be accounted for when hedging several years ahead using load forecasts that generally assume normal weather. Figure 6-2 shows, in the case of ComEd, that over the last ten years, price peaked (moderately) in the summer, and rose again (though not as high) in the winter. Figure 6-2 illustrates a year with the classic price pattern of a summer peak, 2008-2009. It also includes a year in which a summer peak and a secondary, shorter-lived winter peak, 2005-2006. Finally it shows the last year, 2013-2014, with a pronounced winter price peak, whose effects also subsided. The 10-year average is shown as a reference.

Figure 6-2: ComEd Zone Monthly Load-Weighted Electricity Prices - 10-Year Average and Three Selected Years



The 2014 price peak was exacerbated by the correlation of load and price, i.e., shaping. Figure 6-3 shows the monthly spot price ratio (the ratio of the load-weighted spot price to the monthly average price) in the ComEd zones for the same years as in the previous figures. It shows that the January 2014 price was enhanced by the price shape much more noticeably than was the December 2006 peak. This recent experience supports the IPA's strategy to be hedged to no less than 100 percent of expected average load during the winter months.

Figure 6-3: ComEd Zone Spot Price Ratios - 10-Year Average and Selected Years



6.6 Consideration of a Full Requirements Procurement

The current supply portfolios of Ameren and ComEd, by chosen strategy/portfolio design, do not perfectly hedge their load—primarily due to load uncertainty, the mismatch of demand and hedge profiles, and the correlation between price and load. Currently, the utilities' supply customers absorb the residual risk resulting from the utilities' portfolio design. In other words, customers self-insure the residual risk. The effect of this risk becomes apparent in the application of the PEA discussed above. (ComEd further mitigates this impact by voluntarily limiting the PEA to ±0.5 cents per kWh each month.) On the other hand, if the goal of the supply strategy/portfolio design were to provide customers power at a fixed price over a multi-month period (one to three years) similar to most ARES products offered directly or through municipal aggregation, a full requirements product may be a reasonable alternative for consideration. Full requirements contracts provide a form of insurance by outsourcing supply risk to a third party. Full requirements solicitations are used in several jurisdictions as a source of supply for default service load.

Various reasons are brought forth for the use of full requirements procurement:

- Full requirements procurement provides customers price insurance. One function of a competitive retail supplier is to provide price certainty. This justification presumes a policy choice that the default provider should take on that role.
- Full requirements supply more appropriately represents the Price to Compare, since it includes a valuation of the uncertainty in actual pricing. Again, one must determine whether the change, which provides obvious benefits to ARES, and less clearly benefits eligible retail customers, is worth the premium.
- Full requirements pricing reduces the potential for utilities to accumulate high balances (credit or debit) to be amortized by Purchased Electricity Adjustments. When these balances have been a debit, they have been most significant for ComEd. Because ComEd voluntarily limits the size of the monthly PEA to plus or minus half a cent per kilowatt hour, it is susceptible to accumulate large uncollected (or over-collected) balances, although recent changes that allow for an annual resetting and amortization of any balances will mitigate this issue. The uncollected balances are arguably a form of price insurance that is voluntarily underwritten (without a carrying charge) by the utility.

The 2014 Procurement Plan provided guidance into the price premium (or "residual compensation") one could expect to pay for price insurance, as well as the effectiveness of that insurance in removing price uncertainty. The 2014 Plan attempted to facilitate discussion as to whether customers would perceive the insurance as valuable enough to justify the premium. The methodology was critiqued in comments on the draft Plan, in litigation, and again in the workshop described below. Section 6.6.2 revisits the issue, explains different notions of the "premium," and presents additional cost estimates, which the Agency believes are reflective of the methodology suggested by the commenters on the follow-up questions from its June 2014 workshop on full requirements products.

The choice to buy full requirements should not depend on the absolute magnitude of that price premium but rather on whether that price premium is comparable to the value that consumers would perceive they obtain by eliminating the uncertainty around the price. There is no obvious formula for converting the statistics of the cost distributions into dollar measures of value. That depends on customers' risk preferences. Presumably, an informed utility supply customer who values absolute price certainty would choose to take service from an ARES who offers a fixed price directly or through a comparable municipal aggregation plan.

In June 2014 the Agency held a workshop with interested parties to consider the appropriateness of a full requirements portfolio. Following the workshop the Agency issued a Request for Comments ("RFC") and posted the RFC on its website. The RFC included the following questions:

1. At the June 5th workshop some participants suggested that an analysis of a potential full requirements procurement should be for a product that includes capacity, ancillary services, etc., not just a load following energy product (as the IPA had analyzed in the 2014 Procurement Plan). Please comment on the advantages and disadvantages of this product definition, and explain which ancillary services should, or should not, be included (e.g., active power reserves but not voltage support).
2. A participant at the workshop indicated that suppliers of fixed-price full requirements products assume price risks associated with capacity, ancillary services, etc. How would one quantify the anticipated costs of including the non-load following energy components (capacity, ancillary services, etc.) in the product described in question 1?
3. Bids for full requirements contracts include compensation for various costs and risks borne by the product supplier (i.e., "residual compensation" as described in the ICEA presentation). Please

comment on what factors influence the level of this cost and how it should be estimated. Other discussions of full requirements procurement (e.g., the IPA's 2014 Procurement Plan) discuss the concept of a "risk premium." Please also comment on the differences in definition between "residual compensation" and "risk premium" and how the two concepts should be differently understood.

4. For the purposes of modeling the full requirements approach, there was discussion at the June 5th workshop about modeling for the 2015/16 delivery year an implementation of full requirements that would account for the existing block contracts as well as separately modeling (for the 2015/16 delivery year or future implementation years) an approach consisting entirely of full requirements contracts. Please discuss any limitations or adjustments to those two models, and how the existing contracts should be treated in the first model.

5. Please suggest models for how full requirements procurement could be phased into the existing ComEd and Ameren portfolios previously procured by the IPA.

6. The analysis conducted by PA Consulting for the IPA as part of the 2014 Procurement Plan included assumptions that suppliers bidding in a full requirements procurement would hedge their price exposure with forward contracts. Please provide input on what models suppliers use for estimating the costs and risks (including, but not limited to, price and load risk) that they bear as a full requirements product supplier and what inputs the IPA should consider when modeling supplier bidding behavior in a full requirements procurement.

7. To what degree, and how, could the potential benefits of procuring full requirements products (as compared to a block procurement approach) be quantified rather than qualitatively described? What are some of the relevant risk metrics that should be included in such an analysis, and how should they be compared to known procurement costs? Additionally, what are some of the inputs and variables that must be appropriately captured in order to quantitatively assess potential benefits? Are there benefits of the block procurement approach (as compared to a full requirements approach) that could also be assessed and quantified?

8. The IPA's traditional procurement approach hedges in the forward market a percentage of expected load taking into account market conditions. In the 2014 Procurement Plan, the IPA hedged 106% of average load for the summer months to mitigate shaping risk, and for the first time, the IPA is planning a fall procurement for ComEd to adjust the balance of the current delivery year supply to balance an updated summer load forecast. The goal of this second procurement is to reduce load risk. Given the legislative mandate of the Agency to "develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability," are there strategies other than full requirements procurement and the IPA's current approach that the IPA could consider for managing risks?

9. During the workshop the idea was raised that there may be ways to achieve rate stability other than utilizing a full requirements supply strategy. How could the utilities provide firm prices for a defined period through a tariff mechanism? Could the utilities adjust the PEA on an annual basis, as opposed to a monthly basis? Would a "rate stabilization account" approach add unnecessary costs? Are there ways to achieve additional utility price/rate certainty while utilizing the IPA's current competitively-bid block procurement strategy?

10. Please provide examples of studies or other evidence that assesses or quantifies the interest of Illinois residential (and/or small commercial) customers in firm rates. To the extent available, please correlate those examples to evidence of customer choice and switching. Please also provide examples from other retail markets.

The discussion at the workshop, and the responses to the questions,[89] did not reveal a consensus or even majority opinion on most questions. Ameren and ComEd raised a variety of practical implementation concerns and were concerned that the effect of existing hedge portfolios be taken into account when estimating the risk reduction impact of full requirements contracts' risk reduction impact. While the Illinois Competitive Energy Association ("ICEA") and Retail Energy Supply Association ("RESA") generally supported the notion of full requirements being a bundled product (e.g., including ancillary services and RECs in addition to energy), given ComEd's recent consideration of unbundling capacity for eligible customers, they favor excluding capacity from a full requirements product. ICEA and ComEd expressed differing views as to whether PEA fluctuations were a consequence of rate design (to be mitigated by unbundling capacity charges) or supply portfolio design. Most commenters withheld judgment on whether the value of price insurance justified its cost, although the Citizens Utility Board clearly believed that it did not. Based on the comments received and the IPA's knowledge of the Illinois retail market, the IPA feels that there is no clear evidence that, as a class, retail customers who chose to take bundled service from the utilities are willing to pay a premium to mitigate the residual price fluctuations associated with the current procurement strategy.

6.6.1 Experience in Other Jurisdictions

In 2006, Ameren and ComEd conducted a solicitation for full requirements contracts using a "descending clock" auction. The full requirements bids that cleared the auction had higher prices than many stakeholders and policymakers expected, and significantly increased retail rates.[90] State policymakers decided that those prices did not adequately reflect customers' risk preferences. Given Illinois' history, as part of considering procurement of full requirements products, it is reasonable to consider whether full requirements products have been successful elsewhere.

Since August 2002, New Jersey utilities have supplied the default electric load of residential and small commercial customers using full requirements fixed-price tranche contracts. The product provided by these suppliers is called the Basic Generation Service – Fixed Price (BGS-FP) product. "Default" load means the load of customers who have not switched to non-utility suppliers, called "eligible retail load" in Illinois. The contracts are procured using an annual "descending clock" auction, held the previous February. The tranche auctions are used to procure a ladder of 3-year fixed price contracts. The tariffed power price is the average of the prices of the three contracts that overlap a given year. The New Jersey auctions are well established and appear successful.

Larger commercial and industrial customers in New Jersey are also offered a full requirements product that is supplied using tranche auctions, but not at a fixed energy price. Instead of bidding fixed energy prices, prospective suppliers for this Basic Generation Service -- Commercial and Industrial Energy Pricing (BGS-CIEP) product bid a cost per MW, where the MW measure is the PJM capacity requirement associated with a tranche. The auction thus produces a price per MW of capacity requirement. The capacity requirement is generally about 116% of peak load. Annual load factors for BGS-FP load average around 43% in the PSEG zone. The tariffed power price is the load-weighted average PJM spot price, plus approximately $6/MWh for ancillary services, plus the auction price per MW of capacity requirement.

For the last eight years, utilities in Maryland, Delaware, and the District of Columbia have used a similar auction approach for purchasing electricity supply on behalf of their Standard Offer Service customers. They have separate procurements for full requirements tranche contracts, and have employed several laddering schemes and combinations of contract terms over that time. State and District regulators oversee the auctions. Maryland has formalized a process by which a procurement monitor determines in advance a "Price Anomaly Threshold" used to eliminate bids from consideration. The operation of the Price Anomaly

[89] Comments received are available on the IPA website under the "Energy Procurement | Plans Under Development" section.
[90] The IPA does not wish to fully detail the story of the 2006 auction and subsequent legal and political action; suffice to say that policymakers decided the results were unacceptable and adopted a number of legislative solutions including the formation of the IPA.

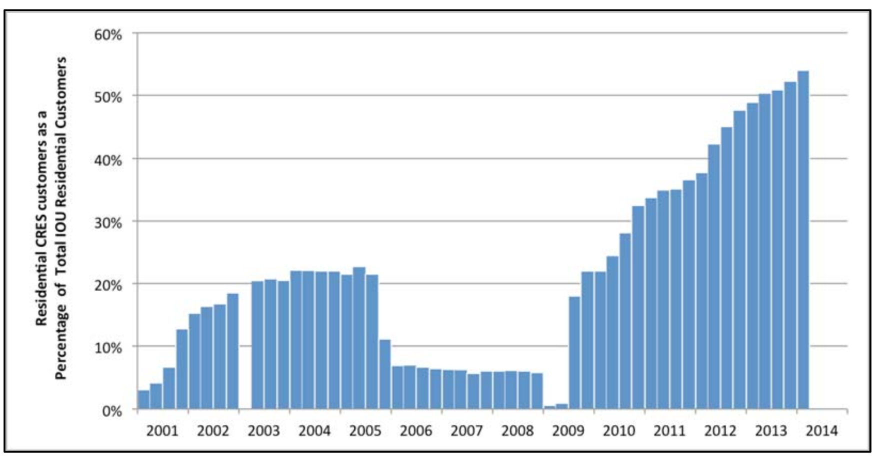
Threshold could result in utility demand being unfilled, so a series of auctions are scheduled to meet residual need.

Utilities in several other states procure full requirements contracts for their default service via an RFP process. In Massachusetts, utilities cover the load for each customer class and zone in two overlapping 12-month contracts. For example, National Grid US (Massachusetts Electric) has residential and commercial customer groups in three zones – six load groups altogether. The company purchases two 6-month contracts for each load group: half the load is purchased 33 weeks in advance and the balance 7 weeks in advance. In Rhode Island, on the other hand, National Grid US (Narragansett Electric) purchases 90% of its residential supply through a set of staggered full requirements contracts of varying durations – 6, 12, 18 and 24 months – and 10% through the spot market. In both cases, procurement is through an RFP evaluated by the utility, not an auction.

Utilities in Pennsylvania submit individual procurement plans. Both PPL and PECO Energy have been using laddered full requirements contracts. In Connecticut, a state agency develops procurement plans for the two utilities, United Illuminating (UI) and Connecticut Light & Power (CL&P). UI has procured 100% of its default service supply through laddered full requirements contracts. CL&P has recently procured 80% of its default service supply through laddered full requirements contracts, and 20% through a portfolio managed by the utilities.

Ohio presents a case with some relevance to Illinois because of the amount of migration both into and out of municipal aggregation. Ohio customer migration was discussed at length in the 2014 Procurement Plan. Significant customer switching occurred in FirstEnergy's territory, primarily through municipal aggregation, during the early years of the deregulation. Then in 2006, Ohio implemented rate stabilization plans ("RSPs") that held electricity prices below market levels for several years. The RSPs for the First Energy companies and Duke Energy Ohio expired at the end of 2008, and they now procure utility default service through a full requirements approach. Customer switching, driven by municipal aggregation, has grown rapidly since the expiration of the RSPs, though maybe not as rapidly as in Illinois. This history of customer switching is illustrated in Figure 6-4.

Figure 6-4: Fraction of Ohio Utility Customers Switching to Competitive Providers



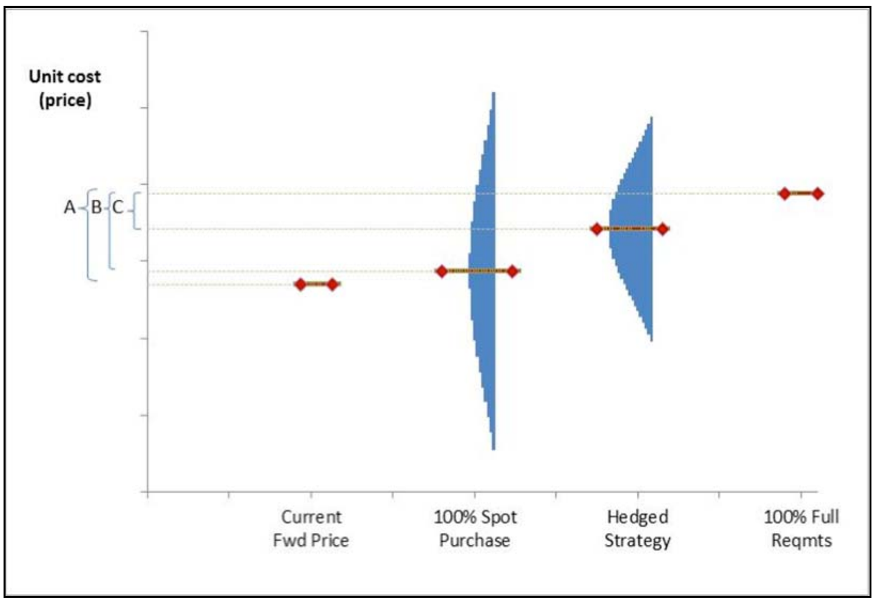
6.6.2 Cost and Risk of Full Requirements Contracting

Figure 6-5 is a conceptual illustration of the relationship between the cost of a full requirements hedge and the cost of supply using other hedging strategies. It is similar to related figures in Section 6 of the 2014 Procurement Plan in that it represents different supply strategies that could be used to fulfill the utilities' obligations. Most supply strategies involve some price uncertainty. In other words, when one embarks on such a strategy, the price it will ultimately produce is not known. The 100% Spot Purchase and Hedged

Supply strategies are shown as rotated bell curves, symbolizing the probability distribution of cost per MWh for each (cost per MWh is the vertical axis); the horizontal mark is the expected value of the price. The full requirements strategy involves a fixed price contract and thus has no uncertainty. The current forward price is an observable value, and also has no uncertainty.

- Current Forward Price: This is the current electricity forward market price at the time that the supply strategy is decided. Because of load forecast and profile uncertainty, it is not possible to use the current forward market by itself as a supply strategy. The price is provided as a reference.
- 100% Spot Purchase: This would be a totally unhedged strategy in which all electricity is purchased from the spot market.
- Hedged Strategy: This strategy involves the use of some of the hedging products described in Section 6.2.1.
- 100% Full Requirements: This represents the purchase of one or more fixed price full requirements contracts to meet the entire load.

Figure 6-5: Identifying the Full Requirements "Insurance Premium"



A full-requirements contract is a form of price insurance, and there should be a price premium associated with that.[91] One estimate of the premium, which can be computed at the time the contract is purchased, is the amount by which the full requirements price exceeds the contemporaneous forward price, which is labeled A in Figure 6-5. Or, the cost of full requirements service could be broken into the actual cost of the service itself (whatever the cost of spot supply turned out to be) and residual compensation or risk premium, whose expected value is labeled B in Figure 6-5.

[91] A premium for an insurance product is necessary for the supplier to be able to offer the product. From the recipient point of view, insurance is an added cost when the insurance is not used, but is likely to be a savings in total cost when the insurance is used (e.g., compare an annual auto insurance premium to the cost of replacing a totaled car).

6.6.2.1 Review of Analysis from 2014 Procurement Plan

The price of a full-requirements energy hedge should be based on the cost incurred and the risk managed by a provider of that hedge. In the 2014 Procurement Plan, the IPA simulated the development of a full requirements portfolio using a Monte Carlo simulation. The Agency undertook the simulation to estimate the cost of a full-requirements hedge, and in particular to see how that price compared to the costs of other procurement strategies, and the value of risk avoidance. The IPA simulated full-requirements contracts of two different durations:

- A one-year contract, in which the hedge would be effective from June to May under a price that was set six weeks before delivery began (in mid-April); and
- The third year of a three-year contract, so that the hedge supplier could have been laddering its own hedge portfolio for three years.

The IPA went on to estimate the price of a full-requirements energy hedge. That estimation entailed a set of assumptions as to how a supplier would price the "insurance premium."

The IPA's simulation (as well as the NorthBridge analysis discussed at length in litigation of the 2014 Procurement Plan, and discussed further below) indicated that full-requirements contracts would be priced at a premium relative to the expected cost of energy under the Agency's usual procurement strategies. In other words, the Agency computed the equivalent of the price difference labeled C in Figure 6-5. The Agency's estimated the statistical distribution of unit energy costs, and projected the amount a supplier would demand as an insurance premium based as a return on VaR (value at risk). The approximate premia (both in $/MWh and relative to the expected cost of an all-spot procurement) were as follows:

Table 6-1: Summary of Price Premia from 2014 Report

	1-year	3-year
Ameren	0.96	3.33
	2.8%	9.2%
ComEd	0.99	2.14
	3.0%	6.0%

6.6.2.2 Critique by Commenters on the 2014 Plan

The IPA's simulation methodology was critiqued in comments on the draft Plan, during litigation, and again in the June, 2014 workshop. The general thrust of the comments was that the simulation relied too much on assumptions about supplier behavior and not enough on the preferences and pricing revealed in full requirements solicitations elsewhere in the country. The Agency's modeling of load and price uncertainty was also questioned.

In comments received on the 2014 Plan, the Illinois Competitive Energy Association ("ICEA") provided an analysis by the NorthBridge Group. That analysis used a different modeling approach to consider the compensation required by a full requirements product supplier, referencing a 2012 study for the supply (including capacity and ancillary services), not just energy. (Based on comments made in July 2014, ICEA now appears to favor excluding capacity from the hedge.) NorthBridge compared the actual costs of full requirements supply to the expected costs of two different hedging strategies using block contracts—one seeking to hedge 80% of load, and one (analogous to the strategy proposed in the 2014 Procurement Plan) seeking to hedge 106%--and estimated a premia for full requirements that ranged from $0.13 to $1.69/MWH. These premia respectively represented 0.2% and 2.7% of the simulated cost of the associated hedged portfolios, and would likely represent larger fractions of the cost of a simulated "all-spot" strategy.

The analysis also included a description of "rate shock" and "supply cost surprise" metrics. "Default service rate shock" measured the ninetieth percentile of the rate change over a six-month period. The difference between this analysis and the situation in Illinois is that in Illinois, rates are fixed for a year except for the PEA, which is capped (in ComEd territory) and for ComEd may additionally be further stabilized by a rate redesign to unbundle capacity charges (consistent with ICEA's proposal to remove them from the hedge). "Supply cost surprise" measured the amount by which annual costs differ from the expectation three months ahead. The NorthBridge analysis reported metrics of the cost impact of very low-probability adverse events (less than 10%), whose values (for a 106% hedged block approach) were approximately $5/MWh (a 7% increase in price and very close to the cap that ComEd has imposed on its PEA). Nonetheless, this point—that there are scenarios under which a block procurement could have higher costs than a full requirements procurement—has been considered by the IPA.

6.6.2.3 Estimating full requirements based on New Jersey experience

The IPA took to heart the comments encouraging the use of actual market data on full requirements pricing. The Agency also sought to minimize the use of models of price and load fluctuations. Such models can always be questioned and, especially in the case of models of customer migration, are supported by rather short historical records. The IPA analyzed auction results from the state that has been conducting full requirements solicitations for the longest period, namely New Jersey.

The IPA developed an estimate to account for the non-energy components of full requirements service, relying only on observable market data, as follows. The full requirements products provided by suppliers in New Jersey is defined to consist of "unbundled Energy, Capacity, Ancillary Services and Firm Transmission Service, including all losses and/or congestion costs associated with the provision of such services, and such other services or products that a Supplier may be required, by PJM or other governmental body having jurisdiction, to provide in order to meet the Supplier Responsibility Share under this Agreement." For that, the BGS-CIEP suppliers are paid the auction price (per MW of capacity requirement), plus the cost of network transmission service, plus the load-weighted PJM spot price for energy, plus $6/MWh. This produces a tariffed price that fluctuates with the wholesale cost of energy.

BGS-FP suppliers provide the same product as do BGS-CIEP suppliers (unbundled Energy, Capacity, Ancillary Services and Firm Transmission Service), but at a fixed price under three-year contracts. Therefore the price of BGS-FP supply should equal the expected price of BGS-CIEP service, plus a premium (or residual compensation) for price insurance. In other words, the following equation should hold:

BGS-FP price = expected PJM spot price + $6/MWh + transmission rate + BGS-CIEP price
+ price insurance premium.

Rearranging, the price insurance premium can be estimated as:

Price insurance premium = BGS-FP price - expected PJM spot price - $6/MWh
- transmission rate – BGS-CIEP price

All these values are available from the New Jersey auction results, except the expected PJM spot price. It can be approximated by the energy futures price as of the BGS auction, adjusted for the historic relationship between load-weighted and average prices (the multiplier is somewhere between A and B in Figure 6-5).[92]

[92] Price difference A is based on the forward price without load-price correlation; price difference B is based on the expected spot prices including the impact of migration as well as load-price correlation (and possibly other uncertainties whose net impacts are anticipated to be small). These price differences both compare full-requirements service to some alternative form of energy procurement, and so are representations of the full requirements premium.

Table 6-2: Premium for price insurance derived from New Jersey auction data

	PSE&G			JCP&L		
	2009-2012	**2010-2013**	**2011-2014**	**2009-2012**	**2010-2013**	**2011-2014**
BGS-FP price ($/MWh)	103.72	95.77	94.30	103.51	95.17	92.56
- Expected spot price	-74.11	-62.85	-56.25	-72.94	-58.67	-52.80
- Ancillary service price	-6.00	-6.00	-6.00	-6.00	-6.00	-6.00
- OATT transmission rate	-6.01	-7.58	-10.33	-4.85	-4.95	-4.90
- BGS-CIEP price	-17.56	-15.23	-19.45	-19.65	-16.70	-20.76
Estimated premium ($/MWh)	0.05	4.11	2.27	0.07	8.85	8.10
Estimated insurance premium (% of expected spot)	0%	7%	4%	0%	15%	15%

Table 6-2 provides evidence that full requirements contract prices include a price insurance premium of several dollars per MWh. (Appendix F provides details of the methodology and calculations used to estimate the insurance premium).

The variability in the estimated premia may be due to the uncertainty around suppliers' forecasts of the BGS-CIEP price and the OATT transmission rate. The BGS-CIEP price is primarily determined by the cost of capacity; at the time of the BGS-FP auction, the PJM RPM Base Residual Auction ("BRA") for the first two years covered by the BGS-FP contract has already been held, but capacity pricing for the third year is still uncertain. The OATT transmission rate for JCP&L has been constant for several years, but the rate for PSE&G has been rising. Table 6-2 is based on the assumption that bidders will accurately forecast the transmission rate. Winning bidders may well not have known about the rate increases, or underestimated them. If the BGS-FP is based on underestimates of the transmission rate, the embedded insurance premium would be larger than indicated in Table 6-2, reducing the difference between the estimates for PSE&G and JCP&L.

6.6.2.4 Review of estimates based on Pennsylvania experience

The NorthBridge comments discussed earlier referenced an analysis conducted in conjunction with a regulatory proceeding in 2012. The Agency takes note also of a subsequent analysis by NorthBridge that formed the basis for testimony in a 2014 proceeding before the Pennsylvania Public Utilities Commission. That study reviewed imputed residual compensation levels from past PECO full requirements procurements, presented in Figure 6-6. The testimony includes an analysis of the specific cost components of prior PECO procurements and residual compensation is defined as what is "required by suppliers to cover the other costs and risks that I did not individually quantify."[93]

[93] PECO Energy Company Statement No. 3, Direct Testimony of Scott G. Fisher at 12. Docket No. P-2014-2409362, March 10, 2014.

Figure 6-6: PECO Residual Compensation[94]

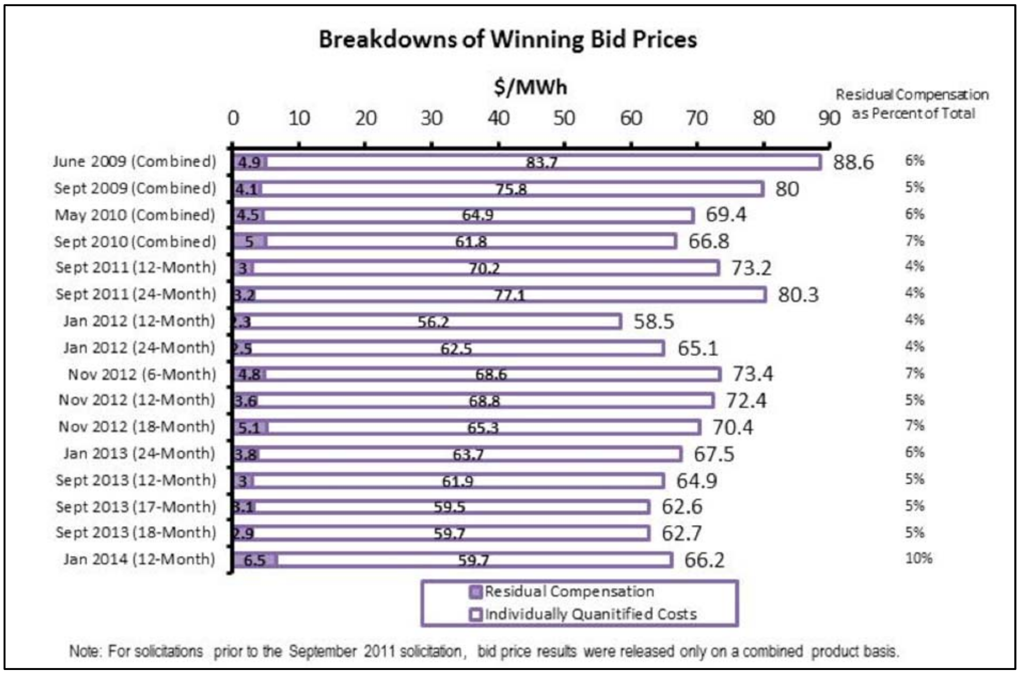


Figure 6-6 also shows additional costs of several dollars per MWh for full requirements service, in line with the other estimates provided herein. There is a notable increase in residual compensation in the January 2014 procurement. The testimony notes that this procurement was coincident with the price increases associated with the so-called polar vortex. Perhaps the events of 2014 indicated to suppliers that they had been underestimating, and hence underpricing, the commitments they were taking on.

The models presented in the 2014 and 2015 Procurement Plans, the model used the NorthBridge study used to support ICEA's comments on the 2014 Procurement Plan, as well as NorthBridge's testimony elsewhere, present a range of methods and estimates of the additional costs associated with full requirements contracts. All of them indicate that full requirements prices generally include a premium relative to expected portfolio costs.

The IPA understands that under certain adverse cases, the actual cost of a block hedging strategy could be greater than the cost of a full requirements strategy. Extreme adverse outcomes are correspondingly unlikely. Nevertheless, the IPA's current hedge strategy has been carefully designed to provide a reasonable level of insurance against price spikes, given that the entire expected load will be covered by fixed-price hedges.

An adverse case of concern would be a large volume of price-induced customer migration. Currently, high migration volumes would most likely be associated with the expiration of municipal aggregation contracts and return of those customers to bundled service after the IPA's procurement volumes are set. The IPA monitors the energy markets regularly to understand the factors that drive customer behavior (for example – price, product, regulations, the environment, etc.) and to anticipate and mitigate such potential return to service. Accordingly, the IPA has recommended a hedging strategy that mitigates load migration risk. The implementation of the fall procurement event is the direct result of the need to mitigate the risk of load migration associated with the expiration of large municipal aggregation contracts.

[94] Id. at 18.

Finally, just as adverse outcomes can increase ratepayer costs, supportive outcomes can reduce them (as is being experienced by Ameren customers in the summer of 2014). Full requirements service would be priced at an expected-cost premium (nobody refutes this fact), meaning that under full requirements service customers would not receive the price reduction benefits of likely favorable cases. The nature of an expected cost premium is that in most scenarios, customers pay more.

6.6.2.5 How Much do Customers Value Price Insurance?

There are a variety of potential policy arguments for full requirements. But, do customers want to pay a premium for price stability? The IPA had hoped that in response to its request for comments it would receive new information on customer willingness to pay for various rate options, and while a few commenters offered some thoughts on the issue (CUB stating an emphatic "no"), they did not provide clarity. Where there is research on the subject, that research has tended to focus on interest in dynamic pricing, pre-paid services, etc. Those studies generally find that is there are distinct customer segments interested in various options—some customers will gladly pay a premium for certainty, other customers will gladly take extra efforts to reduce costs, and yet other customers will ration electricity in favor of more flexible payment options. Quite simply, it is not clear what customers are willing to pay for in their electric rates – and even if some customers would state a clear willingness to pay such a premium, that in itself would not justify forcing all eligible retail customers to pay that premium.

One instructive recent survey came from a report on retail markets in Alberta, Canada. It found that only 13% of customers were willing to "pay a premium price, knowing that the price will not change for a year or more." In contrast 50% "want[ed] the lowest average price, even if that price changes frequently" and 36% "want[ed] a reasonable price, knowing that the price is fixed for several months." Only 2% did not know what they wanted.[95] Another study conducted by CNT Energy in 2006 of a random sample of ComEd and Ameren residential customers gauged interest in either a "fixed" or a "variable" electric rate.[96] Roughly 40% of respondents were interested, to varying degrees, in a variable rate. Only 17% were definitely interested in a fixed rate, and 34% were probably interested in a fixed rate. While this survey was meant to explore interest in variable rates, the relatively small percent of customers who definitely wanted a fixed rate could indicate that there is not a sizable demand for such certainty.[97]

Furthermore, the IPA is not aware of any significant level of customer dissatisfaction in the ComEd service territory with the current methodology of having rates that fluctuate slightly month-to-month due to the Purchased Electricity Adjustment. (The IPA presumes that the fairly consistent and sizable PEA credits in the Ameren service territory are even less likely to spur customer complaints because they result in savings for eligible retail customers.).

While it does not appear that eligible retail customers are clamoring for full requirements procurements in order to completely stabilize their prices, the IPA acknowledges that the current procurement strategy can lead to fluctuations in the PEA. The IPA expects the volatility of the PEAs for ComEd and Ameren to decline as a result of various improvements to the IPA procurement design (and for ComEd customers, ComEd's improvement to its PEA). The mere existence of the PEA does make it slightly more difficult to compare the utility rate to an offer from an ARES. But given the premia described above, the IPA does not believe that adding costs to the price paid by eligible retail customers to ease comparison shopping by customers who have left utility service is an appropriate policy goal for it to pursue under its mandates in the IPA Act.

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[95] "Power For the People — Retail Market Review Committee," Ministry of Energy, Government of Alberta (September, 2012) at 85.
[96] In interest of full disclosure, the Director of the IPA was employed by CNT Energy at that time and participated in the survey design and analysis.
[97] Docket No. 06-0691 (cons.), CUB Exhibit 1.0 (Rebuttal Testimony of Christopher C. Thomas) at 12-13.

The IPA has refined its block procurement approach over time, most significantly by adopting a new hedging strategy in the 2014 Plan (continued into the current Plan) that includes smaller block sizes and a second procurement in the fall. This approach was adopted to address the greatest risk to the portfolio, return of load. Meanwhile, ComEd has made improvements to its PEA methodology such as capping the PEA volatility, the annual resetting of the balance, and the proposed unbundling of capacity from energy that will further reduce PEA volatility. In short, the IPA's block procurement approach successfully meets the mandate of the IPA Act to, "[d]evelop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability"[98] and does not need to be changed to a full requirements approach.

Although many other states with retail competition conduct full requirements procurements, the IPA does not believe this alone is a compelling reason to change course. Notably, not one of those states has a procurement process comparable to Illinois. The IPA was specifically created by the General Assembly to "[o]perate in a structurally insulated, independent, and transparent fashion so that nothing impedes the Agency's mission to secure power at the best prices the market will bear, provided that the Agency meets all applicable legal requirements."[99] It may be the case in other states that the procurement design was instituted so that utilities did not have to make procurement decisions (whose prudence would be reviewed and possibly challenged) and no agency like the IPA was available.[100] Many of those states also consider the default service to be more of a "provider of last resort" service, one that is available to ensure that customers have a rate to fall back on. In contrast, the IPA Act instructs the IPA to actively manage the procurement process to benefit the eligible retail customers with an attractive rate option.

In light of the analysis above, the Agency has declined to include a full requirements procurement in its 2015 Procurement Plan.

6.7 Demand Response as a Risk Management Tool

The discussion above has been focused on traditional energy and capacity supply products. As described more fully in Appendix C (which describes the ComEd load forecast), demand response programs operated by ComEd are not used to offset the incremental demand, over and above the weather-normalized expected case peak load, on days when the weather is hotter than normal. Demand response programs do not affect the weather-normalized load forecast. The programs are supply risk management tools available to help assure that sufficient resources are available under extreme conditions. PJM has a functional capacity market that includes dispatchable demand response as a resource. To the extent that demand response programs receive "capacity credit", PJM pays for this capacity based on the price from the capacity auctions and the proceeds are primarily used to fund payments to the responding customers.

In the case of Ameren, MISO provides the ability for demand response measures to contribute to reducing supply risk. On March 14, 2014, FERC approved MISO's modification to its Module E-1 tariff to treat DR and EE resources similarly to other capacity providing resources for operational planning purposes. MISO Module E permits LSEs to net the effects of DR and EE resources from their coincidental peak and will credit these resources with the equivalent number of Zonal Resource Credits ("ZRCs").

In its 2014 Procurement Plan, the IPA tested the impact of Demand Response Resources on energy costs. The impact on energy costs for non-participating customers appeared small and there appeared to be no additional risk reduction.

[98] 20 ILCS 3855/1-5(A).
[99] 20 ILCS 3855/1-5(G).
[100] For example the Connecticut PURA stated that it directed United Illuminating (UI) to procure 100% full requirements because UI lacked the capability to manage a portfolio. Connecticut Public Utilities Regulatory Agency, Decision in Docket 12-06-02, October 12, 2012, p. 2.

Section 7.5 of this plan provides details and additional discussion regarding demand response resources for both ComEd and Ameren. Section 7.1 includes a discussion of a proposed "Energy Efficiency as a Supply Resource" procurement. This proposal is not a demand response product in the narrow sense of a product that reduces capacity obligations but rather is a procurement that focuses on covering peak hours through demand side resources.

7 Resource Choices for the 2013 Procurement Plan

This chapter of the Procurement Plan sets out recommendations for the resources to procure for the forecast horizon covered by this plan. These include: (1) energy efficiency as a supply resource; (2) incremental energy efficiency; (3) energy procurement strategy; (4) balancing recommendations; and (5) demand response. Procurement of additional Renewable Resources, including wind, solar and distributed generation is considered separately in Chapter 8.

7.1 Energy Efficiency as a Supply Resource ("EEAASR")

7.1.1 EEAASR Background

In its draft 2014 Procurement Plan, the Agency raised the idea of procuring energy efficiency as a supply resource, separate from its Section 16-111.5B procurement, and invited comments from stakeholders for additional feedback. The rationale for the proposal was straightforward: rather than viewing energy efficiency simply as reducing forecast load, demand-side resources could potentially constitute a lower-cost alternative than comparable supply at times when prices are highest or load is greatest. If less-expensive demand-side resources could be procured in lieu of conventional supply during periods of high cost or high load, the Agency could be better-positioned to meet its statutory objective of developing "electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[101]

While logically sound, the details of the approach proved complex. Upon receiving feedback on its draft 2014 Procurement Plan, the IPA determined that the idea lacked the detail and clarity necessary to transition from an alluring thought exercise to a concrete procurement strategy. Although still intrigued by the potential benefits, the Agency did not include the procurement of energy efficiency as a supply resource in its filed 2014 Procurement Plan.

The concept was tabled for further discussion in the 2014 Procurement Plan. Still, the Agency remained interested in its potential benefits and held a workshop on June 18, 2014 to receive continued feedback. Following that workshop, the Agency circulated a set of questions to workshop participants. Received responses were posted on the IPA's website.[102]

As expected, views were divergent. Some parties believed the Agency lacked statutory authority to conduct such a procurement, believing that demand-side resources were not "standard wholesale products" and that Section 16-111.5B set forth the exclusive pathway for including energy efficiency in the Agency's procurement plan. Others believed that while segmenting out more expensive energy procurement blocks was sensible, competition should be between both demand-side and supply-side resources. Still others believed that the issue was ripe for inclusion and suggested a Spring 2015 procurement for the delivery of resources beginning in Fall 2015.

7.1.2 EEAASR Principles

After feedback and further consideration, the Agency has settled on the following key principles to guide an EEAASR procurement:

First, any EEAASR procurement should be structured to provide lower expected total customer costs than a comparable supply-side procurement. Although the Commission has interpreted "lowest total cost over time" as referring to the Agency's entire plan while stressing the value of portfolio diversity,[103] energy efficiency

[101] 20 ILCS 3855/1-5(A); see also 220 ILCS 5/16-111.5(d)(4) (using the same language as the Commission's standard of procurement plan review).
[102] Workshop questions and responses may be found here: http://www2.illinois.gov/ipa/Pages/Plans_Under_Development.aspx.
[103] See Docket No. 12-0544, Final Order dated December 19, 2012 at 234-35.

also participates as a Section 16-111.5B resource, allowing for some of its benefits to be already captured. For energy efficiency to displace blocks of supply in standard energy procurement, the Agency believes an EEAASR procurement should feature a lower expected total cost to ratepayers, inclusive of administrative costs, than what would be accomplished through its block supply procurement.[104]

Second, an EEAASR procurement should be focused on pre-designated “super-peak” blocks. Although procuring demand-side resources responsive to high price or load may have advantages, these approaches offer administrative complexities (such as active management through an operator) that the Agency is not currently equipped to manage or assign.[105] Segregating out expected highest-use blocks in advance and conducting a “super-peak” EEAASR procurement for those blocks offers a clear, consistent approach that enhances delivery certainty and fits squarely within the Agency’s established procurement processes and expertise.

Third, the products procured in an EEAASR procurement should be resources on the customer side of the meter. The Agency envisions that in future procurements demand-side and supply-side resources could compete on level terms, but believes that procurement structure and administrative ease is best served by procuring customer-side products exclusively in its initial EEAASR procurement.

Fourth, the size of the individual blocks to be procured should be small enough to allow for small scale load reductions to compete. Whether such programs feature compelling-enough economics will be determined through a competitive procurement process, and the Agency should ensure that procurement block size is not so large as to exclude otherwise cost-effective load reductions.

Fifth, contracts should be for a length greater than only one year. Given the potential administrative costs of an EEAASR procurement, and the operational costs for resource-providers, multi-year delivery contracts feature far more compelling economics—significantly increasing the likelihood of a “least cost” procurement. Multi-year contracts also provide more value and certainty to the end users who produce the underlying reductions.

Sixth, caution must be taken to ensure against non-delivery. The Agency recognizes that eligible retail customer interests are only furthered to the extent that lower-cost resources are actually delivered. Should non-delivery occur, replacement super-peak supply would have to be procured on the spot market at a potentially greater cost. Therefore, the Agency would need strong credit requirements and non-delivery penalties, perhaps mirroring those for conventional supply contracts. Failure to deliver the resource by a supplier should not create additional costs for eligible retail customers.

Seventh, EEAASR resources may be procured from customers statewide (and, if feasible, not merely “eligible retail customers”), including from competitive-class customers. As supply resources would be similarly unrestricted, demand-side resources displacing supply blocks should not be restricted to customers for whom the Agency procures energy. However, procured demand-side resources should be delivered within the service territory for which they’re being procured (even if not situated within the service territory itself), and the Agency believes its initial EEAASR procurement should be limited to Illinois-based resources.

[104] Three notes on this principle: first, based on feedback received to date, the Agency believes the market currently has and will continue to develop demand-side alternatives featuring strong enough price differentials to provide the lowest total cost to customers; second, as some degree of forecasting is required, the Agency does not believe that the procurement *must* produce lower costs, only that it is *more likely than not* to do so, and thus should be pursued as a strategy expected to bring customer benefits; and third, to the extent quantifiable, the value of any reduction in wholesale LMPs should be considered.

[105] Additionally, price and load-sensitive products are already being offered to the market through demand response and real time pricing options.

7.1.3 EEAASR Procurement Proposal

With these principles in mind, the Agency proposes a procurement event for energy efficiency as a supply resource with the following characteristics:

- **Super-Peak Blocks Using on Pre-Scheduled Dates/Times:** The Agency proposes procuring a demand-side product delivered during the hours of 3 p.m. to 7 p.m. CST on summer non-NERC holiday weekdays (e.g., 4-hour blocks for 5 days a week—other than July 4th if it falls on a weekday—for the period running from June 1 through August 30). This equates to approximately 260 hours per delivery year. To the extent load reductions during the super-peak time result in load shifting to other times, the cost impact of the load reductions should net out the expected increased costs incurred by eligible retail customers at those other times.

- **Multi-Year Contracts:** The Agency proposes to procure 3-year delivery contracts of EEAASR products. The Agency believes that this contract length best mitigates administrative costs and supplier overhead, while capping contract length in a manner consistent with the IPA's scheduled block procurement of supply.

- **100 kW blocks:** The Agency proposes to procure 100 kW demand-side resource blocks. The Agency believes that this block size should be small enough to allow for broad participation and appropriately accommodating of small programs. The Agency notes that large load-reduction programs can purchase multiple blocks, and all load-reduction programs may aggregate to purchase individual or multiple 100 kW blocks.

- **Late 2015 Procurement; June 2016 Delivery:** As an EEAASR procurement will require new contracts and EEAASR suppliers will need ramp-up time to secure and develop resources, the Agency believes that conducting a Spring 2015 procurement or expecting Fall 2015 delivery decreases the likelihood of a successful procurement. By adopting a longer timeframe, the Agency will have time to work through administrative complexities and allow for the market to properly organize.

- **Summer Procurement Only:** While arguments can be made for including a winter EEAASR product in this procurement, the periods (and magnitude) of high winter peak prices are generally less predictable than during the summer. The Agency would prefer to demonstrate the merits of an EEAASR procurement before pursuing what may be a more challenging model with a winter EEAASR procurement, and notes that a winter EEAASR procurement may be most effective if driven by triggered price or load thresholds.

- **Sufficient Volume to Reduce Relative Procurement Cost:** As administrative costs could swallow the benefits of small procurement, the Agency proposes to procure a minimum procurement volume in order to maximize the cost-effectiveness of an EEAASR procurement. The Agency invites feedback on the appropriate minimum procurement volume amount and strategies to ensure that the volume can be filled, both on this draft Plan and in the resulting litigation before the Commission.

- **Optionality:** The Agency is proposing a late 2015 Procurement for June 2016 delivery. However, if the Agency believes that administrative costs may be too significant relative to volume procured or that the market is not appropriately mature, or should some other reason or barrier cause the Agency to believe that an EEAASR procurement would not be in the best interests of customers, the Agency—in consultation with ICC Staff, the Procurement Administrator, and the Procurement Monitor—requests permission to cancel a planned EEAASR procurement no later than August 2015 without further Commission approval.

7.1.4 EEAASR Procurement Issues to Resolve

In addition to these characteristics, there are several issues not yet resolved which should be determined prior to an EEAASR procurement. The following is a sampling of those issues:

- **Vendor/Program Qualification:** The Agency believes it may need to adopt a rigorous qualification process for EEAASR procurement resources. This process would ensure that while bids will ultimately be evaluated on price as required by Section 16-111.5(e)(4) of the Public Utilities Act, they are in fact new demand side resources for purposes of this procurement. While not making any specific recommendation in this Plan, the IPA suggests that the ISO-New England *Manual for Measurement and Verification of Demand Reduction Value from Demand Resources* may be an appropriate starting point for development of protocols for this procurement.
- **Other Programs:** As a general matter, the Agency seeks to avoid overlap of delivered energy savings for this procurement and energy efficiency outcomes for measures instituted via programs authorized under sections 8-103 and 16-111.5B of the Public Utilities Act, and would prefer for an EEAASR procurement to elicit the development of new resources. However, some parties have suggested that the peak hours for which the EEAASR procurement takes place could be "backed out" of participation in Section 8-103 or 16-111.5B programs, thus allowing for dual participation without energy savings overlap. The Agency seeks continued feedback on this topic as well.
- **Product Definition:** Prior to procurement, the Agency will need to develop a more refined definition of resources eligible to participate. It is currently unclear whether standby generation, energy storage, and combined heat and power should be eligible, and the Agency believes there may other resource types it has not yet considered which could inform "product" definition. Further thought may also need to be given to the distinction between energy efficiency and demand response, and to the relevance of that distinction for purposes of this procurement. The Agency believes a more inclusive approach may be advisable to ensure that an EEAASR procurement reaches sufficient scale, but seeks additional feedback from parties on how best to define an EEAASR product.
- **Credit Requirements and Non-Delivery Penalties:** Ideally, an EEAASR procurement would feature no more default or non-delivery risk than a standard energy supply procurement. The Agency has given consideration to approaches to ensure against non-delivery, but would prefer to better understand risks and benefits of various approaches before making a firm recommendation. The Agency looks forward to continued feedback from parties through this docket on how best to ensure that non-delivery risks are mitigated.
- **Verification:** To ensure customer interests are properly protected, load reductions through an EEAASR procurement should be subject to strict measurement and verification requirements. While specific evaluation approaches will be driven by choices made on other unresolved items (such as product definition), the Agency believes that the Illinois Technical Reference Manual for Section 8-103 programs may be an appropriate starting point in the development of EEAASR evaluation protocols.

The Agency is hopeful that the Procurement Plan approval process, with comments on this draft of the 2014 Procurement Plan and the formal litigation of the filed 2014 Procurement Plan before the ICC, will shed further light on how best to resolve open issues. However, to the extent that open issues may remain, the Agency would be open to hosting workshops in Spring 2015 with an eye toward resolution of matters by

Summer 2015 to prepare for a late 2015 procurement.[106] The IPA understands the breadth and depth of issues still needing resolution, but is confident that the proposed procurement and delivery schedule allows sufficient time to accommodate them.

7.2 Incremental Energy Efficiency

7.2.1 Incremental Energy Efficiency in Previous Plans

The IPA's 2014 Procurement Plan was the second plan to include consideration of incremental energy efficiency programs pursuant to Section 16-111.5B of the Public Utilities Act.[107] That Plan included the approval of five expanded or new programs for Ameren and eight for ComEd. As these programs started implementation on June 1, 2014, no results or impacts of those programs are yet available.[108]

In addition to the review of the programs submitted by the utilities, the 2014 Plan included discussion of a number of policy items including: feedback mechanisms, transition year program expansion, DCEO participation, and consideration of all third party bids.[109] In approving the 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 the approval of a methodology for the consideration of potentially duplicative and competing third-party energy efficiency programs.[110] The Commission also requested ICC Staff coordinate additional workshops in 2014, continuing a process requested by the Commission in its consideration of the 2013 Plan to address unresolved issues. Leading into the discussion of programs proposed for approval as part of this year's Plan, sections below describe key items resolved in the Commission's Docket No. 13-0546 Order, consensus items reached through the 2014 workshop process, and open items for which further guidance may be requested in this year's Plan approval proceeding.

Table 7-1 below summarizes the overall expected impacts of previously approved Section 16-111.5B programs. The programs from the 2013 Plan have not yet been fully evaluated but preliminary results reported by Ameren and ComEd suggest that they achieved 126% and 106% respectively of their goals. The programs approved in the 2014 Plan are currently underway.

Table 7-1: Section 16-111.5B Programs From Prior IPA Procurement Plans

	2013 Plan Total Expected Reductions (MWh)	2013 Plan expected reduction in IPA-procured portfolio (MWh)	2014 Plan Total Expected Reductions (MWh)	2014 Plan expected reduction in IPA-procured portfolio (MWh)
Ameren	70,834	25,409	65,680	17,950
ComEd	118,515	22,574	432,848 (2014/15)	88,839(2014/15)
			550,143 (2015/16)	137,288 (2015/16)

[106] Workshops may be necessary for the development of contracts as well, and open policy issues could be addressed coincidental to developing contract terms.
[107] Public Acts 97-0616 (creating Section 16-111.5B) and 97-0824 (amending Section 16-111.5B) were first considered for the 2013 Procurement Plan. For a discussion of the statutory requirements of Section 16-111.5B, please see Section 2.7.
[108] The 2013 Procurement Plan included eight expanded or new programs each for Ameren and ComEd. Official results of the programs from the 2013 plan are likewise unavailable, but preliminary informal feedback indicates savings near or above expectations.
[109] See 2014 IPA Procurement Plan at 81-86.
[110] Docket No 13-0546, Final Order dated December 18, 2013 at 149.

7.2.2 "Duplicative" or "Competing" Programs[111] – Guidance from Docket No. 13-0546

In the docket approving the Agency's 2014 Plan, significant consideration was given to how to address third-party program bids that may be "competing" with or "duplicative" of existing programs under Section 8-103 of the PUA. The review process for duplicative or competing bids approved by the Commission works as follows:

- First, the utilities receive and review the third party RFP results, and determine which bids are, in the utility's estimation, duplicative or competing. The utilities are under no obligation to identify any programs in this manner.
- Next, in the annual July 15 assessment submitted to the IPA, the utility may exclude programs it has determined are duplicative or competing from the estimated savings calculation (and associated adjustments to the load forecast). However, in their submittals to the IPA, the utilities must: (1) describe the duplicative or competing program; (2) explain why the utility believes it is competing or duplicative; and (3) provide the IPA with all of the underlying documents as it would for any other bid.
- In preparing its annual procurement plan, the IPA independently reviews all of the bids submitted by the utilities and determine which the IPA believes are duplicative or competing. The IPA identifies all programs to the Commission in its Procurement Plan filing, along with a recommendation on which, if any, programs should be excluded as duplicative or competing.
- After the Plan has been filed, the parties to the Procurement Plan approval litigation—including the IPA—may opine on whether a particular program is duplicative or competing, and the Commission will make the final determination. To the extent that a utility had previously determined that a program is duplicative or competing but the Commission disagrees, the utility will update the estimated energy savings and load forecast to reflect the readmission of the program.[112]

Consistent with this process, the Agency received a set of recommendations from the utilities on "duplicative" third party programs in mid-July and conducted an independent bid review. The IPA's recommendations resulting from that review, along with how those recommendations compare to the utilities suggested exclusions, are incorporated in this year's Plan in the sections below.

In addition to addressing the process for determining whether a program is "duplicative" or "competing," the Commission also approved a multi-factor inquiry to be employed in making such determinations:

> *(1) similarity in product/service offered; (2) market segment targeted, including geographic, economic, and customer classes targeted; (3) program delivery approach; (4) compatibility with other programs (for instance, a program that created an incentive to accelerate the retirement of older inefficient appliances could clash with a different program that tunes-up older appliances); (5) likelihood of program success (a proven provider versus an undercapitalized or understaffed provider, if such evidence is placed in the record); (6) the effect(s) on utility joint program coordination, and (7) impact on Section 8-103 EEPS portfolio performance.*[113]

In making recommendations on "duplicative" programs for the Plan, the Agency was guided by the factors enumerated above.

[111] As used herein, the Agency understands "competing" to mean programs which may overlap with an existing program, and "duplicative" to mean programs that overlap such that greater market participation by vendors would not yield sufficient additional value to consumers. As some offerings may benefit from multiple delivery channels, "competing" programs are acceptable to the extent that the competition does not render one or both non cost-effective. However, a program is "duplicative" and thus ripe for exclusion when that threshold is crossed.
[112] Docket No. 13-0546, Final Order dated December 18, 2013 at 149; IPA Reply Brief dated October 31, 2013 at 10-11.
[113] Docket No. 13-0546, Final Order dated December 18, 2013 at 149.

This year's submittals contained third-party programs potentially "duplicative" of other third-party proposals or of a DCEO program run under Section 8-103 of the PUA. Although the Commission's Order in Docket No. 13-0546 addresses third-party proposals "duplicative" of "utility-run efficiency programs,"[114] the logic of the above inquiry—if not each individual factor—would seem to apply when comparing a third-party proposal to another proposal or to an existing DCEO program. Consistent with this logic, in their submittals to the IPA, the utilities applied the above factors to determine whether such proposals were indeed "duplicative." The IPA has taken this approach as well.

7.2.3 2014 Workshops

In approving the IPA's 2014 Procurement Plan, the Commission directed workshops to consider multiple unresolved issues. One such issue was barriers to DCEO's participation in the 16-111.5B third-party bid process:

> *[T]he Commission shares in both DCEO and the AG's position that it should endeavor to increase the delivery of overall achievable energy efficiency while also providing needed benefits to low income electric utility customers who often struggle to pay their bills. Thus, the Commission directs that a workshop should be held to address the barriers to DCEO's participation through the third-party RFP process . . . [and] urges the parties to hold any workshops in the timeliest manner practicable and to report to the Commission in the next available IPA procurement proceeding on the results of the workshop.*[115]

Similarly, the Commission recommended workshops for consideration of improvements to potential studies and the third-party RFP process.

> *Given that specific proposals related to potential studies were raised in CUB's Response to Objections and that additional specific recommendations were raised in Staff's Reply to Responses, the Commission is concerned that the record on these issues is not as complete as it should be, particularly in a proceeding with an expedited schedule. As a result, the Commission believes it would be best if such matters were addressed in workshops before a Commission order on such issues is entered. Therefore, the Commission directs Staff to work with CUB, the AG, and any other interested parties to conduct workshops, as needed, to determine what improvements, if any, can be incorporated into the potential studies, the timing of any filings related thereto, as well as improvements to the RFP process.*[116]

The Commission also directed workshops to address oversight of approved programs:

> *The AG recommends, if the IPA does not intend to assume an oversight role for energy efficiency programs, then the IPA should request that the Commission enter an Order that makes clear that the utilities will assume responsibility for the evaluation and successful delivery of these programs, consistent with, to the extent practicable, the evaluation practices followed under Section 8-103 of the PUA . . .The IPA also suggests this is an appropriate topic for discussion in workshops, rather than being decided in this proceeding . . . the Commission agrees with the IPA's suggestion and directs interested parties to address this issue at the workshops discussed above.*[117]

And lastly, the Commission suggested that parties use workshops to discuss any "other recommendations not specifically addressed" by the Commission in its Final Order.[118]

To this end, ICC Staff led a series of workshops over the period of March through June 2014. The workshops were held as a series of conference calls and written requests for responses to questions. While participants

[114] Id. At 148 ("The Commission will next turn to the IPA's fourth policy issue, namely the procedure for removing third-party bids with a TRC greater than one that would conflict with utility-run energy efficiency programs.").
[115] Id. at 145-146.
[116] Id. at 147.
[117] Id. at 149.
[118] Id.

were not able to reach agreement on all issues, a number of consensus items did emerge from the workshops with specific language recommended for adoption.[119]

The consensus items, with the specific consensus language recommended for adoption, are set forth below:

Deeming and Evaluation for Future Section 16-111.5B Energy Efficiency ("EE") Programs

Deeming should be permitted for the Section 16-111.5B energy efficiency programs just as it is for the Section 8-103 energy efficiency programs. Annual updates to the deemed Illinois Statewide Technical Reference Manual for Energy Efficiency ("IL-TRM") and net-to-gross ("NTG") ratio values should occur for the Section 16-111.5B energy efficiency programs, and 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 ICC Docket No. 13-0077 should apply for the Section 16-111.5B energy efficiency 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 energy efficiency programs). Prospective application of standard measure-level savings values from the updated IL-TRM and NTG values recommended by the evaluator that are available prior to the start of a program year should be deemed for one program year. Evaluators should perform IL-TRM savings verification for the Section 16-111.5B energy efficiency programs in a manner consistent with that performed for the Section 8-103 energy efficiency programs. 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 these types of energy efficiency measures under the Section 8-103 energy efficiency programs.

Deeming and Evaluation for Previously Approved Section 16-111.5B EE Programs, Program Year ("PY") 6 and PY7[120]

Ex-post evaluation results for gross savings calculations should be applied retrospectively for custom measures, behavioral measures, and for energy efficiency measures with uncertain savings, which is consistent with the approach used for these types of EE measures under the Section 8-103 energy efficiency programs.

For PY6, the statements set forth in the utilities' contracts with energy efficiency program vendors are the overriding factors in relation to deeming and evaluation for previously approved and implemented Section 16-111.5B energy efficiency programs.

For Ameren in PY7, the NTG and IL-TRM included in the procurement plan filing should be deemed per ICC Order Docket No. 13-0546.

For ComEd in PY7, the evaluator recommended NTG values intended to represent their best estimates of future actual NTG values likely to occur for the program year should be deemed for PY7. The ICC-approved IL-TRM Version 3.0 should be deemed for PY7 for ComEd's Section 16-111.5B energy efficiency programs, which is consistent with the deeming approach and version of the IL-TRM deemed for PY7 for the Section 8-103 energy efficiency programs.

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[119] As discussed in the Staff Report attached as Appendix B-2, this language was circulated to workshop participants on June 18, 2014 with notice that failure to object by June 25, 2014 would be interpreted by ICC Staff as consensus. Staff received no objections to the consensus language.

[120] Note that the workshops adopted the program year terminology of the Section 8-103 programs. Program Year 6 is the energy delivery year 2013/14 and Program Year 7 is the energy delivery year 2014/15.

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 energy efficiency programs.

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 energy efficiency 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 Request for Proposal ("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 energy efficiency 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 any modifications continue to result in a cost-effective energy efficiency program. Negotiations may result in reasonable adjustments to savings goals for the energy efficiency program in comparison to the amount proposed in the bid and reasonable and prudent modifications to the cost structure (e.g., price paid per kWh) that are in line with the original design. Some degree of flexibility within an energy efficiency program should be allowed for vendors implementing energy efficiency programs under Section 16-111.5B of the PUA. Flexibility should not be allowed insofar as the modifications to the EE program result in the following: (1) less confidence in the quality of service, (2) the addition of new energy efficiency measures with no confidence in the savings, (3) duplicates or competes with other energy efficiency programs, (4) cost-ineffective energy efficiency program, or (5) a completely different energy efficiency program proposed in comparison to what was bid and approved. The utilities/IPA should share the description of the vendor's energy efficiency program included in the draft procurement plan with the vendor to help ensure the energy efficiency 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 energy efficiency program vendor and a contract agreement cannot be reached, and if it has terminated a contract with an approved Section 16-111.5B energy efficiency program vendor. The utility should notify the Commission in a filing in the procurement plan docket for which the energy efficiency program was approved (similar to the approach ComEd used for PY7 and the approach proposed by Ameren in ICC Docket No. 13-0546 (Order at 112; Ameren RBOE at 14)). The utilities should notify SAG and keep the IPA apprised of any expected shortfalls in savings. The utility should notify the ICC of changes made (e.g., savings goal changes) in comparison to the approved energy efficiency programs.

Continuity for Multi-Year EE Programs

The utilities should have the capability for any of the Section 16-111.5B energy efficiency programs to have the option to expand into the Section 8-103 energy efficiency portfolio for a given program year (at the utility's discretion) if (1) the Section 16-111.5B savings goal for the energy efficiency program (from the ICC Order in the procurement plan docket or compliance filing/contract) is achieved and the approved budget (from ICC Order in the procurement plan docket) is exhausted and (2) the utility has budget available in the Section 8-103 energy efficiency portfolio. The utilities should make the vendor aware of this option in advance so as to help avoid stopping and re-starting the energy efficiency program (i.e., 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 energy efficiency 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 kilowatt-hour ("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 energy efficiency program disruption.*

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 energy efficiency programs.

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

To the extent that certain third-party EE programs have innovative delivery mechanisms and 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.

The full ICC Staff Report, including a full list of all questions addressed through the workshop process and a complete roster of workshop participants, is attached as Appendix B-2. As the resolution of designated workshop issues provides the IPA with valuable guidance in developing its annual procurement plan, the Agency thanks ICC Staff for the time and resources it put into leading a very comprehensive and detailed process and thanks all other participants for their participation. While the IPA recognizes that parties reserve their right to modify their positions with respect to any of the consensus items and contest their adoption in comments and litigation, the IPA is satisfied with the consensus items and recommends that the Commission approve the consensus language.

The IPA notes that no consensus language was recommended regarding DCEO participation in the third-party RFP process. While DCEO participated in the 2014 workshops, no clear path to resolving its barriers emerged and this remains an open issue.

7.2.4 Third Party Bid Review – Collaboration and Qualitative Evaluations

In preparation for its submittal to the IPA, ComEd sought input from DCEO and entities active in Illinois Energy Efficiency Stakeholder Advisory Group in the review of third party program bids. This review team made collective determinations on whether proposed third party programs met basic program requirements and were duplicative of existing programs. Next, the remaining proposals were scored based on the strength of the program approach and strength of the program team. The results of this process were included in a confidential bid document provided to the IPA.

This strikes the Agency as a very sensible and useful process for addressing stakeholder feedback. Section 16-111.5B(a)(3) of the PUA expressly contemplates that the utilities will develop RFPs in a manner "that considers input from the Agency and interested stakeholders"; involving these stakeholders in the review of RFP responses is a natural extension of that responsibility.[121] The combined expertise of a diverse, sophisticated team of stakeholders working in coordination should yield better evaluations and leave fewer issues unresolved at the time of the plan's filing than through the utilities evaluating bids in relative isolation.

[121] 220 ILCS 5/16-111.5B(a)(3). Along these lines, in last year the Commission expressed that "the utilities should make every effort to coordinate with stakeholders on improving and clarifying" third-party RFPs, but declined "to order the utilities to take any additional formal steps after the RFP to secure additional third-party programs." Docket No. 13-0546, Final Order dated December 18, 2013 at 146.

In the IPA's view, this raises two issues for Commission consideration. The first is straightforward – should the utilities be expressly encouraged to engage stakeholders in the review of third party program bids and "duplicative" program determinations?[122] The IPA sees value in a collaborative process, especially as those same parties could potentially litigate those recommendations in the Commission's Plan approval,[123] but could understand reluctance in encouraging a rigid decision-making model.

The second issue is more complex. The team and program approach scores included in ComEd's submittal contain qualitative information that may be valuable to the Agency and Commission in ensuring that cost-effective energy efficiency opportunities are maximized. However, it is not clear whether or how this information can be utilized.

Under Section 16-111.5B(a)(4) of the PUA, the IPA "shall include in the procurement plan . . . energy efficiency programs and measures it determines are cost-effective." The IPA understands this language to mean that if a program has met basic utility RFP requirements (a threshold for consideration) and passes the total resource cost test (the statutory definition of "cost-effective"), the program "shall" be included by the Agency in its Plan.[124]

The Commission's standard for program approval is different; Section 16-111.5B(a)(5) reads as follows:

> *The Commission shall also approve the energy efficiency programs and measures included in the procurement plan, including the annual energy savings goal, 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.*

The Agency believes that the pay-for-performance nature of Section 16-111.5B programs largely negates risks associated with flawed program design or subpar teams, and fears that new or innovative programs could inherently be subject to less favorable qualitative reviews. Nevertheless, the Commission may want to consider a) the legal question whether its standard for approval affords it the latitude to evaluate programs using qualitative criteria, and b) if so, the policy question of whether it should.

7.2.5 Ameren

Ameren's submittal to the IPA prepared in compliance with sections 16-111.5 and 16-111.5B of the PUA is included in Appendix B of this Plan. The submittal includes seven appendices which may be found on the IPA website posting of the 2015 Procurement Plan at www.illinois.gov/ipa. Two of the Appendices (6 and 7) in Ameren's submittal contain confidential data, and are redacted.

Ameren's submittal includes recommending nine energy efficiency offerings for this Procurement Plan (although as discussed further below, Ameren recommends inclusion of only one behavior modification program). All of these programs passed the TRC test at the time of assessment.[125] These programs are exhibited in Table 7-2.

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[122] Under this model, final decisions on what proposals are recommended for inclusion would still rest with utilities, and no stakeholder with an established interest in a bid's approval or rejection would be able to participate. But the Agency, and potentially also the Commission, may benefit from additional, independent sets of eyes providing review.

[123] Technically, the recommendations being litigated would be the IPA's determinations, which could mirror those presented to the Agency by the utilities, but are produced through an independent review. See Docket No. 13-0546, Final Order dated December 18, 2013 at 149; IPA Reply Brief dated October 31, 2013 at 10-11.

[124] Within this paradigm, the Agency "includes" programs it deems "duplicative" in its filed Plan, but with a recommendation that they be excluded by the Commission in approving the Plan.

[125] Ameren also provided the results of the UCT test and all the proposed programs passed the UCT test. The IPA considers that informational only and has not used the UCT test in its consideration of programs to include in this Plan.

Table 7-2: Ameren Energy Efficiency Offerings

Program	Net Savings (MWh)		Total Utility Cost	TRC
	Program Year 1	Program Year 2		
Moderate Income Kits	1,567	1,567	$1,666,737	1.22
Residential Lighting	48,190	53,556	$21,637,240	1.64
Rural Efficiency Kit Distribution	7,876	7,876	$2,214,245	3.09
Multi-Family Major Measures	38,943	38,943	$32,820,805	1.57
Home Energy Reports	40,013	40,013	$4,555,440	1.12
Behavioral Energy Efficiency	47,111	47,111	$4,488,750	1.59
Small Business Direct Install	9,588	9,788	$7,174,723	1.19
Small Business Refrigeration	17,947	17,947	$7,571,125	1.09
Demand-Controlled Ventilation	5,318	-	$1,146,840	1.20

The total net savings for these programs is estimated as 169,441 MWh at the busbar[126] for the first program year and 169,689 MWh for the second program year (assuming the inclusion of the Home Energy Reports and not the Behavioral Energy Efficiency Program as discussed below in Section 7.2.5.3). The programs also contribute to a peak reduction of approximately 17.66 MW. The estimated savings attributable to eligible retail customers is 72,137 MWh for the first program year. The IPA believes that Ameren's submittal meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix B (subject to a decision being made between the duplicative behavioral programs) should be approved pursuant to Section 16-111.5B(a)(5).

7.2.5.1 Ameren Bid Review Process

To arrive at this set of proposed programs, Ameren received 25 bids: 14 for residential programs; 10 for commercial programs; and one for both. These bids included the residential lighting and behavioral programs that the ICC determined in Docket No. 13-0498 should be moved from the Section 8-103 portfolio to the Section 16-111.5B portfolio.

The joint program was a thermostat program that Ameren determined did not meet the RFP criteria for two reasons: it was "proposed as both a gas and electric savings program, yet the 16-111.5B energy efficiency incremental savings is for the purpose of decreasing electric procurement, not gas;" and "[m]ore than 50% of the energy savings are gas but there are no gas dollars to run the program through IPA."[127] Ameren also determined that three residential bids were duplicative of the Ameren Section 8-103 School Kits program approved by the Commission in Docket No 13-0498, and one commercial program was duplicative of the approved Section 8-103 Standard Lighting program.

Of the remaining 20 programs, 11 had a TRC of less than 1 (5 residential, 6 commercial) leaving 9 programs for consideration. Two residential behavior modification programs were determined by Ameren to compete with each other. As a result, the company requested that the IPA determine which program to be included in the plan. As described further below, the Agency recommends the inclusion of only the Home Energy Reports program.

One proposed program was for only the first delivery year (delivery year 2015-2016), the other proposed programs are for two years (delivery year 2015-2016 and 20162017).

[126] Note that in Ameren's submittal document net savings are primarily listed as at the meter. For consistency net savings in this plan are listed at the busbar.
[127] "Electric Energy Efficiency Compliance with 220 ILCS 5/16-111.5B" Ameren Illinois July 15, 2014 Filing at 14. Included as Appendix B.

The IPA has also reviewed Ameren's criteria for the review of programs, including application of the consideration of duplicative programs as well as the calculation of the TRC. Except to the extent different conclusions are reached below (such as with making a recommendation between programs at the utility's request), the Agency's concurs with Ameren's recommendations.

7.2.5.2 Small Business Direct Install – Demand Control Ventilation

As part of its bid review process, Ameren provided DCEO with all bids that had a positive TRC for a review of whether any proposals may be duplicative of DCEO's program offerings. Among the proposals received by Ameren was a Small Business Direct Install—Demand Control Ventilation program. DCEO believes this program is "duplicative," communicating the following to Ameren:

> *DCEO offers a standard incentive through the standard/custom program for Demand Control Ventilation. This proposal would be a direct competitor to the DCEO incentive. Our major concern would be double dipping of program incentives/savings. Once again we are opposed to funding this project and recommend that Ameren not approve for IPA funding. If funded we would require coordination or approval for Public Sector entities (especially schools) coordinated with DCEO prior to installation.*

Based on the information available to the IPA, the Agency believes that this proposal may safely co-exist with DCEO's current program offering. Although the two programs may be similar in effect, the IPA understands the two programs to target distinct segments of customers – with DCEO focused on public facilities, and the third-party proposal focused on non-public small businesses. The IPA therefore recommends approval of the Small Business Direct Install – Demand Control Ventilation proposal.

The Agency invites DCEO to provide feedback on its draft Plan, further explaining any risk for "double dipping" and providing any other considerations to be taken into account before the IPA makes its final recommendation in its filing with the Commission.

7.2.5.3 Competing Residential Behavioral Modification Programs

Ameren's submittal contained two behavioral modification program proposals—Home Energy Reports and Behavioral Energy Efficiency[128]—determined by Ameren to be "duplicative" of each other. Ameren makes no express recommendation to the Agency on which program to recommend for adoption, and requests that "the IPA determine which Behavior Modification program to award the bid for PY8 and PY9."[129]

The IPA believes that it has two roles in this situation. The first is to determine whether these programs are "competing" or "duplicative" using the seven-factor inquiry outlined above. If the two are not "duplicative," then each may be included and no recommendation need be made between the two. Ameren previously determined that only one program should be adopted because "the total number of residential customers eligible for the program could not support two behavior modification programs" and "running multiple programs would lead to significant confusion of residential customers, which would hamper the adoption of the Behavioral Modification program, rather than increase it."

After a review of each proposal, the Agency agrees with Ameren that these two proposals are "duplicative" and that only one should be approved. Each program targets residential customers using a similar delivery mechanism (engaging customers through energy reports, an online web portal, etc.) with the aim of using rich, relevant data to effectuate behavioral change, thus driving delivered savings. While there are nuanced differences between the programs, the Agency is confident that implementation of both programs would be both confusing and counterproductive, with savings from one program cannibalizing the other.

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[128] Identified as "Company A" and "Company B" respectively in the Ameren Section 16-111.5B submittal document included in Appendix B.

[129] To be clear, the IPA does not believe it has unilateral authority to award this bid; instead, the Agency understands its role as proposing programs for inclusion and making recommendations. Those recommendations may inform the Commission's determination of what programs are approved in its Final Order, but the Commission is not bound by the IPA's recommendations.

Having determined that only one proposal should be adopted, and noting that each proposal met RFP requirements and passes the TRC, the Agency's second role is determining which proposal to recommend for inclusion. Here, the Agency has less guidance from either the PUA or past Commission Orders. As a threshold matter, the Agency has no clear criteria to apply in choosing between competing programs; its role under Section 16-111.5B is to review and verify assumptions about cost-effectiveness and program compatibility, and not to make normative determinations about relative program quality. In this particular instance, the Agency notes that both programs originate from reputable vendors with a track record of delivered savings in this space—criteria that the Agency would otherwise like to use in making a recommendation.

While both proposals were analyzed using the same number of participants, the Behavioral Energy Efficiency proposal features roughly 17% greater estimated expected savings. However, this increased rate of savings may come from using a savings rate taken from a different service territory. The Home Energy Reports program has been operating Ameren's residential behavioral modification program since its inception; its projected savings may be less optimistic, but also more proven and reliable. Taking these factors together, and accounting for similarities in program goals and design, both programs seem likely to deliver similar levels of energy savings to the same customers.

Compelled to make a recommendation, the IPA believes that the Home Energy Reports program team's experience to date in Ameren's service territory and established working relationship with the utility makes it slightly more likely to deliver increased savings to customers and maximize the impact of Section 16-111.5B funds. The IPA thus recommends the Home Energy Reports behavioral program for inclusion in its Procurement Plan, but actively seeks feedback from stakeholders on which proposal may constitute the best approach.

7.2.5.4 Ameren Requested Determinations

Ameren also requested in their filing that the ICC make several determinations:

- "AIC is formally requesting in this submission that the measure values and NTG ratios used in the IPA program analyses, as represented in Appendix 7, are hereby deemed to determine the estimated savings achieved by the programs." (pg. 7)
- "AIC formally requests in this submission that 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' and further that programs resulting in multi-years (PY8 and PY9) will be re-negotiated annually to reflect the annual `deemed' IL-TRM measure values and NTG ratio values" (pp. 7-8)
- "AIC again formally requests approval for an indeterminate fluctuation in savings that may occur by program year end." (pg. 9)
- "AIC once again seeks confirmation that AIC is permitted to recover costs that incidentally (3 -5%) exceed the estimated program costs as consistent with prior ICC findings." (pg. 9)
- "AIC is requesting the Commission pre-authorize a 20% budget shift across program years for the multi-year (PY8 and PY9) programs while remaining within the total approved multi-year program budget to allow for successful energy efficiency programs to continue operation in the early (or later) program years of the multi-year contract." (pg. 9)
- "AIC is formally requesting that these values [savings estimates based on the current IL-TRM and NTG values] be deemed for the implementation and evaluation for the determination of achieved savings on an annual basis." (pg. 14)

- "AIC intends to continue to treat Section 8-103 and 16-111.5B evaluation budgets as merged and operated as a single budget; to the extent ICC approval is necessary to continue this practice, AIC requests it." (pg. 21)

The IPA does not object to any of these requests, as they appear to be consistent with consensus items from the workshops.

Besides these determinations, the IPA requests that the ICC approve the incremental energy efficiency programs proposed by Ameren.

7.2.6 ComEd

ComEd's submittal to the IPA prepared in compliance with sections 16-111.5 and 16-111.5B of the PUA is included in Appendix C of this Plan which may be found on the IPA's website posting of the 2015 Procurement Plan at www.illinois.gov/ipa. Note that the document entitled "ComEd 2014 Third Party Efficiency Program Summary of Bid Review Process, July 8, 2014" contains confidential data and was not included with this Plan.

ComEd's submittal includes recommending ten energy efficiency programs for inclusion in this Procurement Plan. All of these programs passed the TRC test at the time of assessment.[130] These programs are exhibited in Table 7-3.

Table 7-3: ComEd Energy Efficiency Offerings

Program	Net Savings (MWh)		Two Year Program Cost	TRC
	Program Year 1	Program Year 2		
LED Streetlighting	6,077	12,156	$12,663,103	9.02
Residential Lighting(Moved from 8-103)	247,648	241,541	$77,270,755	16.56
Energy Stewards	944	944	$277,000	1.51
Door-to-Door Light Bulbs	1,255	1,255	$2,153,400	1.51
Middle School Take-home Kits	1,354	1,354	$1,304,316	1.25
Direct Install –Schools (Clear Result)	4,548	4,785	$2,148,292	1.06
Direct Install – Schools (Matrix)	6,156	6,156	$1,978,350	1.67
Demand Control Ventilation (Matrix)	6,125	6,125	$2,531,072	2.85
Demand Control Ventilation (Sodexo)	5,658	5,658	$1,713,040	6.11
New Construction	2,339	4,667	$1,749,776	1.25

All of ComEd's proposed programs are for two years. The net savings at the busbar are 282,104 MWh for the first program year, and 284,651 MWh in the second program year. These programs will deliver 159 MW of reduction in peak procurement for the 2015-2016 program year. The savings attributable to eligible retail customers is 103,039 MWh in the first program year, and 104,652 MWh in the second program year. The IPA believes that ComEd's filing meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix C should be approved pursuant to Section 16-111.5B(a)(5).

7.2.6.1 ComEd Bid Review Process

ComEd received 13 bids. One commercial bid was withdrawn by the bidder. Of the remaining 12 bids, 4 were for residential programs and 8 for commercial programs. As discussed below in Section 7.2.6.5 one of the

[130] ComEd also provided the results of the UCT test and eight of the ten proposed programs passed the UCT test. The IPA considers that informational only and has not used the UCT test in its consideration of programs to include in this Plan.

commercial programs was determined by ComEd, consistent with the consensus upon of consulted stakeholders,[131] to not conform with the RFP.

One residential and one business program did not pass the TRC test. Of the remaining programs, while aspects were determined to be “competing” with existing programs, ComEd and the stakeholder reviewers determined that they were in fact not “duplicative” and thus not screened from inclusion. The review of these programs is discussed further below in Section 7.2.6.5.

ComEd also included the residential lighting programs that Commission instructed it to transfer from their Section 8-103 Program Years 7-9 Plan to the Section 16-111.5B filing in Docket No. 13-0495. As part of this transfer, the program scale was readjusted to maximize cost-effective savings.

7.2.6.2 Commercial LED Program

One of the proposed commercial programs—a commercial LED replacement program—was determined by ComEd in consultation with stakeholders to not conform with ComEd’s issued RFP. The proposed approach contained unreasonable risks to consumers because the program could void warrantees and create electrical safety hazards. Upon a review of bid materials, the Agency agrees with this recommendation and does not recommend approval of this program in its Plan.

7.2.6.3 Public School Direct Install Program

ComEd, as well as stakeholders invited to review in the bid evaluation process, reached consensus that a K to 8 Public School Proposal – delivering energy assessments and turnkey installation of no cost, low cost, and capital measures in public schools – was “duplicative” of existing DCEO direct installation offerings to ComEd’s public school customers.

The IPA agrees with this determination. The Agency understands these to be similar offerings targeted to the same customer base, and does not believe that customer interests would be served by a separate delivery channel. The IPA therefore does not recommend approval of this program in its Plan.

7.2.6.4 Commercial Behavioral Program

ComEd and reviewing stakeholders also reached consensus that a commercial behavior program proposal was “duplicative” of ComEd’s existing behavioral offering. The proposed program features an “online portal providing customers with integrated billing, benchmark, weather, building, and savings data.”

Upon IPA review, ComEd’s existing program and the proposed program appear to feature significant overlap in methodology and approach, although it is notable that the proposed program would serve a defined subset of those customers for whom the existing program is available. As such, one could envision the proposed program having additive value as a more targeted product, achieving additional efficiencies. But even so doing, it would still risk significantly eroding the savings potential of the existing program—factors which may have informed ComEd and stakeholders in reaching consensus that this program is “duplicative.”

The IPA agrees with this determination. However, as this proposal featured a TRC ratio of well less than 1.0, the IPA recommends it not be included first on that basis, with the consideration of this program as “duplicative” coming only should some change in estimated TRC make it relevant for inclusion.

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[131] ComEd invited the Illinois Department of Commerce and Economic Opportunity, the Natural Resources Defense Council, the Environmental Law and Policy Center, and the Office of the Illinois Attorney General to participate in the review process.

7.2.6.5 ComEd Review of "Competitive" Programs

In its submittal, ComEd also identified 9 of its 11 programs as "competing" but not "duplicative"—in other words, appropriate delivery conditions could be structured to ensure that consumers benefit from multiple delivery channels, and thus the presence of a similar program would not be grounds for exclusion. Upon review of these programs and application of the seven-factor inquiry, the Agency agrees with those determinations.

7.2.6.6 ComEd Requested Determination

ComEd has requested that, "[t]o the extent that the IPA and the ICC approve procurement of the programs ComEd requests that approval be for both years."[132] The IPA agrees with this request.

Besides this determination, the IPA requests that the ICC approve the incremental energy efficiency programs proposed by ComEd.

7.3 Indicative Quantities and Types of Products to be Purchased

The following tables were constructed using the July 2014 Expected Load Forecasts to provide indicative values for the 2015-2016 delivery year. The actual procurement volumes will be calculated using the March 2015 / July 2015 Expected Load Forecasts. These forecasts are expected to include Approved Energy Efficiency Programs for both Ameren and ComEd. The following tables are calculated assuming no LTPPAs curtailments during the delivery periods, and rounded symmetrically to the nearest 25MW block.

[132] Appendix C at 29.

7.3.1 Ameren

7.3.1.1 Ameren Procurement Delivery Years 2015 - 2020

Table 7-4: Ameren April Procurement, Delivery Year 2015-2016, Preliminary Volumes*

	Expected Load (MW)		106% (June-Oct) 75% (Nov-May) of Expected Load (MW)		Current Contracted Supply (MW)		Required April 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-15	1,097	782	1,163	829	368	303	800	525
July-15	1,218	992	1,291	1,052	427	366	875	700
August-15	1,205	947	1,277	1,004	407	348	875	675
September-15	889	727	942	771	292	275	650	500
October-15	734	609	778	646	274	282	500	375
November-15	799	706	599	529	289	293	325	250
December-15	974	905	731	678	345	322	400	375
January-16	1,077	943	808	707	361	354	450	350
February-16	1,005	900	754	675	344	328	425	350
March-16	842	752	631	564	276	300	350	275
April-16	742	645	557	484	294	294	275	200
May-16	744	639	558	479	270	277	300	200

*Volumes to be adjusted using the March 2015 expected load forecast, which shall also include newly approved energy efficiency programs

Table 7-5: Ameren September Procurement, November-May of Delivery Year 2015 - 2016, Preliminary Volumes*

	Expected Load (MW)		100% of Expected Load (MW)		Anticipated Contracted Supply (MW)**		Required September 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
November-15	799	706	799	706	589	518	200	175
December-15	974	905	974	905	720	672	250	225
January-16	1,077	943	1,077	943	811	704	275	250
February-16	1,005	900	1,005	900	744	678	250	225
March-16	842	752	842	752	626	575	225	175
April-16	742	645	742	645	569	494	175	150
May-16	744	639	744	639	570	477	175	175

*Volumes to be adjusted using the July 2015 expected load forecast, which shall also include newly approved energy efficiency programs
**Including any purchases made in April

Table 7-6: Ameren April Procurement, Delivery Year +1 (2016-2017), Preliminary Volumes*

	Expected Load (MW)		50% of Expected Load (MW)		Current Contracted Supply (MW)		Required April 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-16	1,097	785	549	393	168	153	375	250
July-16	1,203	1,033	602	517	206	187	400	325
August-16	1,207	927	604	464	204	177	400	300
September-16	866	750	433	375	167	125	275	250
October-16	721	626	360	313	128	129	225	175
November-16	795	706	397	353	160	147	250	200
December-16	988	896	494	448	174	169	325	275
January-17	1,062	949	531	474	182	182	350	300
February-17	1,025	921	513	460	172	179	350	275
March-17	839	754	420	377	126	125	300	250
April-17	744	647	372	324	149	115	225	200
May-17	747	631	374	316	141	130	225	200

*Volumes to be adjusted using the March 2015 expected load forecast, which shall also include newly approved energy efficiency programs

Table 7-7: Ameren April Procurement, Delivery Year + 2 (2017-2018), Preliminary Volumes*

	Expected Load (MW)		25% of Expected Load (MW)		Current Contracted Supply (MW)		Required April 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-17	1,091	787	273	197	43	53	225	150
July-17	1,228	1,012	307	253	31	37	275	225
August-17	1,207	924	302	231	29	52	275	175
September-17	872	748	218	187	44	48	175	150
October-17	719	620	180	155	74	82	100	75
November-17	792	702	198	175	85	97	125	75
December-17	990	892	248	223	77	67	175	150
January-18	1,064	937	266	234	82	82	175	150
February-18	1,029	913	257	228	72	79	200	150
March-18	845	749	211	187	76	100	150	100
April-18	748	638	187	159	99	90	100	75
May-18	757	622	189	156	66	80	125	75

*Volumes to be adjusted using the March 2015 expected load forecast, which shall also include newly approved energy efficiency programs

7.3.1.2 Delivery Year + 3 and Delivery Year + 4 (2018-2019 and 2019-2020)

Given the absence of visible and liquid block energy markets four and five years out, it is not recommended that any block energy purchases be made to secure supply for these years in this Procurement Plan.

7.3.2 ComEd

7.3.2.1 ComEd Procurement Delivery Years 2015 – 2020

Table 7-8: ComEd March Procurement, Delivery Year 2015-2016, Preliminary Volumes*

	Expected Load (MW)		106% (June-Oct) 75% (Nov-May) of Expected Load (MW)		Current Contracted Supply (MW)		Required April 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-15	2,352	1,885	2,493	1,998	869	681	1,625	1,325
July-15	2,786	2,220	2,953	2,353	1,009	783	1,950	1,575
August-15	2,371	1,892	2,513	2,006	966	751	1,550	1,250
September-15	1,915	1,532	2,030	1,624	762	605	1,275	1,025
October-15	1,701	1,373	1,803	1,455	700	630	1,100	825
November-15	1,879	1,583	1,409	1,187	747	638	650	550
December-15	2,143	1,817	1,607	1,362	873	727	725	625
January-16	2,133	1,835	1,600	1,376	872	723	725	650
February-16	1,995	1,700	1,496	1,275	802	692	700	575
March-16	1,794	1,522	1,346	1,142	741	652	600	500
April-16	1,622	1,357	1,217	1,018	663	655	550	375
May-16	1,670	1,363	1,252	1,022	681	606	575	425

*Volumes to be adjusted using the March 2015 expected load forecast, which shall also include newly approved energy efficiency programs.

Table 7-9: ComEd September Procurement, Nov-May of Delivery Year 2015-2016, Preliminary Volumes*

	Expected Load (MW)		100% of Expected Load (MW)		Anticipated Contracted Supply (MW)**		Required September 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
November-15	1,879	1,583	1,879	1,583	1,397	1,188	475	400
December-15	2,143	1,817	2,143	1,817	1,598	1,352	550	475
January-16	2,133	1,835	2,133	1,835	1,597	1,373	525	450
February-16	1,995	1,700	1,995	1,700	1,502	1,267	500	425
March-16	1,794	1,522	1,794	1,522	1,341	1,152	450	375
April-16	1,622	1,357	1,622	1,357	1,213	1,030	400	325
May-16	1,670	1,363	1,670	1,363	1,256	1,031	425	325

*Volumes to be adjusted using the July 2015 expected load forecast, which shall also include newly approved energy efficiency programs
**Including any purchases made in April

Table 7-10: ComEd April Procurement, Delivery Year +1 (2016-2017), Preliminary Volumes*

	Expected Load (MW)		50% of Expected Load (MW)		Current Contracted Supply (MW)		Required April 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-16	2,164	1,704	1,082	852	544	556	550	300
July-16	2,540	2,047	1,270	1,024	509	533	750	500
August-16	2,417	1,893	1,208	947	516	551	700	400
September-16	1,891	1,538	945	769	537	555	400	225
October-16	1,703	1,378	851	689	600	630	250	50
November-16	1,894	1,590	947	795	647	638	300	150
December-16	2,151	1,829	1,076	915	598	602	475	325
January-17	2,145	1,846	1,072	923	622	623	450	300
February-17	2,005	1,718	1,002	859	602	617	400	250
March-17	1,801	1,535	901	767	616	652	275	125
April-17	1,630	1,366	815	683	638	655	175	25
May-17	1,680	1,368	840	684	656	606	175	75

*Volumes to be adjusted using the March 2015 expected load forecast, which shall also include newly approved energy efficiency programs

Table 7-11: ComEd April Procurement, Delivery Year + 2 (2017-2018), Preliminary Volumes*

	Expected Load MW		25% of Expected Load (MW)		Current Contracted Supply (MW)		Required April 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-17	2,178	1,704	545	426	544	556	0	0
July-17	2,548	2,055	637	514	509	533	125	0
August-17	2,420	1,905	605	476	516	551	100	0
September-17	1,895	1,546	474	387	537	555	0	0
October-17	1,715	1,383	429	346	600	630	0	0
November-17	1,906	1,594	476	399	647	638	0	0
December-17	2,154	1,840	538	460	598	602	0	0
January-18	2,166	1,861	542	465	172	173	375	300
February-18	2,017	1,735	504	434	152	167	350	275
March-18	1,814	1,549	453	387	166	202	275	175
April-18	1,648	1,377	412	344	188	205	225	150
May-18	1,692	1,374	423	344	206	156	225	200

*Volumes to be adjusted using the March 2015 expected load forecast, which shall also include newly approved energy efficiency programs

7.3.2.2 Delivery Year + 3 and Delivery Year + 4 (2018-2019 and 2019-2020)

Given the absence of visible and liquid block energy markets four and five years out, it is not recommended that any block energy purchases be made to secure supply for these years in this Procurement Plan.

7.4 Ancillary Services, Transmission Service and Capacity Purchases

7.4.1 Ancillary Services and Transmission Service

Both Ameren and ComEd purchase their ancillary services and transmission services from their respective RTOs, MISO and PJM. The utilities also manage their FTRs and ARRs in their respective RTOs consistent with ICC orders in prior Plans. The IPA is not aware of any justification or reason to alter these practices and therefore recommends they remain unchanged.

7.4.2 Capacity Purchases

The IPA concludes that it does not need to include any extraordinary measures in the 2015 Procurement Plan to assure reliability over the planning horizon.

The IPA recommends that ComEd continue to meet all of its capacity obligations through the PJM capacity market in which capacity is purchased in a three-year ahead forward market through mandatory capacity rules.

The 2013 Procurement Plan recommended retaining the 100%/70%/35% hedging strategy for purposes of Ameren's capacity requirements until such time as MISO demonstrated a robust FERC-approved capacity auction. The MISO capacity auction design was approved by FERC and thus no capacity was procured for Ameren in 2013. The 2014 Procurement Plan likewise did not recommend procuring any capacity for Ameren.

Ameren successfully purchased all of its capacity requirements in 2014 via MISO's annual capacity auction. The IPA still expects that auction to demonstrate sufficient liquidity and that it will be unnecessary to purchase capacity for 2015-2017 outside of the MISO capacity auction. The Agency therefore recommends there be no capacity procurement event in 2015.

To address the differences between the MISO capacity auction (prompt year only) and PJM capacity auctions (three year forward), Ameren has raised the issue of whether it makes sense to hedge against potential capacity price increases (via bilateral contracts or other forward capacity hedges). The potential value to Ameren customers on bundled rates would come from the fact that unlike the PJM capacity auction where the results are known three years ahead of time, the MISO capacity auction occurs less than two months before the start of the delivery year. This increases the potential for significant rate changes that are not anticipated by customers, and that they could lack sufficient time to make any adjustments to supply choice options or usage patterns. Hedging capacity for several years for Ameren customers would have the potential to ease that transition, but at a potential premium as Ameren would be hedging in a less liquid and transparent market. In this draft plan the IPA seeks input on the trade-offs related to a potential hedging of Ameren capacity for after the 2015-2016 delivery year. For the 2015-2016 delivery year, capacity would be hedged in the MISO auction. The issue at hand would be the trade-offs related to hedging some level of capacity for future delivery years.

The IPA notes that changes in prices resulting from MISO capacity auctions will affect all of the MISO market participants in Zone 4 (Illinois) equally and that hedging outside the MISO capacity auction may create a significant difference between market prices and Ameren bundled rates.

7.5 Demand Response Products

Section 8-103(c) of the PUA establishes a goal to implement demand response measures, providing 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, as defined in Section 16-111.5 of this Act, and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive. This requirement commences June 1, 2008 and continues for 10 years.*

ComEd provided information regarding its existing demand response programs for 2014 which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 72,700 customers with a load reduction potential of 87 MW (ComEd Rider AC).
- Voluntary Load Reduction ("VLR") Program: VLR is an energy-based demand response program, providing compensation based on the value of energy as determined by the real-time hourly market run by PJM. This program also provides for transmission and distribution ("T&D") compensation based on the local conditions of the T&D network. This portion of the portfolio has roughly 1,200 MW of potential load reduction (ComEd Rider VLR).
- Residential Real-Time Pricing (RRTP) Program: All of ComEd's residential customers have an option to elect an hourly, wholesale market-based rate. The program uses ComEd's Rate BESH to determine the monthly electricity bills for each RRTP participant. This program has roughly 5 MW of price response potential.
- Peak Time Savings (PTS) Program: This program is required by Section 16-108.6(g) of the PUA and was approved by the ICC in Docket No. 12-0484. The PTS program 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 recently sold 48 MW of capacity from the program into the PJM capacity auction for the 2017 Planning Year.

Ameren has recently completed a Voltage Optimization Pilot Program, offers real-time pricing options , and had its peak time rebate program provisionally approved by the Commission this January in Docket No. 13-0105.[133]

The IPA does not propose any additional demand response programs for the 2015-2016 delivery year. Peak Time Rebate (or Savings) programs create value through reduction in capacity charges. Given that the IPA has recommended that the utilities directly contract for capacity, the IPA does not have a direct role in the use of demand response to reduce capacity obligations. However, the technologies utilized for capacity reductions also have the potential to provide longer term demand response that could operate over more peak hours than those used for calculations of capacity obligations. With the ComEd Peak Time Savings program scheduled to commence in 2015, and the scheduled startup of Ameren's PTR program in June 2016, in 2016 the IPA invites stakeholders to provide comments to the IPA on how the Procurement Plan should include additional or complimentary demand response, and whether the roll-out of smart meters affects the timeline for additional programs.

7.6 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.[134] As a part of the goal, the Plan must also include electricity

[133] Docket No. 13-0105, Interim Order dated January 7, 2014 at 19-20. However, Ameren's proposed pilot direct load control program was not approved in that docket.
[134] 20 ILCS 3855/1-75(d).

generated from clean coal facilities.[135] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act[136], Section 1-75(d) describes two special cases: the "initial clean coal facility"[137] 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 ("retrofit clean coal facility").[138] Currently, the IPA 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.

7.6.1 FutureGen 2.0

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.[139] A recent Illinois Appellate Court ruling on the appeal of the Commission's Final Order in Docket No. 12-0544 may provide additional certainty for the project's development.[140] On July 22, 2014, the 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). While it is not yet known whether the appellants will appeal this decision to the Illinois Supreme Court, the opinion favorably addresses a significant potential obstacle to FutureGen's continued development.

The IPA is not aware of any additional change in status of the project that would hinder FutureGen's ability to deliver clean coal electricity as anticipated. Also, the IPA is not aware of any additional retrofitted clean coal facilities seeking inclusion in the Procurement Plan.

7.6.2 Sargas

The Agency has been approached by a team representing Sargas, Inc., a US subsidiary of Sargas AS, a Norwegian technology company. Sargas is seeking to develop a coal-fired power plant in Mattoon designed to burn Illinois coal with 90% post-combustion carbon capture, with captured carbon then used for local enhanced oil recovery. The project would be a single module, 80 MW facility seeking to begin construction as early as 2016 and begin operation as early as 2019.

The regulatory treatment afforded proposed clean coal projects varies significantly by project type. The IPA Act contains provisions specific to an "initial clean coal facility,"[141] "retrofitted coal-fired power plants,"[142] a "clean coal SNG facility,"[143] and a distinct "clean coal SNG brownfield facility."[144]

Based on conversations with the Sargas team, the IPA understands that the proposed Sargas project—a high-pressure combustion facility located on a greenfield site—would not fit into any of the above categories. Instead, the project would constitute a "clean coal facility" as that term is used in the Section 1-10 (definitions) of the IPA Act.[145]

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[135] 20 ILCS 3855/1-75(d)(1).
[136] 20 ILCS 3855/1-10.
[137] Id.
[138] 20 ILCS 3855/1-75(d)(5).
[139] See Docket No. 12-0544, Final Order dated December 19, 2012 at 228-237; see also Docket No. 13-0034, Final Order dated June 26, 2013 ("Phase II" approving sourcing agreement as required in Docket No. 12-0544).
[140] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2014 IL App (1st) 130544, July 22, 2014.
[141] 20 ILCS 3855/1-75(d)(3) .
[142] 20 ILCS 3855/1-75(d)(5) .
[143] 20 ILCS 3855/1-58.
[144] 20 ILCS 3855/1-78 .
[145] 20 ILCS 3855/1-10 ("an electric generating facility that uses primarily coal as a feedstock and that captures and sequesters carbon dioxide emissions at the following levels: at least 50% of the total carbon dioxide emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation before 2016, at least 70% of the total carbon dioxide emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation during 2016 or 2017, and at least 90% of the total carbon dioxide emissions that the facility would otherwise emit if, at the time

The Agency does not have a mechanism for considering sourcing agreements from a standard, non-delineated "clean coal facility" for inclusion in its Plan, and Sargas has not submitted sourcing agreements to the Agency for consideration. Instead, as the IPA understands it, Sargas has requested that the Agency include a competitive clean coal procurement in its 2015 Procurement Plan.[146] In Sargas's view, again as the IPA understands it, the Agency's authority to conduct a competitive clean coal procurement for projects such as Sargas stems from the broad language of the clean coal portfolio standard as manifest in Section 1-75(d)(1) of the IPA Act.

The IPA has concerns with this proposal. The clean coal portfolio standard contains a rate cap requiring a maximum 2.015% average net increase to ratepayers for sourcing agreements with clean coal facilities executed pursuant to the IPA's Plan.[147] Based on representations made by FutureGen in February 2013, FutureGen 2.0's expected rate impact would be 1.32%, or approximately 65% of the statutory limit.[148] Sargas has represented having a cost structure lower than FutureGen that is roughly half the size; assuming sourcing agreements similar to FutureGen's, and assuming the accuracy of FutureGen's rate impact representations, it is possible that both projects could fit under this threshold.

However, FutureGen 2.0 was approved by the Commission as a "retrofitted clean coal facility" as defined by Section 1-75(d)(5) of the IPA Act. That section provides in relevant part as follows:

> *The Agency and the Commission shall consider sourcing agreements covering electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities, as defined by Section 1-10 of this Act. Pursuant to such procurement planning process, <u>the owners of such facilities may propose to the Agency sourcing agreements with utilities and alternative retail electric suppliers</u> required to comply with subsection (d) of this Section and item (5) of subsection (d) of Section 16-115 of the Public Utilities Act, covering electricity generated by such facilities.*

(emphasis added). 1-75(d)(5) of the IPA Act provides an express mechanism for the IPA's consideration of sourcing agreements between alternative retail electric suppliers and owners of retrofitted clean coal facilities. However, for a non-retrofitted greenfield "clean coal facility," such as Sargas, the IPA Act contains no such mechanism for considering sourcing agreements involving ARES.[149]

As the IPA conducts procurement events only on behalf of utilities' eligible retail customers absent express authority to the contrary, the Agency believes that any "clean coal facility" sourcing agreements considered under the general provisions of Section 1-75(d)(1) would run only between the facility owner and the utilities to supply eligible retail customers. With a significantly smaller and migrant customer base responsible for covering sourcing agreement costs, any sourcing agreement produced through a competitive "clean coal facility" procurement would either violate the statutory rate cap or cover only a small portion of the project's

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construction commences, the facility is scheduled to commence operation after 2017. The power block of the clean coal facility shall not exceed allowable emission rates for sulfur dioxide, nitrogen oxides, carbon monoxide, particulates and mercury for a natural gas-fired combined-cycle facility the same size as and in the same location as the clean coal facility at the time the clean coal facility obtains an approved air permit. All coal used by a clean coal facility shall have high volatile bituminous rank and greater than 1.7 pounds of sulfur per million btu content, unless the clean coal facility does not use gasification technology and was operating as a conventional coal-fired electric generating facility on June 1, 2009.")

[146] A competitive clean coal procurement seeking sourcing agreements for projects qualifying under Section 1-75(d)(5) of the IPA Act was initially proposed, but later withdrawn, from the IPA's 2012 Procurement Plan.

[147] 20 ILCS 3855/1-75(d)(2).

[148] See Docket No. 13-0344, Submission and Request for Approval of Pre-Approval of Total Capital Costs of FutureGen Industrial Alliance, Inc. dated February 19, 2013 at 4.

[149] The Commission does have apparent general authority to require clean coal procurement by ARES, as Section 16-115(d)(5) of the PUA requires sourcing electricity from clean coal facilities as a condition of certification. However, it is unclear how this general authority would authorize the IPA to propose procurement activity intended to contractually bind ARES to purchase output from a "clean coal facility." The Agency reads the recent Illinois Appellate Court's opinion to hinge largely on the interplay between Section 1-75(d)(5) of the IPA Act and Section 16-115(d)(5) of the PUA, with particular emphasis given to the passage from Section 1-75(d)(5) quoted above. See Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2014 IL App (1st) 130544, July 22, 2014, ¶ 25.

output.[150] As a result, the Agency believes it would not be possible or wise to conduct a competitive procurement to solicit sourcing agreements for a "clean coal facility."[151]

Based on this review, the Agency believes that Sargas's best path to a sourcing agreement covering the full output of its proposed clean coal facility would be through express statutory authority developed by the Illinois General Assembly. Nonetheless, the Agency invites Sargas, Inc. and its team to provide comments on the IPA's draft 2015 Procurement Plan and to participate in the resulting plan approval process before the Illinois Commerce Commission. Sargas may have a different legal theory supporting inclusion of its proposal or may offer an alternative interpretation of judicial precedent and governing law, and the IPA looks forward to its feedback.

7.7 Summary of Strategy for the 2015 Procurement Plan

Table 7-12 summarizes the recommendations of this Chapter.

[150] Any such sourcing agreement would also be subject to significant load migration risk, which could lead to statutorily mandated contract purchase curtailments.
[151] The proposed Sargas project may face other challenges as well, or offer benefits not mentioned above. However, as the IPA does not believe it can include Sargas's proposal in its draft Procurement Plan, those are not addressed here.

Table 7-12: Summary of 2015 Illinois Power Agency Procurement Plan Recommendations

	Delivery Year	Energy	Capacity	Renewable Resources	Ancillary Services
AMEREN	2015-16	Up to 875MW forecasted requirement (April Procurement) Up to 275MW additional forecasted requirement (September Procurement)	Direct purchase from MISO capacity market	One-year SRECs procurement up to 30.2 GWh Five-year DG REC procurement up to 6.5 GWh No RPS procurement for other resources, target exceeded	Will be purchased from MISO
AMEREN	2016-17	Up to 400MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG)	Will be purchased from MISO
AMEREN	2017-18	Up to 275MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: shortage of 85GWh, revisit next year	Will be purchased from MISO
AMEREN	2018-19	No energy procurement required	Direct purchase from MISO capacity market	No RPS procurement: shortage of 447GWh, revisit next year	Will be purchased from MISO
AMEREN	2019-20	No energy procurement required	Direct purchase from MISO capacity market	No RPS procurement: shortage of 553GWh, revisit next year	Will be purchased from MISO
COMED	2015-16	Up to 1,950MW forecasted requirement (April Procurement) Up to 550MW additional forecasted requirement (September Procurement)	Direct purchase from PJM capacity market	One-year SRECs procurement up to 49.8 GWh Five- year DG REC procurement up to 13.2 GWh. No RPS procurement for other resources, target exceeded	Will be purchased from PJM
COMED	2016-17	Up to 750MW forecasted requirement (April Procurement)	Direct purchase from PJM capacity market	No RPS procurement: shortage of 120GWh, revisit next year	Will be purchased from PJM
COMED	2017-18	Up to 375 MW forecasted requirement (April Procurement)	Direct purchase from PJM capacity market	No RPS procurement: shortage of 428GWh, revisit next year	Will be purchased from PJM
COMED	2018-19	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: shortage of 888GWh, revisit next year	Will be purchased from PJM
COMED	2019-20	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: shortage of 1,124GWh, revisit next year	Will be purchased from PJM

8 Renewable Resources Availability and Procurement

This chapter focuses on the procurement of renewable resources on behalf of eligible retail customers and also provides informational guidance on the IPA's considerations for the use of the Renewable Energy Resources Fund ("RERF"). Procurement on behalf of eligible retail customers is subject to targets for purchase volumes and upper limits on customer bill impacts, which, based on the load forecast, creates a cap on the available budget.

From 2009 through 2012, the IPA's annual electricity procurement plans included purchase of renewable energy resources sufficient to meet the RPS applicable to the eligible load of ComEd and Ameren. In 2013 and 2014, the IPA determined that resources under contract were sufficient to meet the reduced eligible load. The RPS calls for the procurement of the following quantity of renewable energy resources and renewable energy credits as a mandatory part of each utility's annual supply: [152]

- 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

This obligation increases by at least 1.5% each year thereafter to at least 25% by June 1, 2025. [153] The obligation of each electric utility is determined by applying the required percentage to the amount of eligible retail sales from the most recently completed delivery year. In addition, the RPS mandate includes targets for specific resource types: 75% wind, 6% (by June 1, 2015) photovoltaics ("PV") and 1% (by June 1, 2015) distributed generation ("DG") which can be included within the PV requirements. [154]

The cap on the available RPS budget 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 kilowatthour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these resources in 2011.*[155]

This section assesses the renewable resource volume and dollar budgets available for use to both utilities. The assumptions made below reflect the utility's expected load forecasts as described in sections 3.2 and 3.3 and recommended by the IPA to be adopted by the ICC. If the ICC were to adopt a different load forecast, then

[152] Renewable energy resources are defined as: "energy and its associated renewable energy credit or renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, anaerobic digestion, crops and untreated and unadulterated organic waste biomass, tree waste, hydropower that does not involve new construction or significant expansion of hydropower dams, and other alternative sources of environmentally preferable energy. For purposes of [the IPA Act], landfill gas produced in the State is considered a renewable energy resource." 20 ILCS 3855/1-10.
[153] 20 ILCS 3855/1-75(c)(1).
[154] 20 ILCS 3855/1-75(c)(1).
[155] 20 ILCS 3855/1-75(c)(2)(E).

the following analysis would have to be revised accordingly. Likewise, in a future delivery year the load forecast may be updated and differ significantly from what is shown here.

As the target total renewables and wind requirements are forecasted to be met in the 2015-2016 delivery year, the IPA does not recommend procuring any additional wind or generic renewable resources on behalf of Ameren or ComEd during the upcoming year. However, the photovoltaic and distributed generation requirements for both utilities are not forecast to be met. To achieve statutory compliance, the IPA recommends a one-year Solar Renewable Energy Credits (SRECs)[156] procurement to meet both utilities' PV requirements for the 2015-2016 delivery year.

A procurement of DG resources to meet those requirements would require contracts of at least 5 years. Because future load forecasts could change and result in a curtailment of the existing LTPPAs from 2010, there could be risks of conflicting curtailment requirements if new multi-year contracts were entered into using funds collected from eligible retail customers.

The IPA thus proposes using funds collected from hourly customers to conduct a procurement from existing DG resources to allow the utilities to meet their DG requirements. The IPA notes that the recently enacted new Section 1-56(i) of the IPA Act requires the development of a supplemental photovoltaic procurement plan that will include photovoltaic DG resources. To the extent practicable, and accounting for choices yet to be made on procurement structure and design, any procurement of DG resources for the utilities should be considered in a manner that could be synchronized with the Section 1-56(i) procurement process.

The IPA recommends (see Section 8.2.1) that the ICC require the utilities to produce updated load forecasts on March 13, 2015 and to curtail the Long-Term Power Purchase Agreements ("LTPPAs") if the updated forecast indicates the renewable budget will be exceeded.[157] That forecast would also be used for determining the available budget and targets for any PV procurements. These forecasts will also be used to plan the April 2014 forward hedge procurement event (see Section 7.3).

8.1 Current Utility Renewable Resource Supply and Procurement

8.1.1 Ameren

As shown in Table 8-1, Ameren's current renewable resource contracts will cover its total renewables RPS targets for the next two delivery years. Assuming that no additional purchases of renewable energy resources are made, Ameren will fall short of meeting its RPS requirements in the 2017-2018 delivery year by 9%. In the 2018-2019 and 2019-2020 delivery years, the shortfall for total renewables will reach 43% and 48%, respectively.

The Illinois Power Agency Act also sets separate goals for wind, photovoltaic, and distributed renewable generation as fractions of the total renewables requirement.[158] Table 8-1 shows that Ameren is projected to meet its wind generation goals for the next three delivery years. Assuming that no additional purchases are made, Ameren will fall short of the wind goal by 25% and 31% in the 2018-2019 and 2019-2020 delivery years, respectively. Assuming that no additional purchases of PV and DG are made, Ameren will fall short of the photovoltaic and distributed generation goals in each delivery year. Unlike the projection in last year's

[156] The 2014 *Annual Report: The Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts* contains an overview of solar and distributed generation in other states. It was included in the 2014 Report to demonstrate the experiences of other states and provide insights into the potential for a SREC market that could develop in Illinois.
[157] In its Final Order, the Commission adopted Wind on the Wires' proposal that the utilities' updated March load forecasts be made publicly available through filing on e-Docket. See Docket No. 13-0546, Final Order dated December 18, 2013 at 199.
[158] 20 ILCS 3855/1-75(c)(1).

Procurement Plan, Ameren is projected to have surplus RPS funds[159] with which to purchase renewables. (Table 8-3).

The IPA recommends a one-year SRECs procurement to meet Ameren's PV requirement out for the 2015-2016 delivery year.

Table 8-1: Ameren's Existing RPS Contracts vs. RPS Requirements

Delivery Year		Total Renewables	Wind	Photo-voltaics	Distributed Generation
2015-16	**Target (MWh)**	651,767	488,825	39,106	6,518
	Purchased MWh	1,008,810	979,916	8,894	0
	Remaining Target (MWh)	-357,043	-491,091	30,212	6,518
2016-17	**Target (MWh)**	707,299	530,474	42,438	7,073
	Purchased MWh	1,029,245	976,851	12,394	0
	Remaining Target (MWh)	-321,946	-446,377	30,044	7,073
2017-18	**Target (MWh)**	939,118	704,339	56,347	9,391
	Purchased MWh	854,396	848,338	6,058	0
	Remaining Target (MWh)	84,722	-143,999	50,289	9,391
2018-19	**Target (MWh)**	1,046,710	785,033	62,803	10,467
	Purchased MWh	600,000	596,571	3,429	0
	Remaining Target (MWh)	446,710	188,462	59,374	10,467
2019-20	**Target (MWh)**	1,152,527	864,395	69,152	11,525
	Purchased MWh	600,000	596,571	3,429	0
	Remaining Target (MWh)	552,527	267,824	65,723	11,525

8.1.2 ComEd

Table 8-2 shows ComEd's current RPS contracts relative to its renewables requirements. ComEd's forecast indicates that enough renewables have been procured to meet its total renewables and wind targets for the 2015-2016 delivery year. In subsequent delivery years, ComEd is forecasted to fall short of its total renewables target by 7% in 2016-2017, 22% in 2017-2018, 41% in 2018-2019 and 47% in 2019-2020. ComEd is also forecasted to fall short of the photovoltaic and distributed generation 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. Unlike the projection in last year's procurement plan, ComEd (Table 8-4) is projected to have surplus RPS funds[160] with which to purchase renewables.

The IPA recommends a one-year SRECs procurement to meet ComEd's PV requirement for the 2015-16 delivery year.

[159] This is a result of the higher load forecast relative to that utilized in last year's procurement plan. The RPS budget is a function of, among other things, forecasted eligible retail load. Forecasted eligible retail load is significantly higher as of this procurement plan due to the recent observation of communities opting to suspend their municipal aggregation programs and take supply from Ameren.
[160]See prior footnote re: load migration. .

Table 8-2: ComEd's Existing RPS Contracts vs. RPS Requirements

Delivery Year		Total Renewables	Wind[161]	Photo-voltaics[162]	Distributed Generation[163]
2015-16	Target (MWh)	1,319,414	989,561	79,165	13,194
	Purchased MWh	1,464,204	1,433,838	29,395	0
	Remaining Target (MWh)	-144,790	-444,277	49,770	13,194
2016-17	Target (MWh)	1,681,101	1,260,826	100,866	16,811
	Purchased MWh	1,561,397	1,340,016	27,895	0
	Remaining Target (MWh)	119,704	-79,190	72,971	16,811
2017-18	Target (MWh)	1,961,224	1,470,918	117,673	19,612
	Purchased MWh	1,533,198	1,233,838	27,887	0
	Remaining Target (MWh)	428,026	237,080	89,786	19,612
2018-19	Target (MWh)	2,150,200	1,612,650	129,012	21,502
	Purchased MWh	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	888,475	378,812	101,125	21,502
2019-20	Target (MWh)	2,385,685	1,789,264	143,141	23,857
	Purchased MWh	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	1,123,960	555,426	115,254	23,857

Table 8-2 includes ComEd's statutory targets for wind, photovoltaic and distributed renewable procurement over the five-year projection horizon.

8.2 LTPPA Curtailment

8.2.1 Impact of Budget Cap

Section 1-75(c)(2) of the IPA Act requires the IPA to reduce the amount of renewable energy resources to be procured for any particular year in order to keep the "estimated" net increase in charges to eligible retail customers below the statutory cap. For the 2013-2014 and 2014-15 delivery years, the ICC approved the curtailment based on March updated load forecasts of long-term renewables contracts to keep the cost of renewable energy resources below the statutory cap. Curtailment has been required of ComEd's contracts but not Ameren's. Ameren's and ComEd's load forecasts have now significantly increased based on the recent observation of a significant number of municipalities suspending their municipal aggregation programs and returning to utility supplied service. Because the delivery year RPS budget is a function of the amount of eligible utility load, which has increased relative to last year's load forecasts, it is forecasted that the delivery year RPS Budgets exceed the Contractual Cost for RECs already procured in each delivery year. Therefore, both Ameren (Table 8-3) and ComEd (Table 8-4) are forecasted to have RPS funds available in each of the five delivery years covered by this plan.

Table 8-3: Required Reductions (Curtailments) of Long-term Renewable Contracts (LTPPAs) to Meet IPA Act Spending Cap, Ameren

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	Contractual REC Cost, LTPPAs ($)	LTPPA Quantity Reduction (%)
2015-16	9,183,529	13,042,188	$3,858,659	7,826,000	0.0%
2016-17	10,403,861	13,032,625	$2,628,764	7,796,000	0.0%
2017-18	9,412,155	13,004,827	$3,592,673	7,957,000	0.0%
2018-19	8,000,000	12,974,820	$4,974,820	8,000,000	0.0%
2019-20	7,999,000	12,966,712	$4,967,712	7,999,000	0.0%

[161] Wind RPS requirement is 75% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).
[162] PV RPS requirement is 6% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).
[163] Distributed Generation RPS requirement is 1% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

Table 8-4: Required Reductions (Curtailments) of Long-Term Renewable Contracts (LTPPAs) to Meet IPA Act Spending Cap, ComEd

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	Contractual REC Cost, LTPPAs ($)	LTPPA Quantity Reduction (%)
2015-16	23,177,988	28,538,822	5,360,834	22,613,000	0.0%
2016-17	23,498,871	28,051,960	4,553,089	22,674,000	0.0%
2017-18	23,792,264	28,206,252	4,413,988	23,137,000	0.0%
2018-19	23,431,544	28,281,063	4,849,519	23,357,000	0.0%
2019-20	23,558,293	28,327,164	4,768,871	23,484,000	0.0%

While it appears unlikely that curtailment of the LTPPAs would be required in the 2015-2016 delivery year, the IPA recommends that a final determination be based upon the March 2015 load forecasts. In the event that curtailments are required, the IPA recommends that the methodology adopted in the ICC's Order on Rehearing of the 2014 Procurement Plan be employed for the calculation of REC prices for curtailed RECs. As it is highly unlikely that curtailments will be required, and as hourly ACP funds are proposed for a procurement of RECs distributed generation systems, the IPA proposes to address a potential curtailment through continuing its prior offer to purchase curtailed RECs at the imputed REC prices from the 2010 contracts using the Renewable Energy Resources Fund.

8.3 Alternative Compliance Payments

8.3.1 Use of Hourly ACPs Held by the Utilities

As described in Chapter 2, the utilities collect Alternative Compliance Payments ("ACPs") on behalf of customers taking hourly service from the utility.[164] Unlike the ACP funds paid by ARES into the Renewable Energy Resources Fund discussed in Section 8.3.2 below, which are held and administered by the Agency, utility hourly customer ACP funds are held by the utilities.[165] As required by the IPA Act, each utility has disclosed the amount of hourly customer ACP funds being held: as of May 31, 2014; for Ameren, the value is $5,556,580; for ComEd, the value is $7,842,658.

The IPA Act requires the ACP funds from utility hourly customers 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 alternative compliance payment rate or rates in the prior year ending May 31."[166] As described above, for the 2013-2014 and the 2014-2015 Delivery Years, 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.

The curtailment of the LTPPAs appears unlikely in 2015-2016 and the utilities have a shortfall in meeting their DG goals. It therefore appears that utilizing the already collected, and otherwise unspent, hourly ACP funds to allow the utilities to meet their DG goals would be appropriate to further an aspect of the utilities' RPS obligations. Additionally, as contracts for DG resources must be "no less than 5 years" in length,[167] entering into 5 year contracts using existing ACP funds already collected from hourly customers eliminates

[164] See 20 ILCS 3855/1-75(c)(5).
[165] See id.
[166] Id.
[167] 20 ILCS 3855/1-75(c)(1).

the load migration risk present with the renewable resources budget (from which long-term contracts have already been subject to curtailments).

In developing a DG procurement using Hourly ACP funds, the IPA is guided by the following principles:

First, the primary goal of the DG procurement must be to bring the utilities into compliance with statutory requirements for RECs from distributed generation systems, to the extent possible given the balance of existing hourly ACP funds. The sooner a successful DG procurement event is conducted, the sooner the Agency will have made progress in fulfilling its duty under the law of procuring renewable resources for the utilities.

Second, the Agency should strive to structure its procurement so as to ensure the procurement proceeds in a manner consistent with the governing law. With respected to a DG procurement, this includes the obligation that "to the extent available," half of the DG RECs procured originate from "devices of less than 25 kilowatts in nameplate capacity."[168]

Third, the Agency should structure its DG procurement mindful of its obligation to produce procurement plans aimed at ensuring "adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[169]

And fourth, the Agency should proceed with awareness of its concurrent supplemental photovoltaic procurement planning process under Section 1-56(i) of the IPA Act, noting both opportunities for synergies between the two procurements and market confusion challenges that could result from two separate-but-similar procurement processes conducted by the same Agency with distinct counterparties.[170]

Section 1-75(c)(1) of the IPA Act also contains specific provisions on the use of third-party aggregators as counterparties:

> *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.*[171]

While the IPA would like to bring utilities into compliance with DG procurement goals as quickly as possible, organizing the existing distributed generation renewable energy credit market for a Spring 2015 procurement may be ambitious. Unlike with the Agency's supplemental solar photovoltaics procurement under Section 1-56(i) of the IPA Act, which does not define aggregator size, Section 1-75(c)(1) requires that aggregators "aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity."[172]

Meeting a one megawatt aggregation threshold may be especially challenging given the relatively small universe of existing DG systems in Illinois. Any participating system would both need to have RECs available

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[168] Id. Notably, the requirement is not "at least . . . half." As the phrase "at least" is used throughout Section 1-75(c)(1) with respect to procurement targets, but not with respect to the smaller than 25 kW requirement, the Agency believes that procuring, say, 55% of its DG RECs from sub 25 kW systems leaves it at the same compliance level as procuring 45%.
[169] 20 ILCS 3855/1-5(A).
[170] For procurements made using the hourly ACP funds, the utilities are counterparties. For procurements under Section 1-56(i) of the IPA Act, the Illinois Power Agency is the counterparty.
[171] The IPA understands its obligation under this language as requiring it to "solicit" the use of aggregators, enabling a model through which the utilities contract with an entity other than the owner of the DG device. The Agency does not view this language as mandating that every DG REC contract must feature a third-party (i.e., non-system owner) as a counterparty, and would look to permit self-aggregation.
[172] Id.

for procurement (i.e., not already under contract) and be willing to transfer available RECs,[173] and would need to have the knowledge and understanding necessary to participate through an aggregator in an IPA procurement event. Based on these factors, the IPA believes it is unlikely that aggregators would be prepared to deliver one megawatt blocks to a Spring 2015 DG procurement and thus the IPA should structure and time its DG procurement accordingly,[174] but requests feedback from stakeholders on these assumptions through comments on its draft Plan. The Agency also requests feedback on how best to stage or time its procurement so as to maximize the likelihood that goals are met.

The IPA also notes that while it may conduct a DG photovoltaics procurement using funds from the Renewable Energy Resources Fund under Section 1-56(i) of the IPA Act, the ideas presented in this Plan do not necessarily reflect the appropriate structure or process for that procurement. The IPA's supplemental procurement process under Section 1-56(i) will be considered through a separate process, with the draft supplemental procurement plan due to be published on or before September 29, 2014.

With the foregoing principles and considerations in mind, the IPA proposes the following three models as options for a DG procurement using hourly ACP funds for its draft Plan. Recognizing the immense value of stakeholder feedback in the Agency's workshops and subsequent question and comment solicitations made to date, the IPA seeks further feedback from stakeholders on these approaches and other models. The IPA endeavors to use the draft Plan comment process as a mechanism to develop more detailed and refined approach in its filed Plan. Comments should be mindful of the principles articulated above and the governing law, and need not necessarily indicate a specific preferred strategy.

Under each option below, the Agency would seek to commit only those hourly ACP funds that have been collected, and would procure DG RECs until those funds are fully spent or the utilities' 2015-2016 DG goals are met.

Option 1 – Full Competitive Procurement

The Agency's first option involves an approach most similar to the Agency's established one-year REC procurement process: conducting a single procurement competitive bid process with bids selected solely on the basis of price. To meet the statutory requirement that "to the extent available" half of RECs procured be from systems below 25 kW in size, received bids would be placed into two categories – above 25 kW in size and below 25 kW. Maintaining a 50/50 balance would inform the next winning bid to be selected—for example, if the Agency had already selected more RECs from systems larger than 25 kW in size, the next winning bid would be the lowest-price bid from systems smaller than 25 kW in size.

If this approach can achieve the appropriate market response, this approach may feature the lowest REC prices of the procurement models due to the competitive nature of every bid. It also involves a procurement process that is very familiar to the Agency, its Procurement Administrator, the Commission's Procurement Monitor, and other stakeholders.

However, there are concerns about whether the market could self-organize sub-25 kW systems into one megawatt blocks for participation in a competitive price procurement process, even with the IPA's active assistance. To the extent that participation from small systems is unrealistic under this model, the Agency is

[173] Based on industry feedback, the Agency understands this to be a challenge with some existing commercial systems, as claiming that energy is sourced from renewable resources is inconsistent Federal Trade Commission guidelines if the environmental attributes (i.e., the RECs) of the generation are sold, transferred, or assigned. (see http://www.business.ftc.gov/documents/environmental-claims-summary-green-guides for more information). While this factor is unlikely to present a challenge with aggregating smaller residential systems, participation from larger resources may be necessary for a 1 MW threshold to be met.

[174] Additionally, without aggregator participation, the Agency believes it is unlikely that the goal of procuring half of DG RECs from systems below 25 kW can be met. 20 ILCS 3855/1-75(c)(1).

concerned with procurement design models dictating outcomes that leave it out of compliance with statutory requirements. Additionally, participation from small systems consistent with the one megawatt aggregator requirement may only come through speculative bidding, potentially increasing the risk that contracted REC delivery goes unmet.

Variations: One variation on this model involves allowing aggregators to aggregate across all system sizes, with bids being at least one megawatt featuring some balance of at/above- or below-25 kW, and the competitive bid selection process then working to fine tune the system size balance by selecting the next lowest price bid that brings the Agency closest to 50/50 compliance.

Option 2 – 2013 Plan Model

In its 2013 Procurement Plan, based on feedback received at workshops and through comments during the spring and summer of 2012, the Agency proposed a distributed generation procurement model "for Commission review and comment" and "for implementation at such time as the RPS budgets and available ACP funds allow."[175] The model's key features included segmenting the DG system market into sub-25 kW ("small") and 25 kW-2 MW ("large") categories, conducting a competitive procurement for RECs from large systems, and using the larger system procurement's results multiplied by a proposed scalar for the development of a standard offer price for RECs from systems under 25 kW.[176]

The 2013 Plan model calls for 5 year contracts running between the utilities and counterparty entities having aggregated at least 1 MW in nameplate capacity, with 1 MW of aggregated capacity necessary for competitive bidding (large system) or standard offer participation (small system).[177] The IPA would be responsible for developing and administering an aggregator registration process for winning aggregators. Bidding aggregators would have the choice of 4 delivery dates across a calendar year (beginning June 1) to "facilitate new build schedules or initial aggregation efforts."[178]

Open issues for this approach include determining bid selection should there be an over-subscribed small system standard offer procurement, as bids could no longer be selected on the basis of price. Additionally, while the model calls for aggressive aggregator outreach by the IPA, even with that assistance there may be concerns about whether the market can self-organize into 1 MW blocks necessary for procurement participation. As the Agency's Section 1-56(i) procurement does not feature a statutory 1 MW aggregation threshold, the disconnect between the organizing required to meet this procurement's standard and the less stringent organizing necessary to participate in the supplemental solar procurement could create market confusion.

Variations: For the Plan, one potential update to this model would involve the Agency using the results of its Renewable Resources Budget SREC procurement to produce a standard offer price for both small and large systems. If adopted, this variation could require distinct scalars between system size segments based on cost structure assumptions. While providing increased clarity to the market, it is unclear whether a standard offer price is necessary or valuable for large DG systems.

Option 3 – Program Administrator as Aggregator

A third option is for the IPA to conduct a competitive process to solicit a single aggregator for each utility. That aggregator would serve as the single counterparty for all DG procurement contracts, having been the winning aggregator for a single procurement block of all RECs, or through an RFP process for the sale to and purchase by the IPA of all DG RECs at a fixed price established by applying a scalar to renewable resource

[175] IPA 2013 Procurement Plan at 90-91. For a full discussion of this proposal, see pp. 90-96.
[176] Id. at 93-95.
[177] Id.
[178] Id. at 94.

budget SREC procurement results. The primary role of the aggregator, from the IPA's perspective, would be to buy RECs produced by DG systems and sell those RECs to the IPA under a single contract at a specific price and deliver them during a specified period.

This model may also allow for flexibility in offers to the market. Depending on what the Agency views as the most effective way to interact with the market, a standard offer price model or a declining block model may be accommodated (as may a competitive bid process), with no threshold system size necessary for participation. Additional aggregation among eligible systems (for economies of scale, administrative efficiencies, etc.) would still be allowed.

Keys to this model involve a) selecting a program administrator with the capacity to handle this effort, and b) appropriately structuring the relationship with program administrator to ensure that all participant interests are adequately protected. Assigning this degree of authority and control to a third-party program administrator involves risk necessitating significant contractual safeguards. A program administrator model also adds an additional layer of administrative costs, although it is unclear whether these costs would be greater than if all bids came through separate third-party aggregators of 1 MW in size. As with the 2013 Plan approach, criteria for selecting competing bids for a standard offer contract would need to be developed. The process of selecting a program administrator may also introduce delay in procurement.

Variations: One variation on this model includes allowing for a competitive procurement for systems larger than 25 kW consistent with Option 1 above, and employing the program administrator only for systems below 25 kW in nameplate capacity. Another variation involves employing a single program administrator for all system sizes, but allowing for competitive bid procurement for systems above 25 kW in size (run by the program administrator) while employing a standard offer or declining block approach for systems below 25 kW in size.

The models presented above are built around the assumption that the IPA's DG procurement would be conducted for RECs from a single fuel source (solar photovoltaics). However, under the IPA Act, distributed generation systems may be "powered by wind, solar thermal energy, photovoltaic 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."[179]

If DG RECs are available from multiple fuel sources, the IPA believes some of the options available – such as the use of a scalar – could only apply to a single designated fuel source, leaving questions regarding whether or how to procure from others. At a minimum, the IPA believes procuring DG RECs from multiple fuel types would require the development of separate benchmarks, and may involve additional administrative burdens that would need to be justified by procurement scale. As part of the draft Plan review and comment process, the Agency additionally seeks feedback on a) existing availability of DG renewable energy credits from non-photovoltaic sources in Illinois (to the extent known), and b) whether or how procurements could be structured for DG RECs from multiple fuel types.

The IPA Act requires DG contracts to be for a minimum of five-years in length, allowing the utilities to make significant progress towards compliance across all contract delivery years.[180] In order to maximize the impact of available funds, the IPA is not proposing contract lengths of longer than five years.

[179] 20 ILCS 3855/1-10.

[180] Actual compliance targets in future years are unknown. As noted above, because the targets are defined by "a minimum percentage of each utility's total supply to serve the load of eligible retail customers," targets are heavily dependent on load migration trends.

8.3.2 Use of ACPs Held by the IPA

As of this report date, the RERF balance equals $51,574.45, the total amount received in the Agency's RERF attributable to ARES ACP payments less the cost of RECs purchased per the IPA's offer to use RERF funds to purchase curtailed RECs from the 2010 LTPPAs that were not purchased by ComEd using hourly ACP funds. Table 8-5, below, shows the current IPA RERF balance sheet. In September 2014, the IPA expects to receive an estimated $77 million in ACPs for the June 2013 – May 2014 planning year. These expected payments, in the aggregate, are significantly higher than prior year payments. The higher amount is a direct result of significant load switching from utility supply to RES supply in recent months, primarily driven by municipal aggregation activities.

Table 8-5: RERF Balance

Planning Year	Funds Received/Disbursed	Total ACPs
2009-10	2010 - Quarters 3 and 4	$7,148,261.61
2010-11	2011 - Quarters 3 and 4	$5,606,245.18
2011-12	2012 - Quarters 3 and 4	$2,156,777.61
2012-13	2013 – Quarters 3 and 4	$38,382,345.57
2012-13	2014 – Quarters 1 and 2 RECs Purchased	$(1,719,141.52)
Aggregate Total		**$51,574,488.45**

The ICC has held that it does not have jurisdiction over the RERF, and as a result the IPA is not seeking approval for procurement using the RERF in this plan.[181] As previously described newly enacted Section 1-56(i) of the IPA Act will require the IPA to develop a Supplemental Procurement Plan to spend up to $30 million on RECs from photovoltaic resources from the RERF. That Supplemental Procurement Plan will require review and approval by the ICC, and the results of procurements stemming from that supplemental procurement will likewise require ICC approval. While the supplemental procurement plan does not direct the IPA to fully utilize the full RERF balance, 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 add to the ease through which the IPA can use the remaining fund balance to further the RERF's purposes.

[181] Docket No. 12-0544, Final Order dated December 19, 2012 at 112-114.

9 Procurement Process Design

The procedural requirements for the procurement process are detailed in the Illinois Public Utilities Act at Section 16-111.5. The Procurement Administrators, retained by the Agency in accordance with 20 ILCS 3855/1-75(a)(2), conduct the competitive procurement events on behalf of the IPA. The costs of the Procurement Administrators incurred by the Illinois Power Agency are recovered from the bidders and suppliers that participate in the competitive solicitations, through both Bid Participation Fees and Supplier Fees assessed by the IPA. As a practical matter, the utility "eligible retail customers" ultimately incur these costs as it is assumed that suppliers' bid prices reflect a recovery of these fees. As required by the PUA and in order to operate in the best interests of consumers, the Agency and the Procurement Administrators have reviewed the process for potential improvements.

Section 16-111.5(e) of the Public Utilities 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 procurement administrator shall make available to the Commission all written comments it receives on the contract forms, credit terms, or instruments. If the procurement administrator cannot reach agreement with the applicable electric utility as to the contract terms and conditions, the procurement administrator must notify the Commission of any disputed terms and the Commission shall resolve the dispute. The terms of the contracts shall not be subject to negotiation by winning bidders, and the bidders must agree to the terms of the contract in advance so that winning bids are selected solely on the basis of price.*

(3) Establishment of a market-based price benchmark.

> *As part of the development of the procurement process, the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor, shall establish benchmarks for evaluating the final prices in the contracts for each of the products that will be procured through the procurement process. The benchmarks shall be based on price data for similar products for the same delivery period and same delivery hub, or other delivery hubs after adjusting for that difference. The price benchmarks may also be adjusted to take into account differences between the information reflected in the underlying data sources and the specific products and procurement process being used to procure power for*

the Illinois utilities. The benchmarks shall be confidential but shall be provided to, and will be subject to Commission review and approval, prior to a procurement event.

(4) Request for proposals competitive procurement process.

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

(5) A plan for implementing contingencies

[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.

9.1 Contract Forms

Of these five process components, the area with the greatest potential for efficiency improvements resulting in lower costs passed along to ratepayers is item (2): development of standard contract forms and credit terms and instruments. The IPA believes that the forms have now become largely standardized and should remain acceptable to future potential bidders. As was the case with the 2014 procurement events, the process to receive comments from potential bidders can be restricted to changes to the forms, thus reducing Procurement Administrator time and billable hours, while shortening the critical path time needed to conduct a procurement event. This is because, prior to the 2014 procurement events, the forms, terms and instruments had become relatively stable, with fewer comments being received from potential bidders requesting revision or optional terms for each succeeding procurement event. Any procurement event to be conducted under the auspices of the 2015 Procurement Plan would be the ninth iteration of IPA-run procurement events, when including the April 2014 procurement event and planned September 2014 procurement event. In each iteration prior to 2014, potential bidders had an opportunity to comment on documents and those comments have been, where appropriate, incorporated into the documents or provided as acceptable alternative language. In the 2014 procurement events, potential bidders submitted only sparse comments on the proposed changes to the forms.

The recommended improvements in regards to the forms apply to both the energy procurement and RPS procurement. In the procurement events conducted for energy blocks and RECs in 2012 (the Rate Stability Procurement and the standard Spring Procurement including the RPS Procurement) comments have been few, with virtually no new modifications being accepted or made (in part because some comments made by new participants have been handled in prior procurement events). The documents used for the 2012 IPA-run procurement events illustrate both the breadth and depth of bidder input to the current state of the documents and the maturity of the documents themselves.

On the opposite side of this discussion, the IPA also understands that markets are dynamic and periodic review of contract terms is necessary to ensure proper protection of the utilities, utility customers and suppliers. The IPA therefore recommends that the last used forms, namely the energy contracts used in the 2014 procurement events and RPS contracts used in the Spring 2012 RPS Procurements be the starting point for the contracts used in the energy and SREC procurements associated with this plan and 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. For the DG procurement using hourly ACP funds new contracts will likely be needed and the development of those contracts should be coordinated, to the extent possible, with the contracts developed as part of the Section 1-56(i) Supplemental Procurement Plan. Once consensus is reached among these parties, the supplier comment process would be limited to discussion on proposed changes that have been made relative to the previously used contracts or to changes that suppliers believe are necessary because of changes to laws or regulations that directly affect the supplier or the terms of the contract. If based upon supplier comments, consensus to a change cannot be reached among these reviewing parties, then the provisions in the prior contract (the 2014 energy contract or the Spring 2012 RPS contract) would be used.

9.2 IPA Recovery of Procurement Expenses

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."[182] Additionally in April, 2014 the IPA adopted new administrative rules related to fee assessments that codify past practices including defining "bidders" and "suppliers" in procurement events as well as the process for determining those fees.[183]

The IPA has historically recovered the cost of procurement events through two types of fees:

- 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.

For the last several procurements, the Bid Participation Fee has been nominal ($500), which means that the bulk of the costs of the procurement event (which are typically several hundred thousand dollars) are recovered from winning bidders through Supplier Fees. There are two risks for the IPA from recovering costs in this manner:

1. If not all the blocks are procured (but 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 associated with the blocks that are not procured will not be collected.
2. Suppliers may not necessarily pay the Supplier Fees on time (or pay them at all). Suppliers that have bids that are approved by the Commission proceed to the contract execution process with the utility and will get paid under that contract whether or not they have paid the Supplier Fees. When the structure of fees was first introduced, non-payment of the Supplier Fees was an event of default under the contract with the utility. Suppliers had a very strong incentive to pay the Supplier Fees as failure to do so meant that they would not be able to get the compensated under the contract from winning the bid. As procurement events came to be IPA-run, this structure was abandoned as the responsibility for assessing fees to bidders is the IPA's and not the utility's. The incentives for suppliers to pay the Supplier Fees were reduced as a result.

In improving the procurement process design an objective of the IPA is to provide a structure by which the IPA is protected from non-payment of the Supplier Fees and potentially a structure that could adapt to the number of blocks actually procured.

There are two broad categories of solutions:

a. 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.
b. 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.

With the exception of the 2014 procurement events, the pre-bid letter of credit has been strictly a credit instrument held for the benefit of the utility and its customers. The utility may draw upon the pre-bid letter of credit if the supplier fails to complete the contract execution process. At that point, the utility has filed its

[182] 20 ILCS 3855/1-75(h).
[183] Illinois Administrative Code Title 83, Sections 1200.110. and 1200.220.

rates based on the winning bids but would have to buy replacement supply, for which it can use funds under the pre-bid letter of credit to mitigate any impact of the default on rates. The function of the pre-bid letter of credit could be expanded to ensure payment of the Supplier Fees by:

- Having the IPA be another beneficiary to the pre-bid letter of credit and adding a condition for drawing associated with non-payment of the Supplier Fees.
- Requiring suppliers to provide a pre-bid letter of credit with IPA as sole beneficiary in addition to the pre-bid letter of credit with the utility as beneficiary that suppliers are currently required to provide.
- Requiring suppliers to provide a letter of credit with IPA as sole beneficiary instead of the pre-bid letter of credit with the utility as beneficiary that suppliers are currently required to provide.
- Adding a condition to the utility pre-bid letter of credit allowing the utility to draw if the Supplier Fees are not paid by a date certain (and having an agreement between the IPA and the utility on how funds would flow back to the IPA for payment of the Supplier Fees). This is the approach used in the 2014 procurement events.

Alternatively, the fee structure currently in place could change to collect fees to cover the cost of the procurement event substantially ahead of time, together with penalties to suppliers that do not comply with their obligations to pay any fees owed at the conclusion of the procurement event. Several structures are possible, including:

- Continue with a nominal, flat bid participation fee. In addition, bidders pre-pay Supplier Fees in proportion to their indicative offers. These could be set as a percentage of the expected Supplier Fees. Winning bidders then would typically be required to pay additional Supplier Fees while losing bidders would typically receive a refund at the conclusion of the procurement event. The IPA would issue refunds to losing bidders only once additional Supplier Fees have been paid and the cost of the procurement event is recovered. Losing bidders would be at risk of not receiving all or part of their refund if one or more winning bidders did not pay all or part of their additional Supplier Fees.
- Institute a flat bid participation fee that would substantially cover the cost of the procurement event. In addition, bidders that intend to bid on a very high number of blocks would pre-pay an additional nominal fee per block on the basis of their indicative offers. Winning bidders would generally be required to pay a small additional amount and only losing bidders that had intended to bid on a very high number of blocks would be due a refund at the conclusion of the procurement event. These losing bidders would be at risk of not receiving all or part of their refund if one or more winning bidders did not pay all or part of their additional Supplier Fees.

In this draft Plan the IPA welcomes comments on these possible approaches and how the IPA can ensure that in conducting procurement events it complies with Section 1-75(h) of the IPA Act and Part 1200.220 of Title 83 of the Illinois Administrative Code.

9.3 Second Procurement Event

The IPA recommends that two procurement events be held for purchase of energy blocks under the 2015 Procurement Plan. All of the components of the procurement process detailed above would be conducted for the first of these two procurement events to be held in 2015. For the second procurement event for energy blocks under the Procurement Plan, certain activities would not occur as the second procurement event could rely on the documents or processes established for the first procurement event, as follows:

- The procurement administrator will rely on the contract and credit forms established in the first procurement event and suppliers would not comment anew on these documents;
- The procurement administrator will rely on the RFP design and benchmark methodology established in the first procurement event; and
- Suppliers that participate in the first procurement event will have access to an abbreviated qualification and registration process if they also participate in the second procurement event;

The IPA recommends holding one SREC procurement to be conducted in April 2015, and does not anticipate a second SREC procurement event under the 2015 Procurement Plan. The schedule for the DG procurement will be determined at a later date.

9.4 Informal Hearing

Section 16-111.5(o) of the PUA states,

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

This year, Staff led an informal hearing for the purpose of receiving comments on the April 2014 procurement process. Comments were received only from Boston Pacific (the ICC's Procurement Monitor) and the Retail Energy Supply Association ("RESA"). RESA's comments focused only on full requirements procurement as did much of Boston Pacific's. The IPA took those comments into account for its consideration of full requirements in Section 6.6. Boston Pacific's comments also related to observations on the winter 2014 price spikes and impact on procurement events in other states and thoughts on the timing of the bid day.

Regarding bid day timing Boston Pacific had three recommendations. First to allow time after the Spring procurement to allow for a contingency procurement event if needed; second, to avoid scheduling the bid day to conflict with other large procurements in PJM or MISO, and third to schedule the bid day on a Monday so that bidders would not have to hold open positions over a weekend. The IPA agrees with those recommendations and will strive to schedule the bid day accordingly. The IPA notes that the first and second principles could contradict each other, there may not be available windows of time that do not conflict with other procurements but that are also early enough to schedule a contingency procurement.

Comments from informal hearings are available of the Commission's web site.

Appendices

Appendices are available separately at:
www2.illinois.gov/ipa/Pages/Plans_Under_Development.aspx

Appendix A. Regulatory Compliance Index

Appendix B. Ameren Load Forecast

Supplemental Documents

- Section 16-111.5B Submittal (includes Appendices 1 and 3. Appendices 6 and 7 have been marked “Confidential”)
- Appendix 2: Workshop Summaries
- Appendix 4: AIC Potential Study (6 volumes)
- Appendix 5: AIC Third Party RFP

Appendix C. ComEd Load Forecast

Supplemental Documents

- Appendix C-1: Potential Study
- Appendix C-2: Energy Efficiency Analysis Summary
- Appendix C-3: Monthly Savings Curves
- Appendix C-4: Program Details
- ComEd 2014 Third Party Efficiency Program Summary of Bid Review Process, July 8, 2014 (Marked “Confidential”)

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