7 Resource Choices

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; (2) capacity; (3) transmission and ancillary services; (4) demand response; and (5) clean coal. Procurement of Renewable Resources, including wind, solar and distributed generation is considered separately in Chapter 8. Procurement of incremental energy efficiency programs and measures is also considered separately in Chapter 9.[166]

7.1 Energy

7.1.1 Energy Procurement Strategy

The IPA recommends maintaining the energy procurement strategy utilized for the 2016 Procurement Plan as explained below.

- The IPA procurement strategy involves the procurement of hedges to meet a portion of the hedging requirements over a three-year period and includes two procurement events in which the July and August peak requirements will be hedged at 106%, while the remaining peak and off-peak requirements will be hedged at 100%. In the spring procurement event, 106% of the July and August expected peak, 100% of the July and August off-peak, 100% of the June and September peak and off-peak, and 75% of the October through May peak and off-peak requirements for the 2017-2018 delivery year will be targeted for procurement. The fall procurement event will bring the targeted hedge levels to 100% for October through May of the 2017-2018 delivery year. A portion of the targeted hedge levels for the 2018-2019 and the 2019-2020 delivery years of 50% and 25%, respectively, will be acquired spread on an equal basis in the spring and fall procurement events.

The strategy is summarized in Table 7-1

Table 7-1: Summary of Energy Procurement Strategy for all Utilities[167]

Spring 2017 Procurement			Fall 2017 Procurement		
June 2017-May 2018 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2017-May 2018**	**Upcoming Delivery Year + 1**	**Upcoming Delivery Year + 2**
June 100% peak and off peak July and Aug. 106% peak, 100% off peak Sep. 100% peak and off peak Oct. - May 75% peak and off peak	37.5%	12.5%	100%	50%	25%

7.1.2 Energy Procurement Implementation

The following tables and figures were constructed using the July 2016 base load forecasts (which exclude incremental energy efficiency programs) to provide <u>indicative</u> procurement values for the 2017-2018 delivery year. The actual target procurement volumes used for the Spring and Fall 2017 procurements will be calculated using the March 2017 and the July 2017 updated load forecasts respectively.[168] These forecasts are expected to include approved energy efficiency programs for both Ameren Illinois and ComEd. The following

[166] The 2013 through 2016 Plans included the consideration of incremental Energy Efficiency programs in Chapter 7 as part of the Resources Choices discussion. For the sake of clarity, in the 2017 Plan that consideration of Energy Efficiency programs has been moved to its own Chapter 9.

[167] Table shows the cumulative percentage of load to be hedged by the conclusion of the indicated procurement events.

[168] In updating the load forecasts, the utilities are authorized to incorporate methodological refinements to their forecasts, provided that any such refinements are subject to the review and consensus of the IPA, ICC Staff, the Procurement Monitor, and the applicable utility.

tables are calculated assuming no LTPPA curtailments during the delivery periods, and the anticipated procurement volumes are rounded up or down to the nearest 25 MW block.[169]

While the utilities provided five years of load forecasts, 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 those years (Delivery Years 2020-2021 and 2021-2022) in this Procurement Plan. Therefore, the tables and figures that follow only cover Delivery Years 2017-2018, 2018-2019, and 2019-2020.

[169] For additional information on expected load and supply already under contract see Appendices E (Ameren Illinois), F (ComEd), and G (MidAmerican).

Figure 7-1 Ameren Illinois Peak Energy Supply Portfolio and Load

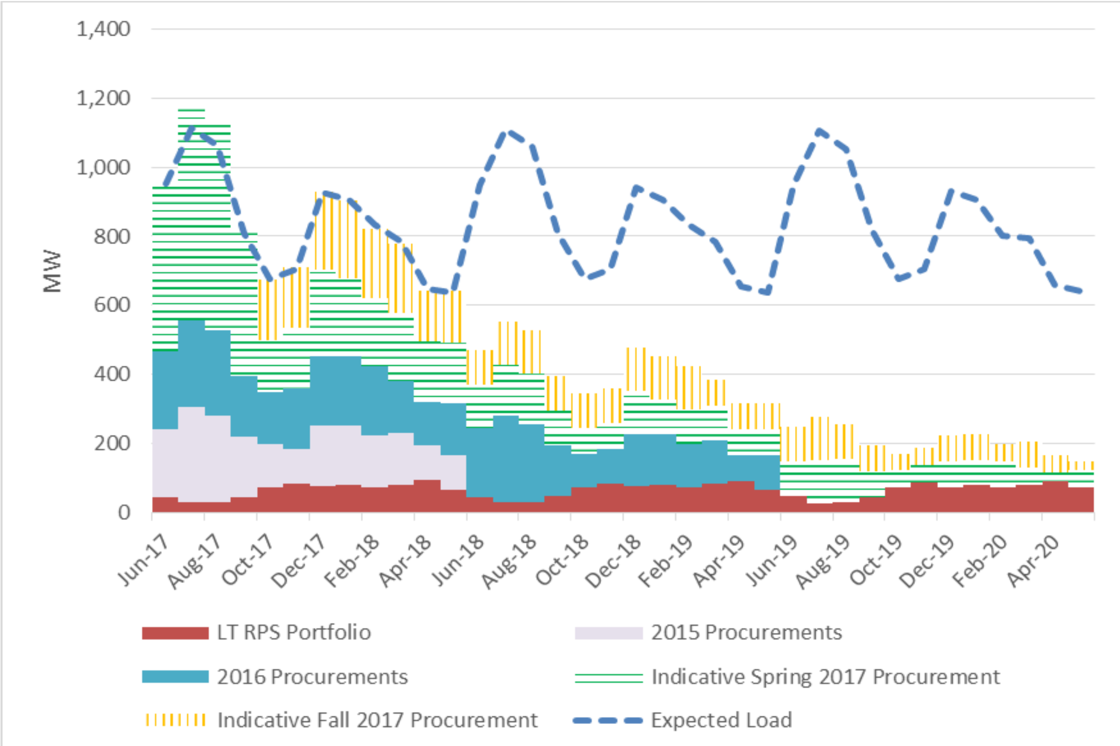

Figure 7-2 Ameren Illinois Off-Peak Energy Supply Portfolio and Load

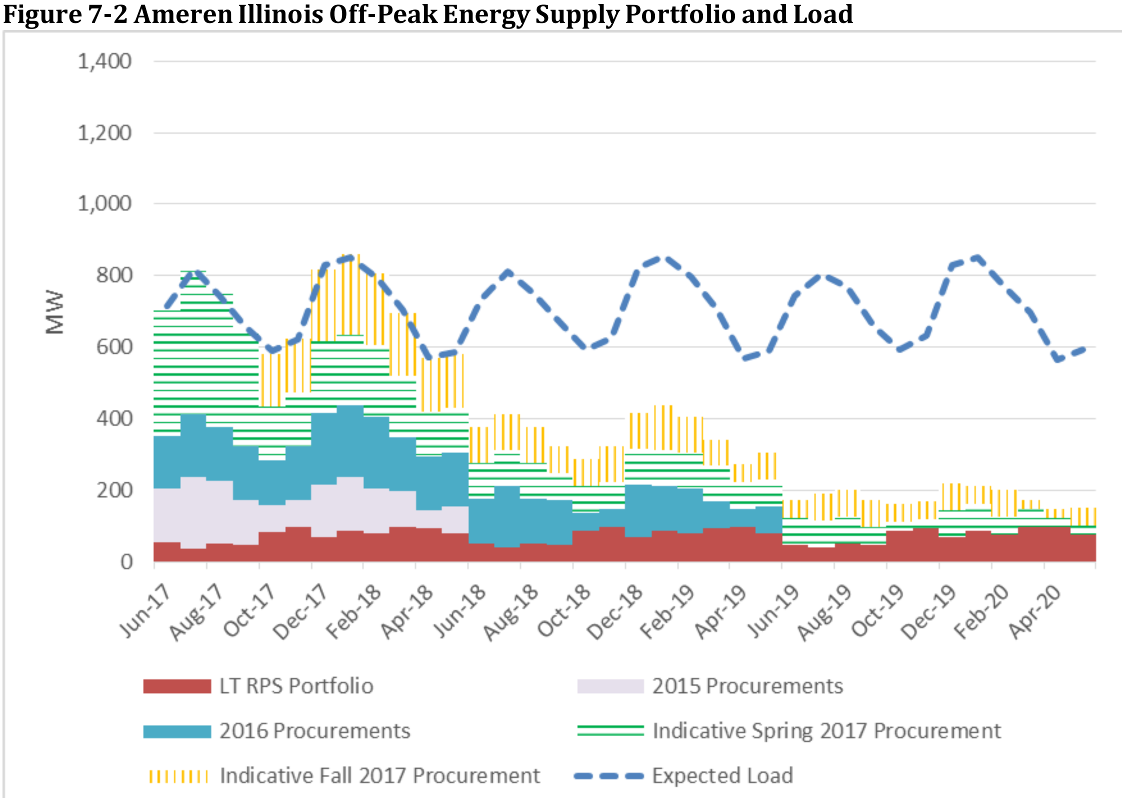

Table 7-2: Ameren Illinois 2017 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2017 Purchases (MW)		Anticipated Fall 2017 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2017-2018				
June-17	475	350	0	0
July-17	625	400	0	0
August-17	600	375	0	0
September-17	425	325	0	0
October-17	150	150	175	150
November-17	175	150	175	150
December-17	250	200	225	200
January-18	225	200	225	225
February-18	200	200	200	200
March-18	200	175	200	175
April-18	175	125	150	150
May-18	175	125	150	150
Delivery Year 2018-2019				
June-18	125	100	100	100
July-18	150	100	125	100
August-18	150	100	125	100
September-18	100	75	100	75
October-18	75	75	100	75
November-18	75	75	100	100
December-18	125	100	125	100
January-19	100	100	125	125
February-19	100	100	125	100
March-19	100	100	75	75
April-19	75	75	75	50
May-19	75	75	75	75
Delivery Year 2019-2020				
June-19	100	75	100	50
July-19	125	75	125	75
August-19	125	75	100	75
September-19	75	50	75	75
October-19	50	25	50	50
November-19	50	25	50	50
December-19	75	75	75	75
January-20	75	75	75	50
February-20	75	50	50	75
March-20	50	50	75	25
April-20	25	25	50	25
May-20	50	25	25	50

Figure 7-3 ComEd Peak Energy Supply Portfolio and Load

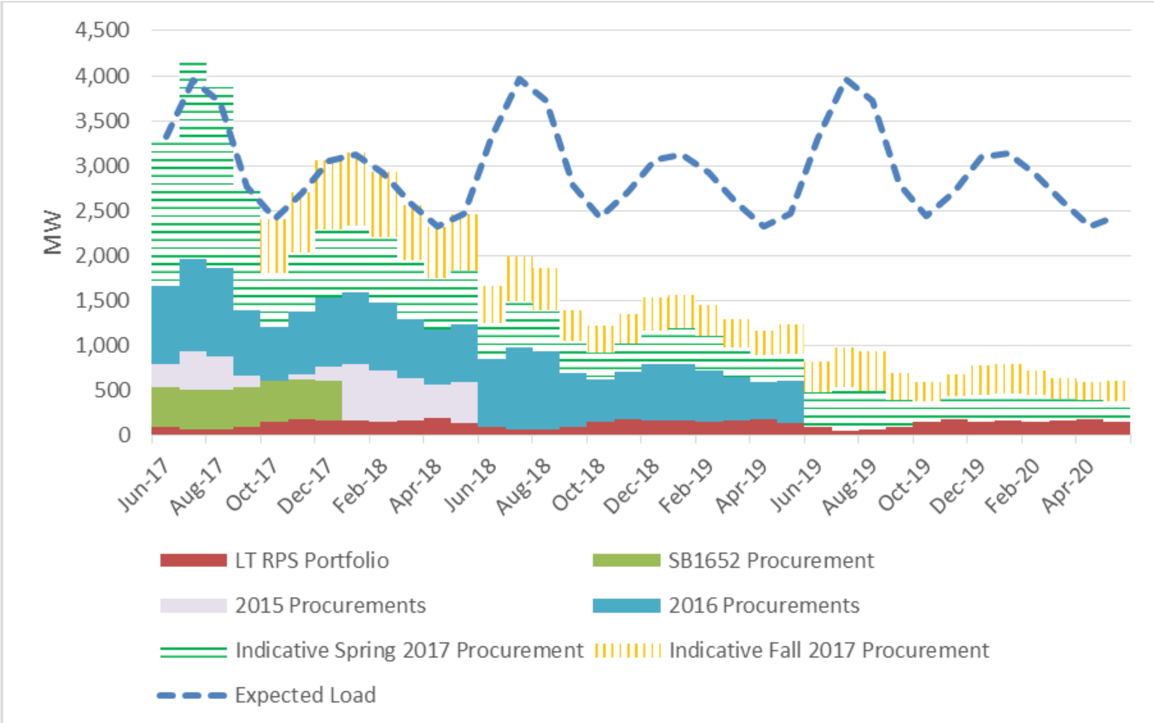

Figure 7-4 ComEd Off-Peak Energy Supply Portfolio and Load

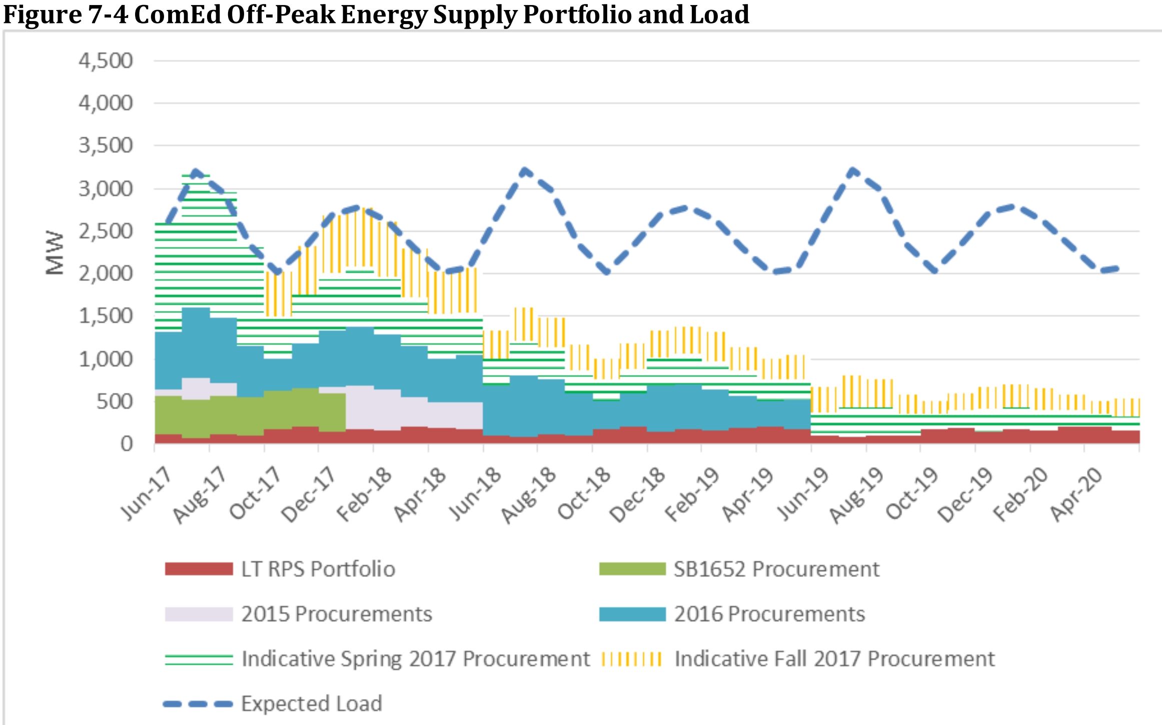

Table 7-3: ComEd 2017 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2017 Purchases (MW)		Anticipated Fall 2017 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2017-2018				
June-17	1,650	1,300	0	0
July-17	2,225	1,600	0	0
August-17	2,075	1,475	0	0
September-17	1,375	1,175	0	0
October-17	600	500	600	525
November-17	650	575	675	575
December-17	750	675	775	675
January-18	750	700	800	700
February-18	725	675	725	650
March-18	650	575	625	575
April-18	575	525	575	500
May-18	600	500	625	525
Delivery Year 2018-2019				
June-18	400	325	425	325
July-18	500	400	500	400
August-18	450	375	475	350
September-18	350	275	350	300
October-18	300	250	300	250
November-18	325	275	325	300
December-18	375	325	375	325
January-19	400	350	375	325
February-19	375	325	350	350
March-19	325	300	325	275
April-19	300	250	275	250
May-19	300	250	325	275
Delivery Year 2019-2020				
June-19	375	275	350	300
July-19	475	350	450	375
August-19	425	325	450	325
September-19	300	250	300	225
October-19	225	175	225	150
November-19	250	200	250	200
December-19	300	275	325	250
January-20	300	250	325	275
February-20	300	250	275	250
March-20	250	200	225	175
April-20	200	150	200	150
May-20	225	175	225	200

Figure 7-5 MidAmerican Peak Uncapped Energy Supply Portfolio and Load

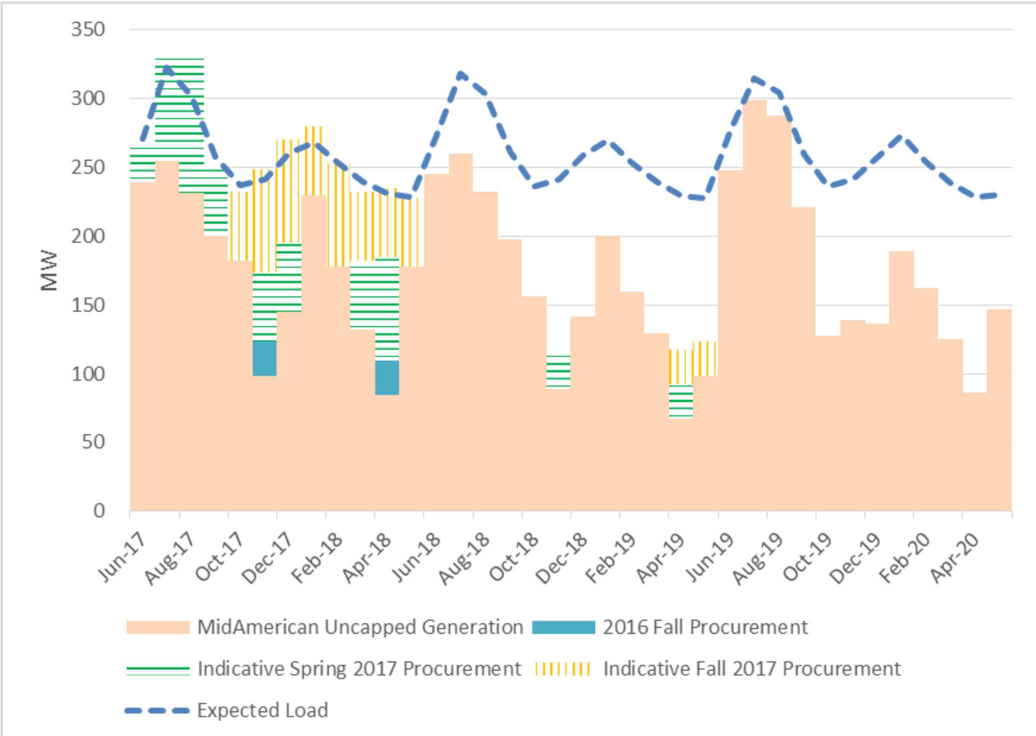

Figure 7-6 MidAmerican Uncapped Off-Peak Energy Supply Portfolio and Load

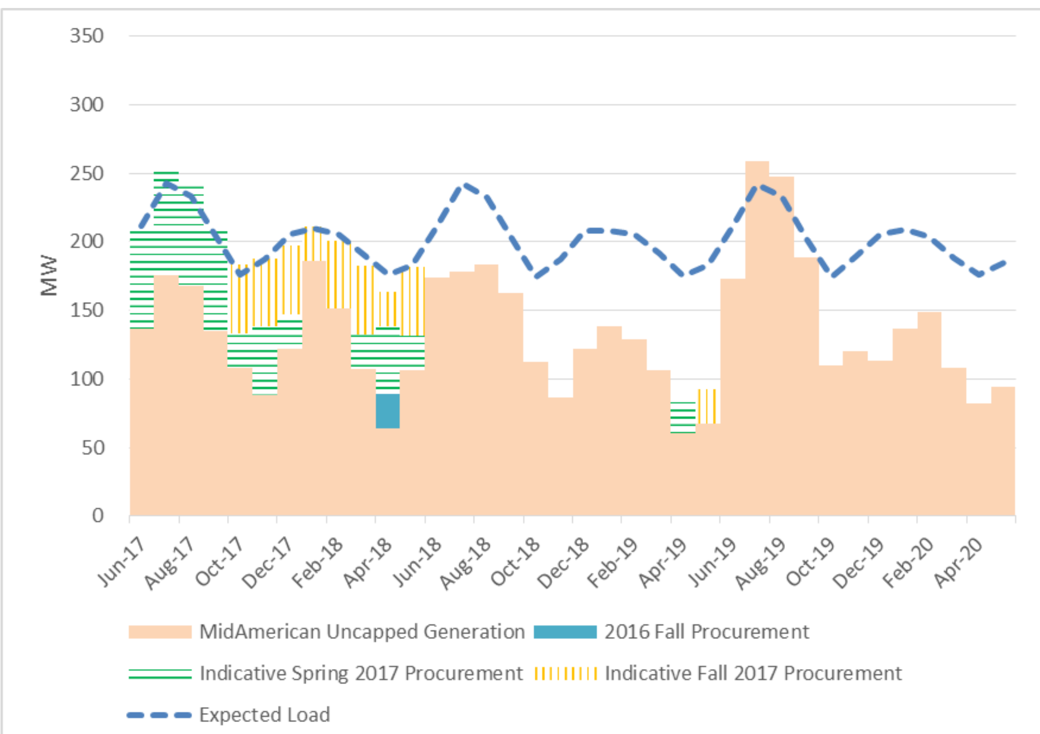

Table 7-4: MidAmerican 2017 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2017 Purchases (MW)		Anticipated Fall 2017 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2017-2018				
June-17	25	75	0	0
July-17	75	75	0	0
August-17	100	75	0	0
September-17	50	75	0	0
October-17	0	25	50	50
November-17	50	50	75	50
December-17	50	25	75	50
January-18	0	0	50	25
February-18	0	0	75	50
March-18	50	25	50	50
April-18	75	50	50	25
May-18	0	25	50	50
Delivery Year 2018-2019				
June-18	0	0	0	0
July-18	0	0	0	0
August-18	0	0	0	0
September-18	0	0	0	0
October-18	0	0	0	0
November-18	25	0	0	0
December-18	0	0	0	0
January-19	0	0	0	0
February-19	0	0	0	0
March-19	0	0	0	0
April-19	25	25	25	0
May-19	0	0	25	25
Delivery Year 2019-2020				
June-19	0	0	0	0
July-19	0	0	0	0
August-19	0	0	0	0
September-19	0	0	0	0
October-19	0	0	0	0
November-19	0	0	0	0
December-19	0	0	0	0
January-20	0	0	0	0
February-20	0	0	0	0
March-20	0	0	0	0
April-20	0	0	0	0
May-20	0	0	0	0

7.2 Capacity

7.2.1 Capacity Procurement Strategy

7.2.1.1 ComEd

Prior procurement plans, including the 2016 Procurement Plan, have recommended that ComEd obtain its capacity needs through the PJM-administered capacity market. For the 2017 Plan, the IPA recommends that ComEd continue to obtain its capacity needs from the PJM-administered capacity market. Table 7-7 summarizes the proposed capacity procurement for ComEd.

7.2.1.2 Ameren Illinois

For Ameren Illinois, the 2015 and 2016 Procurement Plans recommended procurement of at least a portion of the Ameren Illinois capacity needs through bilateral capacity purchases with the remainder of the capacity needs procured from the MISO PRA. As outlined below (and further discussed in Section 5.2), given the current uncertainty around the design of the MISO PRA and the resulting effects of any design changes, the IPA recommends deferring any decision regarding the capacity procurement strategy for the 2019-2020 planning year and beyond until next year's Plan.

The IPA proposes the following capacity procurement strategy:

- As approved under the 2016 Procurement Plan, for the 2017-2018 Planning Year, 75% of the Ameren Illinois Capacity would be procured through an RFP in the fall of 2016, with the remaining 25% being procured in the MISO PRA;
- As approved under the 2016 Procurement Plan, for the 2018-2019 Planning Year, 25% of the Ameren Illinois Capacity would be procured through an RFP in fall of 2016. 50% will be procured through an RFP in the fall of 2017. The remaining 25% will be procured in the MISO PRA; and
- For the 2019-2020 Planning Year, the decision will be deferred until next year's Plan.

Table 7-6 summarizes the proposed capacity procurement for Ameren Illinois.

7.2.1.3 MidAmerican

MidAmerican has elected to procure power and energy through the IPA procurement process for the incremental amount of load that is not currently served or forecasted to be served in Illinois by MidAmerican-owned Illinois jurisdictional generation. As part of that election, MidAmerican provided its forecasted load and capability, a summary of which is presented in Table 7-5 below.

The IPA notes that the magnitude of the proposed capacity procurements for MidAmerican is small relative to its capacity requirements, as shown below. Also, consistent with the discussion regarding the procurement strategy for ComEd, the IPA recommends that MidAmerican obtains 100% of its forecast capacity shortfall from its RTO's capacity market, MISO PRA.

Table 7-5: Summary of MidAmerican Load and Capability

	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022
Coincident Peak Load	434	436	439	441	444
Reserves	33	33	33	34	34
Coincident Peak Load with Reserves	467	469	472	475	477
UCAP MW Total Net Capability	395	395	395	397	397
Capacity Shortfall	71	74	77	78	81

7.2.2 Capacity Procurement Implementation

7.2.2.1 Ameren Illinois

For Ameren Illinois, the IPA concludes that it does not need to include any extraordinary measures in the 2017 Procurement Plan to assure reliability over the planning horizon. As indicated below, for the 2017-2018 and 2018-2019 planning years, the IPA recommends the procurement of part of the capacity needs through bilateral capacity purchases. The remainder of the capacity needs for these planning years will be procured from the MISO PRA. A decision regarding a capacity procurement proposal for the 2019-2020 planning year will be deferred until next year's Plan.

Table 7-6: Summary of Capacity Procurement for Ameren Illinois[170]

June 2017-May 2018 (Upcoming Planning Year)[171]	June 2018-May 2019[172]	June 2019-May 2020
75% RFP in Fall 2016 25% MISO PRA*	25% RFP in Fall 2016 50% RFP in Fall 2017 25% MISO PRA**	To Be Determined In Next Year's Plan

* MISO Auction is expected to clear in April 2017.
** MISO Auction is expected to clear in April 2018.

7.2.2.2 ComEd

For ComEd, the IPA concludes that it does not need to include any extraordinary measures in the 2017 Procurement Plan to assure reliability over the planning horizon. The IPA, as indicated below, recommends that ComEd continue to meet all of its capacity obligations through the PJM-administered capacity market in which capacity is purchased in a three-year ahead forward market through mandatory capacity rules.

Table 7-7: Summary of Capacity Procurement for ComEd

June 2017-May 2018 (Upcoming Planning Year)	June 2018-May 2019	June 2019-May 2020	June 2020-May 2021
100% PJM RPM Auctions*	100% PJM RPM Auctions*	100% PJM RPM Auctions*	100% PJM RPM Auctions**

* PJM RPM Base Residual Auctions for 2017-2018, 2018-2019 and 2019-2020 have already cleared.
** The 2020-2021 Base Residual Auction will likely be held in May 2017.

170 Table shows the incremental percentage of capacity requirements to be hedged or purchased in the indicated procurement events.
171 Procurement approved in the 2016 Procurement Plan.
172 Procurement approved in the 2016 Procurement Plan.

7.2.2.3 MidAmerican

For MidAmerican, the IPA concludes that it does not need to include any extraordinary measures in the 2017 Procurement Plan to assure reliability over the planning horizon. The IPA recommends that MidAmerican continue to procure 100% of its forecast capacity shortfall for the 2017-2018, 2018-2019 and 2019-2020 planning years from the upcoming annual MISO PRAs to be held in April of 2017, 2018 and 2019 respectively, as indicated below.

Table 7-8: Summary of Capacity Procurement for MidAmerican

June 2017-May 2018 (Upcoming Planning Year)	June 2018-May 2019	June 2019-May 2020
100% of expected shortfall from MISO PRA*	100% of expected shortfall from MISO PRA**	100% of expected shortfall from MISO PRA***

* MISO Auction is expected to clear in April 2017.
** MISO Auction is expected to clear in April 2018.
***MISO Auction is expected to clear in April 2019.

7.3 Transmission and Ancillary Services

Ameren Illinois, MidAmerican, and ComEd purchase their transmission and ancillary services (which included energy balancing) from their respective RTOs, Ameren Illinois and MidAmerican from MISO and ComEd from PJM. The utilities also manage their Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR) processes 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 Demand Response Products

Section 8-103(c) of the PUA establishes a goal to implement demand response measures:

> 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.[173]

ComEd provided information regarding its existing demand response programs for 2016-2017 which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 73,000 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 1,163 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.

[173] 220 ILCS 5/8-103(c).

- 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 commenced in 2015 with 56,000 customers, and has grown to 158,000 customers in 2016. ComEd sold 48 MW of capacity from the program into the PJM capacity auction for the 2017-2018 Planning Year increasing to 85 MW in the 2019-2020 Planning Year.

Ameren Illinois has implemented a Voltage Optimization Program (including, for example, Conservation Voltage Reduction ("CVR") Program). Ameren Illinois also offers a Real Time Pricing ("RTP") option and the additional associated Power Smart Pricing ("PSP") program for smaller customers. Pursuant to the Commission's Interim Order in Docket No. 13-0105, Ameren Illinois offers a Peak Time Rebate program (Rider PTR). The program currently has 10,450 customers and Ameren Illinois sold 2.3 MW of capacity in the MISO PRA for the 2017-2018 Planning Year which provides the pool of funds used for customer rebates. This tariff pertains to an optional program available to DS-1 customers as of June 1, 2016, whereby a customer would receive a billing credit if they curtail electric energy use during specific peak usage periods.

MidAmerican administers a program called "SummerSaver Program," a residential Direct Load Control (DLC) program. In addition, there is a potential for load displacement due to curtailment of customers on an interruptible rate. Based on the customer enrollment, MidAmerican estimates its potential total capacity of Demand Response (DR) at 18.9 MW.

The IPA does not propose any procurement of demand response programs from eligible retail customers in the 2017-2018 delivery year. Under current market and regulatory conditions, the IPA believes that a new demand response procurement by the IPA could not meet the standards set forth in Section 16-111.5(b)(3) of the Public Utilities Act. Reasons for this include, for example, the statutory requirement that demand response under this provision must come from "eligible retail customers." Section 16-111.5B of the Public Utilities Act explicitly extends energy efficiency program participation to potentially "eligible retail customers" to accommodate the challenges created by customer switching. In contrast, Section 16-111.5(b)(3)(ii)(A) contains no such provision, and there may simply be no feasible way to ensure that only eligible retail customers participate. This challenge significantly reduces the likelihood that any demand response procurement would be "cost-effective." Further, there could be challenges in "satisfy[ing] the demand-response requirements of the regional transmission organization market in which the utility's service territory is located," and "provid[ing] for customers' participation in the stream of benefits produced by the demand-response products." Fortunately for customers (including both eligible retail customers and those who have switched suppliers or take hourly priced service), the Peak Time Rebate (or Savings) programs as offered by Ameren Illinois and ComEd create value through reduction in capacity charges and the technologies utilized for capacity reductions also have the potential to provide longer term demand response capability that could operate over more peak hours than those used for calculations of capacity obligations.

Going forward, the IPA will continue to assess the demand response market, and continue its involvement in stakeholder discussions regarding Illinois state policy on demand response. As the market changes and legal and regulatory barriers are addressed, the Agency may choose to propose a demand response procurement in a future procurement plan.

7.5 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.[174] As a part of the goal, the Plan must also include electricity

[174] 20 ILCS 3855/1-75(d).

generated from clean coal facilities.[175] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act[176], Section 1-75(d) describes two special cases: the "initial clean coal facility"[177] 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").[178] Currently, the IPA is unaware of any facility meeting the definition of an "initial clean coal facility" that has announced plans to begin operations within the next five years.

7.5.1 FutureGen 2.0

In Docket No. 12-0544, the Commission approved inclusion of FutureGen 2.0 as a retrofit clean coal facility starting in the 2017-2018 delivery year.[179] On July 22, 2014, an Illinois appellate court upheld the Commission's decision to require ComEd and Ameren Illinois to recover FutureGen sourcing agreement costs through a competitively-neutral retail distribution charge applicable to all utility distribution customers (including ARES customers).[180]

In early February 2015, the U.S. Department of Energy (DOE) announced the suspension of federal funding, $1 billion in funding under the American Recovery and Reinvestment Act of 2009 (ARRA), for the Future Gen 2.0 project, indicating that the project had insufficient time to be completed by the ARRA funding expiration in September 2015. The DOE suspension of funding resulted in the termination of project development for FutureGen 2.0 in early 2016, and the Illinois Supreme Court subsequently dismissed the pending appeal of the appellate court's decision as moot through a May 2016 ruling, vacating the judgment of the appellate court without expressing an opinion on its merits while refraining from vacating those portions of the Commission's Order approving the 2013 Procurement Plan concerning FutureGen 2.0 sourcing agreements and related authority.[181] FutureGen has since terminated the prior-approved FutureGen 2.0 Sourcing Agreements with the utilities.

[175] 20 ILCS 3855/1-75(d)(1).
[176] 20 ILCS 3855/1-10.
[177] Id.
[178] 20 ILCS 3855/1-75(d)(5).
[179] 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).
[180] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2014 IL App (1st) 130544, July 22, 2014.
[181] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2016 IL 118129, May 19, 2016.

8 Renewable Resources Availability and Procurement

This Chapter focuses on the procurement of renewable resources on behalf of eligible retail customers and provides informational guidance on use of the Renewable Energy Resources Fund ("RERF"), which contains alternative compliance payments made by ARES as part of their RPS compliance obligations. Renewable energy resource procurement on behalf of eligible retail customers is subject to targets for purchase volumes (represented as a percentage of eligible retail customer load) found in Section 1-75(c)(1) of the IPA Act and capped by the 2.015% upper limit on customer bill impacts found in Section 1-75(c)(2)(E) of the IPA Act. The cap on the available budget for each utility is based on the utility's most recent load forecast.

From 2009 through 2012, the IPA's annual electricity procurement plans included the purchase of renewable energy resources in the form of renewable energy credits ("RECs") sufficient to meet the Renewable Portfolio Standard ("RPS") requirements applicable to the eligible retail customer load of ComEd and Ameren Illinois. For the 2013 and 2014 Plans, given the significant percentage of load that had shifted to ARES through municipal aggregation, and the existing financial commitments of the LTPPAs, the IPA and the Commission determined that potential renewable energy resource procurements were limited by the potential for curtailment of existing contracts due to the rate cap on the Renewable Resources Budgets. As a result, general REC procurements (i.e., procurements intended to meet the overall renewable resource targets present in Section 1-75(c)(1) of the IPA Act) were not held for the 2013-2014 or 2014-2015 delivery years.

The advent of a carve-out for photovoltaic resources and the return of load to the utilities made renewable resource procurement once again possible, and in 2015 the IPA procured Solar Renewable Energy Credits ("SRECs") in a spring procurement event (to meet the photovoltaic procurement sub-target found in the Act), and additionally procured RECs from Distributed Generation ("DG RECs") in the fall of 2015 using only previously collected Hourly ACP funds. In 2016 the IPA procured SRECs for Ameren Illinois and ComEd, and (for the first time) RECs (including, specifically, wind RECs and SRECs to meet those sub-targets in the Act) for MidAmerican in a spring procurement event and DG RECs for all three utilities in a June 2016 procurement event.[182]

Consistent with past years, the 2017 Plan calls for REC procurements to meet the RPS targets and technology-specific sub-targets found in Section 1-75(c)(1) of the IPA Act for Ameren Illinois, ComEd, and MidAmerican, with the budgets for those procurements capped by the operation of Section 1-75(c)(2)(E)'s rate impact cap.

MidAmerican's involvement starting with the 2016 Plan raised questions about how to calculate the renewable resource target appropriate to it. Specifically, as a multi-jurisdictional utility participating in the IPA's procurement planning process to meet a portion of its load requirements, MidAmerican's participation raised a previously unaddressed question as to whether renewable energy resources procurement targets should be calculated for <u>all</u> of its eligible retail customer load, or <u>only</u> for <u>that portion</u> of MidAmerican's eligible retail customer load for which the utility specifically requests procurement. Section 1-75(c)(1) of the IPA Act references procurement percentages applicable to "each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act."[183] While Section 16-111.5(a) defines "eligible retail customer" by customer status that would appear to include MidAmerican's entire eligible retail customer load, this same section also expressly contemplates that MidAmerican may seek procurement for only "a portion of its eligible Illinois retail customers in accordance with the applicable provisions set forth in this Section and Section 1-75 of the Illinois Power Agency Act."[184] In approving the

[182] In 2015 and 2016, the IPA also conducted a series of procurements of SRECs from new photovoltaic systems in Illinois under the separate Supplemental Photovoltaic Procurement Plan ("SPV Plan") pursuant to Section 1-56(i) of the IPA Act; those procurements involved contracts between suppliers and the Agency (rather than with the utilities) using funds from the RERF and were approved through a process separate from the IPA's annual electricity procurement planning process, and thus the resulting RECs from those contracts are not used to meet the renewable energy resource procurement targets discussed herein.
[183] 20 ILCS 3855/1-75(c)(1) (emphasis added).
[184] 220 ILCS 5/16-111.5(a).

2016 Plan, the Commission determined that the renewable resources targets for MidAmerican should only relate to that portion of the "total supply" procured for MidAmerican's jurisdictional eligible retail customers that was included in the 2016 Procurement Plan pursuant to Section 16.111.5 of the PUA and Section 1-75(c) of the IPA Act."[185] The 2017 Plan's procurement targets for MidAmerican thus reflect the Commission's determination made in approving the 2016 Plan.

Section 1-75(c)(1) of the IPA Act requires the procurement of at least a minimum percentage of "each utility's total supply to serve the load of eligible retail customers" from "cost-effective renewable energy resources." Under that provision, specified target percentages of renewable energy resources are required to be procured for each participating utility.[186] The overall renewable energy resources obligation for the utilities in the 2017-2018 delivery year is 13% of the total supply to meet the load of eligible retail customers by June 1, 2017.[187] This obligation increases by at least 1.5% each year thereafter to at least 25% by June 1, 2025.[188] The IPA Act also sets sub-targets for specific resource generating technology types: 75% of the resources procurement shall be generated by wind, 6% for photovoltaics ("PV"), and 1% must come from distributed generation ("DG") which can be used to meet the PV and wind requirements.[189]

The obligation of each electric utility—i.e., the amount of renewable energy resources that have to be procured to meet these statutory minimums—"shall be measured as a percentage of the actual amount of electricity (megawatt-hours) supplied by the electric utility to eligible retail customers in the planning year ending immediately prior to the procurement."[190] This concept can be confusing, as it creates a lag in how the migration of load to or from the ARES manifests itself in changes to renewable energy resource procurement targets. For instance, if a procurement of RECs is scheduled to take place in Spring 2017 for delivery in the 2017-2018 delivery year, the most recently completed year (i.e., the year "ending immediately prior to the procurement") is the 2015-2016 delivery year, as the 2016-2017 delivery year would not have ended prior to the procurement. As a result, customer switching taking place in the fall of 2016 may not manifest itself in significant changes to renewable energy procurement targets until procurements take place in the spring of 2018 for the 2018-2019 delivery year. However, that switching will be reflected in the actual 2016-2017 delivery year load.[191]

The spending cap on the available Renewable Resources Budget ("RRB") is defined as follows:

> The amount of renewable energy resources procured pursuant to the procurement plan for any single year shall be reduced by an amount necessary to limit the estimated average net increase due to the cost of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.015% of the amount paid per kilowatt-hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt-hour paid for these resources in 2011.[192]

As explained in Section 2.5.1, these values are now fixed; the greater of the two is the 2007 calculation, which constitutes 0.18054 ¢/kWh for Ameren Illinois, 0.18917 ¢/kWh for ComEd, and 0.12415 ¢/kWh for MidAmerican. When these values are multiplied against a utility's forecast eligible retail customer load, it

[185] Docket No. 15-0541, Final Order dated December 16, 2015 at 133-134.

[186] 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.

[187] 20 ILCS 3855/1-75(c)(1).

[188] Id.

[189] Id.

[190] 20 ILCS 3855/1-75(c)(2).

[191] These quantities are updated with each Plan's load forecast and will change as those forecasts are updated. The updated quantities reflect the impact of revising the load forecast to account for switching due to municipal aggregation which impacted ComEd and to a less significant extent Ameren Illinois.

[192] 20 ILCS 3855/1-75(c)(2)(E).

creates a budget amount referred to as that utility's "Renewable Resources Budget," which constitutes the maximum that may be spent on renewable resource procurement in a given year under Section 1-75(c)(1) of the IPA Act (additional money may be spent from the renewable energy resources fund for from alternative compliance payments paid by hourly rate customers).

The estimated renewable resource volumes and dollar budgets available for use by each utility and the assumptions that provide the basis for these estimates reflect the utilities' base load forecasts as described in Chapter 3 and adopted by the Commission (and if the Commission were to adopt a different load forecast, then the renewable resource target volumes and budgets would have to be revised accordingly). With each procurement plan, new utility load forecasts are provided to the IPA in July and subsequently updated as necessary the following March to incorporate new data (particularly eligible retail customer switching rates) into the REC procurement targets. Therefore the renewable resource procurement target and related budget estimates presented in future plans could differ significantly from what is presented in this Plan.

In recent years, procurements for Ameren Illinois and ComEd have generally met or exceeded their overall RECs procurement targets. However, some years since 2012 have seen procurements fall short of technology-specific sub-targets. In the 2012 Plan, the IPA included a one-year REC procurement to procure the minimum unbundled RECs required to meet the solar photovoltaic and wind sub-targets (in addition to RECs separately procured through the legislatively mandated 2012 "rate stability" procurements). Due to the volume of long-term (20 year) bundled REC and energy contracts procured in 2010, and declining eligible retail customer load, there were no procurements of renewable resources proposed (or subsequently conducted) in the 2013 or 2014 Plans.

For the 2015–2016 delivery year (2015 Plan), resources under contract from prior IPA procurements for Ameren Illinois and ComEd were sufficient to meet overall RECs targets, but insufficient to meet the law's solar PV requirements. As a result, the IPA proposed and the Commission approved a one-year SREC procurement for ComEd and Ameren Illinois to meet those shortfalls. That SREC procurement was held in the spring of 2015. An additional procurement of DG RECs was held in the fall of 2015 for both ComEd and Ameren Illinois. The 2016 Plan, based on the utility load forecasts as of July 15, 2015 and taking into account MidAmerican's initial year of participation in the IPA procurements, included a spring procurement event for general RECs (MidAmerican only), wind (MidAmerican only), and solar RECs (all utilities) using the utilities' Renewable Resources Budget and a June procurement for distributed generation RECs using hourly ACP funds for Ameren Illinois and ComEd and using the Renewable Resources Budget for MidAmerican.

Turning to the current plan for the 2017-2018 delivery year, existing resources under contract for Ameren Illinois, ComEd and MidAmerican are not sufficient to meet the utilities' renewable resource procurement targets. More specifically, the Ameren Illinois' 2017-2018 targets for overall RECs and wind RECs have been exceeded through prior REC procurements (specifically, the LTPPAs), however Ameren Illinois is short of its PV and DG REC sub-targets. ComEd and MidAmerican are both short of their overall RECs target as well as their wind, solar and DG RECs sub-targets.

To achieve statutory compliance, the IPA recommends Spring 2017 procurements of RECs to meet the ComEd and MidAmerican overall REC targets, and to meet each utility's unmet technology-specific sub-targets (solar PV for all three utilities, wind for ComEd and MidAmerican) for the 2017-2018 delivery year. The quantities to be procured will be based upon the "Remaining Targets" as calculated from the updated March 2017 load forecasts and will be limited to the funds available in the Renewable Resources Budget as reported at that time. As described elsewhere in the Plan, should consensus on the March 2017 load forecasts be needed and not be reached, the quantities of RECs to be procured for the 2017-2018 delivery year will be based upon the "Remaining Target" rows of Table 8-1, Table 8-2, and Table 8-3 for that delivery year found in the Plan.

As discussed above, Section 1-75(c) of the IPA Act also requires the utilities to acquire RECs from distributed generation ("DG") devices amounting to at least 1% of each utility's total RECs target. The Fall 2015 and Summer 2016 DG RECs procurements each experienced very limited participation—there was only one winning bidder in each of those procurements—leaving the targets unmet and raising questions about how to improve the procurement process and facilitate increased participation. For the 2017 Plan, the IPA proposes to schedule at least one DG procurement in 2017 in order to meet the utilities' remaining 2017-2018 delivery year DG REC targets; details related to the structure of the DG procurements are discussed in Section 8.4. Due to the challenges with the prior DG procurements, the IPA is proposing a number of refinements to the 2017 DG procurement in Section 8.4 below.

Under the law, procurements of DG renewable energy resources require contracts of at least 5 years.[193] However, due to the application of the Section 1-75(c)(2)(E) rate impact cap and the potential for continued volatility in the available Renewable Resources Budget caused by customer switching (a risk which could still manifest itself in the potential curtailment of the existing Ameren Illinois and ComEd LTPPAs from 2010), any new long-term obligations entered into using the Renewable Resources Budget would be subject to a high risk of curtailment, a situation which the Agency and Commission have both recognized in rejecting long-term contract proposals from stakeholders in prior years.[194] Therefore, as described further below, the IPA proposes that the DG procurements (for which 5 year contracts are the statutorily mandated minimum length) for ComEd and Ameren Illinois utilized the already-collected balances of alternative compliance payments paid by hourly rate customers; because the MidAmerican service territory does not feature similar load migration risks and because MidAmerican is not a party to the LTPPAs, for MidAmerican, DG contracts will be entered into using the Renewable Resources Budget.

Further, consistent with prior years, the IPA once again does not recommend use of the Renewable Resources Budget for Ameren Illinois or ComEd for renewable energy resource contracts of more than 1 year in length or extending beyond the 2017-2018 delivery year for this Plan. Even if the IPA believes that curtailments are unlikely for the upcoming delivery years, past experience shows that customer switching and load migration—and consequent reduction in available Renewable Resources Budget funds—can happen suddenly and significantly in Illinois, given the opportunity for load shifting in large chunks due to municipal aggregation. With this risk looming, entering into additional contracts featuring obligations beyond the immediate delivery year using the Renewable Resources Budget would be imprudent and unwise, and could result in large and economically inefficient risk premiums in any bids offered by parties understandably concerned about future year curtailments. For Ameren Illinois and ComEd, this may unfortunately limit the use of Renewable Resources Budget funds to meeting the technical requirements of the utilities' RPS mandates rather than achieving broader policy goals such as fostering the development of new renewable generation in Illinois (as might be accomplished through longer-term contracts). However, absent legislative changes to the IPA Act and the PUA, and given the resources currently under contract and continued load volatility, this dynamic will likely continue to limit to what the IPA can propose for use of the Renewable Resources Budget in future years, although the IPA will continue to monitor the operation of this dynamic and analyze it in developing future procurement plans.

The IPA notes that Section 1-56(i) of the IPA Act required the development of an SPV procurement plan for the procurement of RECs from photovoltaic systems using up to $30 million from the RERF. The IPA's Supplemental PV Plan was filed with the Commission in October 2014 and approved in January 2015. The SPV procurements called for in the Supplemental PV Plan were held in June 2015 (using a budget of $5 million), November 2015 ($10 million), and March 2016. ($15 million) There were seven winning bidders to provide 37,082 SRECs in the June 2015 SPV procurement; 11 winning bidders to provide 70,096 SRECS in the November SPV procurement; and eight winning bidders to supply 91,770 SRECs in the March 2016 SPV procurement. These SRECs were procured under five-year contracts from "new" (i.e., energized on or after the date of approval of the Supplemental PV Plan) solar PV DG systems of up to 2 MW in size. As these SRECs

[193] 20 ILCS 3855/1-75(c)(1)

[194] In prior years, both the Agency and the Commission have recognized these risks in rejecting intervenor proposals calling for the Agency to enter into long-term contracts using the Renewable Resources Budget; notably, those proposals called for any new contracts to be curtailed prior to curtailment applying to the existing LTPPAs, further heightening the risks associated with new long-term obligations.

are being purchased by the Agency out of the Renewable Energy Resources Fund and not by the utilities, the SRECs procured under the Supplemental Photovoltaic Plan do not count towards the utilities' statutory targets.

8.1 Utility Renewable Resource Supply and Procurement

8.1.1 Ameren Illinois

As shown in Table 8-1, Ameren Illinois' existing renewable resource contracts alone are sufficient to meet its total renewables targets for the 2017-2018 delivery year. Ameren Illinois is projected to fall short of meeting its RPS requirements in the 2018-2019 delivery year by 37%. In the 2019-2020, 2020-2021, and 2021-2022 delivery years, the shortfall for total renewables is projected to reach 42%, 47% and 51%, respectively.

Table 8-1 also shows the targets and purchasing requirements for Ameren Illinois to meet the goals set by the IPA Act for wind, photovoltaics, and distributed generation based on the currently established fractions of the total renewables requirement.[195] Ameren Illinois is projected to exceed wind sub-target for the 2017-2018 delivery year. Ameren Illinois is projected to fall short of the wind sub-target by 17%, 23%, 30%, and 36% in the 2018-2019, 2019-2020, 2020-2021, and 2021-2022 delivery years, respectively. Ameren Illinois is projected to fall short of its PV and DG goals in each delivery year.

Additionally, Ameren Illinois is projected to have Renewable Resources Budget funds[196] available to purchase renewables over the 5-year forecast period (Table 8-4).

Table 8-1: Ameren Illinois Existing RPS Contracts vs. Forecast RPS Requirements[197]

Delivery Year	Quantities	Total Renewables	Wind	Photo-voltaics	Distributed Generation
2017-2018	Target (MWh)	842,877	632,158	50,573	8,429
	Purchased (MWh)	855,785	848,338	7,429	1,389
	Remaining Target (MWh)	0	0	43,144	7,040
2018-2019	Target (MWh)	955,154	716,365	57,309	9,552
	Purchased (MWh)	601,389	596,571	4,800	1,389
	Remaining Target (MWh)	353,765	119,794	52,509	8,163
2019-2020	Target (MWh)	1,039,309	779,482	62,359	10,393
	Purchased (MWh)	601,389	596,571	4,800	1,389
	Remaining Target (MWh)	437,920	182,911	57,559	9,004
2020-2021	Target (MWh)	1,139,425	854,569	68,366	11,394
	Purchased (MWh)	600,435	596,571	3,864	435
	Remaining Target (MWh)	538,990	257,998	64,502	10,959
2021-2022	Target (MWh)	1,237,782	928,336	74,267	12,378
	Purchased (MWh)	600,000	596,571	3,429	0
	Remaining Target (MWh)	637,782	331,765	70,838	12,378

[195] 20 ILCS 3855/1-75(c)(1).
[196] Available Renewable Resources Budget funds for the upcoming year is a function of, among other things, forecasted eligible retail customer load which can be affected by customer switching.
[197] Volumes are based on the July 2016 expected load forecast. The March 2017 load forecast will update the 2017-2018 volumes and the quantity of DG RECs purchased in the Fall 2015 and Summer 2016 procurements, and future years' actual procurement targets will be based off of those future years' load forecasts.

8.1.2 ComEd

Table 8-2 shows ComEd's current RPS contracts relative to its renewables requirements and includes consideration of ComEd's statutory targets established for total renewable energy resources as well as for wind, photovoltaics, and distributed generation over the five-year forecast horizon. ComEd's forecast indicates that for the 2017-2018 delivery year, total renewables are 775,523 RECs short of the target. In subsequent delivery years, ComEd is forecasted to fall short of its total renewables target by 56% in 2018-2019, 64% in 2019-2020, 67% in 2020-2021, and 70% in 2021-2022. ComEd is also forecasted to fall short of the photovoltaic, wind and distributed generation targets in each of the five delivery years considered in this Plan.

As with Ameren Illinois, ComEd is also projected to have Renewable Resources Budget funds with which to purchase renewables (Table 8-5).

Table 8-2: ComEd Existing RPS Contracts[198] vs. Forecast RPS Requirements[199]

Delivery Year	Quantities	Total Renewables	Wind[200]	Photo-voltaics[201]	Distributed Generation[202]
2017-2018	Target (MWh)	2,311,700	1,733,775	138,702	23,117
	Purchased (MWh)	1,536,177	1,233,860	30,844	2,979
	Remaining Target (MWh)	775,523	499,915	107,858	20,138
2018-2019	Target (MWh)	2,893,330	2,169,998	173,600	28,933
	Purchased (MWh)	1,264,704	1,233,860	30,844	2,979
	Remaining Target (MWh)	1,628,626	936,138	142,756	25,954
2019-2020	Target (MWh)	3,557,835	2,668,376	213,470	35,578
	Purchased (MWh)	1,264,704	1,233,860	30,844	2,979
	Remaining Target (MWh)	2,293,131	1,434,516	182,626	32,599
2020-2021	Target (MWh)	3,905,042	2,928,782	234,303	39,050
	Purchased (MWh)	1,262,768	1,233,838	28,930	1,043
	Remaining Target (MWh)	2,642,274	1,694,944	205,373	38,007
2021-2022	Target (MWh)	4,260,265	3,195,199	255,616	42,603
	Purchased (MWh)	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	2,998,540	1,961,361	227,729	42,603

198 Delivery year 2017-2018 is the last year for the rate stabilization procurement purchases to be delivered, which amounts to 271,473 RECs for ComEd.

199 Volumes are based on the July 2016 expected load forecast. The March 2017 load forecast will update the 2017-2018 volumes and the quantity of DG RECs purchased in the Fall 2015 and Summer 2016 procurements, and future years' actual procurement targets will be based off of those future years' load forecasts.

200 Wind RPS requirement is 75% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

201 PV RPS requirement is 6% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

202 Distributed Generation RPS requirement is 1% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

8.1.3 MidAmerican

Table 8-3 shows the forecast of the statutory targets for MidAmerican's procurement of total renewable energy resources, wind, photovoltaics, and distributed generation over the five-year forecast horizon, reflecting the methodology approved by the Commission in Docket No. 15-0541.[203] Prior to procurements made to meet MidAmerican's 2016-2017 delivery year targets, MidAmerican did not have any renewable resource contracts extending into the five-year delivery period. In the IPA's May 4, 2016 procurement event, RECs were procured for MidAmerican's target requirements via one-year contracts for the 2016-2017 delivery year.

Table 8-3: MidAmerican Existing RPS Contracts vs. Forecast RPS Requirements

Delivery Year	Quantities	Total Renewables	Wind[204]	Photo-voltaics[205]	Distributed Generation[206]
2017-2018	Target (MWh)	65,547	49,160	3,933	655
	Purchased (MWh)	0	0	0	131
	Remaining Target (MWh)	65,547	49,160	3,933	524
2018-2019	Target (MWh)	78,179	58,634	4,691	782
	Purchased (MWh)	0	0	0	131
	Remaining Target (MWh)	78,179	58,634	4,691	651
2019-2020	Target (MWh)	106,245	79,684	6,375	1,062
	Purchased (MWh)	0	0	0	131
	Remaining Target (MWh)	106,245	79,684	6,375	931
2020-2021	Target (MWh)	127,032	95,274	7,622	1,270
	Purchased (MWh)	0	0	0	131
	Remaining Target (MWh)	127,032	95,274	7,622	1,139
2021-2022	Target (MWh)	113,408	85,056	6,804	1,134
	Purchased (MWh)	0	0	0	0
	Remaining Target (MWh)	113,408	85,056	6,804	1,134

8.2 Available Renewable Resources Budget and LTPPA Curtailment

In 2010, pursuant to an IPA procurement, ComEd and Ameren Illinois entered into long-term (20-year) contracts for renewable energy resources ("LTPPAs") from certain wind and photovoltaic generating facilities. In past proceedings, the IPA has sought express authorization for those contracts to be "curtailed" (a mandated reduction in the amount which need be purchased under the contract) should the payments required under the contract exceed the expected Renewable Resources Budget. A curtailment of these contracts can be triggered by a significant number of customers switching to alternative suppliers and consequently load shifting away from the utilities, thus reducing the available budget below the amount necessary to cover all existing renewable energy resource contractual obligations.

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 2.015% rate impact cap. In the past four Plans, in an effort to keep the cost of

[203] For this Plan, consistent with Ameren Illinois and ComEd, MidAmerican electricity usage for calculating its RPS targets and budgets are usage volumes as measured or forecasted at the customers' meters (as opposed to wholesale volumes used for MidAmerican in the 2016 Procurement Plan, which included T&D losses).
[204] Wind RPS requirement is 75% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).
[205] PV RPS requirement is 6% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).
[206] Distributed Generation RPS requirement is 1% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

renewable energy resources below the statutory rate impact cap, the Commission pre-approved the possible curtailment of the LTPPAs based on the information contained in that subsequent March's updated load forecasts. Curtailment was required of ComEd's LTPPAs in 2013–2014 and 2014-2015, but has not yet been required for the Ameren Illinois contracts. Curtailments were not required in the 2015-2016 and 2016-2017 delivery years and, based on the load forecasts supplied by the utilities, are not currently anticipated over the five-year forecast horizon of the 2017 Procurement Plan; however, because curtailment is still possible (and indeed would occur under the Ameren Illinois low load forecast), the Agency is once again requesting pre-approval of pro rata curtailment of the LTPPAs from the Commission should the updated load forecasts demonstrate that curtailment is necessary.

For the 2017-2018 delivery year, the Renewable Resources Budgets for Ameren Illinois and ComEd are expected to exceed the contractual cost for RECs already procured in each delivery year. Therefore, both Ameren Illinois (Table 8-4) and ComEd (Table 8-5) are forecast to have sufficient funds available in each of the five delivery years covered by this plan. MidAmerican likewise has sufficient funds available in each delivery years.

Table 8-4: Forecast Available Renewable Resources Budget Funds and Forecast Reductions (Curtailments) of LTPPAs, Ameren Illinois

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	LTPPA Quantity Reduction (%)
2017-2018	9,412,155	11,727,302	2,315,147	0
2018-2019	8,000,000	11,754,961	3,754,961	0
2019-2020	7,999,000	11,761,534	3,762,534	0
2020-2021	7,753,000	11,758,174	4,005,174	0
2021-2022	5,554,000	11,775,895	6,221,895	0

Table 8-5: Forecast Available Renewable Resources Budget Funds and Forecast Reductions (Curtailments) of LTPPAs, ComEd

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	LTPPA Quantity Reduction (%)
2017-2018	23,804,638	42,064,725	18,260,087	0
2018-2019	23,446,480	42,212,391	18,765,911	0
2019-2020	23,576,285	42,416,545	18,840,260	0
2020-2021	23,188,923	42,359,368	19,170,445	0
2021-2022	18,683,296	42,350,704	23,667,408	0

The contracted REC costs for the 2017-2018 delivery year for Ameren Illinois and ComEd are respectively 80% and 57% of the current estimates of their respective 2017-2018 RPS budget caps. Those budgets depend directly on eligible retail customer load, so it appears that as long as Ameren Illinois's March 2017 forecast for 2017-2018 load is close to 80% of its July 2016 forecast value, and as long as ComEd's March 2017 forecast for 2017-2018 load is close to 57% of its July 2016 forecast value, neither utility will have to curtail its LTPPAs. Under the two utilities' low load forecast scenarios, ComEd would not have to curtail its LTPPAs; however, Ameren Illinois low load forecasts that the Renewable Resources Budget would be exceeded and a partial curtailment of LTPPAs would be needed.

While it appears unlikely that curtailment of the LTPPAs would be required in the 2017-2018 delivery year, the IPA still recommends that a final determination be based upon the March 2017 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 (including the use of Annual Contract Values).[207] While it is again unlikely that curtailments will be required, because hourly ACP funds are proposed for procurement of DG RECs, 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 should hourly ACP funds leftover after the DG procurement be insufficient to purchase curtailed RECs.

Table 8-6 shows the Renewable Resources Budget available for MidAmerican.[208] As discussed above, the Commission determined that the renewable resource targets present in Section 1-75(c)(1) apply only to the incremental load for which the IPA conducts its procurement, and that the calculation of MidAmerican's Renewable Resources Budget funds should reflect MidAmerican's comments on the IPA's 2016 Plan, which also call for MidAmerican's Renewable Resources Budget to be based on incremental load (shown in the table below).

Table 8-6: Forecast Available Renewable Resources Budget Funds, MidAmerican

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)
2017-2018	24,877	824,398	799,521
2018-2019	24,877	901,200	876,323
2019-2020	24,877	741,029	716,152
2020-2021	24,877	721,276	696,399
2021-2022	0	746,534	746,534

8.3 Use of Hourly Alternative Compliance Payments Held by the Utilities

Ameren Illinois and ComEd also collect Alternative Compliance Payments ("ACPs") on behalf of customers taking hourly service from the utility.[209] Unlike the ACP funds paid by ARES into the RERF, which are held and administered by the IPA, utility hourly customer ACP funds are held by the utilities.[210] As required by the IPA Act, each utility has disclosed the amount of hourly customer ACP funds being held as of May 31, 2016: for Ameren Illinois, the balance is $12,665,469 ($12,348.925 after adjusting for DG REC contracts signed after May 31, 2016); for ComEd, the balance is $27,467,027 ($26,818,750 after adjusting for DG REC contracts signed after May 31, 2016).

The IPA Act requires that ACP funds from utility hourly customers be used to "increase [the utility's] spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year by an amount equal to the amounts collected by the utility under the alternative compliance payment rate or rates in the prior year ending May 31."[211] Starting with the 2013-2014 delivery year, the Commission approved the use of hourly ACP funds to purchase RECs from any curtailed LTPPAs. In the unlikely event of future curtailments, the IPA recommends a continuation of that policy, with the caveat that these purchases would be secondary to the already contractually committed use of the hourly ACP funds for the DG

[207] In its Order on Rehearing in approving the 2014 Plan, the Commission requested that the allocation method used "will be reviewed again and determined in the IPA Procurement Plan case for," in that case, "the 2015-2016 year." (Docket No. 13-0546, Order on Rehearing dated June 17, 2014 at 56). Due to the low probability of needing to curtail the LTPPA contracts in the upcoming delivery year, the IPA has determined that the curtailment methodology does not need to be updated at this time and consideration of this issue deferred to a future year where it is more relevant.

[208] Because the Commission determined in Docket No. 15-0541 that the RPS targets found in Section 1-75(c) of the IPA Act only apply to the portion of MidAmerican's load procured by the IPA, this budget is based on a prorated portion of MidAmerican's total forecast load. For the 2017-2018 Delivery Year, the size of the MidAmerican load served by the IPA procurement process is forecast to be 697,236 MWh (out of MidAmerican's total Illinois forecast load of 2,004,708 MWh).

[209] See 20 ILCS 3855/1-75(c)(5).

[210] See id.

[211] Id.

procurement as discussed below. The purchase of curtailed RECs from the LTPPAs would take precedence over new DG procurements undertaken in 2017.

Utilizing the already collected, and otherwise unspent, hourly ACP funds to allow Ameren Illinois and ComEd to meet their DG sub-targets also appears to be the best way to manage risks associated with longer-term contracts. As the IPA Act requires that contracts for DG resources must be "no less than 5 years" in length,[212] entering into 5-year contracts using existing ACP funds already collected from hourly customers eliminates the load migration risk present with the Renewable Resources Budget (from which long-term contracts have been subject to curtailments in the past) while ensuring that there are no impacts on customer rates. Based on this same logic, this approach was proposed by the IPA and approved by the Commission in both the 2015 and 2016 Procurement Plans.

Although distributed generation systems were eligible to participate in the IPA's prior renewable energy resource procurements, the Fall 2015 procurement specifically targeting DG resources was the first of its kind conducted by the IPA. The Fall 2015 procurement was followed by a subsequent DG RECs procurement in June 2016. As previously discussed, the DG procurements held for the utilities in the fall of 2015 and the summer of 2016 featured low participation and fell short of meeting their statutory DG sub-targets.

8.4 Distributed Generation Procurement

The IPA's model for the DG procurement described in the 2015 Plan was the starting point for the DG procurement also proposed and approved in the 2016 Plan. That model is once again updated for this Plan in order to try to achieve procurement results closer to the target volumes.

The IPA recognizes that given the limited amount of distributed generation currently in Illinois, the success of this procurement hinges on the ability of the Illinois DG market both to self-organize and, given the fact that previous-winning systems have 5 year contracts and other systems may already have REC contracts (such as those from the SPV procurement), to continue to grow. To encourage increased participation, the Agency will allow bids to contain DG systems of all qualifying sizes and resource types. Consistent with the law defining a distributed generation device, systems must be no larger than 2,000 kW. The confidential benchmarks used by the Procurement Administrator to evaluate bids may depend on system size, technology, and other factors. Consistent with the approach taken in the SPV procurement (which also featured the requirement that 50% of RECs come from systems of below 25 kW in size) and with past DG procurements, bids that meet or beat the benchmarks will be selected on the basis of price, and on the basis of trying to achieve a 50-50 balance of RECs procured from each of the two categories of systems, namely systems below 25 kW and systems of 25-2,000 kW in size.

Contracts will provide for each system under the contract having a five full years (60 months) of REC deliveries beginning with each system's first delivery of RECs, and allowing for development time between the procurement event and the first REC delivery to facilitate the construction of new systems.

The IPA has held two DG procurements to date. Neither procurement came close to achieving its target REC procurement volumes and each had only one winning bidder. In both procurements, additional entities beyond the winning bidder took part to varying degrees in every step of the bidding process, but challenges (including for example, assembling bids that would meet the requirements of the procurement and obtaining necessary letters of credit by the bid date) limited ultimate participation. As discussed below the IPA is proposing a number of changes to the DG procurement structure utilized for 2017 with the hope that these changes will increase the volume bid and procured. While the IPA is hopeful that these changes can increase participation and help facilitate satisfaction of the Section 1-75I(1) DG procurement targets, the Agency recognizes that there may be provisions of the law (such as the 1 MW minimum bid size requirement) that could prove to be insurmountable barriers to stronger participation absent legislative change.

[212] 20 ILCS 3855/1-75(c)(1).

Section 16-111.5(o) of the PUA requires that the ICC "hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change." On June 30, 2016, the Commission's independent Procurement Monitor, Boston Pacific, provided comments[213] to the Commission as part of this process that included a summary of possible changes to the DG procurement process that could improve participation. The revisions proposed in the Plan reflect the Procurement Monitor's suggestions as well as additional proposals and refinements proposed by the IPA. In addition, the IPA specifically solicited feedback on the draft Plan regarding its DG procurement proposal and received many helpful comments. Many of those comments generally supported the IPA's proposed changes to the DG procurement design, and aspects of those and other comments have been incorporated into the DG procurement proposal.

Available funding, however, has not been a constraint to the DG procurement process and therefore the IPA's DG renewable resource procurements will continue to use hourly ACP funds for Ameren Illinois and ComEd, and use the Renewable Resources Budget for MidAmerican (including forecasts of the available budget over the life of the contracts). Hourly ACP funds that have been collected as of December 31, 2016 and not allocated to the purchase of either DG RECs from the previous five-year DG procurement contracts or curtailed RECs for the 2017-2018 delivery year will be used for Ameren Illinois and ComEd in any procurement conducted prior to June 30, 2017. For any procurement conducted after July 1, 2017, the same approach will be used, but the balance of Hourly ACP funds will be adjusted to the May 31, 2017 balance and, for the second procurement event, any DG contract commitments already entered into in 2017. The IPA will procure DG RECs until funds are fully allocated or the utilities' DG goals are met, whichever comes first. The products to be procured are RECs from DG systems that are interconnected with Ameren Illinois, ComEd, MidAmerican (Illinois service territory only), Mount Carmel, a municipal utility in Illinois, or a rural electric cooperative in Illinois as required by Illinois law. DG systems need not be in the service territory of the utility purchasing the RECs.

8.4.1 Procurement Process

For this Plan, the Agency's approach to procuring DG RECs consists of a two procurement events in a competitive bid process consistent with the requirements of Section 16-111.5 of the PUA and Section 1-75(c) of the IPA Act as was conducted in the 2015 and 2016 procurements. Timing of the procurement events will be determined at a later date based upon if the IPA determines that it will be conducting an April, 2017 contingency procurement under the Supplemental Photovoltaic Plan, and other factors.

Given the requirement in Section 1-75(c) that "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," bids must once again be at least one megawatt in size, but may feature DG systems of all qualifying sizes and resource types subject to the size categories and limits discussed above (specifically that a system may not be greater than 2 MW in size, and the underlying generation technology must be "renewable" such that the system meets the requirements of a "distributed renewable energy generation device").[214]

To further encourage participation, for 2017 the IPA also proposes to allow both bids from 1) identified distributed generation systems (consistent with past practice in DG procurements), and 2) for blocks of RECs where systems less than 25 kW in size will be identified at a later date (distinct from prior DG procurements, but with the goal to encourage participation consistent with the successful approach taken by the Agency in its SPV procurement) with the hope that this will allow bidders to use a REC contract won through the DG procurement process as a mechanism to acquire new customers and to develop the new systems necessary to meet DG REC delivery requirements.

For identified systems, the bidder must identify the specific system(s) that will provide the RECs. Evidence regarding the systems may include, but is not limited to, letters of intent, signed contracts, interconnection or net metering applications, local permits, and similar documents. For blocks of RECs, bidders will have nine

[213] See: https://www.icc.illinois.gov/downloads/public/Boston%20Pacific's%20Comments%20June%2030%202016%20Final.pdf.
[214] See 20 ILCS 3855/1-10.

months to identify specific systems using the same standards as for identified systems.[215] To reduce contract administration burdens on the participating utilities (consistent with the law), verification of these newly identified systems will be conducted by the IPA and the IPA will be responsible for transmitting information about newly-identified systems to the applicable utility. Failure to identify systems by the nine month deadline will result in the forfeiture of any bid assurance collateral requirements, with such forfeiture prorated in cases where systems are identified to partially meet the size of the block of RECs.

As referenced above, the IPA Act requires that the bids "aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity." Consistent with this provision, the first block of DG systems bid by each bidder must be at least one megawatt in size and may include systems from each product size category (i.e., less than 25 kW and 25 kW to 2 MW). Each product size category is offered at a single blended price per REC. Subsequent blocks of DG systems must be bid at higher prices and must each be of a single product size category, must each be offered at a single price per REC that is higher than the price of that category in the first block, and must each be at least 100 kW. Bidders may not designate different REC prices for the RECs generated from a single distributed generation system. While block prices may differ, each bidder's resulting REC contract with a purchasing utility will be at a single blended price, encompassing all successful systems which have been assigned to that utility. Further, consistent with the approach adopted by the Commission in Docket No. 15-0541, resulting contracts shall include a single blended price for each product size category (i.e., less than 25 kW and 25 kW to 2 MW).[216] A pre-determined capacity factor for each eligible technology and potentially varying by project size (or type, e.g., fixed or tracking solar systems) will be used to calculate the five year quantity of RECs for each system.

While each of the utilities has separate compliance targets and budgets, winning bids will be assigned to the utilities by the Procurement Administrator considering each utility's budget and implementing the following priorities: 1) to minimize the administrative burden for utilities and bidders by having each bidder have a single contract with a single utility to the extent feasible; 2) to have utilities get their pro-rata share of the RECs; and 3) to have 50% of the RECs for each utility come from systems below 25 kW. The Procurement Administrator may use its discretion in assigning bids (including prorated shares of bids) to each utility to accommodate the fact that the proration of the total volume of selected bids that would be allocated to each utility's procurement target may not be evenly divided due to the size of the winning bids, and/or each utility's available budget.

Each identified system included in a contract awarded in a procurement held prior to May 31, 2017 must begin accumulating metered deliveries of renewable energy (as tracked by GATS or M-RETS) by May 31, 2018—the end of the 2017-2018 delivery year. An identified system included in a contract awarded in a procurement held on or after June 1, 2017 must begin accumulating metered deliveries of renewable energy by November 30, 2018. For systems identified out of a block of RECs, the deadline for the beginning of accumulation of metered deliveries of renewable energy is nine months later than the deadline for systems bid as identified systems in that corresponding procurement event. Should a system not comply with this requirement, the bidder's contract volume will be reduced accordingly by the amount imputed to that system.[217]

8.4.2 Key Contract Terms

Contracts under the DG procurements will be between winning bidders and Ameren Illinois, ComEd, or MidAmerican; the IPA is not a contract party as it is for the procurements of SRECs using the RERF conducted pursuant to the SPV Plan. Contracts will provide payment for RECs generated over five years for each system

[215] For the IPA's Supplemental Photovoltaic procurements, bidders were given six months to identify systems plus an option to request a three month extension. Nearly all bidders requested the three month extension; therefore it appears that nine months is the practical window for bidders to conduct their marketing and sales processes to identify systems.

[216] See Docket No. 15-0541, Final Order dated December 16, 2015 at 144.

[217] Extensions will be granted for limited circumstances such as (but not limited to) demonstrated delays in a utility approving interconnection of a system, or failure for the tracking system to process registration in a timely manner.

included in the contract as well as the necessary time for the identification and/or development of the systems. Utility contracts will not feature payments prior to REC delivery, such as pre-payment at the execution of a contract or when a system becomes energized. The contract may be transferred or assigned by the winning bidder or seller of the contract consistent with the terms specified within each utility's contract. The IPA will endeavor to harmonize the contract language used by each utility, but recognizes that due to the business rules and practices of each utility, it may not be possible to have identical contract language. For each utility, however, a standard contract will be offered.

8.4.3 Credit Requirements and Bidder/Supplier Fees

Procurements conducted under Section 16-111.5 require that the IPA recover the cost of conducting the procurement through bidder fees,[218] and distributed generation procurements likewise require that the Agency "create credit requirements for suppliers of distributed renewable energy."[219] The IPA proposes the following fees and credit requirements.

- All bidders will pay a $500 bid participation fee. This fee is non-refundable. Bidders who participate in other IPA procurements in 2017 will only have to pay the $500 fee one time.
- For 2017, as a way to ensure that potential bidders have the means and intention to develop systems from blocks bid, the IPA will require a $4/REC letter of credit for both identified systems and for blocks of RECs as part of the bidder registration process.[220]
- Bidders who do not win will have their letters of credit returned. For a bidder who only is successful for a portion of their bids, the level of the letter of credit will be reduced on a prorated basis based upon their winning bids.
- Winning bidders will also be assessed a Supplier Fee that reflects the cost of conducting the procurement less the total of the bid participation fees.[221] An estimated Supplier Fee per REC will be announced prior to the opening of bidder registration, and the final Supplier Fee per REC will be announced after bidder registration is completed but prior to the bid due date. Winning bidders will have seven business days after the approval of the procurement results by the Commission to pay the Supplier Fee due to the IPA. Failure to pay the Supplier Fee will result in the forfeiture of the letter of credit and will be considered a breach of the contract that if not corrected would be cause for termination of the contract.
- As systems demonstrate that they have begun accumulation of metered delivery of renewable energy (as described in Section 8.4.1 above) the pro-rated performance assurance level of the letter of credit will be reduced.[222] Failure to begin accumulation of metered delivery of renewable energy from a system by the system's deadline will also result in the IPA drawing on the letter of credit for that pro-rated amount. Likewise, failure to identify systems from blocks of RECs by the nine-month deadline will result in the forfeiture of the associated performance assurance and the IPA will draw on the letter of credit for that pro-rated amount.

[218] 20 ILCS 3855/1-75(h).
[219] 20 ILCS 3855/1-75(c)(1).
[220] Given the continued challenges surrounding the state budget and appropriations for state agencies including the IPA, the Agency will not accept cash as a means for meeting this requirement.
[221] As the DG procurement is held pursuant to the requirements of Section 1-75 of the IPA Act, subsection (h) requires that, "[t]he Agency shall assess fees to each bidder to recover the costs incurred in connection with a competitive procurement process." This is distinct from the Supplemental Photovoltaic Procurement process held pursuant to Section 1-56(i) of the IPA Act, as Section 1-56(i)(9) allowed the IPA to use the Renewable Energy Resources Fund to cover the administrative costs of SPV procurements. The IPA further notes that increasing participation in the DG procurement will lower the per REC supplier fee compared to previous years.
[222] In past years, DG procurements have required that a portion of the performance assurance continue to be held by the utility over the life of the contract, refunded as deliveries are made. Noting that having a deposit held by a contractual counterparty over a 5-year period may inhibit participation from some bidders, and in an effort to encourage increased participation in the DG procurement process, the IPA is instead proposing this simplified and reduced credit requirement.

To encourage increased participation, to lower the barriers for smaller local installers, to reduce administrative burdens on the utility, and in recognition that the greatest risk of non-delivery resides in the inability to successfully develop a DG system (rather than in the system's ability to delivery RECs once energized and interconnected), there will not be credit requirements, including credit requirements with the utilities, other than those described above. Should the IPA draw on the letters of credit for non-performance, the IPA will use those funds collected to lower the supplier fees for future DG procurements. Failure for a system to begin REC deliveries will impact the given utility' achievement of its DG goals under Section 1-75(c) of the IPA Act and the IPA will adjust procurement targets for future DG procurements to reflect those changes.

While this DG procurement structure does not feature an ongoing security requirement with the utility, winning DG systems will not be eligible to sell RECs generated from that system in any other IPA procurement during the delivery period of the contract.[223] Additionally, the IPA will monitor any failure by identified, energized systems to deliver RECs as scheduled during the delivery period for willful noncompliance; should the Agency determine that the Seller has willfully non-complied with a delivery contract (such as, for instance, via selling DG RECs contractually obligated for utility delivery to a third party instead), that determination may impact the Seller's ability to participate in future IPA procurements.

These and other DG REC delivery contract terms and conditions will be developed to be consistent with the contract process and requirements set forth in Section 16-111.5(e) of the PUA.

8.4.4 Aggregators

Unlike with the IPA's SPV Plan, DG procurements made to meet Section 1-75(c) targets using the procurement mechanisms in Section 16-111.5 of the PUA require the aggregation of "distributed renewable energy into groups of no less than one megawatt in installed capacity." This requirement is manifest in the one megawatt bid requirement mentioned above. The IPA will allow for "self-aggregation" from system owners, so long as those bids are at least one megawatt in size. In all cases, the bidder serves as the counterparty with the utility in contracts for the delivery of RECs; in the case of non-system owners (third-party aggregators), the bidder must have ownership over the RECs or the contractual right to transfer or assign RECs to the utility legally.

Given the number of systems required to constitute a full megawatt, meeting a one megawatt threshold may be challenging for aggregators organizing bids of smaller systems. It may be also especially challenging given the relatively small universe of existing DG systems in Illinois. Any participating system owner would both need to 1) have RECs available for sale (i.e., not already under contract) and be willing to transfer available RECs;[224] and 2) have the knowledge and understanding necessary to participate through an aggregator in an IPA procurement event. The addition of the option to bid blocks of RECs in addition to identified systems is intended to be a means to address this challenge. Potential participants may also choose to join together to create a sufficiently-sized bid (with one entity serving as the "bidder" for purposes of the procurement and resulting contractual counterparty).

In developing the DG RFP rules and process, the IPA and Procurement Administrator may also explore additional ways to facilitate joint participation by entities capable of assembling bids, but not necessarily bids of one megawatt in size, with the goal that through joint participation, a sufficiently-sized bid could be

[223] Exceptions may be made, however, for systems with only partial contracts (such as the marginal winning system in a competitive procurement, for which the contract offered may not cover the full output of the system given the application of the procurement budget or procurement targets).

[224] Based on industry feedback, the IPA understands this may be a challenge for the operators of some existing commercial systems who already claim that their energy is sourced from renewables because the sale, transfer, or assignment of the environmental attributes (i.e., the RECs) is inconsistent Federal Trade Commission guidelines. (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 systems may be necessary for a 1 MW threshold to be met.

submitted. Any mechanisms developed would be consistent with the other provisions of this section, and would be developed in a manner mindful of the need to minimize administrative burdens on contracting utilities and the requirements under the prevailing statute.

8.5 Alternative Compliance Payments Held by the IPA in the Renewable Energy Resources Fund

The RERF balance as of September 27, 2016 equals $188,194,026.84, the total amount received in the IPA's RERF attributable to ARES ACP payments less the cost of RECs purchased by the IPA, expenses related to the SPV procurement process, and a permanent $98 million transfer to the Illinois General Revenue Fund pursuant to Public Act 99-0002. The ICC has held on two separate occasions that it does not have jurisdiction over the RERF, and as a result the IPA does not seek approval for procurement using the RERF in this procurement plan (just as it has not in previous years).[225]

Section 1-56(i) of the IPA Act required the IPA to develop a SPV procurement plan to spend up to $30 million on RECs from photovoltaic resources using the RERF. The Agency's SPV procurement plan was approved by the Commission in Docket No. 14-0651. The SPV procurement plan called for at least three procurement events (with the possibility of a fourth procurement event if funding was available). The first procurement event under that plan was held in June 2015 and successfully allocated the full $5 million budget for that event; the second was held in November 2015 and successfully allocated the full $10 million budget for that event; and the third was held in March 2016 and fully allocated the full $15 million budget for that event. While the SPV procurement plan does not direct the IPA to utilize the full RERF balance (which will increase as ARES make future compliance payments), it is an important first step forward in allowing those funds to be used for their intended purpose. The IPA hopes that future legislative changes will add to the ease through which the IPA can use the remaining fund balance to further the RERF's purposes.

[225] See Docket No. 12-0544, Final Order dated December 19, 2012 at 112-114; Docket No. 15-0541, Final Order dated December 16, 2015 at 144.

9 Energy Efficiency

This Chapter of the Procurement Plan sets out recommendations for the consideration and approval of incremental energy efficiency programs under Section 16-111.5B of the Public Utilities Act.[226] As described in Section 2.6 of this Plan, Section 16-111.5B of the Public Utilities Act requires the IPA to include in its Procurement Plan,

> [A]n assessment of opportunities to expand the programs promoting energy efficiency measures that have been offered under plans approved pursuant to Section 8-103 of this Act or to implement additional cost-effective energy efficiency programs or measures.[227]

The IPA bases its recommendations on "an assessment of cost-effective energy efficiency programs or measures that could be included in the procurement plan" submitted to it by the utilities as part of their July 15th load forecasts.[228] This annual assessment provided by the utilities is required to include the "[i]dentification of cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act,"[229] an "[a]nalysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service,"[230] and an "[a]nalysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply."[231]

Section 16-111.5B was originally enacted as part of Public Act 97-0616, the Energy Infrastructure and Modernization Act ("EIMA"), in 2011. Its provisions are meant to complement, enhance, and expand the utilities' existing energy efficiency program portfolios required by Section 8-103 of the Public Utilities Act through the inclusion in the IPA's annual procurement plans of "new or expanded . . . incremental" programs that would otherwise not be included in the Section 8-103 portfolios due to the operation of Section 8-103's 2.015% rate impact cap.[232] To identify these "incremental" programs, the utilities are required to "conduct an annual solicitation process for purposes of requesting proposals from third-party vendors" developed "consistent with the manner in which it develops requests for proposals under plans approved pursuant to Section 8-103 of this Act, which considers input from the Agency and interested stakeholders."[233] The results of that RFP process are provided to the IPA as part of each utility's assessment. Under this structure, the IPA then "shall include" in its annual plan "energy efficiency programs and measures it determines are cost-effective"[234] and the Commission "shall approve" those programs and measures "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 the PUA.[235]

This section includes discussion related to programs and measures which the IPA recommends for inclusion in the 2017 Plan as well as discussion of other issues related to the operation of Section 16-111.5B, including the status of issues designated for workshop discussion through prior Commission Orders.

[226] The consideration of these programs has been previously included in Chapter 7 of the Plan. For the 2017 Plan, the IPA is presenting these programs in a separate Chapter to increase the clarity of the Plan.
[227] 220 ILCS 5/16-111.5B(a)(2).
[228] 220 ILCS 5/16-111.5B(a)(3).
[229] 220 ILCS 5/16-111.5B(a)(3)(C).
[230] 220 ILCS 5/16-111.5B(a)(3)(D).
[231] 220 ILCS 5/16-111.5B(a)(3)(E).
[232] See 220 ILCS 5/8-103(d).
[233] 220 ILCS 5/16-111.5B(a)(3).
[234] 220 ILCS 5/16-111.5B(a)(4).
[235] 220 ILCS 5/16-111.5B(a)(5).

9.1 Incremental Energy Efficiency Approved in Previous Plans

The IPA's 2017 Procurement Plan is the fifth plan to include energy efficiency programs under Section 16-111.5B. Table 9-1 summarizes the total approved MWh of programs from each previous Procurement Plan and the MWh from the programs proposed for approval in this Plan. For previous years, actual MWh performance varied from these approved levels.

Table 9-1: Projected Savings (MWh) from Section 16-111.5B Programs From Prior IPA Procurement Plans and Proposed in this Plan

Delivery Year	Ameren Illinois	ComEd
2013 – 2014 (Approved in 2013 Plan)	**70,834**	**118,515**
2014 – 2015 (Approved in 2014 Plan)	**65,680**	**430,609**
2015 – 2016	**169,442**	**830,008**
Approved in 2014 Plan	-	547,904
Approved in 2015 Plan	169,442	282,104
Moved from 8-103	*88,203*	*247,648*
Third-Party RFP	*81,239*	*34,456*
2016 – 2017	**230,228**	**984,052**
Approved in 2014 Plan	-	611,958
Approved in 2015 Plan	169,690	284,641
Moved from 8-103	*93,569*	*241,541*
Third-Party RFP	*76,121*	*43,100*
Approved in the 2016 Plan	60,538	87,453
2017 – 2018 (Proposed in this Plan)	**190,172**	**887,268**
2018 – 2019 (Proposed in this Plan)	**209,102**	**641,473**
2019 – 2020 (Proposed in this Plan)	**220,936**	**655,646**

The MWh totals listed above are the approved goals for programs approved in prior procurement plans, and reflect programs available to all potentially eligible retail customers.[236] Please note, however, that the actual impact on IPA energy procurement each year is prorated to the portion of those customers who are actually eligible retail customers (i.e., take supply service from ComEd or Ameren Illinois). See Sections 3.2.3 and 3.3.3 for a discussion of what portion of potentially eligible retail customers are forecast to actually be eligible retail customers.

The IPA's 2016 Procurement Plan included the approval of seven programs for Ameren Illinois and 11 for ComEd. Those programs were all approved for just one year. As with the approval of prior procurement plans including energy efficiency programs under Section 16-111.5B of the PUA, the 2016 Plan approval process afforded the Commission the opportunity to further clarify contested policy and statutory interpretation issues related to Section 16-111.5B implementation.[237] As more extensively discussed in Section 9.2 below,

[236] While the IPA generally procures only for the "eligible retail customers" of participating utilities, Section 16-111.5B programs are available to "all retail customers whose electric service has not been declared competitive under Section 16-113 of this Act and who are eligible to purchase power and energy from the utility under fixed-price bundled service tariffs, regardless of whether such customers actually do purchase such power and energy from the utility." (220 ILCS 5/16-111.5B(a)(3)(C))

[237] Of the fourteen contested issues from Docket No. 15-0541, eight concerned implementation of Section 16-111.5B's energy efficiency procurement provisions.

the Commission directed that specific unresolved issues be addressed through workshops held by the Stakeholder Advisory Group ("SAG") for further consideration. The SAG 2016 Section 16-111.5B Workshop Subcommittee Report, attached as Appendix H, reflecting the input of and feedback from participating parties (including the Agency, Commission Staff, ComEd, Ameren Illinois, and other non-financially-interested stakeholders), summarizes the parties' consideration of these issues and contains 2016 consensus language agreed to by participants (some of which constitutes an update of consensus items developed in prior years' workshops and approved in prior plan approval proceedings).

The IPA's 2017 Procurement Plan marks the second instance in which approval of incremental energy efficiency programs included via Section 16-111.5B is sought for a delivery period for which Section 8-103 utility energy efficiency program portfolios are not yet approved—a timing issue set to occur every third year under existing law. [238] As highlighted in the 2016 Plan, this presents unique challenges, in recognition of which the Commission made the following statement in approving the 2016 Plan:

> The Commission recognizes the challenges of "expansion" of Section 8-103 programs when the portfolio for such programs has not yet been approved. This creates a natural tension: while unapproved programs cannot easily be "expanded," the law calls for IPA plans to fully capture the potential for all achievable cost-effective savings, which presumably includes expanded Section 8-103 programs.
>
> In recognition of this challenge, the Commission directs the SAG to address this topic at workshops. These workshops should demonstrate a genuine commitment to resolving this problem, consistent with the goal of capturing all achievable energy savings. It should also consider solutions such as the conditional approval of Section 8-103 program expansions in the IPA's 2017 Plan and potential contractual mechanisms to accommodate the uncertainty that is present when there is an unapproved Section 8-103 portfolio.[239]

These challenges were discussed extensively at workshops, and each utility's approach is discussed in more detail in the sections below.

Likewise, because the 2017 Procurement Plan features the approval of energy efficiency programs concomitant with consideration of the utility's upcoming three-year portfolios, RFPs issued by the utilities offered bidders the opportunity to bid programs of up to three years in length (as approved Section 16-111.5B programs may then be incremental to an approved Section 8-103 program for the full three-year timespan of the Section 8-103 portfolio).[240]

9.2 2016 Section 16-111.5B SAG Workshop Subcommittee

As referenced above, in approving the 2016 Plan, the Commission directed parties to consider multiple issues through SAG workshops. This approach was also taken in approving prior years' plans. SAG workshops allow for parties to potentially reach agreement on otherwise contested issues, and the IPA believes such workshops generally result in better and more thoughtful outcomes given the increased time allowed for consideration of complex issues (relative to a 90 day docketed proceeding) and the more candid, less adversarial nature of a workshop process (relative to plan approval litigation).

[238] Section 8-103(f) of the PUA provides that, every third year after 2013, "each electric utility shall file, no later than September 1, an energy efficiency and demand-response plan with the Commission." (emphasis added) While this means that the utilities' Section 8-103 dockets have begun prior to the Plan approval proceeding, Section 8-103(f) also provides that the Commission shall "issue an order approving or disapproving each plan within 5 months after its submission"— late January 2017, after a decision is required from the Commission in the IPA Procurement Plan proceeding.

[239] Docket No. 15-0541, Final Order dated December 16, 2015 at 91-92.

[240] This approach was expressly approved by the Commission in Docket No. 15-0541, with the Commission noting that "[l]onger contracts can promote broader participation and better results." Id. at 80.

2016 Section 16-111.5B workshops were organized and administered by the Future Energy Enterprises, LLC, which serves as the SAG Facilitation Team. Participants included Ameren Illinois, ComEd, Northern Illinois Gas Company d/b/a Nicor Gas ("Nicor Gas"), the Office of the Attorney General of Illinois ("IL AG"), the Illinois Department of Commerce and Economic Opportunity ("DCEO"), ICC Staff, the IPA, the Natural Resources Defense Council ("NRDC"), and the Environmental Law and Policy Center ("ELPC").[241] Due to the sensitive nature of the issues and the concern that potential bidders for 2017 third-party energy efficiency ("EE") programs could receive an unfair advantage by participating in IPA Workshop Subcommittee meetings, parties determined that it would not be appropriate to include financially-interested parties (i.e., potential bidders) in workshop participation.

Taken broadly, five discrete issues identified by the Commission in the Docket No. 15-0541 Order were taken under consideration by the SAG workshop process:

1. Review and Update 2013 and 2014 Consensus Items (Consensus Items from Prior Years' IPA Workshops)

2. What TRC-related information do utilities need to provide to the IPA for its analysis of duplicative programs?

3. How will the Section 16-111.5B bids be conducted when the Section 8-103 programs for the next three-year EE Plan have not yet been approved?

4. Administrative cost tracking, categorizing, reporting and analysis (Total Resource Cost ("TRC") Test analysis for Section 16-111.5B programs)

5. Develop a plan to ensure that Section 16-111.5B contracts receive the same level of scrutiny as Section 8-103 contracts. How can performance risk be addressed through the Section 16-111.5B RFP process?

These issues were considered across 10 workshop subcommittee meetings spread over a span of six months from late January to late July. The workshop meetings and associated work resulted in the development of the "Report from the Illinois Energy Efficiency Stakeholder Advisory Group (IL EE SAG) 2016 Section 16-111.5B Workshop Subcommittee" ("2016 SAG Report"), included with the Plan as Appendix H.

The IPA believes that significant and meaningful progress was made in the consideration of all five issues outlined above, and the Agency thanks the SAG facilitation team and workshop participants for genuine, committed efforts toward consensus resolution of complex challenges. While the fourth and fifth issues resulted in some unresolved differences between parties — an expected result when parties are working in good faith toward solutions but have different perspectives, different experiences, and are accountable to different constituencies — none were so significant that the IPA believes further clarification from the Commission is absolutely essential for approval of the 2017 Plan and proposed energy efficiency programs.[242] Given that the majority of contested issues from the 2016 Plan approval litigation concerned issues arising under Section 16-111.5B, and the success that these same parties had in reaching consensus over a wide range of issues in subsequent workshops, the IPA believes this demonstrates that the 2016 Section 16-111.5B subcommittee workshop process was a laudable success.

As stated above, the 2016 SAG Report reflects input and feedback from all participants, and includes new and updated consensus language agreed to by participants for Commission approval. For increased transparency

[241] Representatives from the Illinois Industrial Energy Consumers ("IIEC") did not participate in IPA Workshop Subcommittee meetings, but requested to be included on the email distribution list to follow the discussion of issues.

[242] Other parties, of course, may raise issues for Commission consideration should they feel that clarification is necessary, and indeed stated in comments that clarification would be very helpful.

and continued consistency with the approach taken in prior procurement plans, that consensus language is set forth in Section 9.3.

9.3 2016 Workshop Consensus Items

Included below are the specific consensus items agreed to by participants to the 2016 Section 16-111.5B Workshops. These items, taken from Attachment A of the Workshop Subcommittee Report (included as Appendix H), are intended to update—and thus replace—consensus items previously approved by the Commission, including through approval of the 2016 Plan. As in the past, the IPA requests that the Commission expressly approve the consensus items to be binding upon the energy efficiency programs approved as part of the IPA's 2017 Procurement Plan for the planning of, implementation of, reporting on, and evaluation, measurement and verification of savings achieved by such programs, as well as binding upon parties up to the development of the IPA's 2018 Procurement Plan (at which time any changes to the list below may be considered).

<u>*Section 1: Section 16-111.5B Programs*</u>

This section references various policies for electric utilities managing Section 16-111.5B Programs.

i. *Planning:*

a. *Section 8-103 Portfolio savings and 16-111.5B Program savings shall be tracked separately. Some Programs may be funded by both Sections 8-103 and 16-111.5B, in which case an allocation methodology for savings may be used.*
b. *Section 8-103 and 16-111.5B budgets shall be tracked separately.*

ii. *Procurement:*

a. *Electric utilities shall include all bids and bid reviews in their Energy Efficiency Assessments submitted to IPA pursuant to Section 16-111.5B(a)(3).*
b. *Under the use of pay for performance contracts, the Commission may authorize on a Program basis, a maximum energy savings target and spending cap.*
c. *To the extent that parties are concerned with Energy Efficiency replacing power purchase needs under Section 16-111.5B, it would be appropriate for the IPA, in consultation with ICC Staff, the utilities and/or Evaluators, to estimate the amount that the Section 16-111.5B Programs reduce the IPA's need to procure supply, to serve as a check on the utilities' original estimate required by Section 16-111.5B(a)(3)(G), and to provide useful information to Customers.*
d. *The Commission may determine how the additional information provided pursuant to Section 16-111.5B (a)(3)(D)-(E) should be used as necessary to resolve issues raised in docketed proceedings.*

iii. *Coordination of Section 8-103 and Section 16-111.5B Programs:*

a. *The utilities shall identify new or expanded Cost-Effective Energy Efficiency Programs or Measures that are incremental to those included in Energy Efficiency and demand-response Plans approved by the Commission pursuant to Section 8-103 of the Illinois Public Utilities Act in the annual Energy Efficiency Assessment they submit to the IPA, unless Section 8-103 Programs are already expected to achieve the maximum achievable Cost-Effective savings. An "expansion" of a Section 8-103 Program per Section 16-111.5B is not strictly defined.*
b. *When Section 8-103 Programs are expanded, they should be administered in such a way as to facilitate utility tracking of the original Section 8-103 portion and the Section 16-111.5B portion of the expanded Program.*

iv. *Cost-Effectiveness:*

a. *All Section 16-111.5B Programs included in the Section 16-111.5(b) Procurement Plan must be Cost-Effective at the planning stage, including Programs serving Low Income Customers.*
b. *Cost-ineffective Programs should be dropped during the Procurement Plan proceeding or prior to implementation, should analysis show that the Program is no longer Cost-Effective.*
c. *Section 16-111.5B(a)(3)(D) can be interpreted as the Utility Cost Test, and should be calculated for each Program.*

v. Budget Allocation:

a. *Funds approved pursuant to Section 16-111.5B shall not be spent on Programs that were not approved in an IPA Procurement Plan docket.*
b. *Expenditures on evaluation should be capped for the Section 16-111.5B Programs as they are for the Section 8-103 Programs. Each Program's evaluation budget should not be restricted to three percent (3%) of the Program budget, but evaluation costs should be limited to three percent (3%) of the combined Section 16-111.5B Programs' budget.*

vi. Savings:

a. *When a Section 8-103 Program is expanded into Section 16-111.5B, the savings from the expanded portion of the Program count toward Section 16-111.5B. However, the savings from the non-expanded portion of the Program count toward the utility's Section 8-103 savings goal. Commensurately, when a Section 16-111.5B Program is expanded into the utility's Section 8-103 Portfolio, the savings from the expanded portion of the Program count toward the utility's Section 8-103 savings goal, while the savings from the non-expanded portion of the Program count toward Section 16-111.5B.*

vii. Management of Programs:

a. *Expenditures shall be reviewed for operational prudence and reasonableness in a docketed reconciliation proceeding. However, there is no proceeding required for energy savings per Section 16-111.5B.*

<u>Section 2: Program Flexibility and Budgetary Shift Rules</u>

i. Expansion of Section 16-111.5B Programs

a. *Electric utilities should have the capability for any of the Section 16-111.5B Programs to be able to expand into the Section 8-103 Portfolio for a given Program Year, at the utility's discretion, if: (1) the Section 16-111.5B savings goal for the Program from the Commission Order in the procurement plan case or compliance filing/contract is achieved, and the approved budget (from Commission Order in the Procurement Plan docket) is exhausted; and (2) the electric utility has budget available in the Section 8-103 Portfolio.*

ii. Budget Shifts

a. *The utilities may shift up to 20% of the budget across Program Years for multi-year Section 16-111.5B Programs, assuming the shift remains within the total approved multi-year Program budget, to allow for successful Programs to continue operation in the early (or later) Program Years of a multi-year contract. In such a situation, the kWh savings goals and budgets would be cumulative for the number of years of the contract. Electric utilities should make the vendor aware of the expansion and budget shift options in advance so as to help avoid Program disruption.*

iii. Vendor Contracts

a. 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.

b. Utilities should have flexibility to structure Section 16-111.5B contracts in a manner which best balances the potentially competing objectives of making the procurement process attractive to as many bidders as possible, protecting ratepayers and providing confidence that the savings which are proposed/bid will actually be delivered.

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

d. The utilities should use reasonable and prudent judgment in negotiating the exact terms of the Section 16-111.5B vendor contract after Commission approval and should rely upon the available information and ensure that any modifications continue to result in a Cost-Effective Program. Negotiations may result in reasonable adjustments to savings goals for the Program in comparison to the amount proposed in the bid and reasonable and prudent modifications to the cost structure which are in line with the original design. Once a Section 16-111.5B Program is approved by the Commission, the vendor has the opportunity to negotiate different participation rates and/or Measure levels. Once the contract is signed, those Measures / participation rates will be fixed for the life of the contract for the purpose of setting annual savings goals. However, the vendor and the utility may negotiate a change in the Measure mix, for Program implementation and goal attainment purposes. Some degree of flexibility within a Program is allowed for vendors implementing Programs under Section 16-111.5B. Vendor flexibility is not allowed insofar as the modifications to the Section 16-111.5B 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 other Energy Efficiency Programs; (4) a cost-ineffective Energy Efficiency Program; or (5) a completely different Energy Efficiency Program proposed in comparison to what was bid and approved.

e. The utilities/IPA should share the description of the vendor's Program included in the draft Procurement Plan with the vendor to help ensure the Program is accurately characterized.

f. A process for vendors to submit Program changes should be clearly conveyed to all Section 16-111.5B vendors by the utilities. If a vendor decides to add (or remove) Energy Efficiency 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 Energy Efficiency Measures if they have received pre-approval from the utility for adding that new Energy Efficiency Measure. To help protect against gaming, any Energy Efficiency 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.

g. The utility should notify the IPA, ICC, and the SAG when it has stopped negotiations with an approved Section 16-111.5B 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 IPA Procurement Plan case in which the Program was approved (similar to the approach ComEd used for PY7 and the approach proposed by Ameren in Docket No. 13-0546, Order at 112; Ameren RBOE at 14).

h. The utilities should notify the SAG and keep the IPA apprised of any expected shortfalls in savings from approved Section 16-111.5B Programs. The utility should notify the Commission of changes made, in comparison to the approved Section 16-111.5B Programs.

i. ComEd and Ameren Illinois will provide all costs allocated between Section 8-103, 8-104 and 16-111.5B Programs in the Program Administrator Annual Report produced pursuant to the provisions *of Subsection 6.6 Program Administrator Annual Summary of Activities (Annual Report) set forth in Policy Manual Version 1.0, ICC Final Order Docket No. 15-0487 Appendix.*

j. *For purposes of the Section 16-111.5B Programs Adjustable Savings Goals policy approved in Illinois Energy Efficiency Policy Manual Version 1.0 (ICC Final Order Docket No. 15-0487 Appendix), the Measure participation levels identified in the executed contract to derive the energy savings goals shall be fixed for the life of the contract for the purpose of setting the annual adjusted energy savings goal.*

<u>*Section 3: Evaluation Policies*</u>

i. *Technical Reference Manual*

a. *The Illinois Statewide Technical Reference Manual (IL-TRM) and the IL-TRM Policy Document apply to Section 16-111.5B Programs.*
b. *For Section 16-111.5B Programs, there may be limited circumstances where deviation from the IL-TRM may be appropriate; the utility/vendor should have the option to make the case for the circumstance. However, the IL-TRM values must also be provided for comparison purposes, by filing in the IPA Procurement Plan docket in which the proposed Section 16-111.5B Programs are considered for approval.*

ii. *Evaluation of Section 16-111.5B Programs*

Evaluators and electric utilities managing Section 16-111.5B Energy Efficiency Programs shall follow these evaluation policies:

a. *Evaluation of the Section 16-111.5B Programs should be performed by the Section 8-103 Program Evaluators, and coordinated with Section 8-103 Programs.*
b. *Ex-post Cost-Effectiveness analysis should be performed for the Section 16-111.5B Programs, using actual participation data, consistent with Section 8-103 evaluation policies and practices.*
c. *Section 16-111.5B Program evaluation reports should be filed in the IPA Procurement Plan docket in which the Programs were approved.*
d. *Evaluation plans for Section 16-111.5B Programs should be tailored based on the size and content of the Program. 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 Programs. The value of this effort must be weighed against the cost of conducting such an evaluation for a Program that is: a) not unique or innovative; b) achieves very small savings; or c) is not likely to gain traction as an ongoing Program either in future Section 16-111.5B Program processes or as part of the Section 8-103 Portfolio.*

In addition, the 2016 Workshop report produced consensus language regarding the specific issues that the Commission asked for SAG workshops to consider in the Commission's Order in Docket No. 15-0541. While the application of that language is in many instances designed to be more specific to this year's Plan and associated circumstances than the broader principles governing implementation of Section 16-111.5B outlined above, the Agency requests the same express approval of that consensus language as well.

9.4 Policy Issues for Consideration in the 2017 Plan

In prior years, the IPA has highlighted specific policy issues for further consideration by interested parties in offering comment on the draft Plan or by the Commission in approving the Plan. While the IPA appreciates the significant time and effort that has been put into workshops each year by stakeholders, the Agency highlights the following issues in this draft Plan as ones where more consideration may be needed, and clarification or refinement of past policies and procedures may be warranted.

9.4.1 Scale of Section 16-111.5B programs

As shown in Table 9-1 and discussed further in the sections below, when evaluated on the basis of the amount of savings projected to be achieved, the size of the Section 16-111.5B programs may have peaked in the 2016-2017 delivery year. As bidders continue to become more familiar with the Section 16-111.5B process, and given that this year's RFP offered programs for three years in length, this phenomenon is unexpected.

One possible explanation is that this result could constitute an accurate reflection of the market for energy efficiency in Illinois. However, another possible explanation is that this could be an indicator of barriers to participation by potential bidders. If it is the latter, then what efforts should be undertaken to attempt to increase the number and scale of bids for cost-effective energy efficiency programs?

One possible suggestion is that the utilities could conduct more extensive outreach to disseminate the RFPs in order to find new potential bidders. As discussed below in the review of the bids received for each utility, outreach has been fairly limited. It appears that existing outreach efforts are effective in reaching established energy efficiency industry firms, but it is less clear how well it has reached new firms with the potential to offer new and innovative approaches.

Another possible suggestion is that the utilities could use the Potential Studies required under Section 16-111.5B(a)(3)(A) (and perhaps other screening tools) to specifically solicit new programs that are not part of approved Section 16-111.5B and 8-103 suite of programs. These studies are extensive and paid for by ratepayers, and often yield rich information regarding potential energy efficiency program opportunities. While these potential studies may also be used by the utilities in the development of their Section 8-103 portfolio, the IPA observes that they have, to date, provided limited utility during the consideration of Section 16-111.5B programs.

After receiving comment on its draft Plan, the IPA believes that the best solution for ensuring that the RFP process is able to "fully capture the potential for all achievable cost-effective savings, to the extent practicable" as required by the law would be for the Commission to a) require SAG workshops shortly after the conclusion of the proceeding approving the 2017 Plan at which the utilities and stakeholders can discuss more effective strategies for marketing Section 16-111.5B RFPs and b) to require that the utilities' potential studies and stakeholder feedback be utilized in ensuring that the RFPs, while remaining open-ended, specifically identify any program areas for which bids should be actively sought.

9.4.2 Improving/Refining Bids

There are several potential refinements to the RFP process that could improve the bids received. Concerns have been raised that the nature of the Section 16-111.5B RFP process could allow bidders to propose programs with excessive administration costs by finding headroom in the TRC analysis. Likewise, another concern that has been expressed is a desire for more post-bid negotiations between the utilities and bidders in order to refine/improve the scope, scale, price, etc. of bids. Both concepts suggest that there could be potential to move away from a process where only minor adjustments are made to bids (e.g., adjusting incorrect savings levels provided by bidders) to a model where active negotiations are undertaken in order to improve the quality and value to ratepayers of the proposed programs.

Post-bid negotiations, however, could create significant challenges with successful implementation. With the requirement that the utilities provide an assessment of the bids to the IPA by July 15 of each year, there is limited time available to utilities to undertake such negotiations after a bid is received. Further, the Agency fears that bidders could use a negotiation process as an opportunity to change an initially submitted proposal into something fundamentally different and less connected to the bidder's actual capacity just to attain program approval. Worse still, that dynamic that could eventually result in proposed initial program designs which reflect a bidder's best-case scenario, submitted under the understanding that should the utilities or others be uncomfortable with assumptions made in that proposal (or should that initial proposal fail the TRC), there exists room for negotiation.

Based upon the IPA's experience with its other procurements (e.g., block energy, capacity, renewables), the best mechanism for driving bidders to produce the most honest and accurate proposals oriented around minimizing costs and maximizing benefits may instead be through having clear and explicit processes and rules, and increasing participation to encourage competition between bidders. That approach can drive positive results even if a bid's proposed terms are fixed. Such improvements could perhaps be achieved through improvements to the RFP process as suggested above, although the IPA acknowledges that not every potential third-party energy efficiency program features a cadre of capable bidders equipped to compete. Nevertheless, further examination of this issue may be warranted, and while the IPA is not recommending requiring a post-bid negotiation process at this time, other parties may have more specific proposals worth of consideration in the Plan approval proceeding.

The IPA also has observed that bidders have very rarely participated in the comment process on the draft Plan or the docketed Plan approval proceeding before the ICC. It is not clear to the IPA whether bidders view their program's lack of inclusion in a Plan as the end of their bid, and consideration of certain programs could often benefit from bidder participation in either of these processes. The IPA's proposed solution would call for the communications to bidders about their bids being clarified to make clear to those bidders that they have the right to participate in either the comment process or the docketed proceeding, and that such participation will not prejudice the evaluation of their bid. While the approach taken by the bidder in this year's comment process was seemingly directed at changing a proposed program structure purposes of establishing cost-effectiveness, there are other circumstances in which clarifications and corrections of incorrect assumptions could be made through the comment process to enhance the completeness and accuracy of bid evaluation, or bidder feedback through comments could help refine best practices in bid solicitation and review.

The use of pay for performance contracts, holdbacks, and in the case of Ameren Illinois, surety bonds has been the way in which the utilities have addressed the risk of programs not achieving savings goals. Unlike Section 8-103 programs (featuring goals developed by the utilities), savings goals for Section 16-111.5B programs are proposed by the bidders. While many programs have performed very successfully, other programs have been less successful, and in one case, as extensively litigated in ICC Docket No. 14-0567, a vendor bankruptcy led to costs incurred that did not result in any energy savings. While the IPA appreciates that the ICC must consider whether utilities prudently manage their expenditures, balance must be achieved between necessary risks to achieve cost-effective energy reductions and completely insulating ratepayers or shareholders from any lost expenses.

One suggestion for achieving this balance could be general guidance from the Commission about terms and conditions utilities should include in their contracts offered to vendors, as such clarity could also increase vendor confidence in the program structure. While the IPA is not seeking to litigate each and every utility energy efficiency contract term through a 90-day proceeding addressing a host of other, non-energy efficiency issues, the Plan approval process may allow for general Commission guidance and any specific, discrete questions about contract terms (such as the propriety of surety bonds) to be addressed.

For the past two years, the extent to which programs can include gas savings has been an issue for some of Ameren Illinois' bids. As discussed in Section 9.5.4 below, Ameren Illinois has included a provision in its RFP that attempts to limit measures that have gas savings; it has used that provision to recommend rejection of certain programs or to evaluate others with none or only some of their gas savings. The IPA does not agree with this approach, believing it is inconsistent with the law. The IPA believes that programs (as opposed to specific measures within the program) should be evaluated in their entirety using both the gas and electric savings—as done in each year prior to this year, as done by ComEd in its submission, and in the view of the IPA, as intended by the plain language of the law.[243]

9.4.3 Other Considerations

In Docket No. 13-0546, the Commission approved a process by which duplicative programs that are otherwise cost-effective could be excluded from the Plan. This process has worked reasonably well. Since that time, additional concerns about bids have arisen. For example ComEd has flagged bidder "performance risk" as an issue, one discussed somewhat extensively in filings around the approval of the 2016 Plan. As discussed more specifically in Section 9.6.5, certain bidders have consistently failed to achieve meaningful savings. While pay for performance contracts limits the risk to ratepayers from underachieving programs, there are still administrative and overhead costs associated with these programs and the potential for very poorly performing programs and vendors to produce negative customer experiences and "poison the well."

While the IPA believes that it should not unnecessarily limit Section 16-111.5B offerings, ComEd has proposed a pragmatic and appropriately permissive approach to performance risk for this year's Plan (and Ameren Illinois applies similar logic in a more limited scale in its consideration of duplicative programs). It may be worth formally approving a fixed process or test under which programs identified as posing too significant a performance risk could be removed from inclusion in the Plan. Combined with the idea suggested above about how to refine and improve bids, a better process for addressing particularly weak bids could result in a better overall suite of programs.

9.5 Ameren Illinois

Ameren Illinois' 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 six appendices which may be found on the IPA website posting of the draft 2017 Procurement Plan at www.illinois.gov/ipa. Two of the Appendices (4 and 6) in Ameren Illinois' submittal contain confidential data and are not included in the Appendices of this Plan. Ameren Illinois also provided the IPA with its most recent energy efficiency Potential Study, and on a confidential basis, copies of all the bids received.

The IPA believes that Ameren Illinois' submittal meets the requirements of Section 16-111.5B(a)(1)-(3) and that the programs identified by the IPA as "cost-effective" should be approved by the Commission pursuant to Section 16-111.5B(a)(5).

9.5.1 Ameren Illinois Bids Received

Ameren Illinois received 24 bids: eight for the residential sector, and 16 for the business sector. All bids sought contracts for three years. Of those 24 program proposals, Ameren Illinois classified two as "Not Responsive" (discussed further below in Section 9.5.4); 11 did not pass the TRC; and one was deemed duplicative (discussed in Section 9.5.5); leaving 10 programs that Ameren Illinois recommended as acceptable in its Assessment. For three of those programs, Ameren Illinois recommended that additional conditions be applied (discussed in Section 9.5.6). As discussed in Section 9.5.4 the two programs classified as "Not Responsive" were subsequently analyzed by the IPA, passed the TRC, and are thus included in this Plan.

The 24 bids received represents a decline from the 32 bids received by Ameren Illinois in 2015, a surprising result given the potential for three-year contracts for winning bidders through this year's solicitation (only one year contracts were available in the prior year's solicitation). This reduction in bidder participation may raise concerns about whether Ameren Illinois should be more aggressive in soliciting bids. For this year, after development of its RFP (a process which considered the input of the Agency and interested stakeholders, as

[243] Section 16-111.5B(b) expressly requires that "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103" (i.e., "means that the measures satisfy the total resource cost test"), which in turn expressly requires that "avoided natural gas utility costs" be included in a cost-effectiveness calculation.

envisioned by Section 16-111.5B(a)(3) of the PUA), Ameren Illinois only posted the RFP to the Association of Energy Service Professionals ("AESP") website and conducted no further outreach. Ameren Illinois confirmed that this approach is consistent with its past practice (including in 2015, when it received 32 bids), and AESP is also the primary (but not only) avenue used by ComEd in soliciting bids—and ComEd received more bids in 2016 than in 2015. While posting to the AESP website appears to be sufficient to reach established industry participants, it may be less effective in reaching new participants who could provide innovative new programs.

A second issue that may have complicated bidder participation is the introduction of a surety bond requirement for winning bidders (noticed to potential bidders in the RFP) as a mechanism to help protect ratepayers against potential program performance issues. It is unclear to the Agency whether a measure such as surety bonds is necessary given the pay-for-performance nature of Section 16-111.5B energy efficiency contracts, and if a surety bond requirement produces a chilling effect on participation, it could actually have a net negative impact on ratepayers by reducing the number of cost-effective programs included in the IPA's electricity procurement plan. As with bid solicitation, this is an issue for which the Agency has limited visibility as to its impacts.

9.5.2 Ameren Illinois Bid Review Process

In conjunction with the bid review conducted by Ameren Illinois and stakeholders,[244] Ameren Illinois' consultant AEG performed an analysis on the bids. All documents submitted by the bidders were reviewed, including the program proposal, measure information spreadsheet, and any supporting documentation. AEG reviewed the detailed savings calculations provided by the bidders and then independently calculated savings for each individual measure where a Technical Reference Manual ("TRM")[245] equation is applicable to verify compliance with the TRM. If the results matched, compliance was verified. If AEG found minor discrepancies in the bidder equations that were not in compliance with TRM Ver. 5.0, AEG adjusted the savings so they were in compliance with that version of the TRM (with the exception of one behavioral program, as discussed further below). If there were major discrepancies, AEG went back to the bidder to gather more information to determine why there were differences from the bidder savings and TRM calculations.

In all but one case, the issues were resolved and AEG was able to verify TRM compliant savings. In the instance where AEG calculations differed from the bidder calculations, this occurred because the bidder sought to use calculations based on a different state's TRM. AEG instead independently calculated savings values using the Illinois TRM were utilized, and the Agency believes these were appropriate adjustments.

9.5.3 Review of Ameren Illinois TRC Analysis

The IPA reviewed the TRC analyses provided by Ameren Illinois using the BENCOST tool provided by the utility. The BENCOST model was updated this year to include quantifiable non-energy benefits for water and O&M expenses, a reserve adjustment to the cost of capacity, and an estimate for the future price of carbon.[246] In conducting its review, the IPA reviewed submitted inputs for accuracy and reasonableness, and performed "stress testing" around program cost-effectiveness parameters (such as adjusting the forward energy price curve, levels of administrative costs, etc.) to develop a better understanding of the impacts of adjustments to the model. The IPA generally concurred with the Ameren Illinois inputs, assumptions, and methodology.

[244] Stakeholders who signed non-disclosure agreements with Ameren Illinois and participated in a series of bid review meetings included the IPA, the Office of the Illinois Attorney General, ELPC, NRDC, CUB, and IIEC. ICC Staff also participated, but did not sign a non-disclosure agreement (citing existing statutory obligations to maintain the confidentiality of information).

[245] The TRM is a guidance document developed through the SAG process and approved by the Commission. It provides standard values and methodologies for calculating savings and impacts from energy efficiency measures and programs.

[246] Ameren Illinois initially submitted its analysis using a methodology based on a $25/ton price for carbon, but subsequently updated the analysis to reflect a methodology that used the price impacts from the U.S Energy Information 2016 Annual Energy Outlook which reflect the implementation of the Clean Power Plan. The revised methodology appears consistent with the methodology used by ComEd.

Ameren Illinois included a blanket administrative cost adder of 11.89% for all programs in evaluating individual program cost-effectiveness.[247] This administrative cost adder is lower than the 13.58% proposed by Ameren Illinois last year, and is nearly the same as the approved 11.5% administrative cost adder from last year's plan approval (a percentage adder which reflected the removal of non-scalable costs for the Potential Study consistent with the Commission's directive in Docket No. 15-0541).[248]

According to its submittal, Ameren Illinois's 11.89% administrative cost adder is composed of 3.97% for Evaluation, Measurement and Verification (compared to 3.5% last year),[249] 5.61% for administration (compared to 5% last year), and 2.3% for marketing, education and outreach (compared to 3% last year). In Docket No. 14-0588, the Commission required that the utilities "track administrative costs by program in order to aid in future determinations of appropriate administrative cost assumptions to use in the TRC analysis of the Section 16-111.5B programs."[250] Ameren Illinois provided follow-up information demonstrating costs incurred by program in substantiating actual administrative costs. These administrative cost levels appear to be within an expected range based on prior years, and that small changes to the administrative adder which could come from minor adjustments would not appear to impact which programs pass or fail the TRC.

Ameren Illinois (through its consultant AEG) adjusted the gross energy savings values for certain energy efficiency measures provided by bidders to more accurately reflect values in the Illinois TRM. While one such instance resulted in a disagreement by the bidder (who sought to apply values derived from another state's TRM), those adjustments appear to be reasonable to the IPA. Ameren Illinois (also through AEG) also adjusted certain net-to-gross ratios provided by bidders to reflect the NTG ratios recommended by Ameren Illinois' independent evaluator. Those adjustments appear reasonable to the IPA.

As with last year, the IPA observes that fewer proposed programs passed the Ameren Illinois TRC screening than the ComEd screening. While this could be a function of the bids themselves or the TRC methodology applied, it appears that lower energy and capacity prices in the Ameren Illinois service territory may also simply make the test more difficult to pass. Of the 11 programs that did not pass the TRC, values ranged from 0.15[251] to 0.98.[252]

In addition to calculating TRC values for each program, Ameren Illinois also provided Utility Cost Test ("UCT") results for each program (as required by Section 16-111.5B(a)(3)(D) of the PUA) and an assessment of the cost of procuring each individual energy efficiency program as compared to its calculation of the Cost of Supply (provided pursuant to Section 16-111.5B(a)(3)(E)). The calculation methodology and application of the Cost of Supply was a subject of significant debate in the consideration of the 2016 Plan, with the IPA believing that Ameren Illinois' approach to calculating the Cost of Supply—an approach which disregarded gas savings and transmission & distribution savings, which differed from Ameren Illinois' established practice from prior years, and which differed from (and continues to differ from) the ongoing practice of ComEd—was

[247] In its submittal, Ameren Illinois noted that this adder is only for the purpose of calculative cost-effectiveness, and that for the purposes of cost recovery they estimate the need to include an additional 1.55% to cover those non-scalable costs.
[248] See Docket No. 15-0541, Final Order dated December 16, 2015 at 97-98.
[249] Several commenters on the draft Plan raised concerns that this amount exceeded 3% given the 3% cap on "[t]he resources dedicated to evaluation" in 220 ILCS 5/8-103(f)(7) and consensus items regarding administrative cost adders. Against the backdrop of the Commission's Order in Docket No. 14-0588, however, the IPA's primary concern is whether the adder reflects actual costs. As the Agency has no reason to believe that this does not reflect actual administrative costs, the Agency is comfortable with using a 3.97% value.
[250] Docket No. 14-0588, Final Order dated December 17, 2014 at 224.
[251] This is the program for which Ameren Illinois did not accept the bidder's proposal to use values from another state's TRM; the IPA concurs with Ameren Illinois' determination to use Illinois TRM values.
[252] As discussed in Section 9.5.5, the program with a TRC of 0.98 was also determined to be duplicative. The highest TRC for a non-duplicative program was 0.85.

inappropriately restrictive, especially when used to advocate for the non-adoption of otherwise cost-effective energy efficiency programs.[253]

The IPA continues to have reservations about the methodology used by Ameren Illinois to calculate the Cost of Supply, and one program which passed the TRC test failed the Ameren Illinois Cost of Supply test. As the Agency's is directed by law to include "energy efficiency programs and measures it determines are cost-effective,"[254] and because "cost-effective" refers to a program passing the Total Resource Cost test[255] (which, by law, requires taking into account gas savings, as is done through the TRC but not through the Ameren Illinois approach to calculating "cost of supply"),[256] that program is included in this Plan. However, the Agency is mindful of the Commission's acceptance of the Ameren Illinois approach to calculating the Cost of Supply in Docket No. 15-0541, and the discretion the Commission exercised in deciding not to include two programs with positive TRC test results which failed Ameren Illinois' Cost of Supply analysis, and understands that it could again use its recognized discretion to disqualify that program.

9.5.4 Programs Deemed "Not Responsive to the RFP" by Ameren Illinois

Ameren Illinois determined that two proposals were not responsive to the RFP. In determining that such programs were not responsive to its RFP, Ameren Illinois referenced the following statement within the RFP:

> "The purpose of this RFP is to procure energy efficiency programs that acquire electric savings in accordance with Section 5/16-111.5B of the Act. Accordingly, any programs or measures designed to acquire gas savings will not be accepted. However, if an electric program design captures incidental gas savings through multi-fuel measures, it may be considered. Such savings will be considered for purposes of the TRC test."

Ameren Illinois contends two of the proposals did not meet this requirement through too great a focus on gas savings, and therefore it did not fully evaluate these two proposals.[257]

9.5.4.1 Policy Implications

The Agency understands Ameren Illinois' concern that the IPA procurement plan process could include the approval of energy efficiency programs that might otherwise be funded by gas ratepayers (for instance, pursuant to Section 8-104 of the PUA) rather than a potentially distinct universe of electric ratepayers taking electric distribution service from Ameren Illinois. Conceptually, IPA procurement plans—and the IPA itself—generally address only electricity load requirements and not gas supply. However, the Agency is concerned that a disqualifying approach in the treatment of programs featuring considerable gas savings may be inconsistent with the Public Utilities Act and the IPA Act: Section 16-111.5B(b) of the PUA requires that "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103" (i.e., "means that the measures satisfy the total resource cost test"), which in turn requires that "avoided natural gas utility costs" be included in a cost-effectiveness calculation. While the IPA appreciates that adopting such programs could result in cross-subsidization of gas ratepayers by electric ratepayers, the intent of the General Assembly in enacting Section 16-111.5B, as taken from the language of the statute itself, appears to be that gas savings are not ineligible for consideration under Section 16-111.5B and in fact that such savings must be taken into

[253] The Agency notes that while the Ameren Illinois methodology for calculating Cost of Supply was unclear to some parties last year, causing the Commission to specifically state that "[i]n the future parties should present their method for calculating the cost of supply when asserting that an energy efficiency program exceeds that cost" (Docket No. 15-0541, Final Order dated December 16, 2015 at 105), Ameren Illinois provided a clear statement as to its Cost of Supply methodology in its July 15, 2016 submittal.

[254] 220 ILCS 5/16-111.5B(a)(4).

[255] 220 ILCS 5/16-111.5B(b) ("the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act"); 220 ILCS 5/8-103(a) ("'cost-effective' means that the measures satisfy the total resource cost test).

[256] 20 ILCS 3855/1-10 (requiring that the TRC analysis count, as a benefit, "other quantifiable societal benefits, including avoided natural gas utility costs").

[257] Ameren Illinois did not include these two programs in its submittal to the IPA, and therefore program descriptions for these programs were not included in that submittal's Appendix 5. In order to provide full information on these programs, the IPA has elected to include the program descriptions as included in the original bids in a separate appendix to this Plan, Appendix I.

account in assessing the cost-effectiveness of proposed programs. Further, as described below, using dollar savings (rather than BTUs, as Ameren Illinois employed) to compare the gas and electric impacts of programs demonstrates that due to the low price of gas compared to electricity, these programs actually generate more financial savings on the electric side. Because the concept of cost-effectiveness ultimately reduces impacts to their financial terms, the assertion that these programs have more gas savings than electric savings is arguably incorrect and not a justification for their exclusion.

Further, past practice under Section 16-111.5B has been to count all gas savings in cost-effectiveness determinations. Dismissing programs as inconsistent with the RFP and thus ineligible for inclusion on this basis constitutes a clear departure from past practice—and a departure that would be made not to disqualify programs which fail to produce electric savings, but driven instead by the proportion of gas savings versus electric savings for certain programs while still recognizing gas savings from other proposed programs as required by the law.

The IPA understands that this issue has been a topic of considerable discussion in past years, and that there are legitimate arguments on both sides.

9.5.4.2 Demand Based Ventilation Control Program

One of the programs Ameren Illinois considered to be inconsistent with its RFP is a demand control ventilation program which contains two measures—one for HVAC supply fans, and one for kitchen ventilation. The former reduces both gas and electric usage, while the latter only reduces electric usage. Overall, when normalized on a BTU basis, approximately two thirds of the energy reductions come from decreased gas usage—which exceeded the level that Ameren Illinois considered acceptable and was presented as their basis for not evaluating this program. However, examining savings by dollars saved rather than BTUs shows that two thirds of the financial savings resulted from reduced electric costs.

By considering the program non-responsive, Ameren Illinois did not initially provide a TRC result for the program, and the IPA requested that Ameren Illinois conduct that analysis using the gas savings. The TRC results subsequently provided by Ameren Illinois indicated that the TRC for the program was 1.98 and thus the program is cost-effective.[258]. The IPA believes that Ameren Illinois erred in excluding this program from its evaluation and includes it in the list of programs that are recommended for approval by the Commission.

On August 30, 2016 Ameren Illinois filed its next Section 8-103/8-104 Energy Efficiency Plan with the Commission in Docket No. 16-0413. That Plan includes Demand Control Ventilation measures that could be viewed as duplicative of this program. Since that Plan has not yet been approved by the Commission, the IPA does not consider the program to be "duplicative," as no overlapping program has yet been approved by the Commission. However, the Commission may wish to instead approve this program only on the condition that the comparable measures are not approved in Docket No. 16-0413. The IPA further notes that while Ameren Illinois did not develop a performance risk screenings approach as used by ComEd (see Section 9.6.5), the vendor for this program is also a vendor that was flagged as a potential performance risk in the ComEd review process.

9.5.4.3 Behavioral Program

The other program which Ameren Illinois considered to be inconsistent with its RFP was for a behavioral program that would be a continuation of an existing program. This bid contained multiple options including maintaining the current program scope or additionally expanding at various levels into all-electric households above and beyond continuing the current offering to dual-fuel households. When normalized on a BTU basis, half of the projected energy savings result from reductions in gas usage, but when savings are

[258] The IPA notes that *even if* gas savings were excluded (which, again, the IPA does not believe to be an appropriate methodology, as the law requires consideration of gas savings), the "electric only" TRC result would still be 1.34—thus making the program cost-effective on the basis of electric savings alone.

considered in dollar terms rather than BTU terms, the large majority of the savings result from savings of electricity.

While considering this program "Not Responsive," Ameren Illinois still conducted a TRC analysis of this program using both methodologies from the Illinois TRM version 5.0 but excluding the gas savings, as well conducted as using the previously generally accepted methodology for behavioral programs of looking at only one year of savings (a "No Persistence" model). The analysis was only of the core continuation program (and not the expansion into all-electric homes) and the program narrowly failed the TRC under both methodologies.

The IPA requested additional analysis to include gas savings as well as for the options included in the bid that expanded into all-electric homes.

Table 9-2 summarizes various TRC analyses conducted for this program. While Ameren Illinois provided in the additional analysis the TRC analysis of the expansion options, it did so treating them as standalone programs rather than offered in conjunction with the current program. However, the bid specifically described the expansion options as bundled with the core program,[259] and thus the IPA believes they must be evaluated as bundled together. These results reflect that bundling. It is the opinion of the IPA that the first row of this Table is the appropriate one for use in consideration of this program because it incorporates the methodology contained in the TRM that is currently in effect (TRM Version 5.0), as well as the gas savings required for cost-effectiveness determinations under the law.

Table 9-2: Behavioral Program TRC Sensitivity Analysis

Analysis	Continuation of 250,000 Homes	Continuation + Expand to 50,000 All-Electric Homes	Continuation + Expand to 100,000 All-Electric Homes	Continuation + Expand to 125,000 All-Electric Homes
TRM 5.0	**1.07**	**1.26**	**1.16**	**1.17**
TRM 5.0 Electric Only	0.87	1.10	1.02	1.05
No Persistence	1.19	1.16	1.02	0.97
No Persistence Electric Only	0.93	0.95	0.84	0.80

Even excluding gas savings (which, again, the IPA does not believe to be an appropriate methodology), the TRC results of the bundled programs using the TRM 5.0 methodology are all above 1.0. In addition, while the IPA does not consider Ameren Illinois' Cost of Supply test as a criterion for excluding programs from the Plan, the continuation option on its own, or bundled with any of the expansions, does not pass the Cost of Supply test.

Based on this analysis and Section 16-111.5B's directive that the IPA "shall include . . . energy efficiency programs and measures it determines are cost-effective" in its Plan,[260] the IPA recommends including the behavioral program continuation with expansion into all-electric homes. This raises the question of what level of expansion should be adopted: while TRC results are higher for the smaller expansion, all expansions pass the TRC. In the IPA's view, including the largest cost-effective expansion proposed by the bidder appears most consistent with Section 16-111.5B's requirement to "fully capture the potential for all achievable cost-effective savings, to the extent practicable,"[261] and the Agency thus includes that program. The IPA further

[259]The bidder stated in its bid that the expansion options "all assume that this existing program continues concurrently." A potential source of any lack of clarity regarding the components of the bid may lie in the confusing way in which the bidder structured its bid, as the expansions were listed as options 1 through 3, and the existing program as option 4.
[260] 220 ILCS 5/16-111.5B(a)(4).
[261] 220 ILCS 5/16-111.5B(a)(5).

notes that because all-electric homes inherently have higher electric bills than other homes, maximizing participation of those homes in an energy efficiency program is sensible.

9.5.5 Duplicative Programs

In the docket approving the Agency's 2014 Plan, significant consideration was given to how to address third-party program bids that may be "duplicative" of existing programs under Section 8-103 of the PUA. Based on prior years' Plans, the IPA understands the term "duplicative" to mean a program that overlaps an existing program in a manner in which greater market participation by vendors does not yield sufficient additional value to consumers. Alternatively, while a "competing" program may occupy the same general space, "competing" programs may benefit from multiple delivery channels. The general goal would be that "duplicative" programs are to be avoided, while "competing" programs would be acceptable to the extent that the competition does not render one or both non-cost-effective.

The review process approved by the Commission for analyzing "duplicative" or "competing" bids operates 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 determines which bids the IPA believes are duplicative or competing. The IPA identifies all proposed 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.[262]

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.[263]

[262] Docket No. 13-0546, Final Order dated December 18, 2013 at 149.
[263] Id.

Because Section 8-103 programs have not yet been approved by the Commission, no proposed Section 16-111.5B program can be considered "duplicative" of any existing Section 8-103 program. However, as previously explored by the Commission in Docket No. 14-0588, two proposed Section 16-111.5B programs may indeed be "duplicative" of one another based on application of the criteria above, thus forcing a clear choice between overlapping programs or some other corrective action intended to safeguard against the erosion of customer value.

For this year's Plan, the issue of duplicative programs arises when considering small business bids received in response to this year's RFP. Of the eight small business programs that passed the TRC, six of the programs had varying degrees of overlap in their offerings. Two other programs (Savings Through Efficient Products and New Construction) were determined by Ameren Illinois to be compatible with all other programs.

For the six programs that did have varying degrees of overlap, Ameren Illinois assessed the programs' scope and prior experience with the vendors to recommend that one of the programs (Small Business Whole Building) not be included. The remaining five bids (Small Business Direct Install, Private HVAC, Public HVAC, Exterior Lighting, and Lit Signage) were deemed sufficiently distinct such that they do not create issues of duplication. The Small Business Whole Building program overlaps all of these other programs, and in Ameren Illinois' assessment, including it along with the other programs would violate the duplicative test.

The IPA observes that an alternative approach could be to approve the Small Business Whole Building program, but not the other programs. This approach would have the added benefit of including measures to address refrigeration—something not included in the other bids. However, the IPA notes that Ameren Illinois has included some refrigeration measures in its Section 8-103 portfolio under consideration in Docket No. 16-0413 (which, if approved by the Commission, could mitigate this concern).

One perhaps important aspect of Ameren Illinois' proposal is its past experience with these bidders and the lower success rates of other programs from the bidder that offered the Small Business Whole Building program. As discussed further above and also in considering programs proposed by ComEd below, there may be valid reasons to take poor past program performance into account in evaluating proposals—and especially overlapping proposals for which some choice must be made.

While the IPA believes either approach would be workable, given that a decision between the two approaches must be made, the IPA believes Ameren Illinois' assessment of vendor performance offers value in making this determination and adopts Ameren Illinois' recommendation to exclude the "duplicative" Small Business Whole Building program.

The IPA also recognizes that in the Section 8-103 Plan under consideration in Docket No. 16-0413, Ameren Illinois has included a Small Business Direct Install program. As noted in the discussion of the Demand Based Ventilation Control in Section 9.5.4.2, because that program has not been approved by the Commission, the Small Business Direct Install program proposed under Section 16-111.5B cannot be considered "duplicative" of the Section 8-103 Small Business Direct Install program. To mitigate any such concerns, however, the Commission could consider offering only conditional approval of the Small Business Direct Install program in this Plan, contingent on the Small Business Direct Install program not being approved in Docket No. 16-0413, and with the rejection of the program proposed here contingent on Ameren Illinois (or other stakeholders) demonstrating that if the duplicative screening criteria were applied, the Section 16-111.5B program would in fact be duplicative of the Section 8-103 program.

The IPA further notes that one additional small business program (Deep Retrofit, which targets just gas stations and convenience stores) narrowly failed the TRC test. This program initially passed the TRC, but as discussed in footnote 246, when Ameren Illinois updated its methodology for including the future price of carbon, the results for this program fell just below the TRC to 0.98.

However, even with a positive TRC, Ameren Illinois determined that this program would duplicate measures in both the recommended Small Business Direct Install program as well as the not recommended Small Business Whole Building program. Ameren Illinois initially had recommended not including this program for similar reasons to why it did not recommend including the Small Business Whole Building program, but this "duplicative" determination was rendered moot by the subsequent negative TRC result. Should there be further updates resulting in this program passing the TRC test, for the reasons stated above for the Small Business Whole Building program, the IPA would accept Ameren Illinois' recommendation to consider the Deep Retrofit program as "duplicative" rather than simply not "cost-effective."[264]

9.5.6 Additional Conditions Requested by Ameren Illinois

Ameren Illinois raised additional issues with three programs and requested that additional conditions be applied to their approval.

- For the Residential Retail Lighting program, Ameren Illinois noted that LED prices are dropping, and therefore requested that since the bid was for three years, that "AIC should be granted the ability to reopen the contract on an annual basis to review product type, product quantity and price to ensure the customer is achieving a good value through the program."[265] Given the dynamic nature of the lighting market, this condition appears reasonable to the IPA.
- For the Community LED Distribution program which proposes to distribute LEDs through food pantries, Ameren Illinois raised concerns regarding the number of bulbs to be distributed per household (the program builds off a current year program which is distributing CFL bulbs), the relative newness (in Ameren Illinois service territory) of the distribution approach, and the ongoing reduction of prices for LED bulbs. Due to these concerns, Ameren Illinois requested that the program only be approved for one year (rather than three years as bid) to allow Ameren Illinois to assess the similar CFL distribution program currently underway. While the IPA appreciates Ameren Illinois' concern, an alternative approach could be to apply to this program a similar condition that is applied to the Residential Retail Lighting program, and it is unclear to the Agency how the pay-for-performance nature of Section 16-111.5B contracts would fail to safeguard ratepayers against any failures in these program design approaches.
- For the Low Income Multifamily program, Ameren Illinois notes that the vendor is currently supporting DCEO programs. The RFP includes a condition that "[i]f an IPA bidder later works under the AIC EE Plan as either a contractor or subcontractor, a clear separation of duties and costs will be required under the AIC contract." Ameren Illinois suggests extending that concept to encompass work for DCEO in order to prevent future unfair bidding advantages. While separation of duties appears to be a reasonable concept, the IPA notes that given the fact that DCEO does not have an approved future Section 8-103/8-104 portfolio, it is unknown at this time if this vendor will continue to be a DCEO contractor in the future.

9.5.7 Ameren Illinois Programs Recommended for Approval

Ameren Illinois' submittal includes identification of 10 energy efficiency offerings for this Procurement Plan with a TRC of above 1.0, which were not determined to be "duplicative," and which met the requirements of Ameren Illinois.[266] In reviewing the bids received by Ameren Illinois, the IPA determined that two additional programs should have been included, bringing the total of programs included in this Plan to 12. These programs are exhibited in Table 9-3.

[264] Perhaps further reinforcing a determination to exclude this program is that the vendor in question is the same vendor flagged in the ComEd performance risk discussion in Section 9.6.5 below.
[265] Ameren Illinois Section 16-111.5B Submittal at 28.
[266] Ameren Illinois also provided the results of the Utility Cost Test ("UCT") and all the proposed programs passed the UCT. As it has in prior years, the IPA considers that informational only and has not used the UCT test in its consideration of programs to include in this Plan.

Table 9-3: Ameren Illinois Energy Efficiency Offerings

Program	2017 -2018		2018 – 2019		2019 – 2020		TRC
	Net Savings (MWh)[267]	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	
Community LED Distribution	12,210	$2,675,562	14,900	$2,675,562	17,177	$2,675,562	1.85
Residential Retail Lighting	92,773	$14,446,037	93,324	$14,487,428	93,807	$14,537,878	3.34
Low-Income Multifamily	6,092	$958,568	6,092	$955,165	6,092	$956,299	1.65
Small Business Direct Install	21,759	$5,711,937	21,488	$5,711,977	21,488	$5,751,932	1.18
STEP	1,967	$765,675	1,967	$765,675	1,967	$765,675	1.47
Private HVAC	6,957	$1,134,400	6,957	$1,134,400	6,957	$1,134,400	1.45
Public HVAC	6,957	$1,134,400	6,957	$1,134,400	6,957	$1,134,400	1.45
Exterior Lighting	8,346	$2,516,254	11,095	$3,345,367	13,316	$4,015,213	1.21
Lit Signage	12,978	$3,082,479	14,941	$3,544,850	17,923	$4,253,820	1.05
Commercial New Construction	978	$269,259	1,957	$546,939	-	$113,710	1.51
Behavioral Program (Continuation Plus 125k All-Electric Expansion)	16,254	$2,812,500	24,783	$3,048,750	31,191	$3,358,125	1.17
Demand Based Ventilation Control	2,901	$843,732	4,641	$843,732	4,061	$843,732	1.97

The total net savings for these programs is estimated as 190,172 MWh at the busbar for the 2017–2018 delivery year, 209,102 MWh for the 2018–2019 delivery year, and 220,936 MWh for the 2019–2020 delivery year. These programs also contribute to a peak reduction of approximately 13 MW. The estimated savings attributable to eligible retail customers is 71,008 MWh for the 2017–2018 delivery year, 72,315 MWh for the 2018–2019 delivery year, and 75,900 MWh for the 2019–2020 delivery year.

9.5.8 Ameren Illinois Reservations and Requested Determinations

In its filing, Ameren Illinois made the following reservations:

- "AIC reserves the right to update, revise, amend or end the programs approved in this docket. AIC's positions reflected herein are subject to change and AIC reserves the right to adjust any terms or conditions with any selected implementers to account for its upcoming Section 5/8-103 and Section 5/8-104 integrated energy efficiency and demand response Plan 4 filing, any pertinent ICC Orders, including those addressing customer data and privacy, or other relevant matters."[268]

While the IPA appreciates the challenges created in the timing lag between the approval of Section 16-111.5B programs in this Plan and the ongoing Section 8-103 and 8-104 proceeding, the Agency is concerned that bidders had a reasonable expectation that the provisions of the RFP would be applicable to the consideration of their bids, and after the fact changes could have a negative (or positive) impact on their desire to move forward and implement their proposed programs.

Ameren Illinois also made the following requests:

- "AIC seeks express approval that it is permitted to recover costs that exceed the estimated program costs. In no case will the costs to be recovered be greater than 110% of the estimated program costs

[267] MWh savings shown in Table 9-3 through Table 9-5 are at the busbar.
[268] Ameren Illinois Section 16-111.5B Submittal at 8.

plus administration costs. In lieu of this express approval, AIC will be forced to prematurely discontinue approved programs prior to the estimated budget being expended."[269]

- "AIC may seek approval of programs as part of its Section 5/8-103 and Section 5/8-104 Plan that would render certain programs to be approved as a part of the Procurement Plan duplicative, and may seek conditional findings in this docket to provide for such an outcome."[270]

As in previous years, the IPA does not object to the first request. However as noted in regard to the reservations made by Ameren Illinois, the IPA has concerns related to the second request. This request appears to be a request that changes the playing field for bidders after the fact through allowing a participating utility to receive bids under an open-ended RFP, but then to potentially shape its Section 8-103 portfolio so as to disqualify certain third-party bids after their receipt and analysis. It is unclear at this time how this reservation of rights will be applied by Ameren Illinois, but the Agency will approach any such post-hoc assertion of duplicity with an eye toward a request for proposal process that took place without any such overlapping programs having been identified to bidders.

In addition to adopting these determinations, the IPA requests that the ICC approve the incremental energy efficiency programs as described above.

9.6 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 2017 Procurement Plan at www.illinois.gov/ipa. Please note that a document submitted by ComEd entitled "ComEd Third Party Efficiency Program Results of 2016 Bid Review, July 15, 2016" contains confidential data and, consistent with prior years' practice for confidential submittals, is not included with this Plan or otherwise publicly available.

The IPA believes that ComEd's filing meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Table 9-5 should be approved pursuant to Section 16-111.5B(a)(5).

9.6.1 ComEd Managed Programs

As part of its assessment of energy efficiency programs, ComEd chose to include in its submittal three residential and two business programs that are continuations of existing ComEd managed programs. The programs include Home Energy Reports, Residential Lighting, Residential Upstream Pumping, Small Business Energy Services, and LED Streetlighting.

As the Agency understands it, this approach is intended in part to solve the challenge of how to "expand" 8-103 programs through the Section 16-111.5B process when the upcoming Section 8-103 portfolio has not yet been approved, a topic for which the Commission sought workshop consideration of solutions in Docket No. 15-0541 to inform the development of the 2017 Plan. By moving these programs wholesale into the Section 16-111.5B process, ComEd is able to run them at an "expanded" level that fully maximizes cost-effectiveness while filling out its Section 8-103 portfolio with other cost-effective programs. While distinct from Ameren Illinois' approach (which was to offer an open-ended RFP for any programs through Section 16-111.5B, subject to the conditions discussed above), the IPA is fully supportive of this approach (as was the Commission in previously approving a similar approach taken by ComEd in Docket No. 13-0546) and recommends the adoption of these ComEd Managed Programs as part of the 2017 Plan.

[269] Id. at 10.
[270] Id. at 10.

9.6.2 ComEd Bids Received

ComEd received 27 bids, with one bid withdrawn (a residential lighting program submitted "in error" by the bidder, per ComEd). All bids sought contracts of three years in length. The remaining 26 programs included four residential programs, 14 business programs, five public sector programs, and three low income programs. Of these programs, six failed the TRC,[271] one was duplicative of a ComEd offered program included as part of its Section 16-111.5B submittal (as referenced above, ComEd noticed to bidders in its RFP that certain programs would be run by ComEd and placed wholesale into the Section 16-111.5B portfolio so as to avoid the limitations of the Section 8-103, advising bidders not to bid on any such programs), and three were determined by ComEd to fail to meet minimum performance expectations and thus fit to be disqualified even if cost-effective. This left 16 programs for ComEd to recommend for inclusion in this plan. For two of these programs, that approval contained certain conditional provisions described below in Section 9.6.7.

The 27 bids received was a significant increase over the 17 bids received by ComEd in response to its Section 16-111.5B RFP for the 2016 Plan; given the three-year contract length offerings, this increase is perhaps not surprising. As with Ameren Illinois, ComEd posted its RFP to the AESP website, and also posted the RFP on Exelon's procurement portal (opening it for bids by registered vendors, and automatically notifying all vendors registered with Exelon of its release) and distributed a copy of the RFP (with instructions for vendor registration) to the SAG email distribution list.

While ComEd did not require surety bonds as was done by Ameren Illinois, ComEd has implemented a strict pay for performance model as a reaction to the implications of the disallowance of expenses from a prior Section 16-111.5B program whose vendor went bankrupt.[272] Because ComEd did not impose its revised model until after the close of the bid submittal deadline, the IPA has not had an opportunity to review whether the new requirements will adversely impact bidder participation in response to future ComEd RFPs.

In order to provide the IPA with a broad range of feedback on the bids received, ComEd solicited involvement from members of the SAG. The DCEO and two other organizations participated in the review process: the Natural Resources Defense Council and the Environmental Law & Policy Center. The Office of the Attorney General, the staff of the Illinois Commerce Commission, and the IPA also participated in the discussions but did not formally participate in the review process by providing bid scoring to ComEd. A key topic of discussion during the bid review was how to address programs that may pose a significant performance risk based on program design or the past performance of that bidder. These discussions resulted in the development of the two-part test for performance risk explained further below. The work product ultimately produced through this process was a report that was submitted to the IPA on a confidential basis that included qualitative program review by both stakeholders and ComEd.

9.6.3 Review of the ComEd TRC Analysis

ComEd uses the DSMore tool to conduct its TRC analysis. Unlike the BENCOST tool used by Ameren Illinois, DSMore uses proprietary analytical modules. ComEd provided detailed input and output tables from the analysis. While the IPA was able to review those fixed inputs and outputs, the IPA was not able to modify inputs to examine the impact on the outputs (thus limiting the sensitivity analysis that the Agency could conduct), a limiting feature of DSMore (at least relative to the flexibility offered by BENCOST) that the Agency also referenced in last year's plan.

[271] In comments received on the draft Plan, a bidder requested consideration of revised proposals for two of the programs that failed the TRC. The IPA has declined to adopt those revisions, noting that the revisions were proposed after the bidder was notified that the bids did not pass the TRC, and the revisions lowered the budgets, but not the MWh goals. This approach raises concerns about the accuracy of the bids. Even taking the lower budget and same MWh goals at face value (as opposed to having gone through the full internal ComEd review, stakeholder review, and IPA review), one of the programs still failed the TRC, and the other program only narrowly would have passed. The IPA does not believe the revised proposals should be considered.

[272] See generally Docket No. 14-0567.

For programs analyzed for the 2017 Plan, ComEd included an administrative adder of 9.6% in its TRC Test analysis—lower than the 11.5% estimate used last year.[273] This change resulted from the tracking of actual costs from the past two years, leading to a cost adder of 6.6% (as compared to the previous 8.5%) for program administration and the continuation of a 3% adder for evaluation.

As a manner of "stress testing" TRC results, ComEd also calculated TRC values without the inclusion of its administrative cost adder. One program (a public sector LED program) that did not pass the TRC (0.96) featured a positive TRC result (1.05) from removing the adder.[274] The other five programs that did not pass the TRC had values that ranged from 0.49 to 0.73 and the administrative adder was not a factor in their not passing.

9.6.4 Duplicative Program

As described in Section 9.5.5 above, a multi-step process has been used to consider if a proposed program is duplicative of an existing program. For the development of this Plan, the situation differs due to the lack of approved programs at the beginning for the three-year planning cycle. ComEd identified one bid for Advanced LEDs that it believes is duplicative of the SBES program that ComEd proposes offering and directly managing. The Advanced LED bid includes measures that are also offered by SBES, but it is a more limited offering and therefore creates a potential for lost opportunities (such as refrigeration) if customers participate in the Advanced LED program rather than the more comprehensive SBES program. While the IPA appreciates the potential additional customers that could be reached through this more targeted approach for advanced LEDs, it concurs with ComEd that this program is duplicative under the multi-factor inquiry described in Section 9.5.5 and should not be included in the Plan.

9.6.5 ComEd Identification of "Performance Risk"

In its review of programs for the 2016 Plan, ComEd flagged six programs as having a potential for performance/savings risk—programs for which there was some evidence that it could be challenging for the vendor to meet the energy savings goals proposed. However, ComEd did not recommend excluding any of those programs from the 2016 Plan; the IPA (and ultimately, the Commission) concurred, noting that the pay for performance model limited risks to ratepayers resulting from non-performance.

In its review of programs for the 2017 Plan, ComEd refined this issue to distinguish between "Performance Risk," as discussed in this section, and "Savings Risk," as discussed in Section 9.6.6. For the terminology utilized herein, performance risk is a more serious screen that could warrant the exclusion of programs from the Plan, while savings risk is less significant and not inherently a reason to consider exclusion of the program.

In bid review discussions around program proposals for the 2017 Plan, ComEd and stakeholders developed new screening criteria for programs that could have a significant likelihood of failing to achieve savings based on past performance. This screening was manifest as a two-part test: first, as a way to identify potential "performance risk" vendors, programs were screened to determine whether the bidder submitting the program failed to deliver five percent of their savings goals from prior Section 16-111.5B programs. If a vendor was identified as failing this test, the second screen applied was whether there was new information or a compelling reason that would suggest a different outcome for the proposed programs (e.g., new programs, new delivery approach, changes in team, or different market conditions). If the answer was "no" to both, then ComEd and stakeholders agreed the program posed a performance risk so significant that the program should not be recommended for inclusion.

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[273] Prior to the Commission's Order in Docket No. 14-0588, ComEd had not included an administrative cost adder in its TRC analysis for Section 16-111.5B programs.

[274] Please note, however, that zeroing out administrative costs could be viewed as at odds with the Commission's Order in Docket No. 14-0588, which requires that the utilities track actual administrative costs incurred to inform Section 16-111.5B TRC analyses.

Four programs failed the five percent criteria. One of those four did not pass the TRC, rendering its performance risk screening irrelevant. For the remaining three programs (which targeted Schools/Colleges, Convenience Stores, and Demand Control Ventilation), all three programs were bid by the same vendor. A previous school direct install program offered by that vendor achieved 0% of its goal, while a similar demand control ventilation program achieved only 1.6% of its goal. The Convenience Store program proposal was substantially similar in program design to the Schools/Colleges program. ComEd and the stakeholders agreed there was not any other new information that would suggest a performance improvement, and therefore recommended the exclusion of these three programs.

The Agency is mindful of the potential for Section 16-111.5B as a driver of innovative program approaches from third-party vendors that may not have a foothold in the Section 8-103 portfolio development process, and is thus hesitant to embrace too strong a filter when such a filter would be used to mitigate relatively minor risks. Section 16-111.5B calls for this process to "fully capture all cost-effective energy efficiency, to the extent practicable," and while the Commission has determine that this language does allow it the flexibility to consider criteria other than cost-effectiveness, the clear mandate to "fully capture all cost-effective energy efficiency" informs that such discretion should be very carefully and thoughtfully applied.

At the same time, while the IPA believes that risks associated with non-performance are almost entirely mitigated through pay-for-performance contracting, there are other negative outcomes caused by non-performance which may justify being mindful of performance risk.[275] The two-step approach proposed as part of ComEd's submittal seeks to punish only those vendors performing especially poorly, and even then provides a second step examination that could allow for the inclusion of that vendor's program. It seeks not to punish unfamiliar or unorthodox program design, only egregious non-performance.

With those considerations in mind, the Agency believes this two-step approach developed by ComEd and participating stakeholders strikes a reasonable balance between competing considerations and agrees with its application to these programs. As such, the IPA is not including these three programs pursuant to the recommendation of ComEd.. Should some (or all) of these programs be recommended for inclusion in the Final 2017 Plan, Table 9-4 includes the savings and budgets for these programs.

Table 9-4: Performance Risk Programs

Program	2017 -2018		2018 – 2019		2019 – 2020		TRC
	Net Savings (MWh)	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	
Schools/Colleges	2,632	$624,993	4,211	$999,989	3,685	$874,990	2.04
Convenience Stores	5,573	$1,249,941	8,918	$1,999,906	7,803	$1,749,917	1.22
Demand Control Ventilation	4,203	$999,979	6,725	$1,599,967	5,884	$1,399,971	3.57

9.6.6 ComEd Identification of "Savings Risk"

ComEd and stakeholders also identified four other programs as having some risk of not meeting savings goals, but not at the level of concern of the programs flagged for a performance risk as described above. ComEd did not recommend excluding these programs, but raised the issue for potential consideration by the IPA and/or the Commission. These four programs are discussed below:

- One program (Small Business Monitoring-Based Commissioning) also did not pass the TRC test, rendering the savings risk issue moot.

[275] These outcomes include administrative costs borne through the rider to manage contracts associated with non-performing programs and market dilution from especially poorly designed programs.

- A program that targets faith-based institutions has a small staff and has experienced turnover in key personnel, raising concerns related to whether the vendor has sufficient resources to implement the program.
- The Energy Saver program is a free opt-in online rewards program to incent energy efficiency in residential households. The program has been in operation for a number of years and has consistently failed to meet its savings goals.
- The Small Business New Construction program has long lead times to develop and construct buildings (and therefore generate savings). Due to the pay for performance contracting structure, this could provide financial challenges to the vendor. This program is also one that is flagged in Section 9.6.7 below for receiving only a conditional approval.

The IPA has reviewed these concerns. While it appreciates the savings risks that could exist for these programs, the Agency believes that these risks are sufficiently mitigated by the pay for performance contracting model and therefore does not propose to exclude these programs from the Plan.

9.6.7 Conditional Approvals

One bid for a program to assist Assisted Living Centers was offered by a vendor who currently manages aspects of ComEd's SBES program. Because that management responsibility includes managing trade allies, ComEd is concerned that also serving as a vendor under Section 16-111.5B would present a potential conflict of interest given the differing incentive levels between programs.

Because ComEd will be putting out for bid the future management of the SBES program, the current manager is not necessarily going to be the future manager. Should the current manager (i.e., bidder) be awarded the next management contract, that entity has indicated that they would prefer that management role over just the Assisted Living Center program (if the two are mutually exclusive). ComEd thus requested conditional approval of the Assisted Living Center program such that if the vendor is awarded the SBES contract, it will not proceed with the Assisted Living Center program. The IPA agrees with that conditional approval.

A bid for Small Business New Construction program is potentially duplicative of a program that ComEd plans to propose as part of its Section 8-103 energy efficiency portfolio later this year. Because the Section 8-103 portfolio has not yet been approved by the Commission, ComEd has requested that the approval for the Small Business New Construction bid be only conditionally approved.

Specifically, ComEd has suggested that if the Commission does not approve the similar program in ComEd's Section 8-103 portfolio, then the Small Business New Construction program would proceed; otherwise, the approval of the Section 8-103 program would authorize ComEd not to proceed with this program under Section 16-111.5B. Currently, the Small Business New Construction program is included in this Plan because it meets the requirements for consideration of Section 16-111.5B programs. However, if the Commission wishes to approve it on a conditional basis pending the outcome of the approval ComEd's Section 8-103 portfolio, the IPA would not object to that determination.

9.6.8 ComEd Programs Recommended for Approval

ComEd's submittal includes identification of 21 energy efficiency programs for inclusion in this Procurement Plan (five ComEd managed, and 16 third-party administered). All of these programs passed the TRC test at the time of assessment.[276] These programs are exhibited in Table 9-5.

[276] ComEd also provided the results of the UCT test and 14 of the 16 proposed programs passed the UCT. As it has in prior years, the IPA considers that informational only and has not used the UCT test in its consideration of programs to include in this Plan.

Table 9-5: ComEd Energy Efficiency Offerings

Program	2017 -2018		2018 – 2019		2019 – 2020		TRC
	Net Savings (MWh)	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	
Residential Lighting*	217,863	$38,187,475	210,503	$38,191,850	201,959	$38,196,334	8.34
Residential Behavior*	321,958	$11,283,750	57,952	$11,290,844	55,506	$11,298,115	1.53
Residential Upstream Pumping*	642	$1,200,000	1,285	$1,800,000	2,312	$2,760,000	1.03
Small Business Energy Savings*	190,953	$47,457,500	209,819	$52,191,438	230,912	$57,395,473	1.45
LED Street Lighting*	4,153	$2,459,250	6,056	$3,586,406	6,308	$3,735,191	12.56
Small Commercial Lit Signage	19,989	$4,530,767	24,430	$5,538,748	27,752	$6,294,280	1.24
School Direct Install	4,039	$1,298,639	3,072	$1,116,897	3,072	$1,122,488	1.90
Agricultural Energy Efficiency	2,330	$627,209	3,014	$789,380	3,532	$921,494	1.27
Senior and Assisted Living	22,518	$4,609,096	22,518	$4,609,096	22,518	$4,609,096	1.19
Faith-Based	1,149	$389,681	1,149	$389,681	1,149	$378,652	2.57
Rural Kits	1,241	$591,690	1,241	$591,690	1,241	$591,690	2.71
AC Tune Up	20,326	$4,190,893	20,326	$4,246,219	20,326	$4,303,412	1.51
New Construction Service Small Buildings	289	$87,857	1,851	$563,081	2,362	$718,279	3.23
Energy Saver	5,456	$240,786	6,894	$304,290	8,333	$367,794	1.52
Moderate Income Kits	11,645	$1,994,400	11,645	$1,994,400	11,645	$1,994,400	4.91
Middle School Energy Education Campaign	2,861	$1,139,356	2,861	$1,214,356	2,861	$1,214,358	1.78
Savings Through Efficient Products	2,397	$795,381	2,397	$829,791	2,397	$865,907	1.94
Enhanced Building Optimization	13,102	$2,500,000	13,102	$2,500,000	13,102	$2,500,000	1.92
LED Distribution	15,996	$3,056,000	12,997	$2,483,000	9,998	$1,910,000	1.80
Low Income Kits	22,048	$6,156,372	22,048	$6,156,372	22,048	$6,156,372	1.97
Low Income Multifamily Retrofits	6,313	$2,558,683	6,313	$2,558,683	6,313	$2,558,684	1.65

* ComEd Managed Programs.

The total net savings for these programs is estimated as 887,268 MWh at the busbar for the 2017–2018 delivery year, 641,473 MWh for the 2018–2019 delivery year, and 655,646 MWh for the 2019–2020 delivery year. The programs also contribute to a peak reduction of approximately 41 MW. The estimated savings attributable to eligible retail customers is 493,196 MWh for the 2017–2018 delivery year, 329,546 MWh for the 2018–2019 delivery year, and 331,957 MWh for the 2019–2020 delivery year.

The IPA agrees with this assessment and requests that the Commission approve the incremental energy efficiency programs as described above.

9.7 MidAmerican

Section 16-111.5B of the Public Utilities Act calls for each utility that participates in the procurement planning process set forth in Section 16-111.5 to include additional information related to energy efficiency.[277] However, as discussed in the 2016 Plan, Section 16-111.5B's compliance "requirements" include requiring that a utility submit its "most recent analysis submitted pursuant to Section 8-103A of this Act and approved by the Commission under subsection (f) of Section 8-103 of this Act,"[278] the "[i]dentification of new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act,"[279] and a requirement to "develop requests for proposals consistent with the manner in which it develops requests for proposals under plans approved pursuant to Section 8-103 of this Act."[280] These requirements are seemingly of limited applicability to MidAmerican, given that Section 8-103 of the Public Utilities Act expressly "does not apply to an electric utility that on December 31, 2005 provided electric service to fewer than 100,000 customers in Illinois"[281]—such as MidAmerican.[282]

In its initial Section 16-111.5B submittal offered on July 15, 2015, MidAmerican provided information related to the discrete requirements of Section 16-111.5B(a)(3)(A)-(G) to the extent such requirements could be applicable to it, but did not identify new or expanded energy efficiency programs that could be included in an IPA Procurement Plan. Given the apparent inapplicability of many of Section 16-111.5B's provisions to MidAmerican, the Agency concluded that this approach was acceptable. Upon review, the Commission agreed with MidAmerican and the Agency, finding that Section 8-103 indeed does not apply to MidAmerican and agreeing that because MidAmerican's submittal "provides substantive responses and accompanying information where appropriate," it meets MidAmerican's requirements under Section 16-111.5B.[283]

For the 2017 Plan, MidAmerican has provided the Agency with an incremental energy efficiency submittal similar in scope and substance to that which it submitted for the 2016 Plan. This submittal contains relevant information where appropriate and a brief statement as to the inapplicability of a Section 16-111.5B provision where it is not. In light of the Commission's Order in Docket No. 15-0541 and the Agency's corresponding interpretation of Section 16-111.5B, the IPA believes that MidAmerican's July 15, 2016 submittal meets the requirements of Section 16-111.5B as it applies to that utility.

As those requirements as applied to MidAmerican do not include the identification of incremental energy efficiency programs for inclusion in the IPA's annual procurement plan, no such programs have been analyzed or are recommended for inclusion in the 2017 Plan.

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[277] 220 ILCS 5/16-111.5B(a) ("Beginning in 2012, procurement plans prepared pursuant to Section 16-111.5 of this Act shall be subject to the following additional requirements…").
[278] 220 ILCS 5/16-111.5B(a)(3)(B).
[279] 220 ILCS 5/16-111.5B(a)(3)(C).
[280] 220 ILCS 5/16-111.5B(a)(3).
[281] 220 ILCS 5/8-103(h); see also Docket No. 15-0541, Final Order dated December 16, 2015 at 68.
[282] Instead, MidAmerican is governed by Section 8-408 of the Public Utilities Act, and its last five-year energy efficiency plan filed pursuant to those provisions was approved by the Commission in December 2013. See generally Docket Nos. 13-0423 and 13-0424 (consol.), Final Order dated December 18, 2013.
[283] Docket No. 15-0541, Final Order dated December 16, 2015 at 69.

10 Procurement Process Design

The procedural requirements for the procurement process are detailed in the Illinois Public Utilities Act at Section 16-111.5.[284] The Procurement Administrator, retained by the IPA in accordance with 20 ILCS 3855/1-75(a)(2), conducts the competitive procurement events on behalf of the IPA. The costs of the Procurement Administrator incurred by the IPA are recovered from the bidders and suppliers that participate in the competitive solicitations, through both Bid Participation Fees and Supplier Fees which are assessed by the IPA. The "eligible retail customers" for each of the participating utilities 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 IPA and the Procurement Administrator review the procurement process each year in order to identify 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[285], 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*

[284] See generally 220 ILCS 5/16-111.5.

[285] The Act requires the procurement administrator to notify bidders that the procurement administrator may, in its discretion, enter into post-bid price negotiations with bidders. In order to encourage best and final bids from the bidders and taking into consideration the mandated use of confidential benchmarks, the procurement administrators in previous procurements have decided not to engage in post-bid negotiations.

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.

10.1 Contract Forms

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, 2015 and 2016 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 2017 Procurement Plan would be the eleventh iteration of IPA-run procurement events, when including the Spring 2016 procurement events,[286] the March 31, 2016 Supplemental Photovoltaic Procurement, the June 23 summer procurement of RECs from distributed generation, and the planned Fall 2016 procurement events for the procurement of capacity for Ameren Illinois and the procurement of standard energy products for all of the utilities. 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, 2015 and 2016 procurement events, potential bidders submitted only limited comments on the proposed changes to the forms.

In the procurement events conducted for energy blocks and RECs since 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. The contract documents utilized for the MidAmerican energy blocks and RECs procurement events were similar to the Ameren Illinois contract documents.

[286] The Spring 2016 procurement events include: the April 25 procurement of standard energy blocks and the May 4 procurement of RECs

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 for the utilities, utility customers and suppliers. The IPA therefore recommends that the last used forms, namely the energy, capacity and RPS contracts used in the 2016 procurement events be the starting point for the contracts used in the energy, capacity, REC procurements associated with this plan. The IPA also recommends that the IPA, Commission Staff, Procurement Administrator, Procurement Monitor, and utilities undertake a joint review of such contracts in order to identify what terms, if any, need to be modified.

10.2 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."[287] 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.[288]

The IPA 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 (and no additional procurement event is held), the IPA will not recover the full cost of the procurement through the combination of the Bid Participation Fees and the Supplier Fees. The Supplier Fees are collected from the "winning bidders" based on the recommended blocks approved by the Commission; the Supplier Fees associated with the blocks that are not procured are not 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.

The IPA considered a number of approaches for addressing these risks involving 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.

Until the 2014 procurement events, the pre-bid letter of credit had been strictly a credit instrument held for the benefit of the utility and its customers. The utility was able to draw upon the pre-bid letter of credit if the

[287] 20 ILCS 3855/1-75(h).
[288] 83 Ill. Admin. Code. 1200.110, 1200.220.

supplier failed to complete the contract execution process. At that point, the utility that had filed its rates based on the winning bids would have to buy replacement supply, for which it could use funds under the pre-bid letter of credit to mitigate any impact of the default by a supplier on rates. Starting with the 2014 procurement events, the function of the pre-bid letter of credit was expanded to ensure payment of the Supplier Fees by adding a condition to the utility pre-bid letter of credit 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 that was used in the 2014, 2015 and 2016 procurement events.

The IPA has previously received comments on these possible approaches and how the IPA could 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. Based on those comments and subsequent review of the alternatives, the IPA recommends that the approach used in the procurement events since 2014 be continued to support the procurement events recommended in this Plan. That approach is for the energy, capacity and non-DG REC contracts to maintain the condition in the utility pre-bid letter of credit allowing the utility to draw if the Supplier Fees are not paid by a date certain. Likewise, as used in the recent procurement events, there will also be an agreement between the IPA and each utility on how funds would flow back to the IPA for payment of the Supplier Fees under this circumstance.

10.3 Second Procurement Event

The IPA recommends that procurement events be held in the spring and fall of 2017 for purchase of energy blocks, capacity and RECs under the 2017 Procurement Plan, and two procurements of DG REC be held at dates to be determined. The components of the energy and RECs procurement process detailed above would be conducted in the spring event. For the fall procurement event, for energy blocks under the Procurement Plan, certain activities would not occur as the fall procurement event could rely on the documents or processes established for the spring procurement event, as follows:

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

The IPA recommends that the fall procurement event includes the procurement of standard energy products for MidAmerican, Ameren Illinois and ComEd as well as a portion of the Ameren Illinois capacity requirements.

10.4 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.*

On May 23, 2016 the ICC Staff posted a public notice for the informal hearing for the purpose of receiving comments regarding on the procurement process for the procurement events that were held during the summer and fall of 2015 and the spring of 2016. The Summer 2015 event involved the initial procurement of SRECs under the provisions of new Section 1-56(i) of the IPA Act and the Agency's resulting supplemental photovoltaic procurement plan. The Fall 2015 procurements involved the procurement of standard energy products to meet the requirements of ComEd's and Ameren Illinois's eligible retail customers for November 2015 through May 2016, MISO Zonal Resource Credits capacity products for Ameren Illinois, distributed generation RECs for ComEd and Ameren Illinois, and SRECs under the Supplemental Photovoltaic Procurement Plan. The Spring 2016 procurement events included the purchase of a portion of the three utilities' energy requirements to meet eligible retail customers' needs for the 2016-2017, 2017-2018, and 2018-2019 delivery years, as well as the purchase of RECs for ComEd, MidAmerican and Ameren Illinois, the procurement of SRECs for each utility, and the purchase of RECs from wind generation for MidAmerican.

Initial comments, which were due to the Commission by June 30, 2016, were received from Boston Pacific Company, Inc. ("Boston Pacific").[289] No reply comments were received. Boston Pacific's comments included a summary of the results of the procurement events held between Summer 2015 and Spring 2016, provided recommendations for consideration regarding the DG procurement process, and noted that the current locational preference for REC procurements may result in higher costs for Illinois ratepayers.[290] Boston Pacific's recommendations regarding the DG procurement process were focused on improving bidder response to the DG RFP including: allowing bidders to offer speculative RECs, reducing credit requirements and supplier fees, switching to unit-specific contracts, and ensuring that bidders have sufficient lead time to develop DG systems. Boston Pacific also commented that the priority provided to RECs bid from sources in Illinois and the Adjoining States[291] established under the Illinois Power Agency Act has resulted in higher RECs costs relative to RECs procured from other states.

Comments received in the informal hearing process are available on the Commission's website.

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[289] Boston Pacific serves as the Commission's procurement monitor.
[290] "Initial Comments on the Summer 2015 through Spring 2016 Electric Procurement Events Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act," Presented to the Illinois Commerce Commission by Boston Pacific Company, Inc. June 30, 2016.
[291] The Adjoining States include: Missouri, Iowa, Wisconsin, Michigan, Indiana, and Kentucky.

Appendices

Appendices are available separately at:

www2.illinois.gov/ipa/Pages/Plans_Under_Development.aspx

Note, the term "Expected Case" used in these appendices is synonymous with "Base Case" used in the main body of the Plan.

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