2018

ILLINOIS POWER AGENCY

ELECTRICITY PROCUREMENT PLAN

2018 Plan

Filed for Illinois Commerce Commission Approval

September 25, 2017

Prepared in accordance with the
Illinois Power Agency Act (20 ILCS 3855), and the Illinois Public Utilities Act (220 ILCS 5)

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1 Executive Summary

This is the tenth electricity procurement plan (the "Plan," "Procurement Plan," or "2018 Procurement Plan") prepared by the Illinois Power Agency ("IPA" or "Agency") under the authority granted to it under the Illinois Power Agency Act ("IPA Act") and the Illinois Public Utilities Act ("PUA"). Chapter 2 of this Plan describes the specific legislative authority and requirements to be included in any such plan, including those set forth in previous orders of the Illinois Commerce Commission ("Commission" or "ICC").

The Plan addresses the provision of electricity for the "eligible retail customers" of Ameren Illinois Company ("Ameren Illinois"), Commonwealth Edison Company ("ComEd"), and MidAmerican Energy Company ("MidAmerican"). Following MidAmerican's participation for its second time in the 2017 IPA Procurement Plan, MidAmerican has again elected to have the IPA procure power and energy for a portion of its eligible Illinois customers through the 2018 Plan.[1]

As defined in Section 16-111.5(a) of the PUA, "eligible retail customers" are for Ameren Illinois and ComEd generally residential and small commercial fixed price customers who have not chosen service from an alternate supplier. For MidAmerican, eligible retail customers include residential, commercial, industrial, street lighting, and public authority customers that purchase power and energy from MidAmerican under fixed-price bundled service tariffs. The Plan considers a 5-year planning horizon that begins with the 2018-2019 energy delivery year and lasts through the 2022-2023 delivery year.

The 2017 Procurement Plan, as approved by the Commission in Docket No. 16-0453, called for the energy and renewable resources requirements for Ameren Illinois, ComEd, and MidAmerican to be procured by the IPA through two block energy procurements (spring and fall) and two procurements of renewable energy credits from distributed renewable energy generation devices. In addition, the 2017 Plan included a Fall 2017 capacity procurement for Ameren Illinois. The 2017 Procurement Plan also recommended a continuation of the energy procurement strategies proposed in the 2016 Procurement Plan.

In addition to authorizing the IPA's proposed procurements for standard wholesale products, such as energy, capacity, and ancillary services, the Commission's Order approving the 2017 Plan stated that it "takes notice that Public Act 099-0906 will become effective on June 1, 2017," and that "[a]ny resulting inconsistencies in the 2017 Plan as approved by the Commission will be resolved by deferring to applicable provisions of Public Act 099-0906."[2] The Final 2017 Procurement Plan thus reflected compliance with this directive in the Commission's Order by not including a previously proposed Spring 2017 Renewable Energy Credit procurement or any incremental energy efficiency programs previously proposed in the Agency's filed plan.

1.1 Power Procurement Strategy

The 2018 Plan proposes to continue using the risk management and procurement strategy that the IPA has historically utilized: hedging load by procuring on and off-peak blocks of forward energy in a three-year laddered approach. The IPA believes the continuation of its tested and proven risk management strategy is the most prudent and reasonable approach, and the approach most likely to meet its statutorily mandated objective to "[d]evelop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and

[1] While procurement plans are required to be prepared annually for Ameren Illinois and ComEd, Section 16-111.5(a) of the PUA states that "[a] small multi-jurisdictional electric utility . . . may elect to procure power and energy for all or a portion of its eligible Illinois retail customers" in accordance with the planning and procurement provisions found in the IPA Act. On April 9, 2015, MidAmerican formally notified the IPA of its intent to procure power and energy for a portion of its eligible retail customer load through the IPA for the first time. and to participate in its 2016 procurement planning process. This Plan reflects the continued inclusion of MidAmerican in the IPA's 2018 procurement planning process.

[2] See Docket No. 16-0453, Final Order dated December 13, 2016 at 105.

environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[3]

The IPA's energy hedging strategy for the 2018 Procurement Plan is consistent with the strategy used for the 2017 Plan. That strategy involves the procurement of hedges in 2018 to meet a portion of anticipated eligible retail customer energy supply requirements for a three-year period and includes two block energy procurement events, one in the Spring and the second in the Fall. Details of this procurement strategy can be found in Section 7.1.

Additionally, for Ameren Illinois, as a refinement to the approach taken in the 2017 Plan, for the 2019-2020 delivery year, the IPA recommends procuring 50% of its forecasted capacity requirements in bilateral transactions and the remaining balance through the MISO PRA.[4] The IPA will defer a decision for the 2020-2021 planning year until next year's Plan. For ComEd, consistent with the strategy adopted in prior plans, the IPA proposes that forecasted capacity requirements be secured by ComEd through the PJM Reliability Pricing Model process. Consistent with the approach taken in the 2017 Plan, the IPA recommends that MidAmerican's forecasted capacity deficit be secured by MidAmerican through the annual MISO PRA.[5]

In addition to the various proposals above, the IPA recommends that ancillary services, load balancing services, and transmission services be purchased by Ameren Illinois and MidAmerican from the MISO marketplace and by ComEd from PJM's.

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

Table 1-1: Summary of Energy Hedging Strategy for all Utilities[6]

Spring 2018 Procurement			Fall 2018 Procurement		
June 2018-May 2019 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2018-May 2019**	**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%

Table 1-2: Summary of Capacity Procurement for ComEd

June 2018-May 2019 (Upcoming Delivery Year)	June 2019-May 2020	June 2020-May 2021	June 2021-May 2022
100% PJM RPM Auctions*	100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions

[3] 20 ILCS 3855/1-20(a)(1).

[4] The PRA is an annual capacity auction that determines clearing prices on a zonal basis. The PRA provides load serving entities in MISO with an option for meeting their capacity obligations by buying capacity from the auction.

[5] MidAmerican utilizes the IPA's procurement process to meet only that portion of its requirements not under existing contracts (or allocated to its Illinois service territory).

[6] Table 1-1 shows the cumulative percentage of load to be hedged by the conclusion of the indicated procurement events.

Table 1-3: Summary of Capacity Procurement for Ameren Illinois[7]

June 2018-May 2019 (Upcoming Delivery Year)[8]	June 2019-May 2020	June 2020-May 2021
25% RFP in Sep. 2016 50% RFP in Fall 2017 Remaining balance, MISO PRA	25% RFP in Spring 2018 25% RFP in Fall 2018 Remaining balance, MISO PRA	To Be Determined In Next Year's Plan

Table 1-4: Summary of Capacity Procurement for MidAmerican

June 2018-May 2019 (Upcoming Delivery Year)	June 2019-May 2020	June 2020-May 2021
100% of expected deficit through MISO PRA	100% of expected deficit through MISO PRA	100% of expected deficit through MISO PRA

1.2 Renewable Energy Resources

Through the passage of Public Act 99-0906, "the Agency shall no longer include the procurement of renewable energy resources in the annual procurement plans" and "shall instead develop a long-term renewable resources procurement plan."[9] Thus, the procurement of Renewable Energy Resources is not included in this Plan. The Agency is developing a separate Long-Term Renewable Resources Procurement Plan, the initial draft of which will be released for public comment in late September 2017.

[7] Table shows the incremental percentage of capacity requirements to be hedged or purchased in the indicated procurement events.

[8] Procurement percentages approved in prior Procurement Plans (which may not necessarily reflect actual procurement volumes).

[9] 20 ILCS 3855/1-75(a).

1.3 Procurement Recommendations

Table 1-5 summarizes the IPA's recommendations as described in this Plan.

Table 1-5: Summary of Procurement Plan Recommendations Based on July 15, 2017 Utility Load Forecast (Quantities to be Adjusted Based on the March and July 2018 Load Forecasts):

	Delivery Year	Energy	Capacity	Transmission and Ancillary Services
AMEREN ILLINOIS	**2018-2019**	Up to 600MW forecasted requirement (Spring Procurement) Up to 225MW additional forecasted requirement (Fall Procurement)	25% RFP in Sep. 2016 50% RFP in Fall 2017 Remaining balance from MISO PRA[10]	Will be purchased from MISO
	2019-2020	Up to 150MW forecasted requirement (Spring Procurement) Up to 125MW forecasted requirement (Fall Procurement)	25% RFP in Spring 2018 25% RFP in Fall 2018 Remaining balance from MISO PRA	Will be purchased from MISO
	2020-2021	Up to 125MW forecasted requirement (Spring Procurement) Up to 125MW forecasted requirement (Fall Procurement)	To Be Determined In Next Year's Plan	Will be purchased from MISO
	2021-2022	No energy procurement required	No further action at this time	Will be purchased from MISO
	2022-2023	No energy procurement required	No further action at this time.	Will be purchased from MISO
COMED	**2018-2019**	Up to 2,325MW forecasted requirement (Spring Procurement) Up to 825MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2019-2020	Up to 525MW forecasted requirement (Spring Procurement) Up to 525MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2020-2021	Up to 500 MW forecasted requirement (Spring Procurement) Up to 475MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2021-2022	No energy procurement required	100% PJM RPM Auctions	Will be purchased from PJM
	2022-2023	No energy procurement required	No further action at this time	Will be purchased from PJM

[10] Procurement percentage targets for the 2018-2019 Delivery Year were approved under the prior Procurement Plans. Actual procurement volumes may not match percentage targets.

MIDAMERICAN	**2018-2019**	Up to 150MW forecasted requirement (Spring Procurement) Up to 75MW additional forecasted requirement (Fall Procurement)	100% of expected deficit from MISO PRA	Will be purchased from MISO
	2019-2020	Up to 25MW forecasted requirement (Spring Procurement) Up to 25MW additional forecasted requirement (Fall Procurement)	100% of expected deficit from MISO PRA	Will be purchased from MISO
	2020-2021	No energy procurement required	100% of expected deficit from MISO PRA	Will be purchased from MISO
	2021-2022	No energy procurement required	No further action at this time	Will be purchased from MISO
	2022-2023	No energy procurement required	No further action at this time	Will be purchased from MISO

1.4 The Action Plan

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

1. Approve the base case load forecasts of ComEd, Ameren Illinois, and MidAmerican as submitted in July 2017.
2. Approve two energy procurement events scheduled for spring 2018 and fall 2018. The energy amounts to be procured in the spring will be based on the updated March 15, 2018 base case load forecasts developed by Ameren Illinois, MidAmerican, and ComEd, in accordance with the hedging levels stated in this Plan, and as ultimately approved by the ICC. The energy amounts to be procured in the fall will be based on the July 15, 2018 base case load forecasts developed by Ameren Illinois, MidAmerican, and ComEd, in accordance with the hedging levels stated in this Plan, and as ultimately approved by the ICC.
3. Approve two capacity procurement events for Ameren Illinois scheduled for spring 2018 and fall 2018. The capacity amount to be procured in the spring will be based on the updated March 15, 2018 base case load forecast developed by Ameren Illinois in accordance with the hedging level stated in this Plan, and as ultimately approved by the ICC. The capacity amount to be procured in the fall will be based on the July 15, 2018 base case load forecast developed by Ameren Illinois, in accordance with the hedging level stated in this Plan, and as ultimately approved by the ICC.
4. The March 15, 2018 and the July 15, 2018 forecast updates provided by the utilities to be used to implement this Plan will be pre-approved by the ICC as part of the approval of this Plan, subject to the review and consensus of the IPA, ICC Staff, the Procurement Monitor, and the applicable utility. In the event that the parties do not reach consensus on an updated load forecast required in Items 2 and 3 above, then the most recent consensus load forecast will be used for the applicable procurement event. If the Parties are unable to reach consensus on either of the updated load forecasts required in Items 2 and 3 above, then the July 2017 load forecast will be used for the applicable procurement event.
5. Approve procurement by ComEd, Ameren Illinois, and MidAmerican of capacity, network transmission service and ancillary services from each utility's respective Regional Transmission Organization ("RTO").

The Illinois Power Agency respectfully files its 2018 Procurement Plan, which the IPA believes is compliant with all applicable laws and will produce the "lowest total cost over time, taking into account any benefits of price stability," for Commission approval and requests approval of the specific action items listed above.

2 Legislative/Regulatory Requirements of the Plan

This Section of the 2018 Procurement Plan describes the legislative and regulatory requirements applicable to the Agency's annual Procurement Plan, including compliance with previous Commission Orders. A Regulatory Compliance Index, Appendix A, provides a complete cross-index of regulatory/legislative requirements and the specific sections of this plan that address each requirement identified.

Public Act 99-0906, which became effective on June 1, 2017, substantially modifies what elements are to be included in the IPA's annual "power procurement plan." Starting with the 2018 Procurement Plan, the IPA will no longer include the procurement of renewable energy resources as part of the annual procurement plan.[11] The procurement of renewable energy resources to comply with the Illinois Renewable Portfolio Standard requirements in Section 1-75(c) of the IPA Act will instead be addressed through the IPA's separately-developed Long-term Renewable Resources Procurement Plan, the draft of which is scheduled to be issued by the IPA for comment in September of 2017. Public Act 99-0906 also includes revisions to the state's energy efficiency portfolio standard (found in Section 8-103 of the PUA) as well as the elimination of the mechanism through which incremental energy efficiency programs are included in IPA procurement plans under Section 16-111.5B of the PUA.[12] This procurement plan is focused only on the procurement of standard wholesale products to meet the needs of the Ameren Illinois, ComEd and MidAmerican eligible retail customers.

2.1 IPA Authority

The Illinois Power Agency ("IPA" or "Agency") was established in 2007 by Public Act 95-0481 to ensure that ratepayers, specifically customers in service classes that have not been declared competitive and who take service from the utility's bundled rate ("eligible retail customers"),[13] benefit from retail and wholesale competition. The original objective of the IPA Act was to improve the process to procure electricity for those customers.[14] In creating the IPA, the General Assembly found that Illinois citizens should be provided "adequate, reliable, affordable, efficient, and environmentally-sustainable electric service at the lowest total cost over time, taking into account benefits of price stability."[15] The Illinois Power Agency Act ("IPA Act") thus directs the IPA to "[d]evelop electricity procurement plans" and conduct competitive procurement processes to bring resources under contract in a manner consistent with those findings.

Each year, the IPA thus must develop a "power procurement plan" and conduct a competitive procurement process to procure supply resources as identified in its procurement plan as approved by the Commission pursuant to Section 16-111.5 of the Public Utilities Act ("PUA").[16] The purpose of the power procurement plan is to secure the electricity commodity and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company ("ComEd") and Ameren Illinois Company ("Ameren Illinois"), as well as "small multi-jurisdictional utilities" should they request to participate.[17] The Illinois Power Agency Act ("IPA Act") directs that the procurement plan be developed and the competitive procurement process be conducted by "experts or expert consulting firms," respectively known as the "Procurement Planning Consultant"[18] and "Procurement Administrator."[19] The Illinois Commerce Commission

[11] See 20 ILCS 3855/1-75(a); 220 ILCS 5/16-111.5(b)(5).

[12] See 220 ILCS 5/16-111.5B(a)(5) (as modified by P.A. 99-0906, effective June 1, 2017) ("The requirements set forth in paragraphs (1) through (5) of this subsection (a)" – i.e., the solicitation, inclusion, and approval of incremental energy efficiency programs in IPA procurement plans – "shall terminate after the filing of the procurement plan in 2015, and no energy efficiency shall be procured by the Agency thereafter. Energy efficiency programs approved previously under this Section shall terminate no later than December 31, 2017.").

[13] 220 ILCS 5/16-111.5(a).

[14] 20 ILCS 3855/1-5(2)-(4).

[15] 20 ILCS 3855/1-5(1).

[16] 20 ILCS 3855/1-20(a)(2), 1-75(a).

[17] 20 ILCS 3855/1-20(a)(1). MidAmerican elected to participate in the 2016 and 2017 Procurement Plans and will continue to participate in the 2018 Plan. See also 220 ILCS 5/16-111.5(a). ("This Section shall not apply to a small multi-jurisdictional utility until such time as a small multi-jurisdictional utility requests the Illinois Power Agency to prepare a procurement plan for its eligible retail customers.")

[18] 20 ILCS 3855/1-75(a)(1).

[19] 20 ILCS 3855/1-75(a)(2).

is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[20]

Public Act 99-0906, signed into law on December 7, 2016 which took effect on June 1, 2017, modified the IPA's procurement planning process in part through the introduction of new requirements impacting the Agency. Among them include the development of a separate zero emission standard procurement plan and the procurement of zero-emission credits from zero-emission generators (i.e., nuclear power plants);[21] the development of a separate long-term plan for the procurement of renewable energy resources (which includes the development of an adjustable block program to procure renewable energy credits from distributed generation and community solar projects; and the development of a low-income solar program using, in part, money held in the Renewable Energy Resources Fund);[22] and the elimination of the statutory requirement that the Agency include cost-effective incremental energy efficiency programs in its annual power procurement plan.[23]

2.2 Procurement Plan Development and Approval Process

Although elements of procurement planning process are ongoing, with the Agency continually soliciting and incorporating stakeholder input and lessons from past proceedings while monitoring ongoing energy market activity, the formal process for composing the 2018 Procurement Plan began on July 15, 2017. By that date, each Illinois utility that procures electricity through the IPA (ComEd, Ameren Illinois, and MidAmerican) had submitted load forecasts to the Agency. These forecasts – which form the backbone of the Procurement Plan and which are covered in Sections 3.2, 3.3, and 3.4 in greater detail – cover a five-year planning horizon and include hourly data representing high, low, and base/expected scenarios for the load of the eligible retail customers.

After the receipt of load forecasts from the utilities, the IPA next prepares a draft Procurement Plan. On August 15, 2017, the Plan was made available for public review and comment. The Public Utilities Act provides for a 30-day comment period starting on the day the IPA releases its draft plan. The 2018 Plan comment period concluded as scheduled on September 14, 2017. Written comments were received from Ameren Illinois, ComEd, and Illinois Commerce Commission Staff. During the 30-day comment period, the Agency held public hearings within each participating utility's service area for the purpose of receiving public comment on the draft Procurement Plan.[24]

After the receipt of comments, and within 14 days after the conclusion of the comment period, the IPA "shall revise the procurement plan as necessary based on the comments received" and file that revised Plan with the Commission.[25] Within 5 days after the Procurement Plan is filed with the Commission, parties must file Objections to the Plan.[26] Typically, the presiding Administrative Law Judge sets the dates for Responses and Replies to Objections shortly after the docket opens. For this proceeding, the Agency has included a proposed briefing schedule with its petition accompanying the filing of this Plan The Commission must enter an order

[20] 220 ILCS 5/16-111.5(b), (c)(2).

[21] See 20 ILCS 3855/1-75(d-5).

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

[23] See 220 ILCS 5/16-111.5B.

[24] 220 ILCS 5/16-111.5(d)(2). Public hearings on the draft 2018 Plan took place on September 6, 2017 in Chicago, and September 7, 2017 in Springfield and Moline. No Comments were received at the hearings.

[25] See 220 ILCS 5/16-111.5(d)(2).

[26] 220 ILCS 5/16-111.5(d)(3).

confirming or modifying the Plan within 90 days after it is filed by the IPA.[27] With a filing date for the 2018 Plan of September 25, 2017, this year's deadline for approval will fall on December 26, 2017.[28,29]

Under the Public Utilities Act, the Commission approves the Procurement Plan, including the load forecasts used in the Plan, if the Commission determines that "it will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[30]

2.3 Procurement Plan Requirements

At its core, the Procurement Plan consists of three pieces: (1) a forecast of how much energy (and in some cases capacity) is required by eligible retail customers; (2) the supply currently under contract; and (3) what type and how much supply must be procured to meet load requirements and to satisfy all other legal requirements associated with the Procurement Plan. To that end, the Procurement Plan must contain an hourly load analysis, which includes: multi-year historical analysis of hourly loads; switching trends and competitive retail market analysis; known or projected changes to future loads; and growth forecasts by customer class.[31] In addition, the Procurement Plan must analyze the impact of demand side and renewable energy initiatives, including the impact of demand response programs and energy efficiency programs, both current and projected.[32] Based on the hourly load analysis, the Procurement Plan must detail the IPA's plan for meeting the expected load requirements that will not be met through pre-existing contracts,[33] and in doing so must:

- Define the different Illinois retail customer classes for which supply is being purchased, and include monthly forecasted system supply requirements, including expected minimum, maximum, and average values for the planning period.[34]
- Include the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year that, separately or in combination, will meet the portion of the load requirements not met through pre-existing contracts or in the case of MidAmerican, including allocations to eligible Illinois customers of energy and capacity from company owned generating resources.[35] Such standard wholesale products include, but are not limited to, monthly 5 x 16 peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity obligations, capacity purchase plan, and ancillary services.[36]
- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[37]
- Assess the price risk, load uncertainty, and other factors associated with the proposed portfolio measures, including, to the extent possible, the following factors: contract terms; time frames for security products or services; fuel costs; weather patterns; transmission costs; market conditions; and the governmental

[27] Id.

[28] 90 days from September 25, 2017 is December 24, 2017. As December 24th this year is a Sunday, and December 25th is a State Holiday, the effective deadline for Commission approval will be Tuesday, December 26, 2017.

[29] Commission approval occurs through the entry of an official administrative order approving the Plan by the Commission at a public meeting (regular open meeting, bench session, etc.). The Commission's last public meeting for 2017 is currently a regular open meeting scheduled for December 20, 2017, with a meeting also scheduled in the week prior for December 13, 2017.

[30] 220 ILCS 5/16-111.5(d)(4).

[31] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).

[32] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).

[33] 220 ILCS 5/16-111.5(b)(3).

[34] 220 ILCS 5/16-111.5(b)(i), (b)(iii).

[35] 220 ILCS 5/16-111.5(b)(3)(iv).

[36] Id.

[37] 220 ILCS 5/16-111.5(b)(3)(v).

regulatory environment.[38] For those portfolio measures that are identified as having significant price risk, the Plan shall identify alternatives to those measures.

- For load requirements included in the Plan, include the proposed procedures for balancing loads, including the process for hourly load balancing of supply and demand and the criteria for portfolio re-balancing in the event of significant shifts in load. [39]
- Include demand-response products, as discussed below.

2.4 Standard Product Procurement

As noted in Section 2.3, the IPA Act provides examples of "standard wholesale products."[40] This listing has been understood by the Commission to be non-exhaustive and non-static. [41] Instead, as articulated by the Commission in approving the 2015 Plan, "[w]henever the Commission is confronted with a unique product, there must be an examination of the attributes of the product and whether those are consistent with other commonly traded products in the wholesale market" to determine whether the product meets this definition, and such products "must be routinely traded in a liquid market and have transparent prices that allow participants a degree of assurance that they are receiving fair market prices."[42]

Reading Subsection 16-111.5(b)(3)(vi) in conjunction with Subsection 16-111.5(e) and the ICC's Order approving the IPA's 2014 Procurement Plan,[43] the IPA understands that the definition of "standard product" also includes wholesale load-following products (including "full requirements" products) so long as the product definition is standardized such that bids may be judged solely on price. [44] With respect to demand-side products, in approving the 2015 Plan the Commission determined that block super-peak energy efficiency products proposed for procurement by the Agency "should not be procured at this time," but left open the possibility that "as demand-side markets evolve and energy efficiency products become more standardized, the Commission could envision a time in which these products might satisfy Section 16-111.5 of the PUA."[45]

2.5 Demand Response Products

The IPA may include cost-effective demand response products in its Procurement Plan. The Procurement Plan must include the particular "mix of cost-effective, demand-response products for which contracts will be executed during the next year, to meet the expected load requirements that will not be met through preexisting contracts."[46] Under the PUA, cost-effective demand-response measures may be procured whenever the cost is

[38] 220 ILCS 5/16-111.5(b)(3)(vi).

[39] 220 ILCS 5/16-111.5(b)(4).

[40] 220 ILCS 5/16-111.5(b)(3)(iv).

[41] See Docket No. 14-0588, Final Order dated December 17, 2014 at 156 ("the list enumerated in 16-111.5(b)(3)(iv) contains the phrase 'including but not limited to' which expands the list rather than limits it;" "the phrase 'standard wholesale products' cannot be static and it depends on the products that may be traded in wholesale markets at a given time").

[42] Id.

[43] While not adopting ICEA's full requirements proposal, the Commission's Final Order approving the IPA's 2014 Plan made clear that wholesale load-following products, including "full requirements" products, may qualify as a "standard product." See Docket No. 13-0546, Final Order dated December 18, 2013 at 94 ("the Commission agrees with Staff and the IPA that full requirements products should be considered a 'standard product' under Section 16-111.5").

[44] *See, e.g.*, 220 ILCS 5/16-111.5(e)(2) (requiring development of standardized "contract forms and credit terms" for a procurement); 16-111.5(e)(3)-(4) (creation of a price-based benchmark and selection of bids "on the basis of price"); Docket No. 09-0373, Final Order dated December 28, 2009 at 115-116 (Commission approval of long-term renewable resource PPA project selection based on price alone). Note also that the Commission's Order approving the 2015 Procurement Plan indicates that "as demand-side markets evolve and energy efficiency products become more standardized, the Commission could envision a time in which these products might satisfy Section 16-111.5 of the PUA." (Docket No. 14-0588, Final Order dated December 17, 2014 at 156).

[45] Docket No. 14-0588, Final Order dated December 17, 2014 at 156.

[46] 220 ILCS 5/16-111.5(b)(3)(ii).

lower than procuring comparable capacity products, if the product and company offering the product meet minimum standards.[47] Specifically:

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;[48]
- The products must at least satisfy the demand-response requirements of the regional transmission organization market in which the utility's service territory is located, including, but not limited to, any applicable capacity or dispatch requirements;[49]
- The products must provide for customers' participation in the stream of benefits produced by the demand-response products; [50]
- The provider must have a plan for the reimbursement of the utility for any costs incurred as a result of the failure of the provider to perform its obligations;[51]; and
- Demand-response measures included in the plan shall meet the same credit requirements as apply to suppliers of capacity in the applicable regional transmission organization market.[52]

Public Act 97-0616, the Energy Infrastructure Modernization Act ("EIMA"), required ComEd and Ameren Illinois to file tariffs instituting an opt-in market-based peak time rebate ("PTR") program with the Commission within 60 days after the Commission has approved the utility's AMI Plan.[53] ComEd's PTR program was provisionally approved in Docket No. 12-0484, and Ameren Illinois' PTR program was likewise provisionally approved in Docket No. 13-0105.[54] These programs are discussed further in Section 7.4, where demand response resource choices are examined.

Public Act 99-0906 made significant revisions to the energy efficiency and demand response portfolio standard found in Section 8-103 of the Public Utilities Act, creating new requirements that become effective on January 1, 2018. Both ComEd and Ameren Illinois have filed petitions with the ICC regarding their respective energy efficiency and demand response programs since Public Act 99-0906 was signed into law on December 7, 2016. On June 30, 2017, ComEd filed its 2018-2021 Energy Efficiency and Demand Response Plan; for its demand response goal, ComEd proposed to implement a demand response program element that would fund the enrollment into its air conditioning ("AC") cycling program of any purchasers of qualified smart thermostats from ComEd's other residential program elements.[55] Concurrent with ComEd's filing, Ameren Illinois also filed its Energy Efficiency and Demand-Response Plan; Ameren Illinois proposed to achieve demand response reductions and meet its obligations under Section 8-103B(g)(4.5) through the peak demand reduction coincident to the electric energy efficiency savings proposed in its plan.[56] These Plans were approved by the Commission on September 11, 2017.

2.6 Clean Coal Portfolio Standard

The IPA Act contains an aspirational goal that cost-effective clean coal resources will account for 25% of the electricity used in Illinois by January 1, 2025.[57] As a part of the goal, the Plan must also include electricity

[47] Id.

[48] 220 ILCS 5/16-111.5(b)(3)(ii)(A).

[49] 220 ILCS 5/16-111.5(b)(3)(ii)(B).

[50] 220 ILCS 5/16-111.5(b)(3)(ii)(C).

[51] 220 ILCS 5/16-111.5(b)(3)(ii)(D).

[52] 220 ILCS 5/16-111.5(b)(3)(ii)(E).

[53] 220 ILCS 5/16-108.6(g).

[54] See Docket No. 12-0484, Interim Order dated February 21, 2013 at 32; Docket No. 13-0105, Interim Order dated January 7, 2014 at 19.

[55] See Docket No. 17-0312, Order dated September 11, 2017 at 19.

[56] See Docket No. 17-0311, Order dated September 11, 2017 at 46-47.

[57] 20 ILCS 3855/1-75(d).

generated from clean coal facilities.[58] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[59] Section 1-75(d) describes two special cases: the "initial clean coal facility"[60] 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" (i.e., "retrofit clean coal facility").[61] Currently, there is no facility meeting the definition of an "initial clean coal facility," that the IPA is aware of, that has announced plans to begin operations within the next five years.

In Docket No. 12-0544, the Commission approved inclusion of the FutureGen 2.0 project as a "retrofit clean coal facility" starting in the 2017 delivery year; that administrative approval and the associated cost recovery mechanism were subsequently appealed, and initially upheld by the Illinois First District Appellate Court.[62] With an appeal still pending before the Illinois Supreme Court, the U.S. Department of Energy announced in February 2015 that federal funding for the project would be suspended.[63] The FutureGen Alliance's Board of Directors "approved a resolution, dated January 6, 2016, ceasing all FutureGen Project development efforts"[64] and FutureGen exercised its right to terminate the prior-approved FutureGen 2.0 Sourcing Agreements with ComEd and Ameren Illinois. 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.[65]

2.7 2016-2017 Legislative Proposals and Related Developments

As mentioned elsewhere in this Chapter, Public Act 99-0906 removed statutory provisions requiring the inclusion of incremental energy efficiency programs from the IPA's annual procurement plans and moves the Agency's planning related to renewable energy to a separate Long-Term Renewable Resources Procurement Plan. Specifically, Public Act 99-0906 modified Section 16-111.5B's incremental energy efficiency requirements to make clear that such requirements apply only to "[p]rocurement plans prepared and filed . . . during the years 2012 through 2015."[66] While an extension was offered for "programs and measures approved . . . for the period June 1, 2016 through May 31, 2017,"[67] even programs initially included in the IPA's 2017 Plan (which would start with the June 1, 2017 through May 31, 2018 delivery year) were deemed "void."[68]

While the IPA no longer has obligations related to energy efficiency in its Procurement Plans through these changes, it now carries enhanced responsibility and jurisdiction with respect to renewable energy resource procurement. Under changes made to Section 1-75(c) of the IPA Act and Section 16-111.5 of the PUA, the Agency's responsibility for renewable energy resource procurement is transitioning from meeting percentage-based renewables requirements applicable to eligible retail customer load to meeting similar percentage-based requirements for <u>all</u> retail customer load.[69] As part of this transition, the IPA is now tasked with developing a separate Long-Term Renewable Resources Procurement Plan through which it proposes procurements and

[58] 20 ILCS 3855/1-75(d)(1).

[59] 20 ILCS 3855/1-10.

[60] Id.

[61] 20 ILCS 3855/1-75(d)(5).

[62] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2014 IL App (1st) 130544, July 22, 2014.

[63] See, e.g., http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead.

[64] Supplemental Brief of Appellee FutureGen Industrial Alliance, Inc. on the Issue of Mootness, dated January 13, 2016, at 1.

[65] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2016 IL 118129, May 19, 2016.

[66] 220 ILCS 5/16-111.5B(a).

[67] 220 ILCS 5/16-111.5B(d)(1).

[68] 220 ILCS 5/16-111.5B(d)(3).

[69] See 20 ILCS 3855/1-75(c)(1)(B). Among other changes, the revised law also now features quantitative targets for the procurement of renewable energy credits from new generating facilities as well. (See 20 ILCS 3855/1-75(c)(1)(C)).

programs to meet these new targets,[70] conducting "initial forward procurements" of renewable energy credits from new wind projects and new utility-scale solar and brownfield site photovoltaic projects,[71] developing an adjustable block program to support the development of new distributed photovoltaic generation and community solar projects,[72] and developing a low-income solar incentive program to support the development of a low-income solar marketplace.[73] The Agency expects to publish its draft of Long-Term Renewable Resources Procurement Plan in September; as with its annual procurement plan, that renewables-only plan is then subject to comment and Commission approval.

Incremental energy efficiency programs and renewable energy resource procurement provided for the bulk of contested issues in recent IPA Plan approval proceedings. As those issues are now handled through separate proceedings and processes, this could potentially reduce the number of contested issues and intensity of arguments in attaining approval of the IPA's annual procurement plan. And while those changes constitute the most important developments to the IPA's annual planning process since the Agency developed its 2017 Plan, other proposals also merit discussion.

During legislative discussions around Senate Bill 2814 of the 99th General Assembly (which ultimately became Public Act 99-0906), a proposal was introduced (as part of Amendment 2 to that bill) that would have expanded the Agency's role related to capacity procurement for Ameren Illinois—specifically, requiring the IPA to conduct capacity procurements to meet the capacity requirements of all retail customers of Ameren Illinois, rather than just eligible retail customers. This Amendment was not included in the final legislation, and thus no change to the scope of the IPA's capacity procurement authority was made. As discussed further in Section 5.2.1, MISO also proposed a Competitive Retail Solution before the Federal Energy Regulatory Commission ("FERC") to restructure its capacity market with a specific focus on Zone 4 (which serves central and southern Illinois) and Zone 7 (lower Michigan). The MISO proposal was rejected by FERC on February 2, 2017. That these proposals were actively considered, but not adopted, indicates ongoing interest in how MISO's capacity market is structured, and the ongoing interest of some stakeholders in reforming that market. This issue is likely to continue to be one that will see future proposals and robust debate, and the IPA will continue to monitor these developments and provide feedback on specific proposals where appropriate.

On a national level, litigation and federal policy decisions have continued to shape the Clean Power Plan proposed by the United States Environmental Protection Agency ("U.S. EPA"). On August 3, 2015, the U.S. EPA released its Clean Power Plan rules promulgated pursuant to Section 111(d) of the Clean Air Act, requiring states to develop strategies intended to reduce carbon dioxide emissions associated with electricity generation. On February 9, 2016, the U.S. Supreme Court stayed implementation of the Clean Power Plan pending judicial review.[74] Under the Clean Power Plan, initial state compliance plans were scheduled to be due to the U.S. EPA by September 6, 2016, but the stay delayed the timing for the state compliance plan development. In March 2017, President Trump issued an Executive Order seeking to revise or terminate the Clean Power Plan;[75] the U.S. EPA more recently indicated that it plans to publish a new or revised rule for public comment in the fall of 2017.[76] While additional and continued litigation regarding the Clean Power Plan is likely, the likelihood and potential impact of any federal CO_2 emissions reduction regulations appears reduced, at least for the foreseeable future.

[70] See 20 ILCS 3855/1-75(c)(1)(A); 220 ILCS 5/16-111.5(b)(5).

[71] See 20 ILCS 3855/1-75(c)(1)(G).

[72] See 20 ILCS 3855/1-75(c)(1)(K).

[73] See 20 ILCS 3855/1-56(b)(2).

[74] See, e.g., http://www.nytimes.com/2016/02/10/us/politics/supreme-court-blocks-obama-epa-coal-emissions-regulations.html; http://www.scotusblog.com/wp-content/uploads/2016/02/15A773-Clean-Power-Plan-stay-order.pdf.

[75] See, e.g., https://www.nytimes.com/2017/03/28/climate/trump-executive-order-climate-change.html; https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1.

[76] See, e.g., "Power plant rule repeal announcement likely this fall: EPA," The Hill, September 7, 2017, http://thehill.com/policy/energy-environment/349679-power-plant-rule-repeal-announcement-likely-this-fall-epa.

3 Load Forecasts

3.1 Statutory Requirements

Under Illinois law, a procurement plan must be prepared annually for each "electric utility that on December 31, 2005 served at least 100,000 customers in Illinois."[77] Section 16-115(a) of the PUA allows small multi-jurisdictional electric utilities to elect to have the IPA procure power and energy for all or a portion of its eligible retail customer load in Illinois. Besides the two electric utilities that serve at least 100,000 customers in Illinois, Ameren Illinois and ComEd, a third electric utility, MidAmerican, which serves fewer than 100,000 electric customers, has elected to have the IPA procure electricity[78] for a portion of its load.[79] The plan must include a load forecast based on an analysis of hourly loads. The statute requires the analysis to include:

- Multi-year historical analysis of hourly loads;
- Switching trends and competitive retail market analysis;
- Known or projected changes to future loads; and
- Growth forecasts by customer class.[80]

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

> *Each utility shall annually provide a range of load forecasts to the Illinois Power Agency by July 15 of each year, or such other date as may be required by the Commission or Agency. The load forecasts shall cover the 5-year procurement planning period for the next procurement plan and shall include hourly data representing a high-load, low-load and expected-load scenario for the load of the eligible retail customers. The utility shall provide supporting data and assumptions for each of the scenarios.*[81]

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

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

3.2 Summary of Information Provided by Ameren Illinois

In compliance with Section 16-111.5(d)(1) of the Public Utilities Act, Ameren Illinois provided the IPA with the following documents for use in preparation of this plan:

- Ameren Illinois Company Load Forecast for the period June 1, 2018 – May 31, 2023 (See Appendix B)
- Spreadsheets of the expected (base), high, and low load forecasts. (Summarized in Appendix E)

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[77] 220 ILCS 5/16-111.5(a).

[78] MidAmerican registers with MISO its generation resources allocated to serve its Illinois customers as historical resources. Incremental amounts of electricity refer to the capacity and energy that would be needed in addition to the historical resources to meet the projected loads.

[79] Utilities that serve fewer than 100,000 electric customers in Illinois are not obligated to, but "may elect to procure power and energy for all or a portion of their eligible Illinois retail customers" using the IPA process 220 ILCS 5/16-111.5(a). This is the third procurement process in which MidAmerican elected to have the IPA procure power and energy for a portion of its Illinois jurisdictional load.

[80] 220 ILCS 5/16-111.5(b)(1).

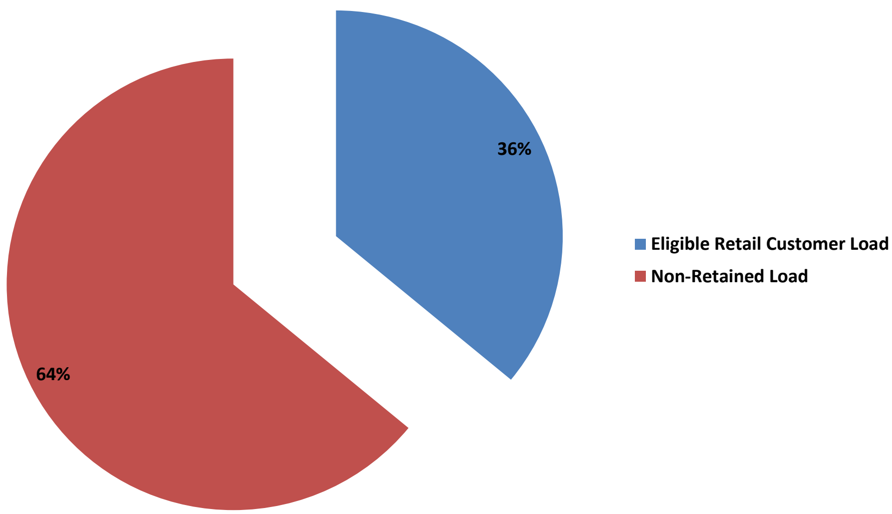
[81] 220 ILCS 5/16-111.5(d)(1).

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

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

Figure 3-1 shows the forecasted annual percentage of usage by eligible retail customer load and non-retained retail customer load.[82]

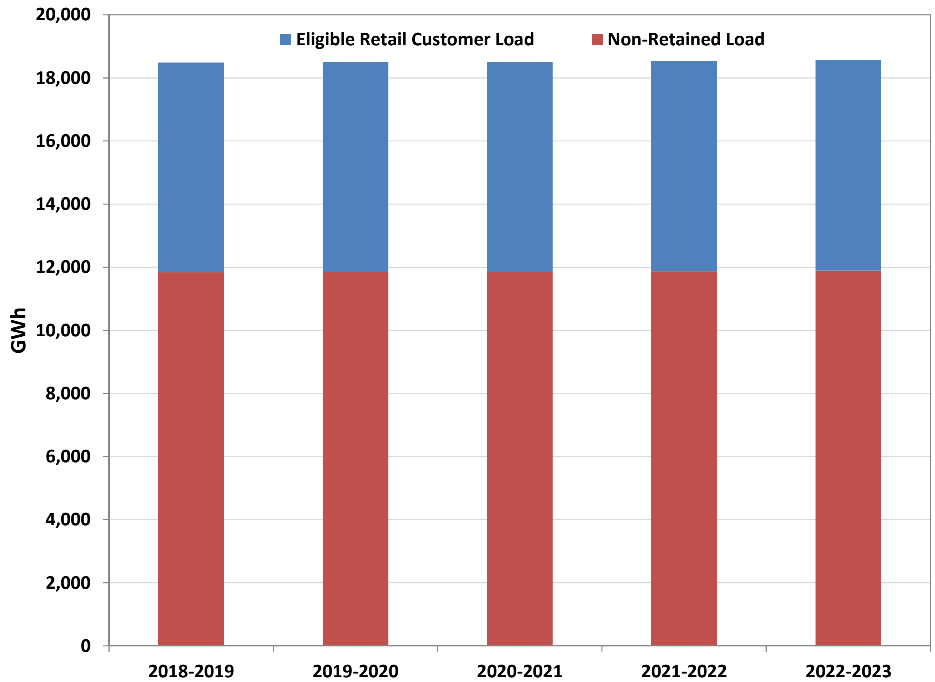
Figure 3-1: Ameren Illinois' Forecast Non-Competitive Class Customer Load Breakdown, Delivery Year 2018-2019



Ameren Illinois' forecasts are performed on the total Ameren Illinois delivery service load using a regression model applied to historical load and weather data. A separate analysis is performed for each customer class to account for the differing impacts of weather on the different customer classes. Figure 3-2 shows the Ameren Illinois 5-year forecast by retained/not retained load.

[82] Ameren Illinois assigns load profile classifications at the point of service level and only to points of service that are metered. The classifications are as follows: DS1 – Residential, DS2 – Non-Time of Use Commercial & Industrial with demands less than 150 kW, DS3 – Time of Use Commercial & Industrial with demands between 150 kW and 1,000 kW, DS4 – Time of Use Commercial & Industrial with demands above 1,000 kW, and DS5 – Lighting. The DS3 and DS4 classes are fully competitive, meaning that customers in these classes must receive supply from ARES or Ameren Illinois real time pricing. Customers in the DS1, DS2 and DS5 classes are eligible to take fixed-price supply service from Ameren Illinois or an ARES.

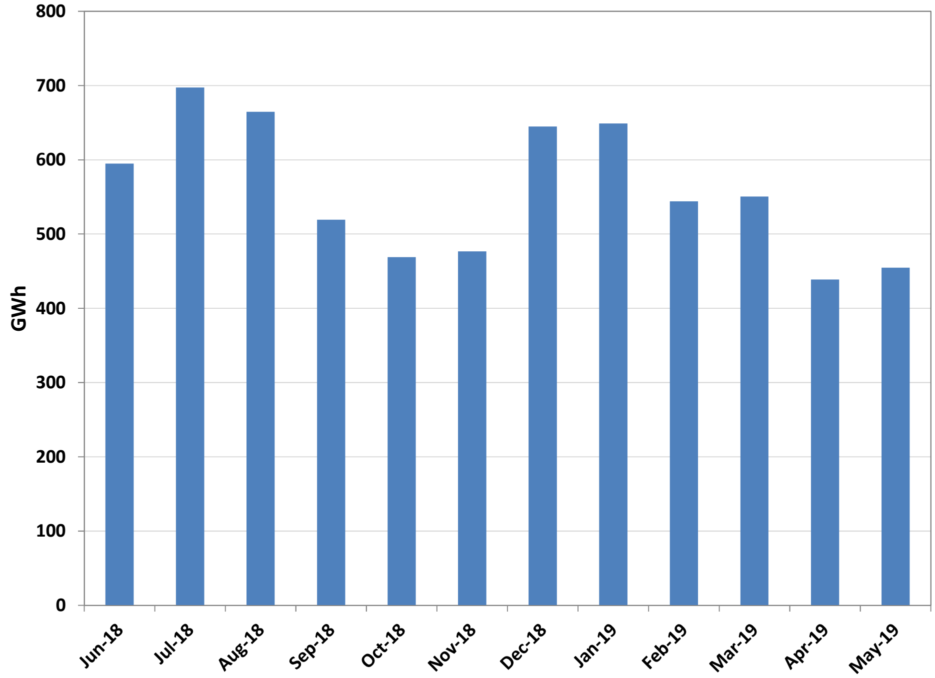
Figure 3-2: Ameren Illinois' Forecast Non-Competitive Class Customer Load by Delivery Year



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

Figure 3-3 provides a monthly breakdown of the base-case forecast of Ameren Illinois eligible retail customer load, that is, the load of customers who are forecasted to take bundled supply procured under this Procurement Plan.

Figure 3-3: Ameren Illinois' Forecast Eligible Retail Customer Load* by Month



*Total load, prior to netting QF supply.

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

3.2.1 Macroeconomics

The Ameren Illinois base case load forecast is based on a statistically adjusted end-use forecast that combines technological coefficients (efficiencies of various end-use equipment) and econometric variables (income levels and energy prices). Ameren Illinois did not define "high" and "low" cases by varying the econometric (or other) variables. Instead, Ameren Illinois looked at the statistics of the residual from the model fit and the high and low cases are based on a 95% confidence interval.

Ameren Illinois' "high" and "low" forecasts are uniform modifications of the base case, excluding incremental energy efficiency, by rate class. Specifically, in each case, a single multiplier is defined for each of the three non-fully competitive delivery service rate classes, and the "before switching" load forecast for every hour is multiplied by the rate class multiplier.

Table 3-1: Load Multipliers in Ameren Illinois Excursion Cases

Rate Class	Low Case	High Case
DS1	0.940	1.080
DS2	0.93	1.07
DS5	0.940	1.080

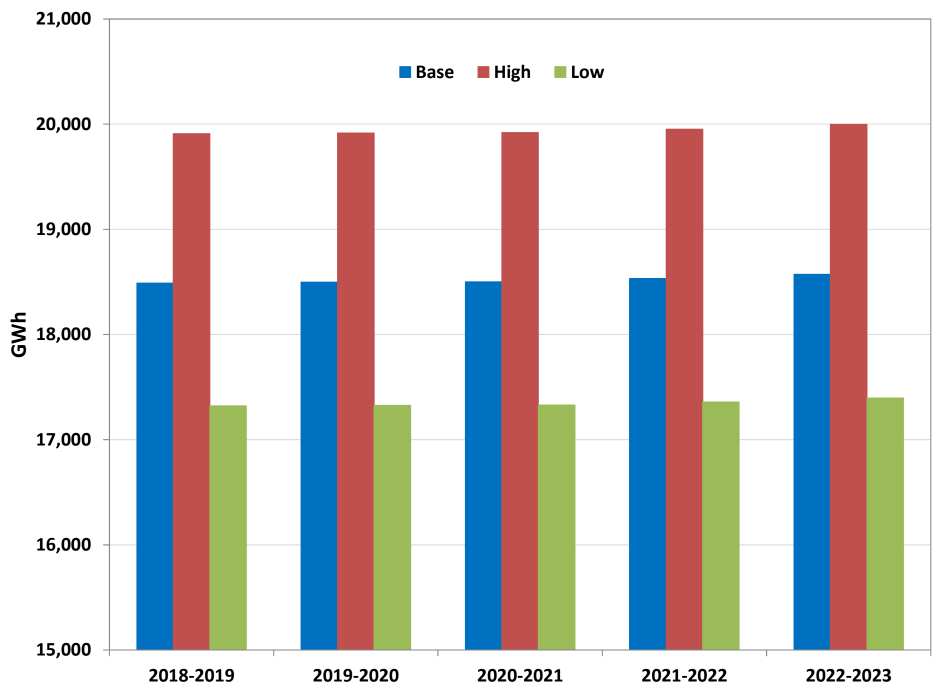
In regression models, residuals indicate the difference between the predicted and actual values. Patterns associated with residuals may indicate the impact of non-specified variables. Because the excursion cases are based on the statistics of the residuals, they reflect the influence of variables not modeled. The forecasting model appears to be dominated by technological and weather effects. The econometric variables are related to short-term decision-making. Uncertainty around long-term economic growth will appear in the residuals.

3.2.2 Weather

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

Figure 3-4 shows the base, high, and low case forecasts of Ameren Illinois eligible retail customer load, assuming no switching. The difference between the high, low and base cases show the variation Ameren Illinois attributes to macroeconomics and weather. The low case is about 6% lower than the base case and the high case is about 8% higher than the base case.

Figure 3-4: Ameren Illinois' Eligible Retail Customer Load before Switching in Ameren Illinois' Forecasts



3.2.3 Switching

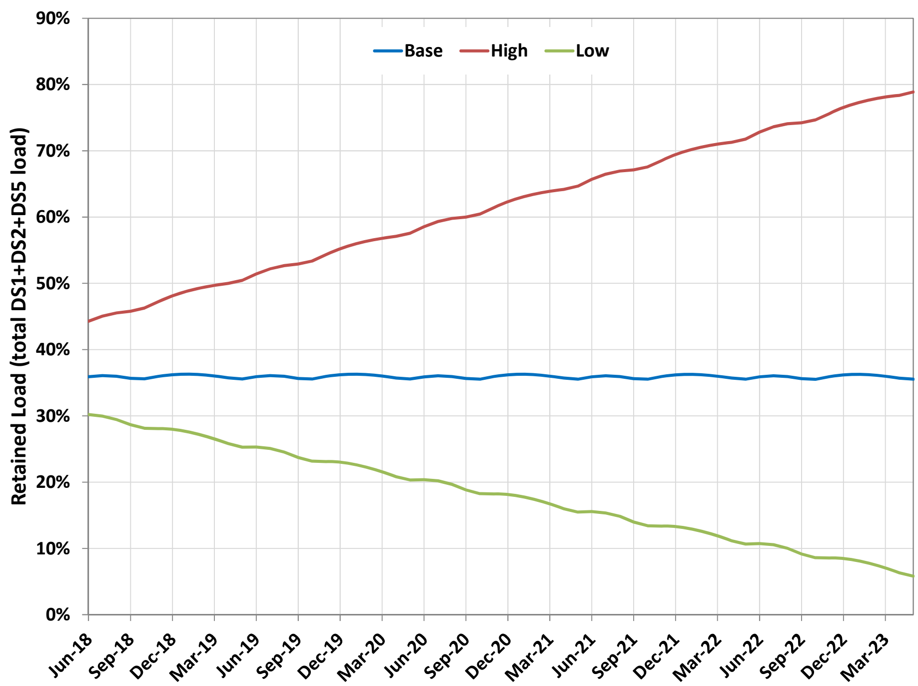
According to Ameren Illinois, customer switching to alternative retail electric suppliers, in particular through municipal aggregation, is the greatest driver of load uncertainty. As of April 2017, customer switching has resulted in approximately 62-68% of residential and small commercial load taking service from alternative retail electric suppliers rather than from Ameren's default service. Ameren Illinois expects the amount of load supplied by ARES will remain flat across the planning horizon. This expectation is partially based on the fact that the vast majority of municipal aggregation contracts were renewed after their recent expiration. Additionally, as shown in Table 3-2 presented in the next Section, ARES offerings to individual customers, in general, appear to be higher than the default utility rate; the rates offered by ARES to the aggregated loads may be lower and thus more comparable to the Ameren Illinois default service rate.

Ameren Illinois has also developed additional switching scenarios that address high and low switching scenarios for this planning period. A low switching scenario envisions a situation where a larger return of residential and, to a lesser extent, commercial customers, is realized. These scenarios reflect various switching rates which are the reflection of the percentage of load that is being served by alternative retail electric suppliers. Residential and small commercial switching rates under the low switching and a corresponding high load scenario are forecasted to be 54% and 61%, respectively, in May 2018, 47% and 53%, respectively, in May 2019, and 18% and 25%, respectively, by the end of the planning horizon.

Conversely, should future Ameren Illinois tariff rates exceed customers' perceived value of ARES contracts, a higher switching scenario is possible. Thus Ameren Illinois' high switching and a corresponding low load scenario assumes that residential and small commercial switching rates will approach 67% and 74%, respectively, in May 2018, 72% and 78%, respectively, in May 2019, and 91% and 98%, respectively, by the end of the planning horizon.

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

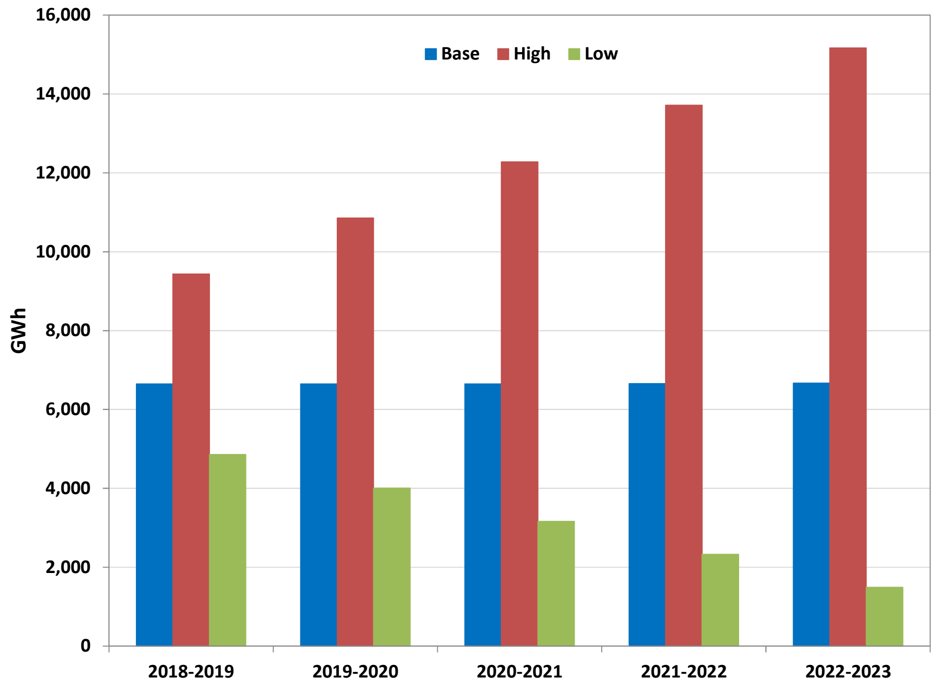
Figure 3-5: Utility Load Retention in Ameren Illinois' Forecasts



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

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

Figure 3-6: Supply Obligation in Ameren Illinois' Forecasts



3.2.4 Load Shape and Load Factor

Figure 3-7 and Figure 3-8 display the hourly profile of Ameren Illinois supply obligation in each case (relative to the daily maximum load). Figure 3-7 illustrates a summer day and Figure 3-8 a spring day. In these figures the curves are normalized so that the highest value in each is 1. There is little difference between the profiles of the high, low and base cases.

Figure 3-7: Sample Daily Load Shape, Summer Day in Ameren Illinois' Forecasts

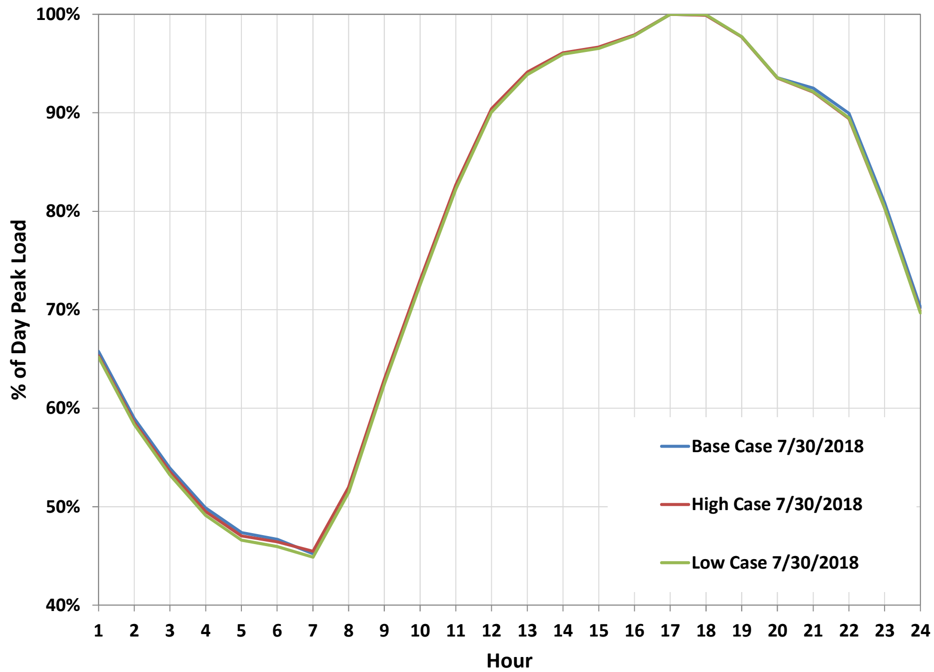
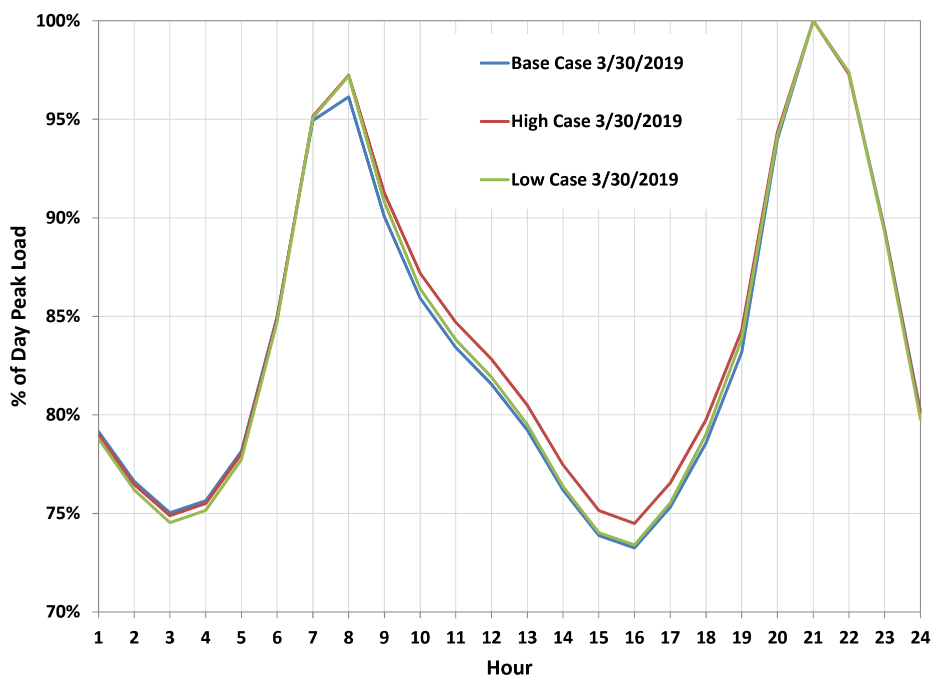
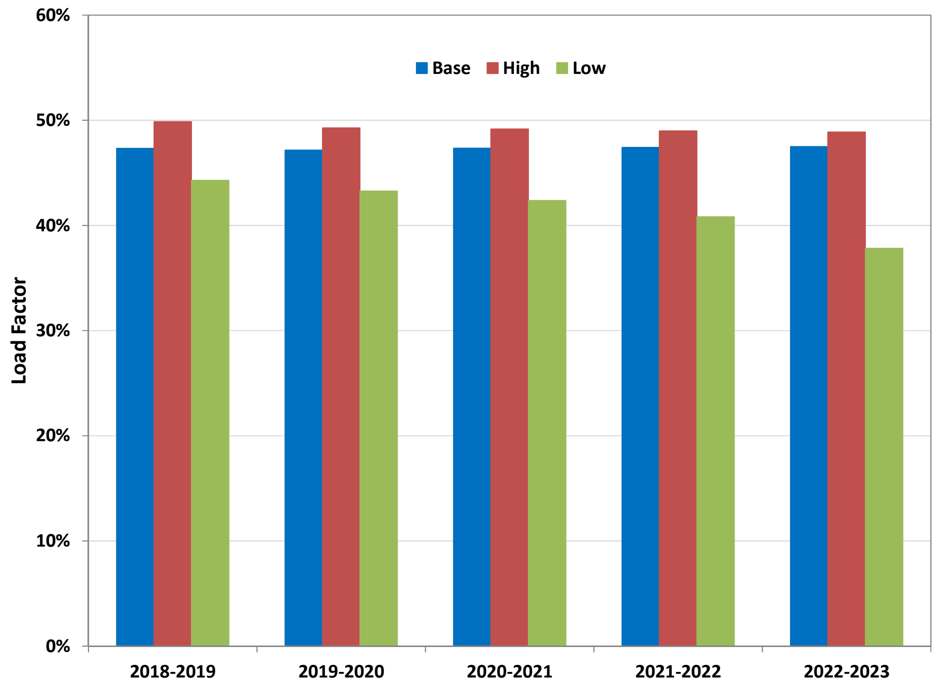


Figure 3-8: Sample Daily Load Shape, Spring Day in Ameren Illinois' Forecasts



One calls a load shape "peaky" if there is a lot of variation in it – for example, if there is a large difference between the lowest and highest load values or, in these normalized curves, if the lowest point is well below 1. A load shape that is not peaky is one in which the load is nearly constant. The peakiness of a case is usually borne out by the load factors. The load factor in any time period, such as a year, is the ratio of the average load to the maximum load. In general, peaky load curves have low load factors. Figure 3-9 shows that the low case has the lowest load factors, while Figure 3-7 and Figure 3-8 show that the low case load profile is not peakier than the other two cases as would be expected. This can be attributed to a difference in weather assumptions between the low case and the other two cases.

Figure 3-9: Load Factor in Ameren Illinois' Forecasts



3.3 Summary of Information Provided by ComEd

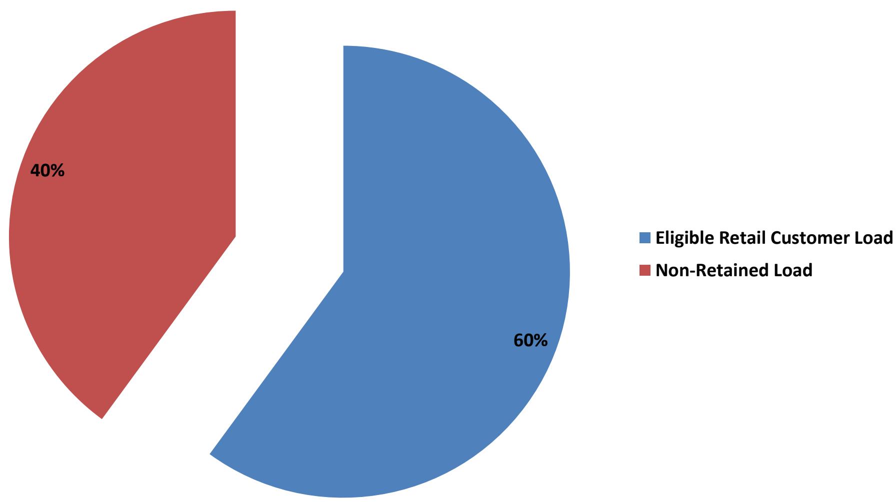
In compliance with Section 16-111.5(d)(1) of the Public Utilities Act, ComEd provided the IPA the following documents for use in preparation of this plan:

- *Load Forecast for Five-Year Planning Period June 2018 – May 2023.* (See Appendix C) This document also contained several appendices.
- Information supporting the load forecasts including spreadsheets of load profiles, hourly load strips, model inputs, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix F)

ComEd forecasts load by applying hourly load profiles for each of the major customer groups to the total service territory annual load forecast and subtracting loads projected to be served by hourly pricing, ARES, and municipal aggregation. Hourly load profiles are developed based on statistically significant samples from ComEd's residential, non-residential watt-hour, and 0 to 100 kW delivery customer classes. The profiles show clear and stable weather-related usage patterns. Using the profiles and actual customer usage data, ComEd develops hourly load models that determine the average percentage of monthly usage that each customer group uses in each hour of the month.

ComEd did not supply its forecasts for medium and large commercial and industrial customers, whose service has been deemed to be competitive and who therefore cannot be eligible retail customers. Figure 3-10 shows the forecasted annual percentage of usage by eligible retail customer load and non-retained retail customer load.

Figure 3-10: ComEd's Forecast Non-Competitive Class Customer Load Breakdown, Delivery Year 2018-2019



As noted above, ComEd provides a forecast of total usage for the entire service territory and allocates the usage to various customer classes using the models specific to each class. A suite of econometric models, adjusted for other considerations such as customer switching, is used to produce monthly usage forecasts. The hourly customer load models are applied to create hourly forecasts by customer class.

In determining the expected load requirements for which standard wholesale products will be procured, the ComEd forecast must be adjusted for the volume served by municipal aggregation and other ARES. The ComEd 5-year annual load forecast, shown in Figure 3-11, is based on the rate of customer switching in the past, expected increases in residential ARES service, and the anticipated additional migration of 0 to 100 kW customers to ARES and municipal aggregation. The figure breaks down the total forecast of residential and small commercial customer load in the same way as Figure 3-10 does for a single year.

Figure 3-11: ComEd's Forecast Non-Competitive Class Customer Load by Delivery Year

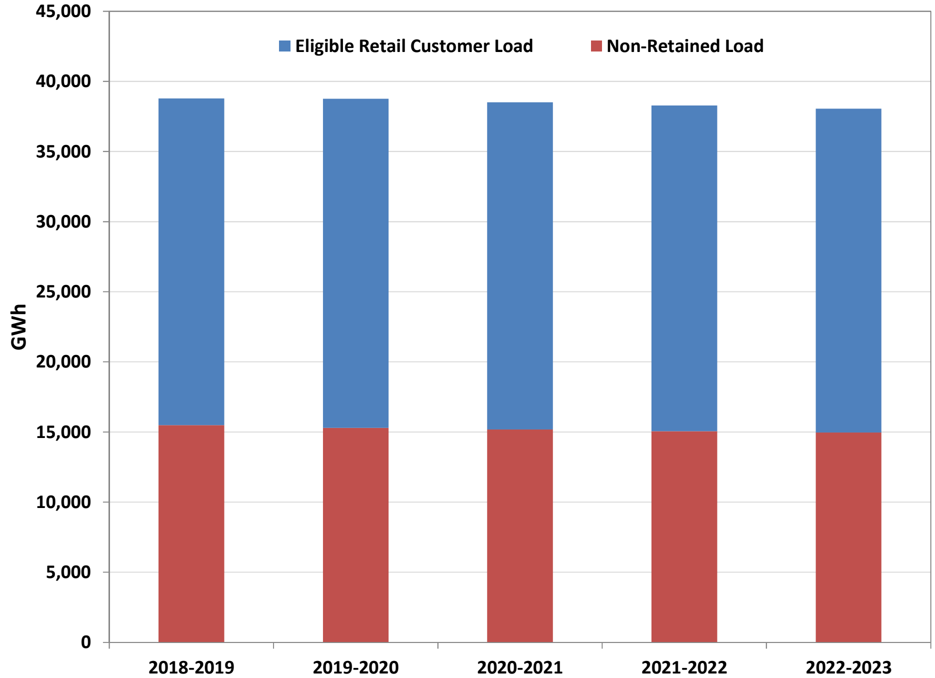
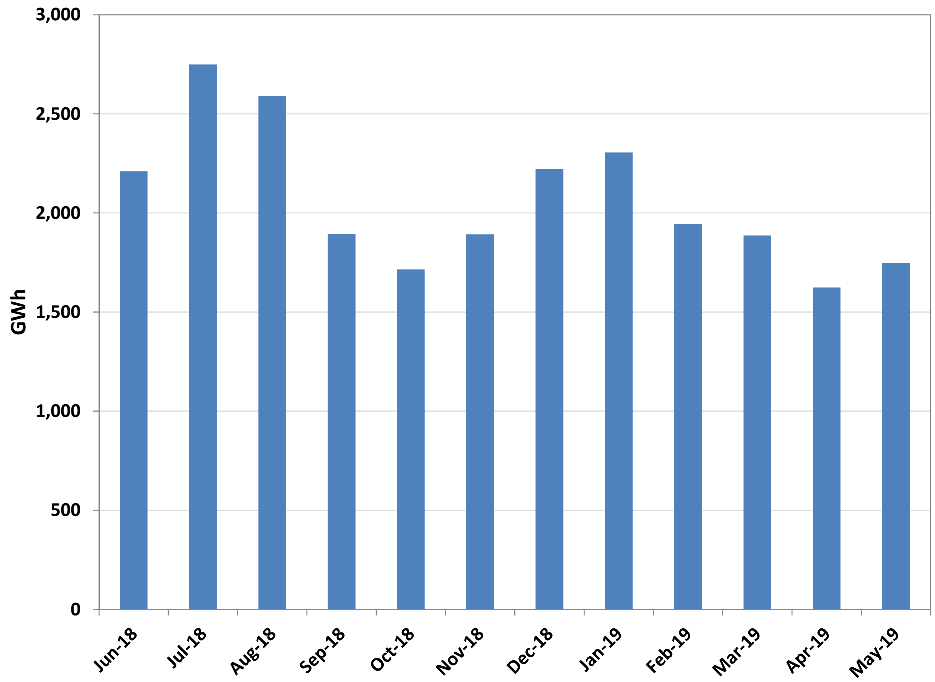


Figure 3-12 provides a monthly breakdown of the base-case forecast of ComEd's eligible retail customer load, that is, the load of customers who are forecasted to take bundled supply under this Procurement Plan.

Figure 3-12: ComEd's Forecast Eligible Retail Customer Load by Month



ComEd provides a base case load forecast and two excursion cases: a low-case forecast and a high-case forecast. Each excursion case addresses three different uncertainties, simultaneously moving in the same direction: macroeconomics, weather, and switching.

3.3.1 Macroeconomics

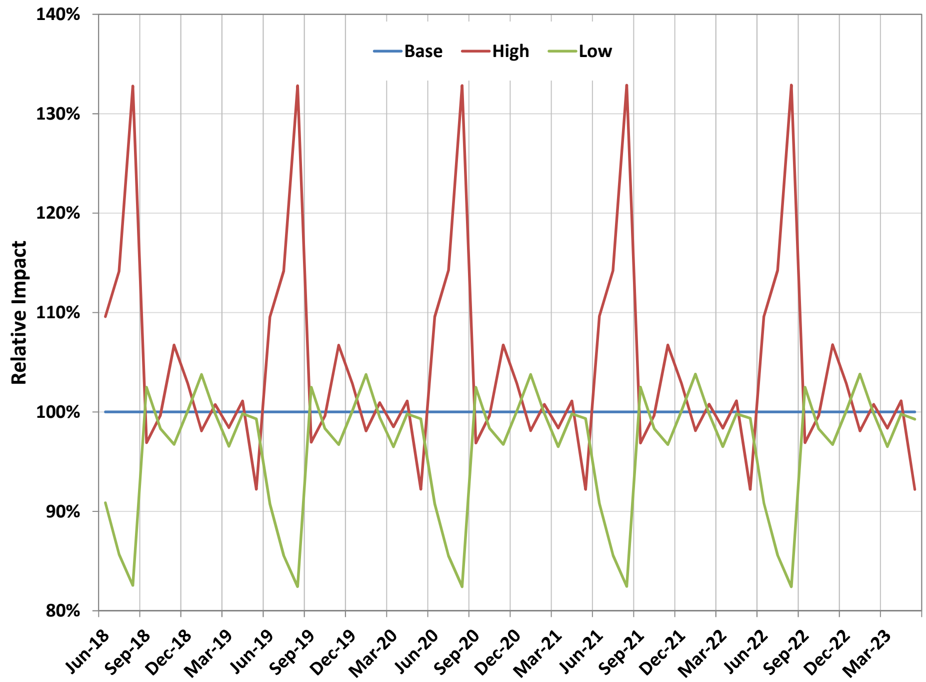
ComEd's base case load forecast is driven by a Zone Model that includes both macroeconomic variables (Gross Metropolitan Product for Chicago and other metropolitan areas within ComEd's service territory, household income) and demographics (household counts). ComEd did not use this model to define "high" and "low" cases. ComEd modified the service area load growth rates, increasing them by 2% in the high case and reducing them by 2% in the low load (because the growth rate in the base case is below 2%, presumably this implies negative load growth in the low case throughout the projection horizon).

3.3.2 Weather

ComEd includes "high weather" and "low weather" in its characterization of the high and low cases. Under the sample year approach, the high-load forecast assumes that the summer weather is hotter than normal, and the low-load forecast assumes that the summer weather is cooler than normal.

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

Figure 3-13: Weather Impacts in ComEd's Forecasts

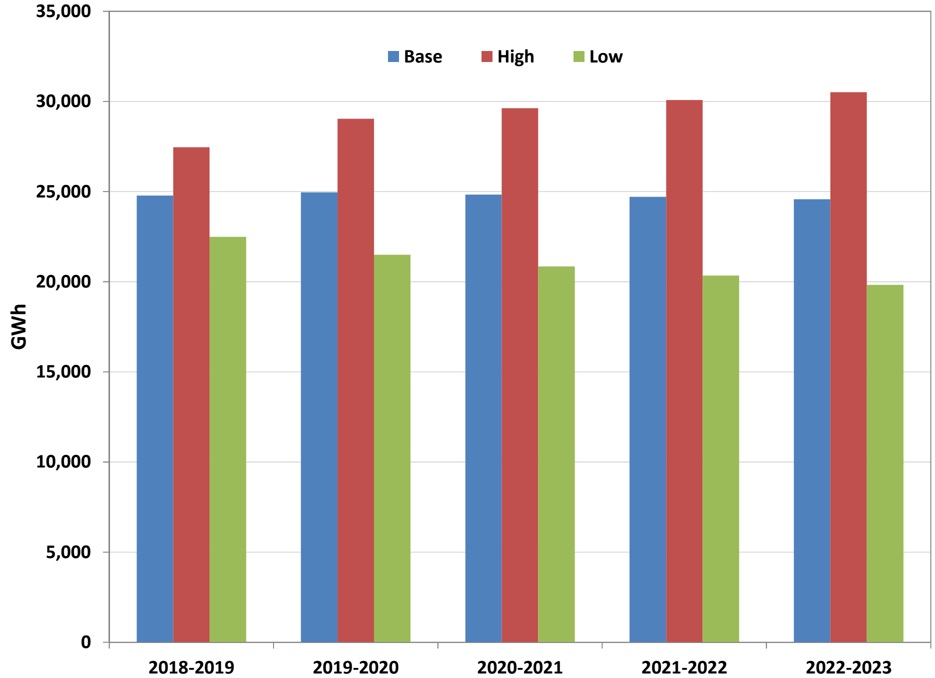


3.3.3 Switching

The high switching (low load) case assumes residential, watt-hour, and 0 to 100 kW blended usage to be reduced by 4% from the expected load level over the course of the calendar years 2018 and 2019 as the communities that are opting out from ComEd service renew their municipal aggregation programs. Municipal aggregation has historically been a major factor in the rapid expansion of residential ARES supply. In total, there are 358 communities within the ComEd service territory that had approved aggregation as of April of 2017, exactly the same number of communities that was reported last year. The percentage of eligible retail customers taking blended service in this switching scenario is 57% (based on usage) as of December 2019 compared to 61% in the expected load forecast.

The low switching (high load) case assumes additional communities opt out of municipal aggregation in the years 2018 and 2019 such that residential usage increases by 4% from the expected load level over the course of the calendar years 2018 and 2019. The percentage of eligible retail customers taking blended service in this switching scenario is 65% (based on usage) as of December 2019 compared to 61% in the expected load forecast. Figure 3-14 shows the forecasted ComEd supply obligation in each case.

Figure 3-14: Supply Obligation in ComEd's Forecasts



3.3.4 Load Shape and Load Factor

Figure 3-15 and Figure 3-16 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-15 illustrates a summer day, and Figure 3-16 a spring day. The high case is definitely peakier on a summer day than the base case, and the low case is flatter. During the sample spring day, there is no significant difference between the profiles of the high and base cases, but the low case is a slightly peakier.

Figure 3-15: Sample Daily Load Shape, Summer Day in ComEd's Forecasts

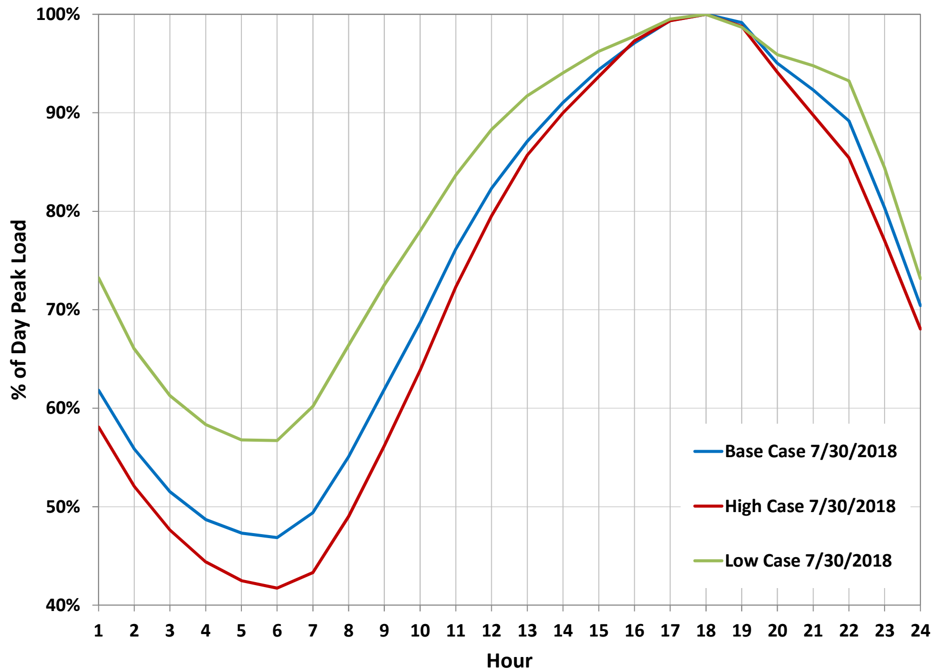
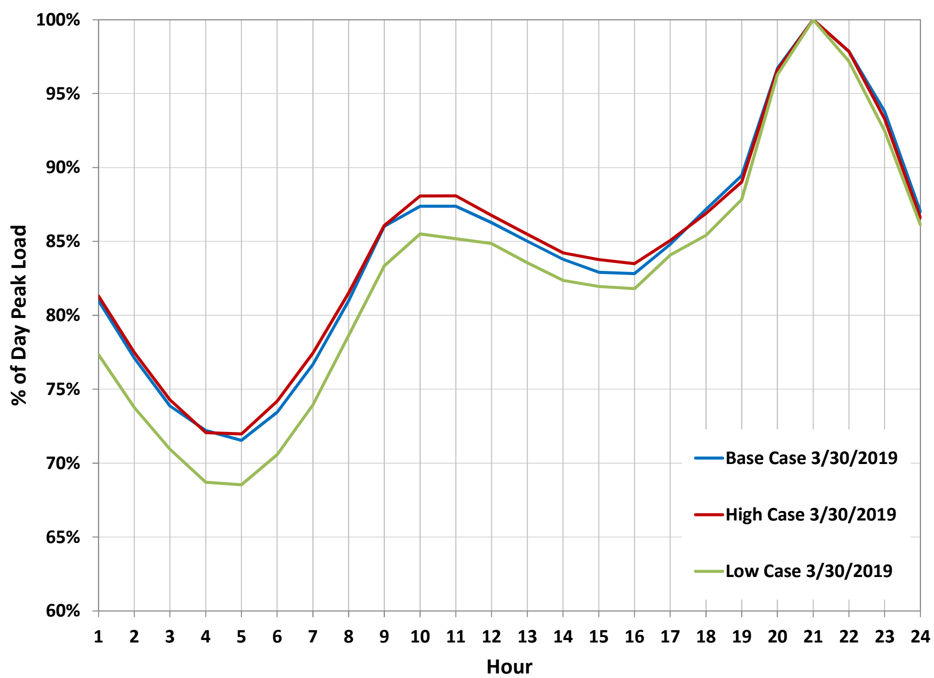
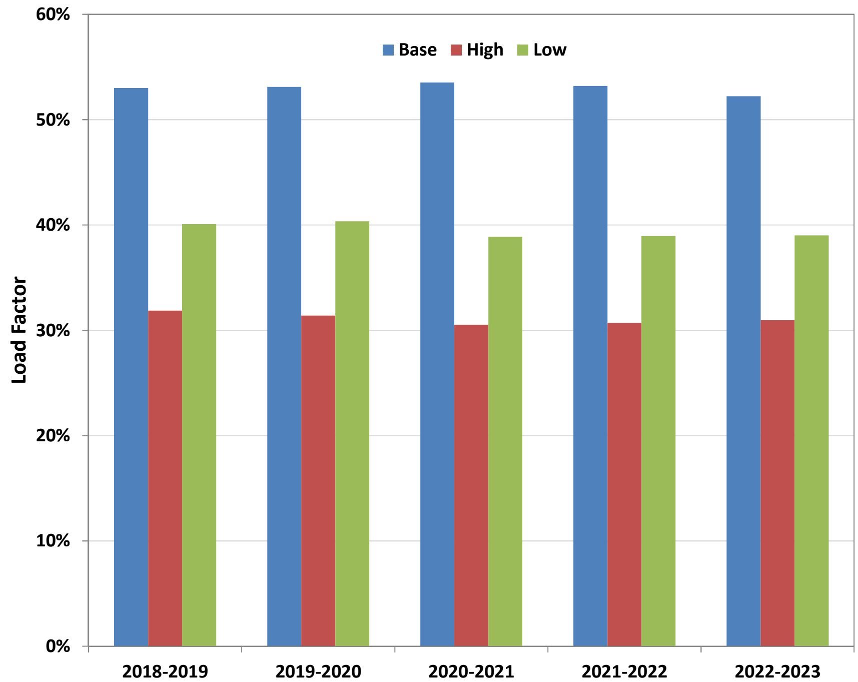


Figure 3-16: Sample Daily Load Shape, Spring Day in ComEd's Forecasts



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

Figure 3-17: Load Factor in ComEd's Forecasts



3.4 Summary of Information Provided by MidAmerican

In compliance with Section 16-111.5(d)(1) of the Public Utilities Act, MidAmerican provided the IPA the following documents for use in preparation of this plan:

- *Methodology for the 2018-2027 Illinois Electric Customers and Sales Forecasts.* This document contained a discussion of load forecast methodology for all MidAmerican scenarios and supporting data for the base scenario forecast. The load forecast included a multi-year historical analysis of hourly load data, forecasted load and capability along with the impact of demand side and renewable energy initiatives. MidAmerican's load forecast was further broken down by revenue class, projected kWh usage and sales, which factored in economic and demographic variables along with weather variables based on weather data. Additionally, the load forecast accounted for sales forecasts based on variables and model statistics along with the non-coincident electric gross peak demand forecast and represents all of the eligible retail customer classes, except the customer being served by an ARES. MidAmerican methodology also includes the discussion of the energy efficiency and switching trends. Pursuant to Section 16-111.5(d)(1), MidAmerican's load forecast covered a five-year procurement planning period. (See Appendix D)
- Spreadsheets of load profiles, hourly load strips, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix G)

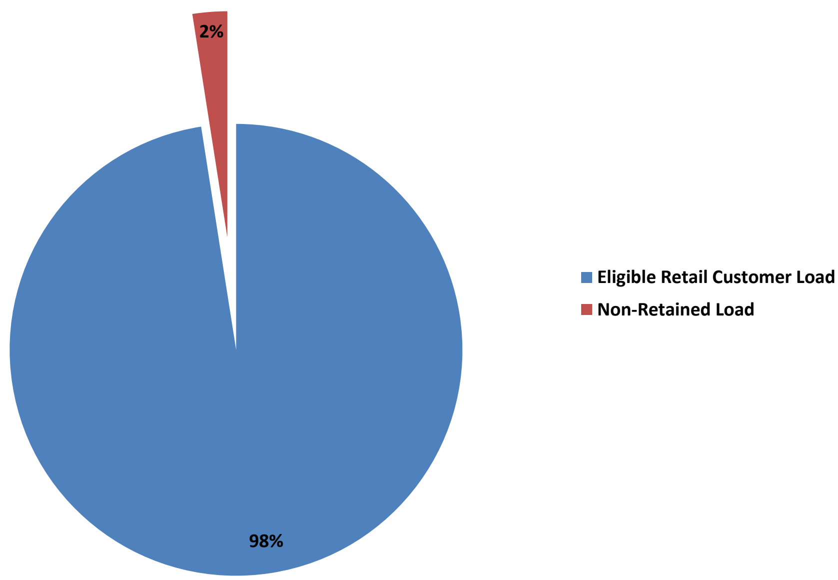
MidAmerican forecasts load by using econometric models on a monthly basis. For the residential, commercial and public authority classes, sales are determined by multiplying customers by use per customer. For the industrial class, sales are modeled directly. For the street lighting class, sales are forecast using trending.

The gross peak numbers used in the analysis are the historical gross peaks, which take into account demand side management impacts.

MidAmerican has one active alternative retail supplier in its Illinois service territory. MidAmerican has no customer classes that have been declared competitive. Figure 3-18 shows the forecasted annual percentage of usage by eligible retail customer load and non-retained retail customer load. The low level of switching among

MidAmerican's eligible retail customers relative to the much higher switching levels for Ameren Illinois and ComEd is likely due to a combination of market conditions in MidAmerican's service area, including the relatively low cost of MidAmerican-owned resources allocated to its Illinois load (which would lead to little or no municipal aggregation activity, and little profit opportunity for ARES).

Figure 3-18: MidAmerican's Forecast Retail Customer Load Breakdown, Delivery Year 2018-2019



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

In determining the expected load requirements for which standard wholesale products will be procured, the MidAmerican forecast is adjusted for the volume served by the ARES. The MidAmerican 5-year annual load forecast, shown in Figure 3-19, incorporates the rate of customer switching in the past, and expected increases in the ARES service. The retail choice switching forecast was derived by reviewing recent switching activity and projecting forward recent trends. The figure breaks down the total forecast of the total customer load, in the same way as Figure 3-18 does for a single year.

Figure 3-19: MidAmerican's Forecast Retail Customer Load by Delivery Year

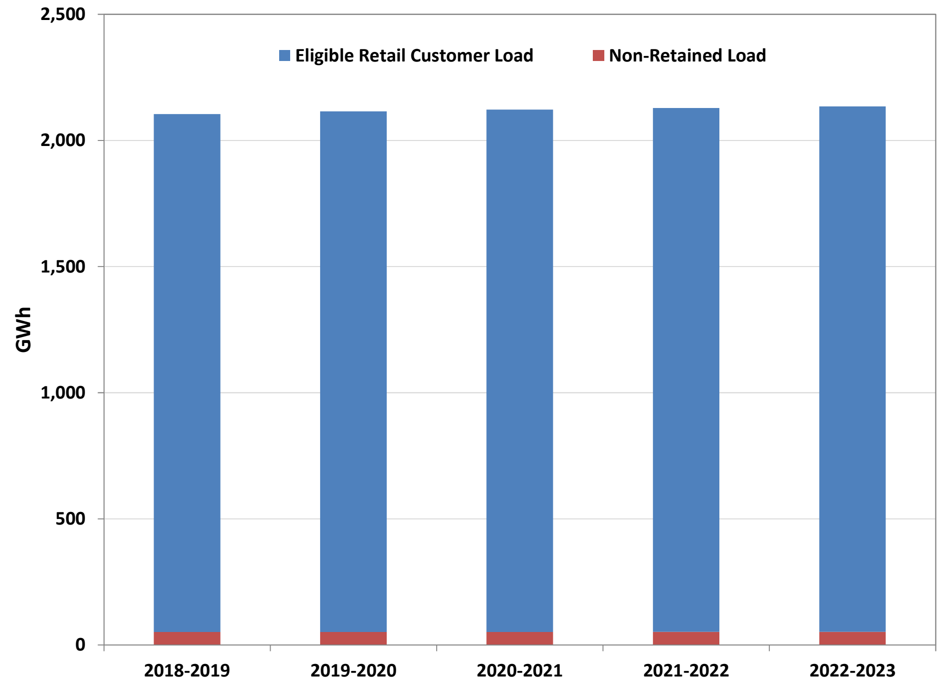
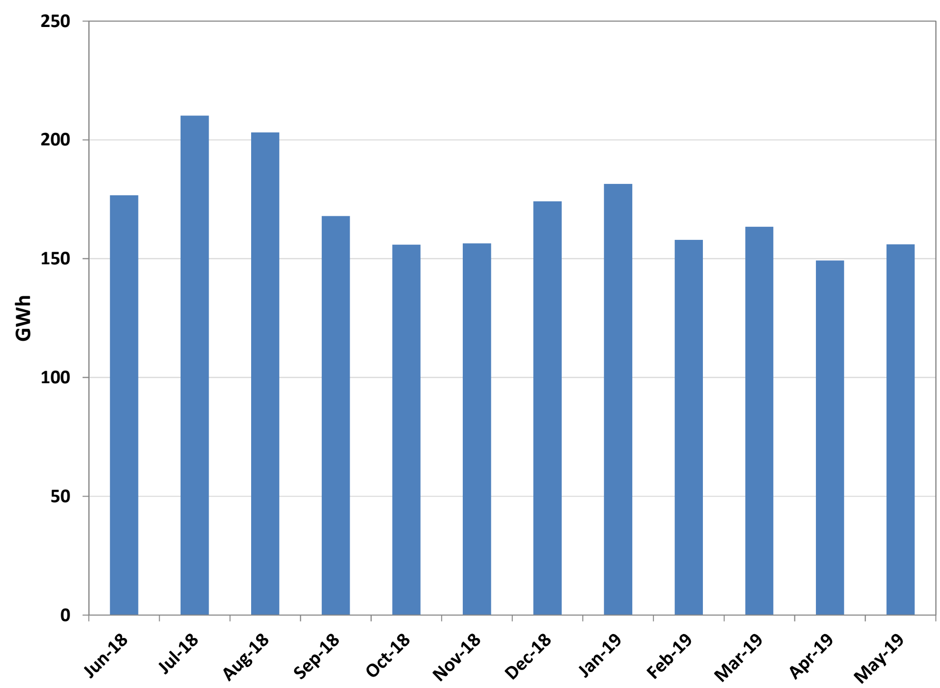


Figure 3-20 provides a monthly breakdown of the base case forecast of MidAmerican retained eligible retail customer load, that is, the load of customers on bundled supply to be considered under this Procurement Plan.

Figure 3-20: MidAmerican's Forecast Eligible Retail Customer Load by Month



MidAmerican provided a base-case load forecast and two excursion cases: a low-case forecast and a high-case forecast. The required low and high hourly load forecast scenarios were created by taking the 95% confidence interval around each class-level sales, customer, and use per customer forecast, as well as the 95% confidence interval around the non-coincident gross peak demand forecast. The load forecasting software used for the sales, customer, use per customer, and non-coincident peak demand forecasts provided the upper and lower bounds of a 95% confidence interval around each monthly forecast value. This software feature allowed the construction of upper and lower bound forecasts for the residential, commercial, industrial and public authority sales forecasts. The street lighting sales forecast was multiplied by 0.99 and 1.01 to generate, respectively, a lower and upper bound street lighting sales forecast.

3.4.1 Macroeconomics

MidAmerican's reference case load forecast is based on the model utilizing economic and demographic data that were obtained from an external source database. For MidAmerican's Illinois service territory, economic and demographic variables specific to the Quad Cities metropolitan area were used in the forecasting process. The Quad Cities area encompasses MidAmerican's Illinois service territory. The list of economic and demographic variables considered for the forecast includes real gross metropolitan area product, manufacturing, population, households, employment, etc. As mentioned above, MidAmerican used this model to define "high" and "low" cases applying the 95% confidence interval to arrive at the lower and upper bounds.

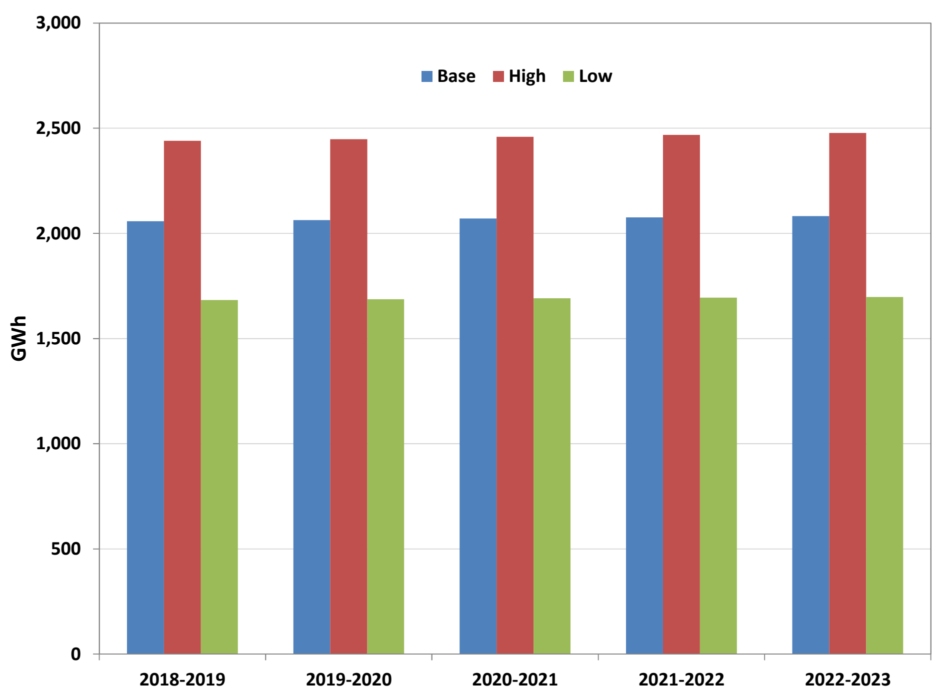
3.4.2 Weather

The reference case temperature assumptions in the hourly load forecast model were not changed for the scenarios. The reference case weather-related assumptions in the sales, the use per customer, and the non-coincident peak demand forecast models for MidAmerican's Illinois service territory were not changed in the scenarios.

3.4.3 Switching

The reference case forecasts for retail switching sales, customers, and demand in MidAmerican Illinois service territory were not changed in the scenarios. Figure 3-21 shows the forecasted MidAmerican Illinois supply obligation in each case.

Figure 3-21: Supply Obligation in MidAmerican's Forecasts



3.4.4 Load Shape and Load Factor

Figure 3-22 and Figure 3-23 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-22 illustrates a summer day, and Figure 3-23 shows a spring day. There is no meaningful difference between the base, low, and high load shapes on a sample summer day, or on a sample spring day.

Figure 3-22: Sample Daily Load Shape, Summer Day in MidAmerican's Forecasts

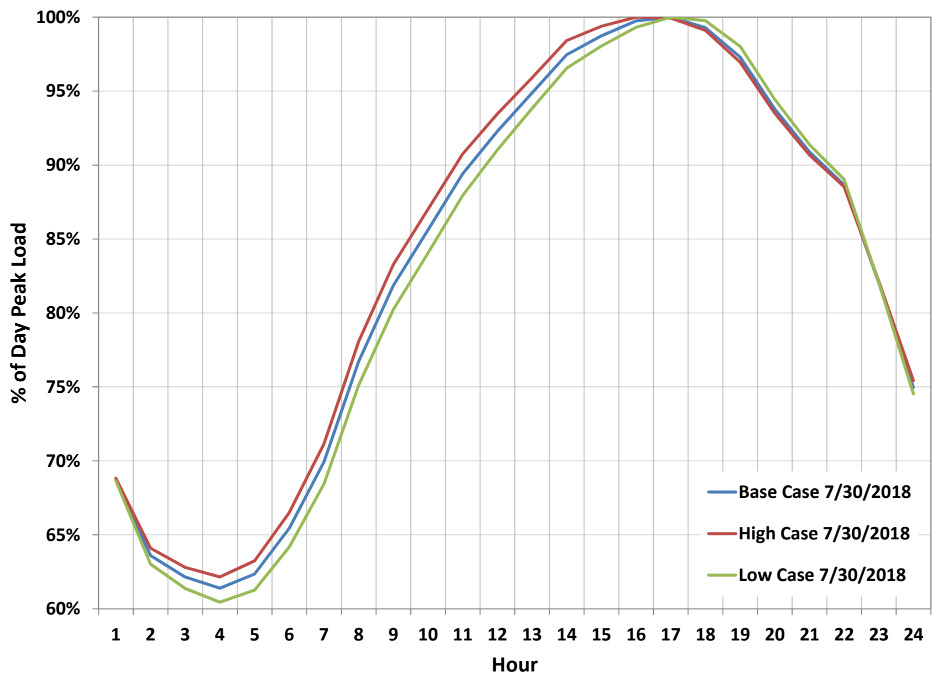
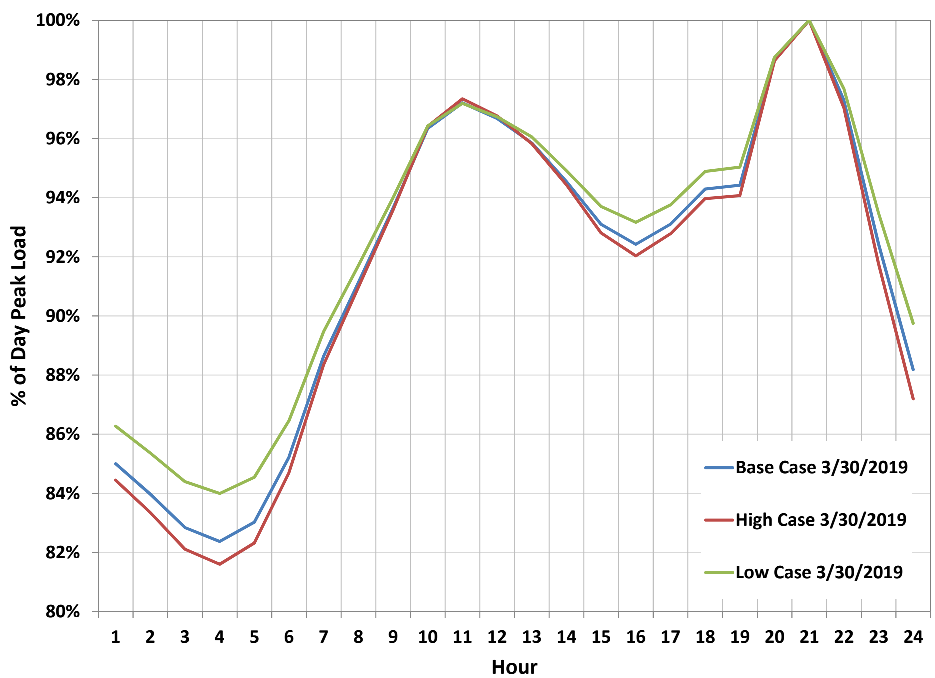
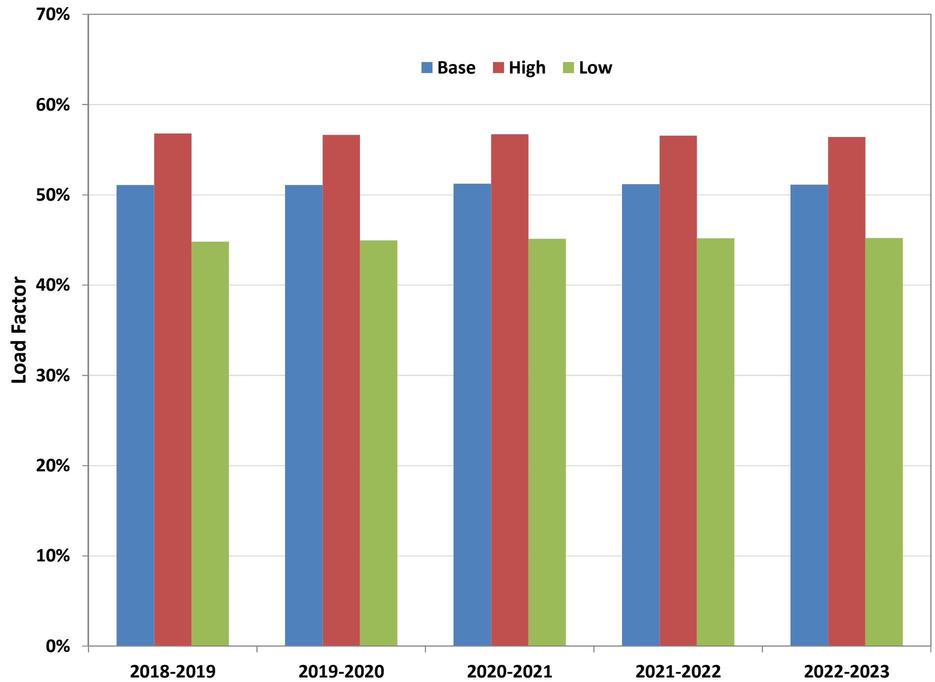


Figure 3-23: Sample Daily Load Shape, Spring Day in MidAmerican's Forecasts



The annual load factors are shown in Figure 3-24. As expected, the base, the high, and the low case load factors are consistent being within the 45-57% range.

Figure 3-24: Load Factor in MidAmerican's Forecasts



3.5 Sources of Uncertainty in the Load Forecasts

In the past, the Agency has procured power for the utilities to meet a monthly forecast of the average hourly load in each of the on-peak and off-peak periods. The Agency has addressed the volatility in power prices by "laddering" its purchases: hedging a fraction of the forecast two years ahead, another fraction one year ahead, and a third fraction shortly before the beginning of the delivery year. Even if pricing two years ahead were extremely advantageous, the Agency does not purchase its entire forecast that far ahead because the forecast is itself uncertain. It is therefore important to understand the sources of uncertainty in the forecasts.

Furthermore, even if the Agency could perfectly forecast the average hourly load in each period, and perfectly hedge that forecast, it would still be exposed to power cost risk. Load varies from hour to hour. Energy in one hour is not a perfect substitute for energy in another hour because the hourly spot prices differ. A perfect hedge would cover differing amounts of load in different hours, and would have to be based on a forecast of the different hourly loads. The "expected hourly load" is not an accurate forecast of each hour's load (see Section 3.5.3). This is not an issue of uncertainty; it would be true even if the expected hourly load were a perfect forecast of the average load, and the hourly profile (the ratio of each hour's load to the average) were known with certainty. So it is treated here together with the other uncertainties.

3.5.1 Overall Load Growth

Ameren Illinois and ComEd construct their load forecasts by forecasting load for their entire delivery service area, then forecasting the load for each customer class or rate class within the service territory, and then applying multipliers to eliminate load that has switched to municipal aggregation or other ARES service. Customer groups that have been declared competitive – medium and large commercial and industrial customers – are removed entirely, as the utilities have no supply or planning obligation for them. In contrast, MidAmerican, a utility serving a much smaller number of electric customers in Illinois territory, does not have any customer groups that have been declared competitive. There is only one entity providing ARES service in the MidAmerican Illinois service territory serving a relatively small segment of customers. Similar to the other two utilities, MidAmerican constructs its load forecast by using a top-to-bottom approach.

Ameren Illinois does not explicitly address uncertainty in load growth. In other words, Ameren Illinois does not define "load growth scenarios" and examine the consequences of high or low load growth. Ameren Illinois addresses both load and weather uncertainty by defining high and low scenarios at particular confidence levels of the model fit, that is, of the residuals of its econometric model. The high and low cases, which represent the combined and correlated impact of weather and load growth uncertainties, represent a variation of only -6%/+8% in service area load. However, Ameren Illinois' high and low cases also include extreme customer migration uncertainty.

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

Like Ameren Illinois, MidAmerican addresses the load and weather uncertainty by defining high and low scenarios at particular confidence levels, i.e., by applying the 95% confidence interval around reference sales, customer and use per customer forecast, and the non-coincident gross peak demand forecast. The street lighting sales forecast, however, was multiplied by 0.99 and 1.01 to generate, respectively, a lower and upper bound of street lighting sales forecast, which is more similar to the ComEd's approach.

3.5.2 Weather

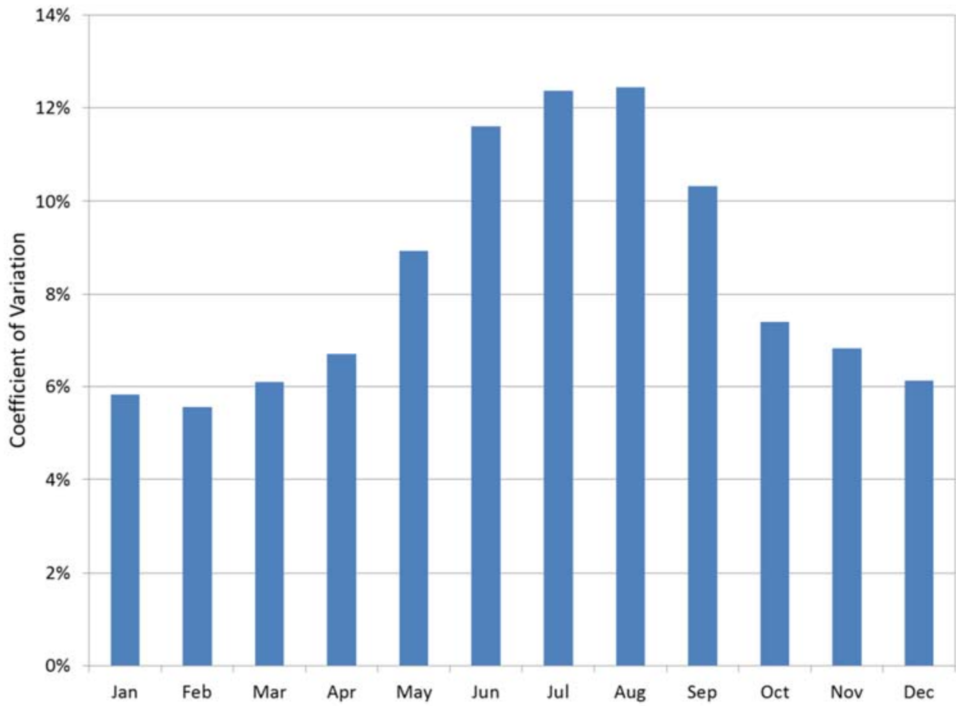
On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The discussion of high and low scenarios in Sections 3.2.2, 3.3.2, and 3.4.2 notes the way that Ameren Illinois, ComEd, and MidAmerican have incorporated weather variation into the high and low load forecasts. Ameren Illinois treats weather uncertainty together with load growth uncertainty. ComEd's forecasts are built around two sample years. Much of the impact of weather is on load variability within the year. MidAmerican's base case weather-related assumptions are not changed for the high-case and low-case load forecasts. The base-case load forecast is built on the "weather normalized" historical sales.

3.5.3 Load Profiles

As noted above, the "average hour" load forecast is not an accurate forecast of each hour's load. Within the sixteen-hour daily peak period, mid-afternoon hours would be expected to have higher loads than average, and early morning or evening hours would be expected to have lower loads. More importantly, multiplying the average hourly load by the cost of a "strip" contract (equal delivery in each hour of the period) gives an inaccurate forecast of the cost of energy. This is because hourly energy prices are correlated with hourly loads (energy costs more when demand is high). Technically, this is referred to as a "biased" forecast, because the expected cost will predictably differ from the product of the "average hour" load forecast and the "strip" contract price.

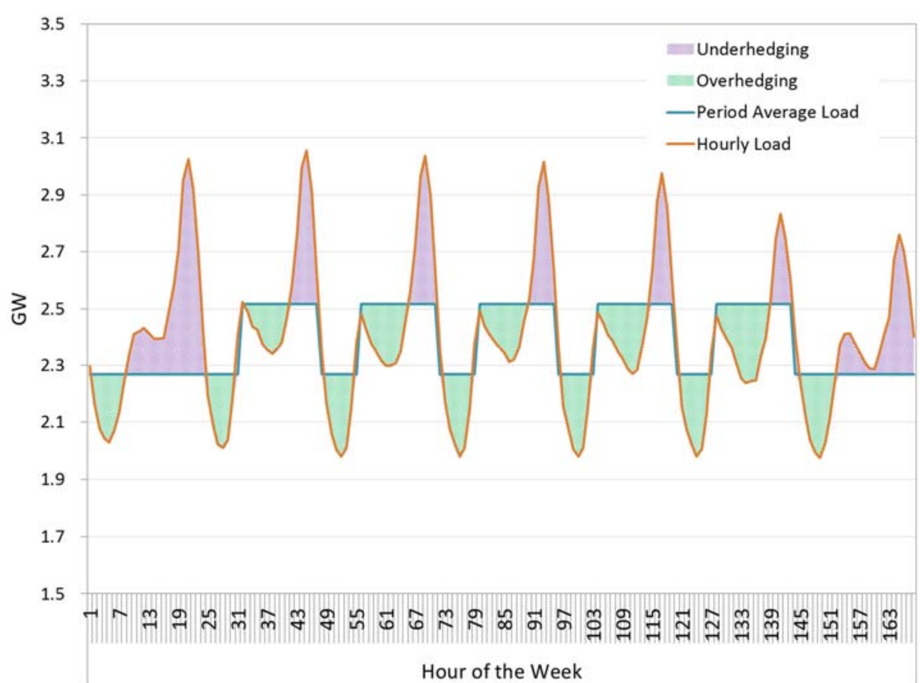
Figure 3-25 illustrates this disconnect by showing, for each month, the average historical "daily coefficient of variation" for peak period loads. This figure is based on historical ComEd loads from 2009 through 2016, normalized to the monthly base case forecasts in the first delivery year. To calculate the daily coefficient of variation, the variances of loads within each day's peak period are averaged to produce an expected daily variance. That variance is then scaled to load by first taking the square root and then dividing by the average peak-period hourly load forecasted for the month. As the figure shows, there is significant load variation during the day in the high-priced summer months.

Figure 3-25: Coefficient of Variation of Daily Peak-Period Loads



Because of this variation, even if the average peak and off-peak monthly load is perfectly hedged, the actual hourly load will still be imperfectly hedged. In other words, if the Agency were to buy peak and off-peak hedges whose volumes equaled respectively the average peak period load and average off-peak period load, there would still be unhedged load because the actual load is usually greater or less than the average. This is illustrated in Figure 3-26, below.

Figure 3-26: Example of Over- and Under-Hedging of Hourly Load



3.5.4 Municipal Aggregation and Individual Switching

In its base case, Ameren Illinois projects that approximately 62% of potentially-eligible retail customer load[83] will have switched away from Ameren Illinois fixed price tariff by the end of the 2018-2019 delivery year. This level represents a flat trend in the switching statistics considering the 62% assumed in the July 2016 forecasts and is informed in part by the vast majority of municipal aggregation contracts which were renewed after their recent expiration. In addition, Ameren Illinois' current plan year tariff price continues to be similar to comparable ARES prices for individual customers. ComEd projects that 40% of potentially-eligible retail load will have switched to ARES service by the end of the 2018-2019 delivery year, which represents a decline from the 43% switching rate assumed in the July 2016 forecasts. At this point, the uncertainty around municipal aggregation and switching may be more related to the chance that utility load will increase due to customers return to default service. To a lesser extent, the same is true with regards to the uncertainty around the extent to which, as aggregation levels decline, individual retail switching may or may not increase. But this is uncertain and it is possible that customer migration away from utility supply could resume within the planning horizon. Both Ameren Illinois and ComEd have assumed a wide range of switching fractions in the low and high scenarios (return to utility service would be represented as a decrease in the switching fraction over time).

In addition to offers to customers made through municipal aggregation programs, ARES offer a variety of products directly to customers – some of which have a similar structure to the utility bundled service, while others vary significantly in structure. These include offers with pass-through capacity prices, "green" energy above the mandated RPS level, month-to-month variable pricing, longer-term fixed prices, options to match prices in the future, options to extended contract terms, and options to adjust prices retroactively.[84] Individual customers who choose one of these other rate structures presumably have made an affirmative choice to take on those alternative services.

Although switching from default service to an ARES by individual customers has some impact, Ameren Illinois and ComEd switching forecasts have been dominated by municipal aggregation. While the IPA recognizes that many ARES focus on individual residential switching, the IPA is not aware of a significant number of residential customers leaving default service to take ARES service outside of a municipal aggregation program. As shown in Table 3-2, this is currently the case because of the appreciable difference between the utility price to compare and representative ARES prices available to eligible utility customers.[85] It appears that, currently, ARES fixed price offers for a 12-month term are higher than the respective utility summer rates and do not appear to offer savings or benefits to individual residential customers. It is reasonable to assume that switching behavior by individual customers (other than those who chose an ARES rate that is not an "apples-to-apples" comparison to the utility rate, or one that offers additional perceived value) will not be a significant factor in the load forecast, except for transition to municipal aggregation, opt-out from municipal aggregation, and return from municipal aggregation. The ARES offer currently applicable to MidAmerican's service territory is a variable rate which is not comparable to the utility's price.

Table 3-2: Representative ARES Fixed Price Offers and Utility Price to Compare[86]

Utility Territory	Utility Price to Compare (¢/kWh)	Representative ARES Price (¢/kWh)
Ameren Illinois (Zone I)	5.37	6.32
Ameren Illinois (Zone II)	5.37	6.47
Ameren Illinois (Zone III)	5.37	6.32
ComEd	6.89	8.10

[83] "Potentially-eligible retail customer load" refers to the load of those customers eligible to take bundled service from the utility.

[84] For more information on choices offered by ARES, see the 2017 Annual Report of the ICC Office of Retail Market Development at https://www.icc.illinois.gov/downloads/public/2017%20ORMD%20Section%2020-110%20report.pdf.

[85] Representative ARES prices are an average of 12-month fixed price offers from ARES available at https://www.pluginillinois.org/OffersBegin.aspx, September 19, 2017.

[86] Offers without an explicit premium renewable component. Monthly service fees and early termination fees are ignored.

3.5.5 Hourly Billed Customers

Customers who could have elected bundled utility service but take electric supply pursuant to an hourly pricing tariff are not "eligible retail customers" as defined in Section 16-111.5 of the PUA. Therefore, these hourly rate customers are not part of the utilities' supply portfolio for purposes of this procurement planning process and the IPA does not procure energy for them. Ameren Illinois and ComEd did not include customers on hourly pricing in their load forecasts; they appropriately considered these customers to have switched. The amount of load on hourly pricing is small and unlikely to undergo large changes that would introduce significant uncertainty into the load forecasts. MidAmerican does not have hourly billed customers.

3.5.6 Energy Efficiency

Public Act 95-0481 created a requirement for ComEd and Ameren Illinois to offer cost-effective energy efficiency and demand response measures to all customers,[87] with updates to those savings targets adopted through Public Act 99-0906. Both Ameren Illinois and ComEd have incorporated into their forecasts the expected impacts of these updated measures (as applied to eligible retail customer load).

MidAmerican offers energy efficiency programs pursuant to a separate provision of the Public Utilities Act found in Section 8-408. In submitting its load forecast, MidAmerican stated that estimated past energy savings are implicit in the historical data used to derive the electric sales forecast models. Without adjustment, this method implies that the level of future estimated program savings will be similar to past estimated program savings. Estimated program impacts in the forecast period are not projected to deviate measurably from estimated historical levels, so no adjustment was made to the forecasting models.

3.5.7 Demand Response

As noted by the utilities in their load forecast documentation, demand response does not impact the weather-normalized load forecasts. As such, the IPA notes that they are more like supply resources. Section 7.4 of the Plan contains the IPA's discussion and recommendations for demand response resources.

3.5.8 Emerging Technologies

An emerging technology that could have a significant impact on the Illinois power market as well as the IPA's future procurement plans involves energy storage, in particular, lithium-ion (Li-ion) battery storage integrated with solar PV distributed generation. The Agency's 2016 *Annual Report: The Costs and Benefits of Renewable Resource Procurement* included an update on the development of the energy storage technology.[88] Based on storage data compiled by the U.S. Department of Energy, as of the end of 2016, there were 47 operational battery-based storage systems with a total capacity of 275.3 megawatts ("MW") operating in PJM and 14 projects totaling 22.4 MW operating in MISO; the majority of these projects in terms of capacity were utility scale storage projects. Illinois was listed as having 14 projects with 135 MW in operation.[89]

While utility scale energy storage technology continues to be developed and deployed, distributed solar PV integrated with distributed storage offers significant potential to enhance the benefits and spur the development of solar distributed generation. However, the costs of Li-ion batteries for use with distributed solar PV systems such as residential rooftop solar while declining on the average of 23% annually from 2010 to 2015, remain high relative to the value proposition for residential and small commercial solar PV applications.[90] Li-ion battery costs for distributed generation applications are forecast to continue to decline with a large stepwise decline anticipated as the Tesla "giga-factory" producing the 14 kWh Powerwall battery

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[87] See P.A. 95-0481 (Section originally codified as 220 ILCS 5/12-103).

[88] That report can be found here: http://www.illinois.gov/sites/ipa/Documents/IPA-2016-Renewables-Report.pdf.

[89] U.S. Department of Energy Global Energy Storage Database, www.energystorageexchange.org/projects, accessed August 1, 2017.

[90] Kristen Ardani, et. al., National Renewable Energy Laboratory, "Installed Cost Benchmarks and Deployment Barriers for Residential Solar Photovoltaics with Energy Storage: Q1 2016," NREL/TP-7A40-67474.

for residential applications becomes fully operational in 2020.[91] It is too early to forecast the impact on load forecasts associated with distributed solar PV integrated with battery storage, and the Agency notes that while Public Act 99-0906 will encourage the development of distributed solar PV, there are not clear provisions in Illinois law to encourage the adoption of integrated storage technologies. The Agency plans to continue to monitor the development of this technology as well as the utility scale energy storage market in the coming years.

3.6 Recommended Load Forecasts

3.6.1 Base Cases

The IPA recommends adoption of the Ameren Illinois, ComEd, and MidAmerican base case load forecasts. Ameren Illinois and ComEd forecasts include already approved energy efficiency programs, and MidAmerican's forecast includes verified energy efficiency program impacts as well.

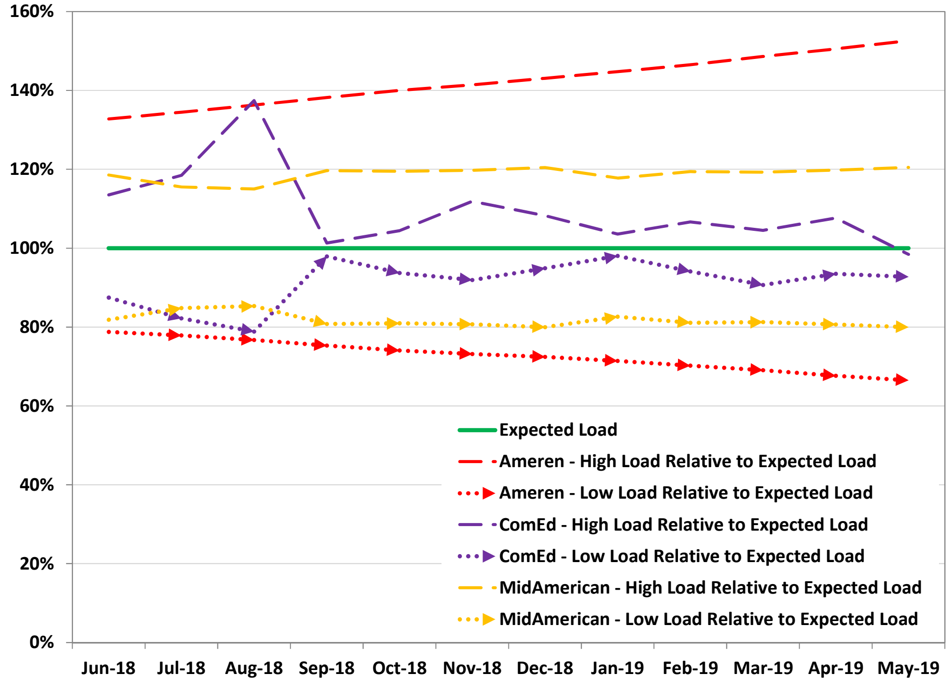
3.6.2 High and Low Excursion Cases

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

As illustrated in Figure 3-27, the Ameren Illinois low and high load forecasts are on average equal to 73% and 142% of the base case forecast, respectively, during the 2018-2019 delivery year. Comparatively, for the same period, ComEd's low and high load forecasts are on average equal to 91% and 110% of the base forecast, respectively. This reflects the differences in switching assumptions used by the two utilities. MidAmerican's low and high load forecast deviations from the base case are flat and symmetrical being equal to 82% and 119%, respectively. Switching assumptions play no explicit role in the MidAmerican high and low load forecasts. Instead, the MidAmerican high and low load forecasts are a product of a mathematical construct.

[91] Danielle Muoio, "New aerial photos appear to show just how massive Tesla's Gigafactory is," Business Insider, July 10, 2017, http://www.businessinsider.com/tesla-gigafactory-massive-photos-2017-7.

Figure 3-27: Comparison of Ameren Illinois, ComEd, and MidAmerican High and Low Forecasts for Delivery Year 2018-2019



Another potential use of the high and low cases would be to analyze the risks of different supply strategies. A key driver of that risk is the cost of meeting unhedged load on the spot market. One of the main reasons is the disparity between load and the selected hedging instrument. As in Figure 3-26, load is variable while the hedging instrument (standard block energy) features a constant delivery of energy. The spot price at which the unhedged volumes are covered is positively correlated with load. However, as explained below, the high and low cases are less suitable for such a risk analysis.

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

The Ameren Illinois and MidAmerican load scenarios have identical monthly load shapes (differing by uniform scaling factors). These shapes will not provide much information about the cost of meeting fluctuating loads, except for the information contained in the expected load shape.

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

4 Existing Resource Portfolio and Supply Gap

Starting with the 2014 Procurement Plan, the IPA has procured energy supply in standard 25MW on-peak and off-peak blocks. The energy block size was reduced from 50 MW to match supply with load more accurately.[92] These purchases are driven by the supply requirements outlined in the current year procurement plan and are executed through a competitive procurement process administered by the IPA's Procurement Administrator. This procurement process is monitored for the Commission by the Commission-retained Procurement Monitor. The history of the IPA-administered procurements is available on the IPA website.[93] The 2017 Procurement Plan included the procurement of energy supply to meet the needs of ComEd's and Ameren Illinois' eligible retail customers, as well as that portion of MidAmerican's eligible retail customer load not met through its allocation of existing generation. The current plan will continue the procurement of energy supply for each of the three utilities.

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

The current IPA procurement strategy involves 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 2018-2019 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 2018-2019 delivery year. A portion of the targeted hedge levels for the 2019-2020 and the 2020-2021 delivery years of 50% and 25%, respectively, will be acquired spread on an equal basis in the spring and fall procurement events.

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

- A 20-year bundled REC and energy purchase (also known as the 2010 long-term power purchase agreements or LTPPAs), starting in June 2012, made by Ameren Illinois and ComEd in December 2010 pursuant to the Final Order in Docket No. 09-0373.
- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017.[94]

Under the current utility load forecasts, which contemplate relatively flat customer switching, curtailment of the Ameren Illinois and ComEd LTPPAs is unlikely for the 2018-2019 delivery year. MidAmerican is not covered by either LTPPAs or Rate Stability procurements.

[92] See 2014 IPA Procurement Plan at 93.

[93] http://www2.illinois.gov/ipa/Pages/Prior_Approved_Plans.aspx.

[94] P.A. 97-0616 also mandated associated REC procurements, but these REC procurements do not impact the (energy) resource portfolio. Additionally, twenty-year power purchase agreements between Ameren Illinois and ComEd and the FutureGen Industrial Alliance, Inc. were directed by the Commission order approving the Agency's 2013 Procurement Plan. (See Docket No. 12-0544) However, DOE funding support for FutureGen 2.0 was suspended, and in early 2016, the project's development was ultimately terminated.

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

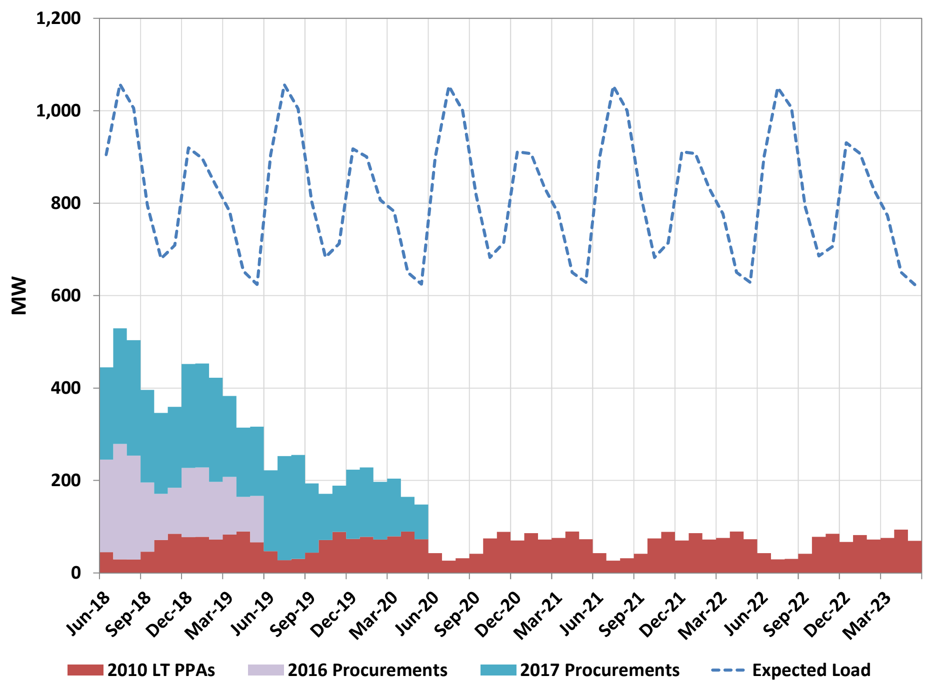
4.1 Ameren Illinois Resource Portfolio

Figure 4-1 shows the current supply gap in the Ameren Illinois supply portfolio for the five-year, June 2018 through May 2023, planning period, using the base case on-peak forecast described in Chapter 3.

Ameren Illinois' existing supply portfolio, including long-term renewable energy resource contracts, is not sufficient to cover the projected load for the 2018-2019 delivery year. Additional energy supply will be required for the entire 5-year planning period. Approximately 64% of the Ameren Illinois eligible load has switched to ARES suppliers. The Ameren Illinois base case scenario load forecast assumes that switching will be flat across the current planning horizon.

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

Figure 4-1: Ameren Illinois' On-Peak Supply Gap - June 2018-May 2023 Period - Base Case Load Forecast

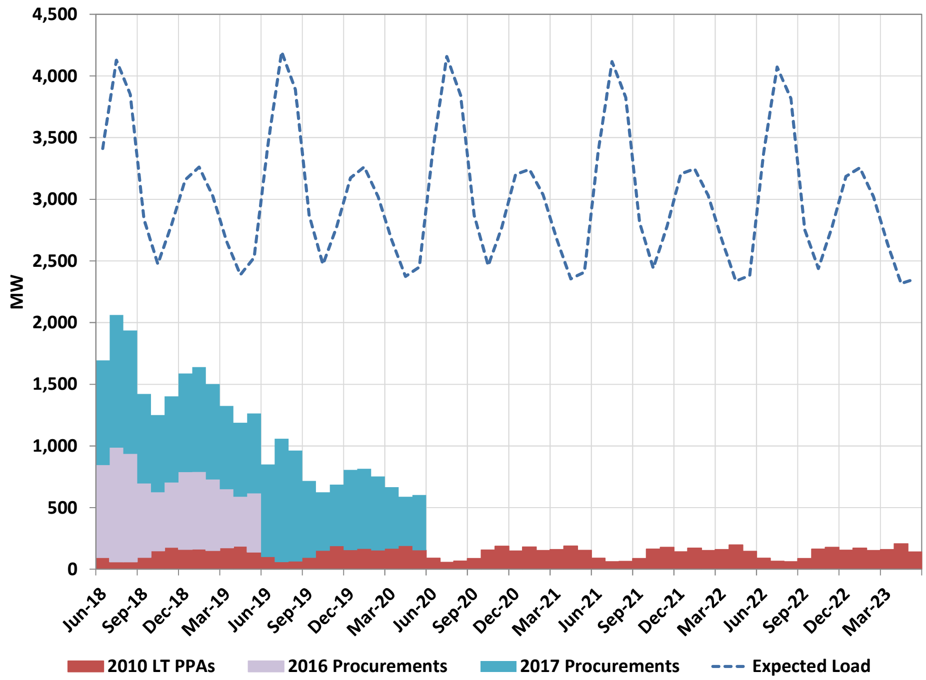


Under the base case load forecast scenario, the average supply gap for peak hours of the 2018-2019 delivery year is estimated to be 412 MW, the peak period average supply gap for the 2019-2020 delivery year is estimated to be 616 MW, and the average peak period supply gap for the 2020-2021 delivery year is estimated to be 758 MW. While the planning period is five years, the IPA's hedging strategy is focused on procuring electricity supplies for the immediate three delivery years.

4.2 ComEd Resource Portfolio

Figure 4-2 shows the current gap in the ComEd supply portfolio for the June 2018-May 2023 planning period, using the base case load on-peak forecast described in Chapter 3.

Figure 4-2: ComEd's On-Peak Supply Gap - June 2018-May 2023 period - Base Case Load Forecast



ComEd's current energy resources will not cover eligible retail customer load starting in June 2018. The average supply gap during peak hours for the 2018-2019 delivery year under the base case load forecast is estimated to be 1,521 MW. The average supply gap during peak hours for the 2019-2020 and 2020-2021 delivery years is estimated to be 2,289 MW and 2,901 MW respectively.

4.3 MidAmerican Resource Portfolio

MidAmerican has requested that the IPA procure electricity for the incremental load that is not forecasted to be supplied in Illinois by MidAmerican's Illinois jurisdictional generation. MidAmerican's existing eligible retail customer load is served by an allocation of generating capacity from MidAmerican's resources, which include its generating facilities located in Iowa ("Illinois Historical Resources").

In reviewing the load forecast and resource portfolio information supplied by MidAmerican for the 2018 Plan, the IPA notes that MidAmerican "dispatches" its Illinois Historical Resources whenever the expected cost to generate electricity is less than the expected cost of acquiring it in the market. In determining the amounts of block energy products to be procured for MidAmerican, the IPA treats the allocation of capacity and energy from MidAmerican's Illinois Historical Resources in a manner analogous to a series of standard energy blocks. This approach is consistent with the 2017 Procurement Plan approved by the Commission.

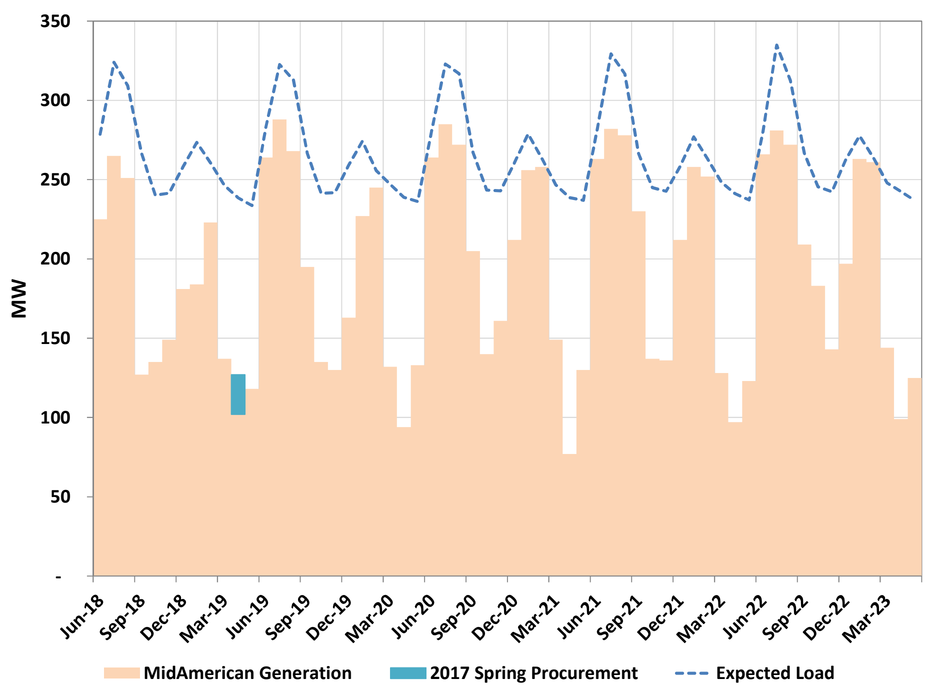
The IPA recognizes that in MidAmerican's case the amount of energy production available varies hour-to-hour, and it does not behave exactly the same as fixed energy blocks. For example, the amount of energy to be delivered under fixed energy blocks remains constant during the contract delivery period while MidAmerican's generation does not. According to the MidAmerican methodology submitted as part of the July forecast, the energy production by its Illinois Historical Generation fleet depends on the forecasted energy prices: the lower the forecast price, the lower the generation dispatch. Thus, the forecast supply gap for MidAmerican has uncertainty on both inputs to the estimate (load and supply uncertainty). However, one important aspect of MidAmerican's risk position is the positive correlation between the two major inputs, i.e., the hourly load and the hourly dispatch of the generation fleet. This positive correlation reduces the uncertainty of the differential to some degree because deviations in the load forecast will be largely negated (or offset) by the corresponding deviation in the generation dispatch.

The IPA believes that the methodology used with regards to MidAmerican's supply procurement is reasonable given this correlation and that the overall hedging levels and laddered procurement approach are consistent with the proposed approach for Ameren Illinois and ComEd. The IPA understands that the basic methodology adopted in the 2017 Procurement Plan and continued in this Plan has produced hedge volumes that successfully matched the supply/load balance for June and July, 2017. The IPA and MidAmerican will monitor the actual performance of this approach and will revisit it in future procurement plans, if warranted.

Due to current and anticipated MidAmerican generating unit retirements, MidAmerican will rely to a greater extent on the IPA procurements to make up the difference between generation allocated to serve its Illinois eligible retail customer load. MidAmerican's current forecasts include an allocation of approximately 49 MW from MidAmerican's 25 percent ownership in the Quad Cities nuclear generating Units 1 and 2 through the 5-year forecast period ending May 31, 2023. The Quad Cities units could be retired before the end of the current forecast period and potentially before the end of the current plan's 3-year procurement horizon.[95] MidAmerican would modify its generation forecast to incorporate the impact of these retirements on the projected supply gaps to be covered by the IPA procurements.

Figure 4-3 shows the current supply gap in the MidAmerican supply portfolio for the five-year planning period, using MidAmerican's base case on-peak load forecast. The average supply gap during peak hours for the 2018-2019 delivery year under the base case load forecast is estimated to be 87 MW. The average supply gap during peak hours for the 2019-2020 delivery year is 75 MW and for the 2020-2021 delivery year the supply gap is 66 MW.

Figure 4-3: MidAmerican's On-Peak Supply Gap - June 2017-May 2022 period - Base Case Load Forecast



95 See "Exelon Announces Early Retirement of Clinton and Quad Cities Nuclear Plants," June 2, 2016, http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement.

5 MISO and PJM Resource Adequacy Outlook and Uncertainty

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

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

- North American Electric Reliability Corporation ("NERC"), the entity certified by the Federal Energy Regulatory Commission ("FERC") to establish and enforce reliability standards with the goal of ensuring the reliability of the American bulk power system.
- Midcontinent Independent System Operator, Inc. ("MISO"), which operates the transmission grid in most of central and southern Illinois, serving Ameren Illinois and MidAmerican.
- PJM Interconnection, L.L.C. ("PJM"), which operates the transmission grid in Northern Illinois, serving ComEd.

From the review of these entities' most recent resource adequacy documentation, it is apparent that over the planning horizon PJM will maintain adequate resources to meet the collective needs of customers in those regions. MISO, on the other hand, could be short resources starting in the 2018-2019 timeframe if unconfirmed retirements in fact retire and thus are excluded from the supply mix.[96] If unconfirmed retirements do not retire and those resources remain in the supply mix, MISO could then be short of resources in the 2022-2023 timeframe if future capacity plans are not solidified by Load Serving Entities ("LSEs") and states, as explained later in this subsection.

5.1 Resource Adequacy Projections

In PJM, capacity is largely procured through PJM's capacity market, the Reliability Pricing Model ("RPM"), which was approved by FERC in December 2006. In 2015, PJM implemented changes to the RPM construct, which established a Capacity Performance product.[97] RPM is a forward capacity auction through which generators offer capacity to serve the obligations of load-serving entities. The primary capacity auctions, Base Residual Auctions ("BRAs"), are held each May, three years prior to the commitment period. In the RPM construct, the commitment period is referred to as a "Delivery Year". In this Plan, "Delivery Year" is also used in relation to all capacity and energy procurements.[98] In addition to the BRAs, up to three incremental auctions are held, at intervals of 20, 10, and 3 months prior to the Delivery Year. The 1st, 2nd, and 3rd Incremental Auctions are

[96] Unconfirmed retirements (per NERC) or low certainty resources (per MISO) are units that are potentially due to retire but have not made a public announcement about retirement. They may be available to serve MISO load but do not have any firm commitments to do so. The unconfirmed retirements are potentially due to a variety of regulatory and economically driven reasons. MISO does not include the capacity associated with unconfirmed retirements in their resource adequacy analysis. FERC on the other hand includes these resources in their base case, and then conducts a sensitivity analysis to test the impact on the reserve margin of excluding the resources. In MISO unconfirmed retirements are identified through the surveys which are conducted by MISO jointly with the Organization of MISO States ("OMS").

[97] On June 9, 2015, FERC accepted PJM's proposal to establish a new capacity product, a Capacity Performance Resource, on a phased-in basis, to ensure that PJM's capacity market provides adequate incentives for resource performance during emergency conditions (FERC Docket No. ER15-623 *et al.*, 151 FERC ¶ 61,208). Resources that are committed as capacity performance resources will be paid incentives to ensure that they deliver the promised energy and reserves when called upon in emergencies. Capacity Performance has been fully implemented for the 2018-2019 and 2019-2010 delivery years, with transitional capacity performance incremental auctions conducted for the 2016-2017 and 2017-2018 years to facilitate improved resource performance during those years by allowing a portion of capacity to be rebid as Capacity Performance Resources in a new procurement. Implementation of Capacity Performance has generally resulted in increased capacity clearing prices, in particular for the ComEd zone.

[98] A Delivery Year is June 1 through May 31 of the following year. The use of "Delivery Year" in this Plan also applies to the MISO RTO where the term "Planning Year" is normally used.

conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement.[99] A Conditional Incremental Auction may be conducted, if and when necessary, to secure commitments of additional capacity to address reliability criteria violations arising from the delay of a backbone transmission upgrade that was modeled in the BRA.

Just prior to the beginning of each Delivery Year, the Final Zonal Net Load Price, which is the price paid to LSEs for capacity procured as part of the RPM, is calculated. This price is determined based on the results of the BRA and subsequent incremental auctions for a given year. As the procurement of the majority of the capacity via the RPM is done during the BRA, there is little variation between the BRA clearing price (Preliminary Zonal Capacity Price) and the Final Zonal Net Load Price as shown in Figure 5-1. However, while Figure 5.1 shows little variation in the ComEd zone between the BRA clearing price and the Final Zonal Net Load Price for the Delivery Years through 2015-2016, Delivery Years 2016-2017 and 2017-2018 show a significant variation between the prices. This is because the Final Zonal Net Load Price for 2016-2017 and 2017-2018 includes the incremental costs of each year's transitional Capacity Performance Incremental Auction ("CPIA").[100] Figure 5.1 also shows higher BRA prices in the ComEd zone for Delivery Years 2018-2019, 2019-2020, and 2020-2021, relative to 2017-2018,[101] which may be attributable to any of the following:

- First, the transition to full implementation of the Capacity Performance product[102] beginning with the 2018-2019 BRA may have increased the incidence of maintenance and other costs required to be a Capacity Resource;[103]
- Second, tariff changes to right-shift PJM's Variable Resource Requirement curve, i.e. the RTO-wide and zonal demand curve for BRAs, were approved in FERC Docket No. ER14-2940 on November 28, 2014, and applied to the 2018-2019 BRA conducted in August 2015;[104]
- Third, transmission upgrades in the MISO territory may have reduced the capacity import capability into the ComEd zone of PJM for the 2018-2019 and subsequent delivery years;[105]

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[99] Deferred short-term resource procurement only applies prior to the 2018-2019 Delivery Years.

[100] The BRA clearing price (Preliminary Zonal Capacity Price) for the ComEd zone for 2016-2017 was $59.37/MW-Day. 60% of resources procured in the 2016-2017 CPIA were Capacity Performance Resources. The preliminary incremental cost component for the 2016-2017 CPIA was $38.17/MW-Day and the final incremental cost component was $39.86/MW-Day. After factoring in the adjustments to account for the results of the 1st, 2nd, and 3rd incremental auctions, the Final Zonal Net Load Price was $101.62/MW-Day, a 71% increase from the BRA clearing price. 70% of resources procured in the 2017-2018 CPIA were Capacity Performance Resources. The BRA clearing price for the ComEd zone for 2017-2018 was $119.81/MW-Day. The preliminary incremental cost component for the 2017-2018 CPIA was $27.69/MW-Day and the final incremental cost component was $29.97. After factoring in the adjustments to account for the results of the 1st, 2nd, and 3rd incremental auctions, the Final Zonal Net Load Price for 2017-2018 was $153.61/MW-Day, a 28% increase from the BRA clearing price.

[101] Starting in 2017-2018, and subsequently in 2018-2019, 2019-2020, and 2020-2021, the ComEd Zone was modeled as a separate Locational Deliverability Area ("LDA"). See PJM, "2017/2018 RPM Base Residual Auction Planning Period Parameters," http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2017-2018-rpm-bra-planning-parameters-report.ashx, at 3 ("The ComEd, BGE and PPL LDAs will be modeled in a BRA for the first time."). In the latter three of those years, the ComEd zone was a constrained LDA in the BRA results, i.e. the ComEd zonal clearing price separated from the rest of the PJM RTO.

[102] As discussed above, for 2016-2017, around 60 percent of PJM's reliability requirement was procured as Capacity Performance Resources, and for 2017-2018, around 70 percent was procured as Capacity Performance Resources. In 2018-2019 and 2019-2020, 84% of resources procured were Capacity Performance Resources. In the 2020-2021 BRA, 100% of resources procured were Capacity Performance Resources. See, e.g., PJM, "Overview of Capacity Performance," http://www.pjm.com/~/media/committees-groups/task-forces/scrstf/20160404/20160404-item-04-capacity-performance-overview.ashx; PJM, "2020/2021 RPM Base Residual Auction Results," http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx, at 1.

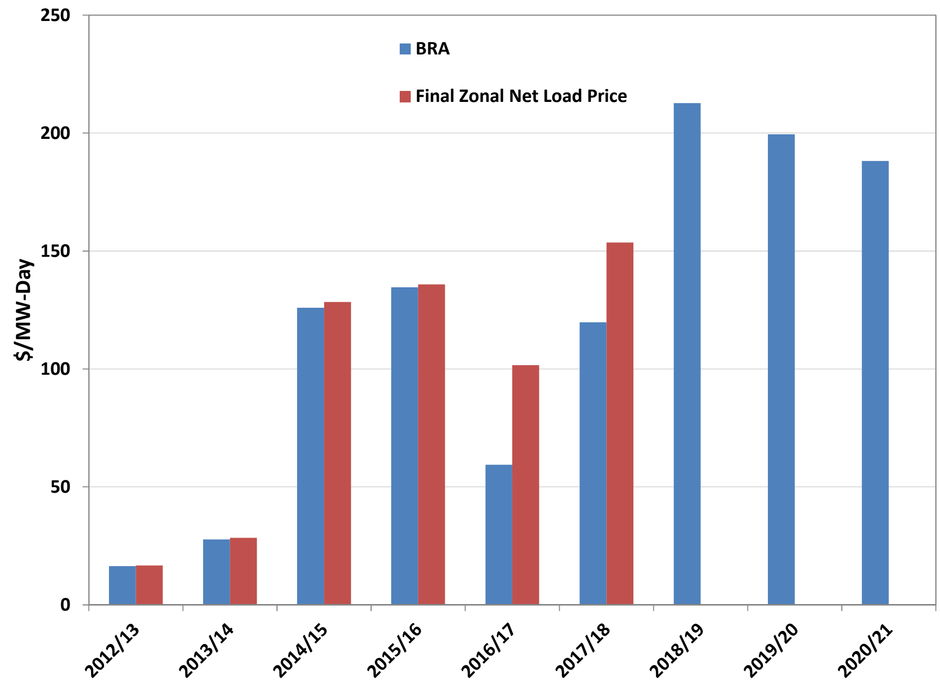
[103] PJM, "2018/2019 RPM Base Residual Auction Results," http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2018-2019-base-residual-auction-report.ashx, at 29.

[104] See PJM tariff filing, FERC Docket No. ER14-2940, September 25, 2014, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13643607, at 21; Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing, 149 FERC ¶ 61,183, FERC Docket No. ER14-2940, November 28, 2014, at 17.

[105] Monitoring Analytics, "Analysis of the 2018/2019 RPM Base Residual Auction (Revised)," July 5, 2016, http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf, at 41.

- Fourth, lower energy market prices may have lowered energy market revenues for generators in the ComEd zone, leading to higher capacity market offers.[106]

Figure 5-1: PJM RPM (ComEd Zone) Capacity Price for Delivery Years 2012-2013 to 2020-2021[107]

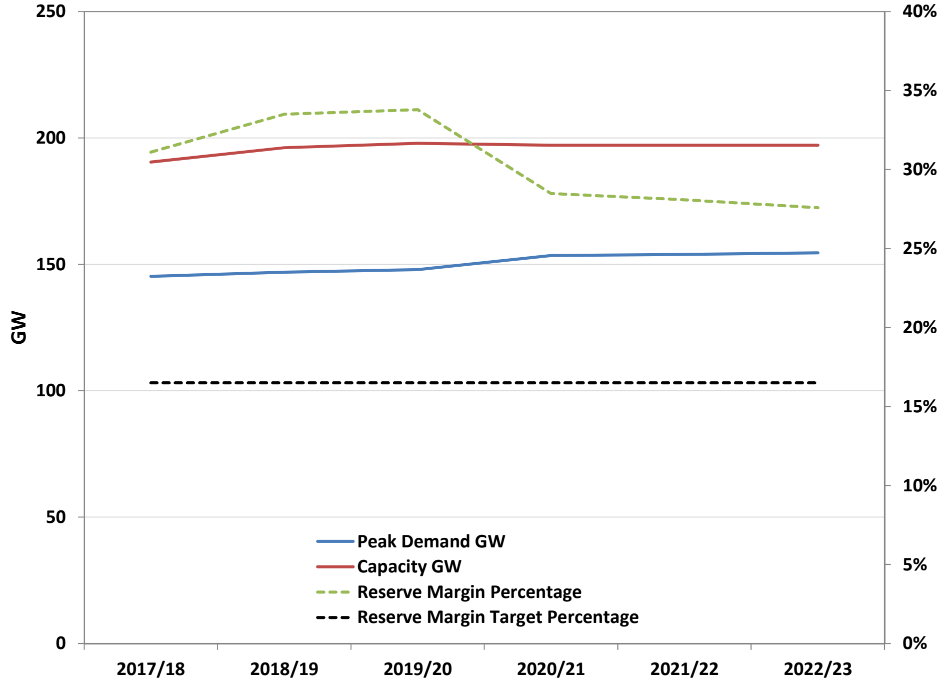


As shown in Figure 5-2, PJM is projected to have sufficient resources to meet load plus required reserve margins for the Delivery Years 2017-2018 to 2022-2023, with projected reserve margins above the 16.5% target reserve margin. For the 2017-2018 Delivery Year, the reserve margin is approximately 15% above the target reserve margin, peaks at 17.3% above the target reserve margin in 2019-2020 and then drops to 11% above the target reserve margin for the 2022-2023 Delivery Year.

[106] PJM, "2018/2019 RPM Base Residual Auction Results," http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2018-2019-base-residual-auction-report.ashx, at 29.

[107] 2017-2018 is the latest Delivery Year for which the Final Zonal Net Load Price has been calculated. It will be calculated for future Delivery Years as the start of the year approaches.

Figure 5-2: PJM NERC Projected Capacity Supply and Demand for Delivery Years 2017-2018 to 2022-2023



Source: NERC 2016 Long Term Reliability Assessment ("NERC 2016 LTRA")

The MISO Resource Adequacy Construct, specified in Module E-1 of its Tariff,[108] contains the Resource Adequacy Requirements ("RAR") that require LSEs in the MISO region to procure sufficient Planning Resources to meet their anticipated peak demand, plus a planning reserve margin ("PRM")[109] for the Delivery Year. An LSE's total resource adequacy obligation is referred to as the Planning Reserve Margin Requirement ("PRMR"). On June 11, 2012 FERC conditionally approved MISO's proposal to enhance its RAR by establishing an annual construct based upon meeting reliability requirements on a locational basis, including the use of an annual Planning Resource Auction ("PRA"). MISO implemented the Module E-1 RAR, which became fully effective on June 1, 2013. More details on the locational construct of the MISO RAR and MISO's are provided in Section 5.2.

As shown in Figure 5-3, based upon the NERC 2016 LTRA, on a region-wide basis MISO is expected to have sufficient resources to meet load plus required reserve margin for the Delivery Years 2017-2018 to 2021-2022 with projected reserve margins above the 15.2% target reserve margin. However, in 2022-2023 NERC estimates that MISO is projected to have insufficient resources to meet load plus required reserve margin. For the 2017-2018 Delivery Year, the reserve margin is approximately 3% above the target reserve margin, dropping to approximately 0.8% above the target reserve margin for the 2021-2022 Delivery Year. Figure 5-3 also shows MISO's analysis presented in the 2016 MISO Transmission Expansion Planning ("MTEP") report, which addresses resource adequacy. The MISO assessment forecasts the reserve margin dropping below the target reserve margin as early as 2018-2019. MISO and NERC explain that the difference is primarily due to how each assessment accounts for unconfirmed retirements in the supply mix.[110] As noted above, MISO does not include the capacity associated with unconfirmed retirements in its resource adequacy analysis. NERC on the other hand includes the capacity associated with these resources in its base case. NERC conducted a

[108] Under the MISO Tariff Module E-2 outlines, the RAR compliance obligations for a new LSE during a transitional period until the new LSE's assets can be included in the full annual RAR process in accordance with Module E-1.

[109] The PRM (or target reserve margin) is determined by MISO, based on a Loss of Load Expectation ("LOLE") of one day in ten years, or state-specific standards. If a state regulatory body establishes a minimum PRM for the LSEs under its jurisdiction, then that state-set PRM would be adopted by MISO for jurisdictional LSEs in such state.

[110] Due to the uncertain outcome of pending regulatory requirements, up to 3.2 GW of capacity (1.8 GW in 2017-2018 increasing to 3.2 GW in 2022-2023) are categorized as unconfirmed retirements.

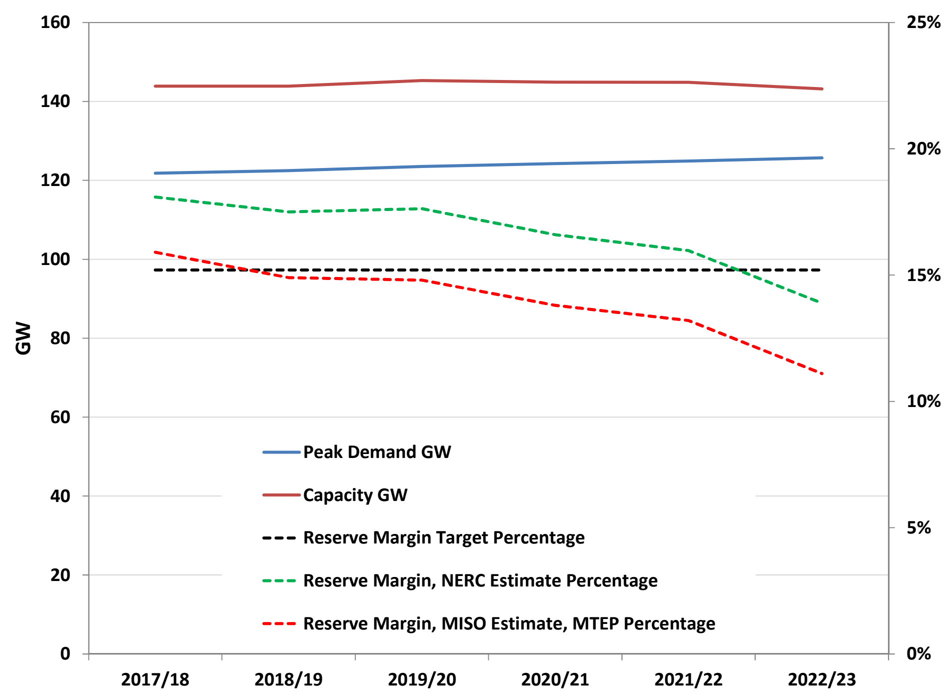
sensitivity analysis to test the impact on the reserve margin of excluding the resources. With the unconfirmed retirements excluded from the resource mix, NERC's analysis produces the same results as MISO's, with the reserve margin dropping below the target reserve margin in 2018-2019. On the flip side, if MISO had included the unconfirmed retirements in its supply mix, it would get a similar result to NERC.

Both NERC and MISO draw the same conclusions from the long-term resource assessments which can be summarized as follows:

- MISO projects that each zone within the MISO footprint will have sufficient resources within its boundaries to meet the respective local clearing requirement.
- Several zones are short against their total zonal requirement, when only resources within their boundaries or contracted to serve their load are considered. However, those zones have sufficient import capability, and MISO has sufficient surplus capacity in other zones which can be imported to meet the zonal requirements of the zones which are short. Surplus generating capacity for zonal transfers within MISO could become scarce in later years if no action is taken in the interim by MISO LSEs.
- All zones within MISO are sufficient from a resource adequacy point of view in the near term when available capacity and transfer limitations are considered. Regional shortages in later years may be rectified, and MISO is engaged with stakeholders in a number of resource adequacy reforms to help rectify these out-year shortages.

The LTRA results represent a point-in-time forecast, and the NERC assessment notes that MISO expects the projected reserve margin shortfalls to change significantly as future capacity plans are solidified by LSEs and states. For example, there are enough Tier 2 and Tier 3 resources to mitigate any long-term resource shortfalls.[111]

Figure 5-3: MISO NERC Projected Capacity Supply and Demand for the Delivery Years 2017-2018 to 2022-2023



[111] Tier 2 resources are planned resource additions that are active in the MISO Queue. Tier 3 resources are planned resource additions that are currently not in the MISO queue.

Source: NERC 2016 Long Term Reliability Assessment, MISO 2016 MTEP Book 2 Resource Adequacy

The RTO-based reliability assessments examined in this Section are important measures of resource reliability in Illinois because the Illinois electric grid operates within the control of these two RTOs. The IPA concludes that it does not need to include any extraordinary measures in the 2018 Procurement Plan to assure reliability over the planning horizon.

5.2 MISO Resource Adequacy Update

Because changes resulting from the evolution of MISO's resource adequacy construct may have a significant impact on the IPA's capacity procurement strategy, it is important for the IPA and stakeholders to maintain an informed approach to manage the procurement of capacity. In this section of the Plan, the IPA provides an update of MISO's unsuccessful proposal to implement changes to its resource adequacy construct applicable to states with retail choice. Also, in this section the IPA reports on the results of MISO's PRA for the 2017-2018 Delivery Year, and concludes with a proposal to refine the capacity procurement strategy for Ameren Illinois.

5.2.1 Update on Competitive Retail Solution

The 2017 Procurement Plan reported that MISO was proposing a competitive retail solution ("CRS") to address resource adequacy for Illinois and Michigan, the states within MISO that have competitive retail choice. On November 1, 2016, MISO filed its CRS proposal to establish a three-year forward capacity auction ("Forward Auction") to complement the existing PRA ("Prompt Auction") with FERC.[112] On February 2, 2017, FERC issued an order rejecting the proposal noting that the proposal had not been shown to be just and reasonable, and not unduly discriminatory or preferential.

FERC's main reasoning for its rejection was based on the bifurcated nature of the proposal.

> *"The proposed Forward Auction would apply only to load in Competitive Retail Areas, which accounts for only a small (less than 10 percent) portion of the total load within MISO, and would occur more than three years prior to the Prompt Auction, thereby bifurcating the MISO capacity market. As discussed below, this bifurcated approach could have uncertain, and potentially adverse, impacts on price formation in both the Forward Auction and the Prompt Auction."*[113]

As proposed by MISO, the Forward Auction would occur more than three years prior to the Prompt Auction. The proposal therefore bifurcated the MISO capacity market into two distinct market clearing mechanisms held at different points in time. In FERC's view, single market-wide clearing processes (i.e., the current practice in all FERC-jurisdictional wholesale capacity markets) are typically more efficient than bifurcated clearing processes. FERC was therefore convinced that MISO's proposed construct would likely result in clearing prices and capacity resource selections that lack the desirable properties associated with a single market-wide clearing process, and could have uncertain, and potentially adverse, impacts on price formation in both the Forward Auction and the Prompt Auction.[114]

In further making its case for rejection, FERC noted that due to the bifurcated structure, which requires owners of supply resources to decide whether to offer into the Forward Auction more than three years prior to the Prompt Auction for the same Delivery Year, it was not clear the extent to which these supply resources will offer into the Forward Auction or how this uncertainty will impact clearing prices in the Forward and the Prompt Auction. FERC argued that such unpredictable and variable supply participation could result in significant and unnecessary price volatility in both the Forward Auction and the Prompt Auction.[115]

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[112] MISO tariff filing, "Proposed Competitive Retail Solution in new Module E-3 and corresponding revisions to existing Tariff sections in Modules A, D, and E-1," FERC Docket No. ER17-284-000, November 1, 2016, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14389956.

[113] Order Rejecting Tariff Filing, 158 FERC ¶ 61,128, FERC Docket No. ER17-284-000, February 2, 2017, at 2.

[114] See id. at 3.

[115] See id. at 3.

FERC also found that MISO had not adequately explained or provided clear Tariff language to demonstrate that the CRS Proposal would reasonably allocate transmission capability across capacity zones and across sub-regions in the MISO footprint between the Forward Auction and the Prompt Auction, noting that in past Prompt Auctions, transmission capability constraints between Zones and sub-regions have caused substantial price separation, as recently evidenced in the 2016-2017 PRA. Consequently, the allocation of Zonal and sub-regional transmission capability between the Forward Auction and the Prompt Auction could significantly impact clearing prices in both the Forward Auction and the Prompt Auction. For example, allocating an insufficient amount of transmission capability to the Prompt Auction could prevent load serving entities in the Prompt Auction from procuring lower-cost capacity.[116]

MISO did not seek rehearing of FERC's order.

5.2.2 2017-2018 PRA Results[117]

For the 2017-2018 Delivery Year, all MISO zones cleared in the PRA at a single price of $1.50/MW-Day. This was a significant drop in price relative to the prior year when Zone 1 cleared at $19.72/MW-Day, Zones 2-7 cleared at $72/MW-Day, and Zones 8-10 cleared at $2.99/MW-Day.

MISO reports that the 2017-2018 lower price was a result of a net regional increase in supply (more offers of demand response, energy efficiency, solar and wind resources than the prior year) and lower demand in the Midwest.[118] A significant change that contributed to the drop in price was the increase in the Sub-Regional Export Constraint ("SREC") in the South to Midwest direction. The SREC increased from 876 MW to 1,500 MW, an increase of over 70%.[119] The increase in the SREC limit, abundant regional supply and modest load growth expectations could continue to suppress capacity prices resulting from the PRA in the near future.

The IPA is aware that MISO is considering certain tariff changes to the calculation of the Capacity Import Limit and Local Clearing Requirement for each of its Local Resource Zones, which could have the effect of raising PRA clearing prices over the long term for Zone 4 by limiting the import of capacity from outside Illinois. MISO states that it intends to file these changes at FERC by March 2018, with implementation in the 2019/2020 PRA if ultimately approved.[120]

5.2.3 Refinement of Capacity Procurement Strategy for Ameren Illinois

As outlined in Section 7.2, the IPA recommends a refinement of the capacity procurement strategy for Ameren Illinois eligible retail customer load, which is, for the 2019-2020 Delivery Year only, to procure 25% of its capacity requirements in bilateral transactions in the Spring of 2018, 25% in the Fall of 2018, and the remaining balance through the MISO PRA in April of 2019.

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116 See id. at 4.

117 This summary includes only those developments which had taken place prior to the date on which the IPA filed its 2018 Plan, as only those developments provided the record against which the IPA's proposed capacity procurement strategy was approved. To the extent any developments subsequent to September 2017 may impact the Agency's future proposals regarding capacity procurement strategy, those will be discussed in future annual power procurement plans.

118 See MISO press release at: https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/MISOclearsfifthannualPlanningResourceAuction.aspx.

119 MISO, "2017/2018 Planning Resource Auction Results," April 14, 2017, https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/Planning%20Year%2017-18/2017-2018%20Planning%20Resource%20Adequacy%20Results.pdf, at 5.

120 MISO's indicative figures show that the proposed rule changes could increase the Local Clearing Requirement for the Illinois zone (Zone 4) by 35%. See "PRA, CIL, CEL, and LCR Alignment," MISO Presentation to Loss of Load Expectation Working Group, August 2017, https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2017/20170808/20170808%20LOLEWG%20Item%2004%20PRA%20CIL%20CEL%20LCR%20Alignment.pdf, at 9. See also Minutes of September 13, 2017 MISO Resource Adequacy Subcommittee, https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RASC/2017/20171011/20171011%20RASC%20Item%2001c%20Minutes%2020170913.pdf, at 5 ("MISO is now targeting a firm filing date no later than March 2018 [...] and implemented by the 2019/20 [delivery year].").

For the 2018-2019 Delivery Year, the approved capacity procurement strategy for Ameren Illinois called for the procurement of 75% of its requirements in IPA administered procurements, including 25% in the Fall of 2016 and 50% in the Fall of 2017, with the remaining balance through the MISO PRA in April of 2018. For the 2019-2020 and future delivery years, the IPA, in its 2017 Plan, deferred the decision until this 2018 Plan was filed.

As noted earlier, the MISO CRS Proposal was rejected by FERC in February 2017, and the PRA remains as the only capacity auction for all load in MISO. While there has been significant volatility in the results of the MISO PRA over recent years, the clearing price has declined in the last two auctions with the corresponding benefit to load in the short term. The IPA is concerned that uncertainty around potential coal plant retirements, ongoing changes to the rules at MISO and FERC, and other potential legislative and regulatory changes represent significant uncertainty in the capacity market resulting in PRA price volatility. The IPA is also concerned that observed and expected PRA price volatility results in significant risk premiums in forward capacity prices.

In light of the current situation, the IPA plans to take a balanced approach to risk management by proposing that 50% of the Ameren Illinois capacity requirements be hedged in the near-term forward market through IPA administered Requests for Proposals ("RFPs") in a laddered fashion as indicated above and shown in Table 5-1, and that the remaining balance be procured in the MISO PRA (i.e, open position). This refinement in hedging strategy is prudent and should result in "the lowest total cost over time, taking into account any benefits of price stability"[121] for Ameren Illinois' eligible retail customers. The IPA plans to continue monitoring the capacity markets in MISO and associated regulatory developments and, accordingly, make adjustments to the recommended strategy in future Procurement Plans.

[121] 220 ILCS 5/16-111.5(d)(4).

6 Managing Supply Risks

The Illinois Power Agency Act lists the priorities applicable to the IPA's portfolio design, which are "to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[122]

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

> *an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the following factors: contract terms, time frames for securing products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment; the proposed procurement plan shall also identify alternatives for those portfolio measures that are identified as having significant price risk.*[123]

This Chapter discusses and assesses risk in the supply portfolio, as well as tools and strategies for mitigating them. Developing a risk management strategy requires knowledge of the risk factors associated with energy procurement and delivery, and of the tools available to manage those risks. Section 6.1 describes the relevant risk factors. Sections 6.2 and 6.3 describe the tools for managing supply risk and the types of contracts and hedges that can be used to manage supply risk. Those products provide the basis for building a supply portfolio. Section 6.4 addresses the complementary issue of reducing or re-balancing the supply portfolio when needed, and the legal, regulatory and policy issues that may arise if utilities have to do so by selling previously purchased hedges over-the-counter. Section 6.5 provides a historical summary of the Ameren Illinois, ComEd, and MidAmerican Purchased Electricity Adjustment ("PEA") rates as a guide to the historical impact of risk factors.[124] This section also addresses the changes in MidAmerican pricing that reflect the costs of participating in the IPA procurements. Section 6.6 discusses the IPA's historical approach to risk and portfolio management. Finally, Section 6.7 addresses the role of demand response programs in risk management.

Section 6.6.2 addresses the cost and uncertainty impacts of supply risk factors. Risk is often taken to mean the amount by which costs differ from initial estimates. Utility energy pricing in Illinois for Ameren Illinois and ComEd customers is based on estimates and cost differences are trued up after the fact through the PEA. Prior to the 2016-2017 delivery year, MidAmerican provided power and energy to its eligible Illinois customers only from MidAmerican owned generation, with energy costs for MidAmerican customers in Illinois recovered through base rates regulated by the Illinois Commerce Commission. Starting with the 2016-2017 delivery year, MidAmerican pricing for its Illinois customers also included the cost of energy obtained in IPA procurements, which is reflected through a cost recovery process similar to what is used by Ameren Illinois and ComEd

6.1 Risks

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

6.1.1 Volume Uncertainty and Price Risk

The accuracy of load forecasts directly impacts volume uncertainty. Accurate customer consumption profiles, load growth projections, and weather forecasts impact both the total energy requirement and the shape of the

[122] 20 ILCS 3855/1-20(a)(1).

[123] 220 ILCS 5/16-111.5(b)(3)(vi).

[124] See 220 ILCS 5/16-111.5(l). This policy is manifest through riders filed by each utility – ComEd's Rider PE (Purchased Electricity), and Ameren Illinois' Rider PER (Purchased Electricity Recovery).

load curve. Chapter 3 describes the load forecasting processes utilized by Ameren Illinois, ComEd and MidAmerican. The risk factors that determine overall volume risk include: changes in customer load profiles and usage patterns, the uncertainties associated with load growth and short-term weather fluctuations, technology changes such as smart meters and behind the meter generation and storage, and customer switching. For the Illinois utilities, a key factor in volume risk is the uncertainty associated with customer switching which directly impacts the results of the utilities' load forecasts. The opportunities for potentially eligible retail customers to take service from ARES or through municipal aggregation resulted in substantial portions of the potentially eligible retail customer load switching away from the utilities for non-utility retail contracts that ran through the 2014-2015 procurement year. More recently, the number of residential customers taking ARES supply has declined. The primary uncertainty surrounding customer switching going forward appears to be the potential for additional retail load migration back to the utilities.

Customer switching decisions are influenced by the difference between utility and third party pricing. Customer switching behavior impacts volume risk and, in turn, variability in utility customer volumes impacts price risks. The IPA's historical procurement strategy involves buying power in a "laddered" approach with a large fraction of the power to serve retail customers in the delivery year procured through forward purchases in the two years prior to the delivery year. In a period of rising prices, those forward purchases are likely to be priced below market. Therefore, the blended price of utility supply may be less than the current price of an ARES offer, even an offer through municipal aggregation. This price difference can result in increased customer migration back to the utility. The reverse can occur as well; higher utility supply costs relative to alternatives through ARES suppliers or municipal aggregation can result in eligible retail customers migrating away from the utilities.

6.1.2 Residual Supply Risk

Hedging imperfection can contribute to supply risks through mismatches in procurement supply shape, supply delivery points and customer load locations, or the intermittent nature of renewable energy sources. The standard on-peak and off-peak block energy products procured by the IPA do not reflect the variation in hourly loads. These products provide constant volume and prices across a fixed number of hours while hourly prices as well as load vary across the day and within each of the peak and off-peak periods. Because of this variation, if the average peak and off-peak monthly load is perfectly hedged, the actual hourly load will still be imperfectly hedged. Residual supply risk will remain since the actual load will vary between being greater than or less than the average. The cost to cover the intermittent output from renewable resources in the supply portfolio may not be hedgeable and therefore can result in residual supply risk as well.

6.1.3 Basis Differential Risk

Basis differential risk relates to the uncertainty that the price of energy delivered at a given delivery point is not the same as the settlement price at the point(s) or zone where the energy is ultimately consumed. Locational mismatches are generally not a risk for the IPA procurements since the delivery points for the hedge contracts are the LSE's load zone.

6.2 Tools for Managing Supply Risk

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

Following the enactment of the Electric Service Customer Choice and Rate Relief Law (Public Act 90-0561) in 1997, ComEd and Ameren Illinois divested their generating plants to unregulated affiliates or third parties. They have no contracts for unit-specific physical delivery, other than certain Qualifying Facilities (as designated under the federal Public Utilities Regulatory Practices Act) contracts. As the utilities do not purchase and take title to electricity, the utilities' supply positions, other than RTO spot energy, are exclusively price hedges. MidAmerican has retained the resources that serve its Illinois customers; most of these resources are located outside of Illinois. MidAmerican allocates a portion of the capacity and energy from specified resources under its control for its Illinois eligible retail customers. Prior to the 2016 Plan procurements, the allocated capacity and energy from MidAmerican owned resources were sufficient to meet the needs of MidAmerican's Illinois eligible retail customers. Current and planned retirements among these resources are reducing the capacity available for allocation to MidAmerican's Illinois customers. As a result, MidAmerican requested that the IPA procure the portion of energy and capacity that is not forecast to be met by the Illinois-allocated MidAmerican resources. Following the approach started for the 2016 Plan and continued under the 2017 Plan, with the 2018 Plan, the IPA will procure the net energy requirements between MidAmerican's eligible retail customer load and the MidAmerican controlled generation allocated to its Illinois customers. Likewise, the portion of MidAmerican's capacity requirements for eligible retail customers in Illinois not covered by MidAmerican's owned resources will be procured through the MISO PRA.

Physical electricity supply and load balancing for ComEd, Ameren Illinois, and MidAmerican are coordinated by the respective RTOs (PJM for ComEd and MISO for Ameren Illinois and MidAmerican). ComEd, Ameren Illinois, and MidAmerican are considered to be LSEs by the RTOs. Each RTO provides day-ahead and real-time electricity markets and clearing prices. The generators supply their energy to the RTO, and the RTO delivers energy to LSEs and customers. The RTO ensures the physical delivery of power. The cost of managing this delivery, including the cost of managing reliability risks, is passed on to the LSEs financially. The risks faced by LSEs in supplying energy to customers are mostly financial. The LSEs still need to manage certain operational risks such as scheduling and settlement. There are other, non-financial risks associated with electricity retailing, such as customer billing or accounts receivable risks, but those are not associated with the supply portfolio.

Each RTO charges a uniform day-ahead price for all energy scheduled to be delivered in a given hour and delivery zone. To the extent that real-time demand differs from the day-ahead schedule, load is balanced by the RTO at a real-time price: if demand exceeds the day-ahead schedule, then the LSEs pay the real-time price; and if demand is less than the day-ahead schedule, the LSEs are credited with the real-time price. Both the day-ahead and the real-time prices are referred to as Locational Marginal Prices ("LMPs") because they depend on the delivery location or zone.

6.3 Types of Supply Hedges

The 2014 Procurement Plan contained a detailed description of a number of different types of supply hedges, which are listed below. One point made in that Plan is that hedges available in the market are not perfect; the risks listed in Section 6.1 cannot all be hedged away except perhaps through a specially tailored "full requirements" hedge contract, whose price premium may not be acceptable in return for that degree of risk reduction.[125]

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

Unit-Specific Hedges

Unit-specific hedges are tied to the output of a specific generating unit which can depend on how the unit is dispatched, including contracts that fall into the following categories:

- As-available
- Baseload
- Dispatchable

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

Unit-Independent Hedges

Other energy supply hedges are available that are not dependent on the operation of a specific generating unit including:

- Standard forward hedges (block contracts)
- Shaped forward hedges
- Futures contracts
- Options
- Full requirements hedges

6.3.1 Suitability of Supply Hedges

Not all of the types of hedges listed in Section 6.3 are suitable for use in this Procurement Plan, and not all may be readily available in electricity markets.[126] Illinois law requires that "any procurement occurring in accordance with this plan shall be competitively bid through a request for proposals process," provides a set of requirements that the procurement process must satisfy, and mandates that the results be accepted by the ICC.[127] Among the specific requirements, the Procurement Administrator must be able to develop a market-based price benchmark for the process; the bidding must be competitive; and the ICC's Procurement Monitor is required to report on bidder behavior.[128] The level of bidding competitiveness can be gauged by the breadth of participation by bidders in the procurement.

Hedges most suitable for use by the Agency are those standardized products that are well-understood, and preferably widely-traded. If a product has liquid trading markets, or is similar to other products with liquid markets, a bidder can control its risk exposure. Availability of information on current prices and the price history of similar products help bidders provide more competitive pricing, and help the Procurement Administrator produce a realistic benchmark. Prior to its 2014 Procurement Plan, the IPA had generally restricted its hedging to the use of standard forward hedges in 50 MW increments. The IPA began using 25 MW increments and a second, fall procurement with the 2014 Plan. The Agency's recommended plans have been stated in terms of monthly contracts, although procurement events have met some of these needs with multi-month contracts.

The IPA has in the past purchased energy products that are not typically traded, such as the long-term PPAs with new build renewable generation that were authorized in the 2010 Procurement Plan. As noted in Section 2, these products still must be standardized in such a way that the winning bidders may be selected based on price alone, and the price is subject to a market-based benchmark. As discussed in Chapter 2, while the ICC clarified its understanding of the definition of "standard wholesale product" in its approval of the 2014 and 2015 Procurement Plans, the IPA's authority to procure other products, including shaped forward contracts and option contracts, could be subject to future litigation. Markets for products that are specifically designed for the IPA's requirements, such as full requirements contracts or over-the-counter options, will likely have limited transparency. The IPA's procurement structure requires a benchmarking and approval process and may not be compatible with such a low level of transparency.

Quoted prices for futures contracts at the PJM Northern Illinois Hub and the MISO Illinois Hub provide reasonable indications of the future prices anticipated by the market, making such contracts easier to benchmark. The markets for long-dated (i.e., further in the future) contracts are generally less liquid than the

[126] There has been substantial debate in the approval of prior Procurement Plans related to whether a full requirements approach is a more suitable approach for eligible retail customers. In approving the 2015 Plan and rejecting the Illinois Competitive Energy Association's full requirements procurement proposal as "not supported by the record," the Commission stated that it "wishe[d] to make clear that it is not inclined to consider future years' full requirements procurement proposals absent new arguments supported by an analysis quantifying benefits to eligible retail customers." Docket No. 14-0588, Final Order dated December 17, 2014 at 114. Since that decision, the IPA has not been made aware of any new arguments in favor of full requirements (let alone new arguments supported by analyses quantifying benefits to eligible retail customers), and notes the continued success of its procurement approach in producing highly competitive service rates for Ameren Illinois, MidAmerican, and ComEd eligible retail customers.

[127] 220 ILCS 5/16-111.5(b), (e), (f).

[128] 220 ILCS 5/16-111.5(f).

markets for near term contracts, however. The Agency would need to obtain competitive pricing on such contracts if it were to incorporate them in its portfolio. However, it would be difficult or impossible to conduct the statutory RFP process for exchange-traded futures contracts: setting a price through an RFP process structured per legislative mandates is incompatible with price-setting either in an open outcry auction or by a market-maker. It is also unclear how the margin requirements would fit within the current regulatory framework, if price movements require the utility to post margin many months in advance of delivery. The same concerns are even more applicable to options contracts.

6.3.2 Options as a Hedge on Load Variability

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

Options can be perceived as attractive tools to hedge against customer migration and other forms of load fluctuations. According to option pricing theory, options are not any more useful for hedging price risk than are forward contracts unless one is exposed to other risks that correlate with and enhance price risk (for example, loss of load accompanied with declining prices). In theory, option prices are determined by the value of the option as a price hedge. If an option had additional value as a hedge against load migration risk, some might consider options to be a bargain. It turns out that options are expensive when used as hedges for load migration risk. This is because if a call option on 1 MW of load has a price V, then that should be its value as a price hedge. If the 1 MW is not currently served by the utility, but may return with some probability P, then the value of this option should be only P times V which is less than its price. In other words, the value of the option as a hedge against load migration risk is less than its value as a price hedge. But it is the value as a price hedge that determines the option's price.

There are also other costs and logistical obstacles to using options:

- A large part of the volume of options on the market is traded on exchanges. They have a particular advantage in that the trading exchange bears the counterparty default risk. However, the Agency's structured procurement process prevents the Agency from buying options on the exchanges.
- Option contracts can be relatively illiquid, making it more difficult to assure fair pricing. If options purchased through the IPA procurement process required an affirmative exercise decision, which most likely they would, the utilities would seek regulatory comfort on their exercise decision-making before agreeing to use options. For example, if an exercise decision were dependent on the utility's load forecast or view of municipal aggregation, the utility would want to be able to show it had acted prudently. If the utility exercised a put option, to sell the underlying hedge, it would want to be sure that decision did not make it a wholesale market participant for purposes of FERC Order 717. If the option exercise was purely financial and automatic—resulting only in a cash payment from the option holder—these concerns might not be as important, but counterparty credit would be an issue.
- The use of options is subject to regulations under the Dodd-Frank Act of 2010 (specifically Title VII). Under this act, the trading of options (and other swaps) would be reported to a central database for clearing purposes. Trade details (price, volumes, time stamped trade confirmations, and complete audit trails) would need to be reported. In addition, trade records must be kept for 5 years after the termination of trade (either through exercise or expiration), and must be made available within five business days of request. This would add to either the purchase cost or the ownership cost of options.

6.4 Tools for Managing Surpluses and Portfolio Rebalancing

The Illinois Power Agency Act specifies that the Procurement Plan "shall include … the criteria for portfolio re-balancing in the event of significant shifts in load."[129] It is therefore appropriate to consider what tools are available to conduct such rebalancing, keeping in mind that the utilities, not the Agency, are the owners of the forward hedges and that selling of excess supply in the forward markets may have unintended cost and accounting consequences.

- To date, the only rebalancing of hedge portfolios prior to the delivery date has been the curtailment of long-term renewable contracts due to budget restrictions. Spending on these contracts was subject to a limit related to a statutorily-mandated rate impact cap calculated based on eligible retail customer load, making the budget available for payment under those contracts subject to fluctuation due to load migration away from (and back to) utility supply.[130]
- Sales of excess supply by the utilities via a reverse RFP to rebalance their supply portfolio may create a de facto "wholesale marketing function" within the utilities. The employees involved in wholesale marketing activities would be subject to the separation of functions in accordance with FERC Order 717.[131]
- To date, the utilities have scheduled excess supply in their portfolios, or made up supply deficits in the RTOs' day-ahead markets with residual balancing occurring in the RTOs' real-time markets. This has been the dominant mode of portfolio rebalancing.
- As an alternative form of rebalancing, the Agency could conduct "reverse RFP" procurement events, in which the bids are to buy rather than sell forward hedges. The Agency does not believe that it has the authority to sell excess supply via its authority to "conduct competitive procurement processes" under 20 ILCS 3855/1-20(a)(2).
- The Agency could conceivably issue an RFP to purchase derivative products, such as put options on forward hedges, which would have a similar risk reduction effect to selling forwards. This may avoid legal and contractual difficulties associated with selling forward hedge contracts. This approach would also require the utilities to ensure they had regulatory approval to exercise the options after purchasing them, and the employees who exercise the option could become classified as part of a "marketing function." The Agency does not envision entering into derivative contracts for rebalancing purposes.
- The Agency could conduct multiple procurement events in a year if the rebalancing required is to increase the supply under contract. Since 2014, the IPA has conducted two energy procurements each year, one in the spring and the other in the fall. Conducting multiple procurements each year provides for a more precise portfolio balance, which is the direct result of using more current load forecasts.

6.5 Purchased Electricity Adjustment Overview

The PEA functions as a financial balancing mechanism to assure that electricity supply charges match supply costs over time. The balance is reviewed monthly and the charge rate is adjusted accordingly. The PEA can be a debit or credit to address the difference between the revenue collected from customers and the cost of electricity supplied to these same customers in a given period. The supply costs are tracked, and the PEA adjusted, for each customer group. The PEA is applicable to the purchased electricity costs of Ameren Illinois, ComEd, and MidAmerican.

[129] 220 ILCS 5/16-111.5(b)(4).

[130] As the state's renewable portfolio standard is transitioning to being funded through a delivery services charge assessed to all utility retail customers, future curtailment of these agreements is no longer a meaningful risk. (See 20 ILCS 3855/1-75(c)(1)(E)).

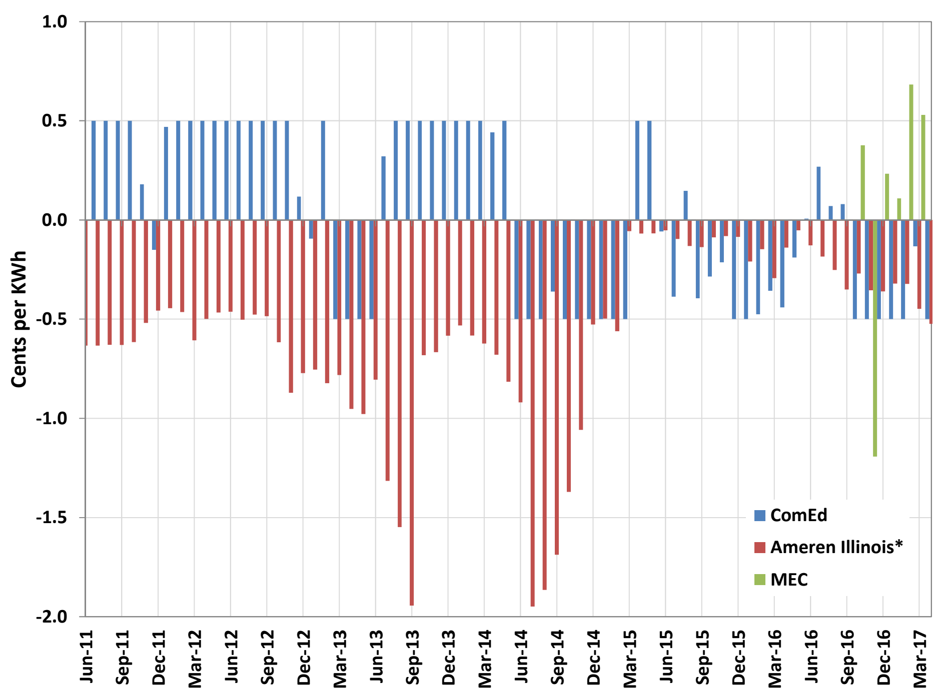
[131] 125 FERC ¶ 61,064, Oct. 16, 2008.

The PEA provides some guidance as to the amount by which the complete set of risk factors caused the cost of energy supply to differ from utility estimates. Figure 6-1 shows how the PEAs for Ameren Illinois and ComEd have changed over the last five years. The figure also shows the applicable MidAmerican PEAs starting with October 2016. While Ameren Illinois' PEAs have been generally "negative" (i.e., operating as a credit to customers) over this period, ComEd's have been "negative" as well as "positive" (i.e., operating as charge to customers). ComEd has voluntarily limited its PEA to move between +0.5 cents/ kWh and -0.5 cents/kWh, and the figure shows that ComEd's PEA has oscillated between those limits. Although based on a relatively short period, the MidAmerican PEA has shown more volatility ranging from a negative 1.1192 cents/kWh in November 2016 to a positive 1.077 cents/kWh in April 2017. MidAmerican and the IPA plan to monitor this situation over the next year and assess whether adjustments to the forecast process are warranted.

In April 2014, the Commission approved an adjustment to ComEd's PEA that allows the accumulated balance of deferrals associated with the computation of the PEA each June to be rolled into the base default service rate for the next year and the associated balance to be reset to zero. The ComEd PEA increased from a credit to a charge for two months in the spring of 2015. This was due to how the ICC instructed ComEd to recover customer care costs from eligible retail customers, and not due to costs related to energy procurement. Absent that cost recovery, the PEA would have operated as a credit to customers in those two months. The ComEd PEA also reflected charges in August 2015 and June, July, August, and September 2016, but reflected credits for most of the recent months from October 2016 through April 2017.

From July 2013 through September 2013 and for July 2014 through November 2014, the magnitude of the Ameren Illinois negative PEAs increased significantly. The IPA understands that this change was largely the result of the long position in the supply portfolio of Ameren Illinois resulting from the increase in municipal aggregation switching, and that long position was subsequently settled favorably to customers within the MISO balancing markets. This drove an over-collection from eligible retail customers during the previous winters and the large negative PEA values represent the return of those proceeds to the remaining eligible retail customers. Since December 2014, the negative values of the Ameren Illinois PEAs have been much smaller as portfolio volumes have become better matched with actual load.

Figure 6-1: Purchased Electricity Adjustments in Cents/kWh, June 2011 – April 2017



*-Uniform across all zones in the Ameren Illinois service territory since Oct. 2013. For previous months, values differed slightly by Zone.

6.6 Estimating Supply Risks in the IPA's Historical Approach to Portfolio Management

6.6.1 Historic Strategies of the IPA

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

Forward hedges have been procured on a "laddered" basis. The Agency originally sought to hedge 35% of energy requirements on a three-year-ahead basis, another 35% on a two-year-ahead basis, and the remainder on a year-ahead basis. Prior to 2014, procurements had been annual, in April or May, rather than on a more frequent or ratable basis. For example, in the spring of 2010, the Agency procured forward hedge volumes as close as possible to 35% of the monthly average peak and off-peak load forecasts for the 2012-2013 delivery year. In the spring of 2011, the Agency procured forward hedge volumes to bring the total volume as close as possible to 70% of then-current monthly average peak and off-peak load forecasts for the 2012-2013 delivery year. And in the spring of 2012, the Agency procured forward hedge volumes to bring the total volume as close as possible to 100% of then-current monthly average peak and off-peak load forecasts for the 2012-2013 delivery year. In the 2013 Procurement Plan, the Agency indicated it was considering a change in hedging from 100%/70%/35% of the expected load to 75%/50%/25%. Because there were no procurements in 2013, that hedging strategy was not formally adopted or implemented.

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

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

In the 2016 Procurement Plan, other than moving October from the group of months fully hedged in the April procurement to the group of months to be fully hedged in the Fall procurement, no substantial changes to the strategy were implemented, but consideration was given to adjusting the cumulative hedge ratios for various delivery months, effective at the next to last scheduled event prior to delivery.

For the 2017 Procurement Plan, the IPA continued the use of two procurement events for standard energy blocks; one that was held in April 2017, and a second scheduled for August 2017.

Under the 2018 Procurement Plan, the IPA proposes to continue the use of two procurement events to be held in the spring and fall. The hedge ratios are proposed to remain at the values set for the 2017 Plan.

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

6.6.2 Measuring the Cost and Uncertainty Impacts of Supply Risk Factors

Given the volatility in forward energy prices from month to month and within months experienced in the last several years, the IPA investigated the merit of considering alternative procurement schedule strategies with the goal of further minimizing the volatility of the resulting portfolios of contracts for each delivery month in developing its 2016 Plan.

For the 2016 Plan, the IPA conducted a detailed analysis related to procurement scheduling and volatility.[132] The results of that analysis indicated that the closer the procurement events are held to the product delivery date, the greater the impact of volatility on the products procured. The on-peak convenience volatility curves shown in this analysis demonstrated these results. However, other factors also impact the scheduling of procurement events relative to delivery timing and may result in reasonable decisions to hold procurement events in close proximity to product delivery dates.

The results of the 2016 Plan analysis suggested that volatility, as measured by the standard deviation of daily forward prices within a trade month, is not significantly different from trade month to trade month and is generally somewhat higher in any trade month for delivery in a summer month (e.g., July) than for delivery than other months. High volatility for winter delivery months (e.g., January) is a recent development.

The cost to eligible retail customers for qualified service in a given month is driven by the average price paid for blocks of on-peak and off-peak energy secured under a procurement plan. The stability of that cost is a function of the long-term trends (both predictable and random) in forward prices over the procurement period and the more random draw of the forward price on the days in which components of the portfolio are procured. The IPA performed a "backcast" analysis to study the effects of different procurement schedules for the on-peak energy component of the monthly portfolios for October 2014 through September 2015 delivery using the PJM Northern Illinois Hub forward price data. A Monte-Carlo simulation was conducted with 10,000 iterations. In each iteration a forward price was drawn from a normal distribution for each delivery month and from each designated event date range (one to two months of trade days), and a weighted average portfolio cost for each delivery month under each procurement schedule, based on the designated target levels was calculated. The distributions over all iterations of the portfolio average costs were analyzed to determine means and standard deviations.

While the IPA did not include modeling of seasonal futures prices in the 2016 Plan Monte Carlo simulation, it appears that the fairly stable volatility of average futures prices and the maturity-varying profile of convenience yields both lend support to a strategy of using multiple procurements which may be evenly spaced and sized. In order to avoid excessive uncertainty in procurement costs, the shape of the convenience yield curves indicates that the last procurement should be made several months in advance of contract expiry.

Based on this analysis, the IPA sees no reason to change the energy procurement schedule and approach for its 2018 Plan from the approach established in the 2015 Plan which was utilized again for the 2016 and 2017 Plans.

6.7 Demand Response as a Risk Management Tool

Demand response programs operated by ComEd are not used to offset the incremental demand, over and above the weather-normalized base case peak load. The programs, however, are supply risk management tools available to help assure that sufficient resources are available under extreme conditions. Under the current

[132] See 2016 IPA Procurement Plan at 71-80.

PJM capacity construct, demand resources participate fully as a source of supply in the capacity procurement process, and the RPM provides capacity compensation for demand resources that clear in RPM auctions in the same manner as cleared generation resources receive compensation. To participate fully as a source of supply, the demand response resource must, either by itself or, if seasonal, by being coupled with another eligible seasonal resource, be able to meet the annual availability requirements imposed on resources by PJM's adoption of Capacity Performance requirements.

In the case of Ameren Illinois and MidAmerican, MISO provides the ability for demand response measures to reduce supply risk. On March 14, 2014, FERC approved MISO's modification to its Module E-1 tariff to treat demand response and energy efficiency resources similarly to other capacity providing resources for operational planning purposes. MISO distinguishes between capacity resources that clear the capacity auction and load modifying resources ("LMR") that have no capacity supply obligation. LMR have different obligations than capacity resources, but do count toward planning resources. By qualifying as an LMR, the demand resource is able to help meet resource adequacy requirements obligations and receives compensation for providing planning resource capability. Also, by qualifying as an LMR, the demand resource is obligated to curtail during emergencies and may be penalized for failure to do so.

FERC Order No. 745 requires ISOs and RTOs to compensate demand response resources participating in wholesale markets at the market price. In January 2016, the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals ruling and upheld FERC's jurisdiction over demand response competing in wholesale markets, holding that the Federal Power Act provides FERC with the authority to regulate wholesale market operators' compensation of demand response bids and affirming the validity of the methodology used by FERC to provide compensation.[133] Chapter 7 of this plan provides details and additional discussion regarding demand response resources.

[133] See FERC v. Electric Power Supply Ass'n, 2016 WL 280888, 136 S. Ct. 760 (2016).

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.

7.1 Energy

7.1.1 Energy Procurement Strategy

The IPA recommends maintaining the energy procurement strategy utilized for the 2017 Procurement Plan as explained below.

The IPA's proposed energy hedging strategy for the 2018 Procurement Plan is entirely consistent with the strategy used for the 2017 Plan.

- Procure hedges consisting of standard 25 MW energy blocks.
- Hedges will be calculated on the expected monthly average peak and off-peak load.
- Conduct two procurement events in 2018, one in the Spring and one in the Fall.

At the conclusion of the Spring procurement event, the resulting aggregated hedges in each utility's supply portfolio should be as follows:

- For the period of June through September of the prompt Delivery Year (2018-2019), the aggregated hedges should be approximately 100% of the each monthly average peak and off-peak load, except for July and August peak, which should be 106%. For the period of October through May of the prompt Delivery Year, the aggregated hedges in the portfolio should be approximately 75% of each monthly peak and off peak average load.
- For the second Delivery Year (2019-2020) the aggregated hedges in the portfolio should be approximately 37.5% of each monthly peak and off peak average load.
- For the third Delivery Year (2020-2021) the aggregated hedges in the portfolio should be approximately 12.5% of each monthly peak and off peak average load.

At the conclusion of the Fall procurement event, the resulting aggregated hedges in each utility's supply portfolio should be as follows:

- For the prompt Delivery Year (2018-2019) the aggregated hedges in the portfolio should be approximately 100% of the average monthly peak and off-peak load, except for July and August peak, which should have been hedged at 106% in the Spring procurement.
- For the second Delivery Year (2019-2020) the aggregated hedges in the portfolio should be approximately 50% of the average monthly peak and off-peak load.
- For the third Delivery Year (2020-2021) the aggregated hedges in the portfolio should be approximately 25% of the average monthly peak and off-peak load.

The strategy is summarized in Table 7-1.

Table 7-1: Summary of Energy Procurement Strategy for all Utilities[134]

Spring 2018 Procurement			Fall 2018 Procurement		
June 2018-May 2019 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2018-May 2019**	**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 2017 base load forecasts to provide indicative procurement values for the 2018-2019 delivery year.[135] The actual target procurement volumes used for the Spring and Fall 2018 procurements will be calculated using the March 2018 and the July 2018 updated load forecasts respectively. The IPA recommends that each utility submit forecast updates that reflect the most accurate and up-to-date information and modeling available at the time. In updating the load forecasts, the utilities may incorporate refinements to their forecasts including but not limited to changes to variables' values (such as switching) and reasonable enhancements to econometric models, provided that any such refinements are properly disclosed and subject to the review and consensus of the IPA, ICC Staff, the Procurement Monitor, and the applicable utility.

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 2021-2022 and 2022-2023) in this Procurement Plan. Therefore, the tables and figures that follow only cover Delivery Years 2018-2019, 2019-2020, and 2020-2021.

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

[135] The anticipated procurement volumes are rounded up or down to the nearest 25 MW block. 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

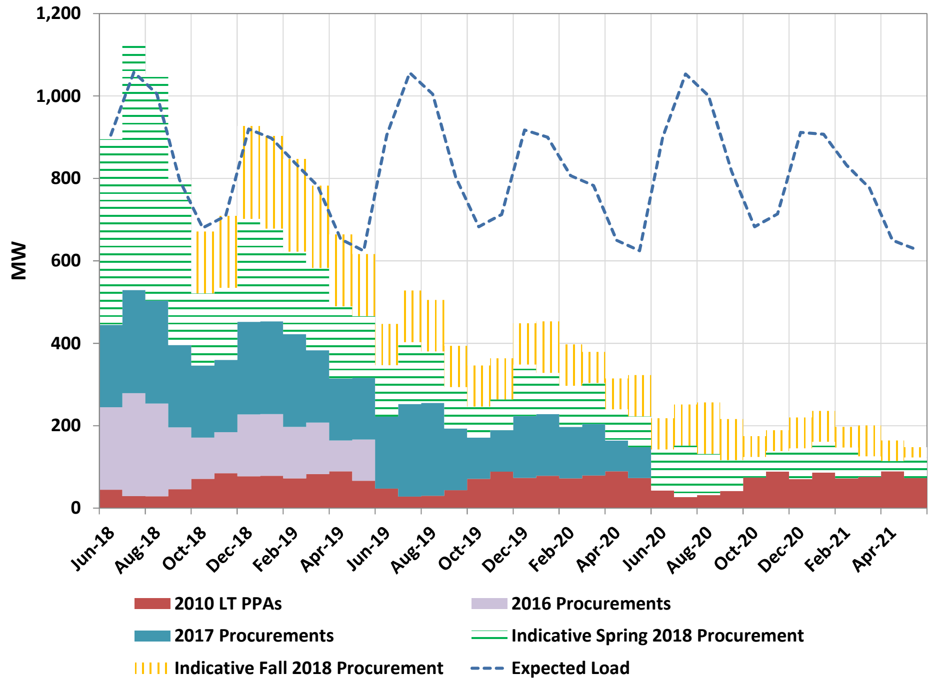


Figure 7-2: Ameren Illinois Off-Peak Energy Supply Portfolio and Load

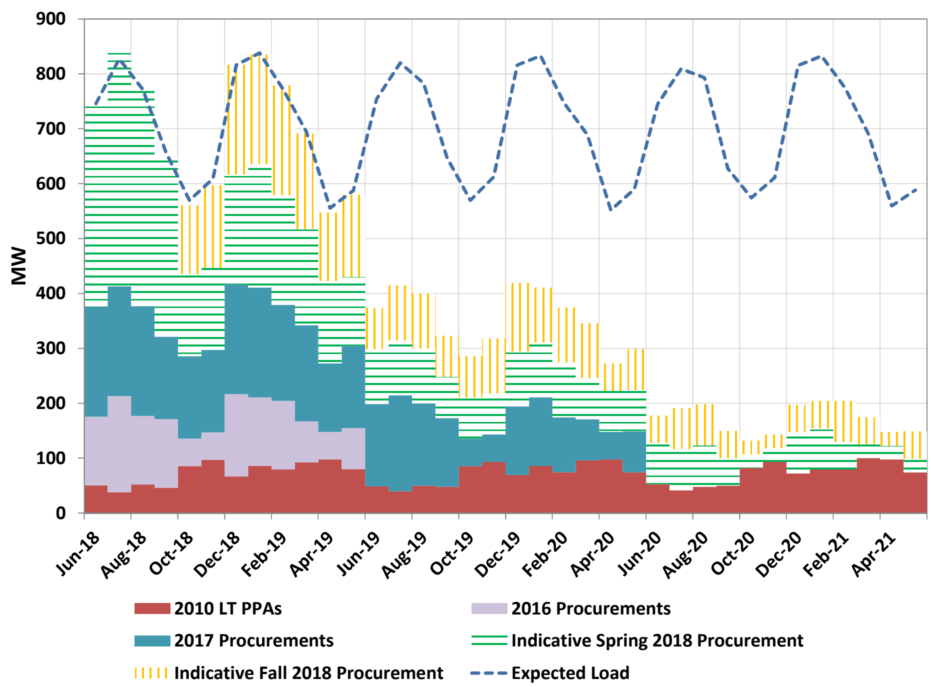


Table 7-2: Ameren Illinois 2018 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2018 Purchases (MW)		Anticipated Fall 2018 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2018-2019				
Jun-18	450	375	0	0
Jul-18	600	425	0	0
Aug-18	550	400	0	0
Sep-18	400	325	0	0
Oct-18	175	150	150	125
Nov-18	175	150	175	150
Dec-18	250	200	225	200
Jan-19	225	225	225	200
Feb-19	200	200	225	200
Mar-19	200	175	200	175
Apr-19	175	150	175	125
May-19	150	125	150	150
Delivery Year 2019-2020				
Jun-19	125	100	100	75
Jul-19	150	100	125	100
Aug-19	125	100	125	100
Sep-19	100	75	100	75
Oct-19	75	75	100	75
Nov-19	75	75	100	100
Dec-19	125	100	100	125
Jan-20	100	100	125	100
Feb-20	100	100	100	100
Mar-20	100	75	75	100
Apr-20	75	75	75	50
May-20	75	75	100	75
Delivery Year 2020-2021				
Jun-20	100	75	75	50
Jul-20	125	75	100	75
Aug-20	100	75	125	75
Sep-20	75	50	100	50
Oct-20	50	25	50	25
Nov-20	50	25	50	25
Dec-20	75	75	75	50
Jan-21	75	75	75	50
Feb-21	75	50	50	75
Mar-21	50	25	75	50
Apr-21	25	25	50	25
May-21	50	25	25	50

Figure 7-3: ComEd Peak Energy Supply Portfolio and Load

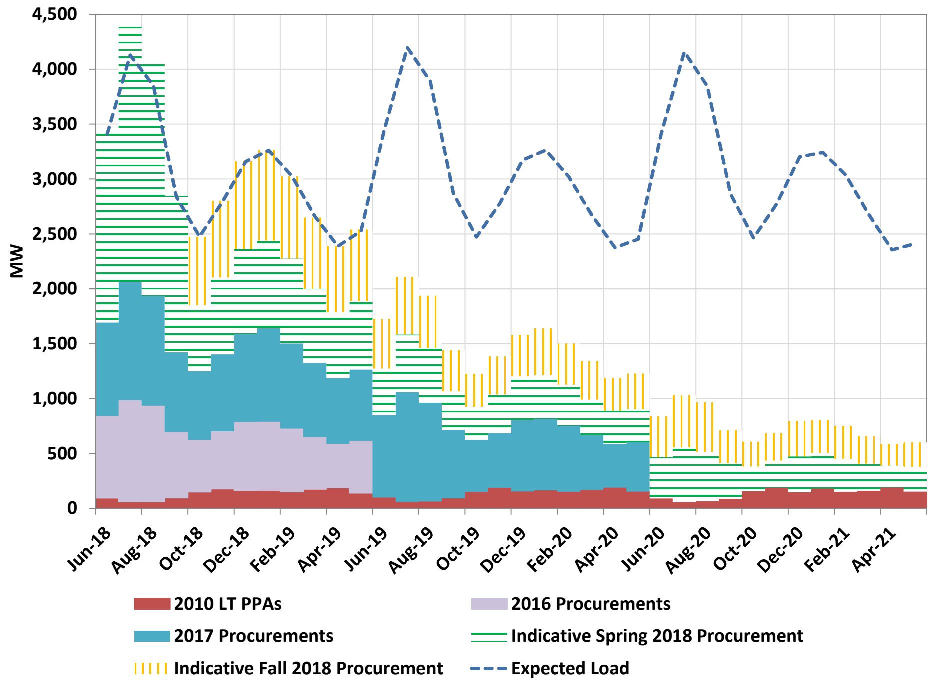


Figure 7-4: ComEd Off-Peak Energy Supply Portfolio and Load

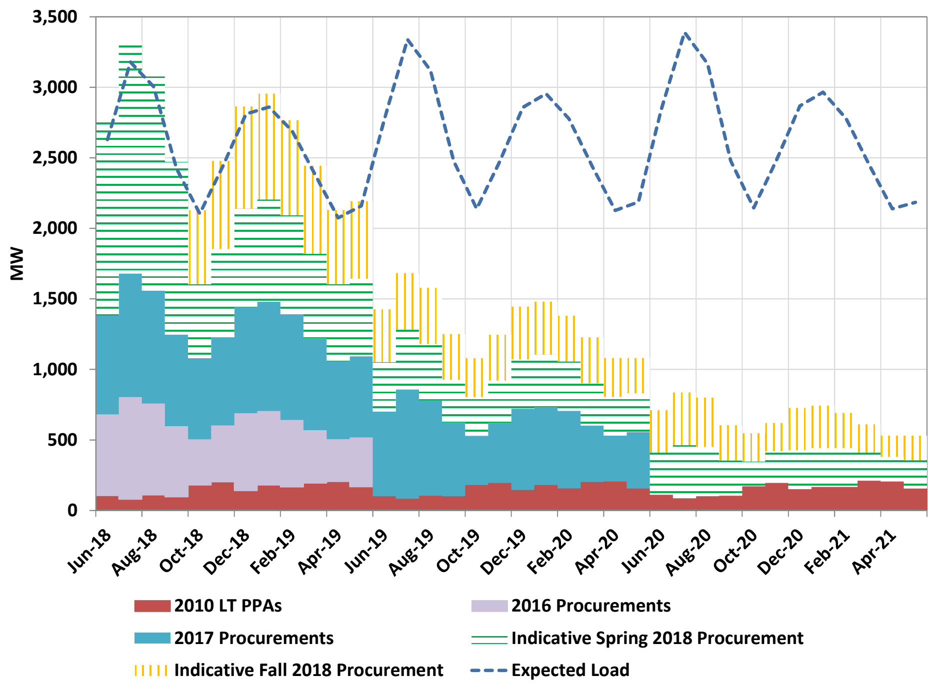


Table 7-3: ComEd 2018 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2018 Purchases (MW)		Anticipated Fall 2018 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2018-2019				
Jun-18	1,725	1,400	0	0
Jul-18	2,325	1,650	0	0
Aug-18	2,150	1,550	0	0
Sep-18	1,425	1,225	0	0
Oct-18	600	525	625	525
Nov-18	700	625	700	625
Dec-18	775	700	800	725
Jan-19	800	725	825	750
Feb-19	775	700	750	675
Mar-19	675	600	650	625
Apr-19	600	550	600	525
May-19	625	550	650	550
Delivery Year 2019-2020				
Jun-19	425	350	450	375
Jul-19	525	425	525	400
Aug-19	500	400	475	400
Sep-19	350	300	375	325
Oct-19	300	275	300	275
Nov-19	350	300	350	325
Dec-19	400	350	375	375
Jan-20	400	375	425	375
Feb-20	375	350	375	325
Mar-20	325	300	350	325
Apr-20	300	275	300	275
May-20	300	275	325	250
Delivery Year 2020-2021				
Jun-20	375	300	375	300
Jul-20	500	375	475	375
Aug-20	450	350	450	350
Sep-20	325	250	300	250
Oct-20	225	175	225	200
Nov-20	250	225	250	200
Dec-20	325	275	325	300
Jan-21	325	275	300	300
Feb-21	300	275	300	250
Mar-21	250	200	250	200
Apr-21	200	175	200	150
May-21	225	200	225	175

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

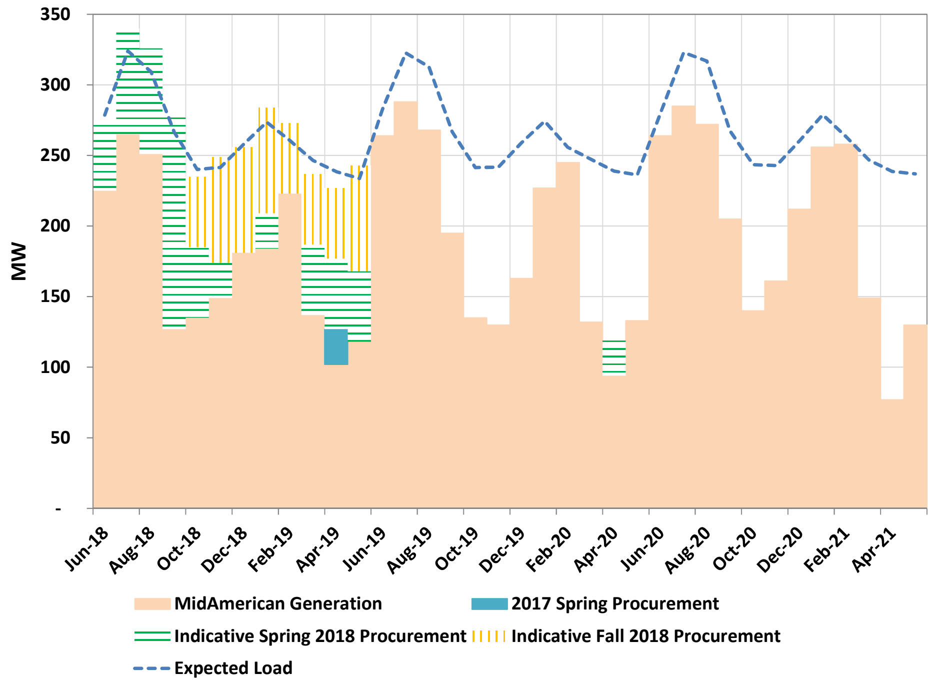


Figure 7-6: MidAmerican Off-Peak Energy Supply Portfolio and Load

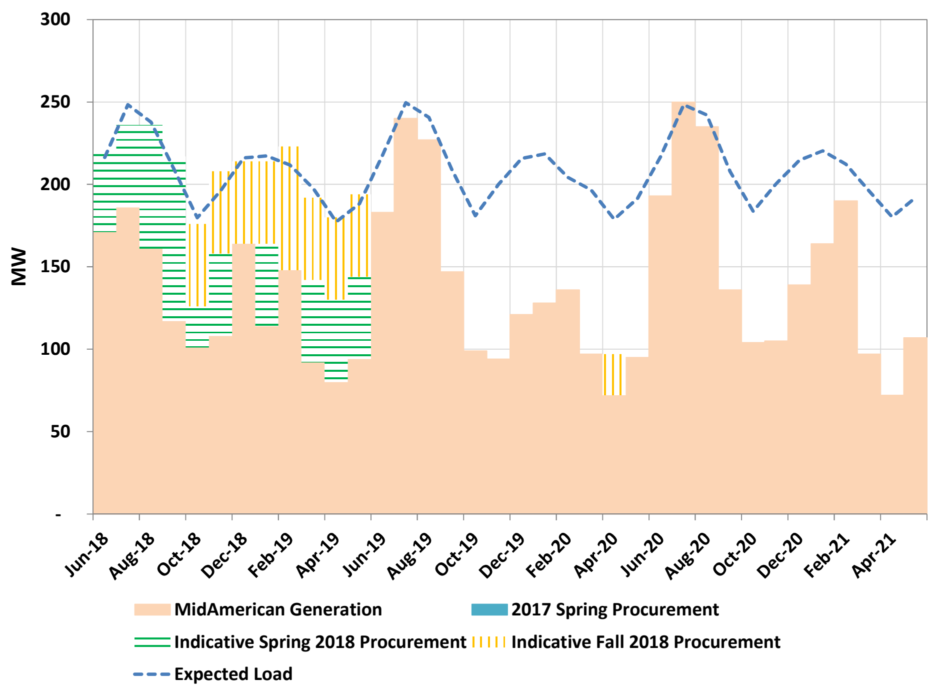


Table 7-4: MidAmerican 2018 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2018 Purchases (MW)		Anticipated Fall 2018 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2018-2019				
Jun-18	50	50	0	0
Jul-18	75	50	0	0
Aug-18	75	75	0	0
Sep-18	150	100	0	0
Oct-18	50	25	50	50
Nov-18	25	50	75	50
Dec-18	0	0	75	50
Jan-19	25	50	75	50
Feb-19	0	0	50	75
Mar-19	50	50	50	50
Apr-19	50	50	50	50
May-19	50	50	75	50
Delivery Year 2019-2020				
Jun-19	0	0	0	0
Jul-19	0	0	0	0
Aug-19	0	0	0	0
Sep-19	0	0	0	0
Oct-19	0	0	0	0
Nov-19	0	0	0	0
Dec-19	0	0	0	0
Jan-20	0	0	0	0
Feb-20	0	0	0	0
Mar-20	0	0	0	0
Apr-20	25	0	0	25
May-20	0	0	0	0
Delivery Year 2020-2021				
Jun-20	0	0	0	0
Jul-20	0	0	0	0
Aug-20	0	0	0	0
Sep-20	0	0	0	0
Oct-20	0	0	0	0
Nov-20	0	0	0	0
Dec-20	0	0	0	0
Jan-21	0	0	0	0
Feb-21	0	0	0	0
Mar-21	0	0	0	0
Apr-21	0	0	0	0
May-21	0	0	0	0

7.2 Capacity

7.2.1 Capacity Procurement Strategy

7.2.1.1 ComEd

Prior procurement plans, including the 2017 Procurement Plan, have recommended that ComEd obtain its capacity needs through the PJM-administered capacity market. For the 2018 Plan, the IPA recommends that ComEd continue to obtain its capacity needs from the PJM-administered capacity market. Table 7-9 summarizes the proposed capacity procurement for ComEd.

7.2.1.2 Ameren Illinois

For Ameren Illinois, the 2016 and 2017 Procurement Plans recommended a procurement of a portion of the Ameren Illinois capacity needs for the 2017-2018 and 2018-2019 delivery years through bilateral capacity purchases obtained through the IPA competitive procurement process, with the remainder of its capacity needs procured through the MISO PRA. As outlined below and further discussed in Section 5.2.3, for this Plan, the IPA recommends a refinement of the capacity procurement strategy, which is the procurement of 50% of the capacity requirements in the near-term forward markets through IPA administered RFPs in a laddered fashion, and the remaining balance through the MISO PRA.

Specifically, for Ameren Illinois, the IPA proposes the following capacity procurement strategy:

- For the 2018-2019 Delivery Year, no change to what has already been approved in prior Procurement Plans. That is 25% to be procured through the September 2016 RFP, 50% to be procured through the August 2017 RFP;[136] and any remaining balance to be procured in the MISO PRA.
- For the 2019-2020 Delivery Year, procure 25% of the forecasted capacity requirements through an RFP administered by the IPA in Spring, 2018, and an additional 25% of the forecasted capacity requirement in the Fall of 2018, and procure the remaining balance through the MISO PRA scheduled for April of 2019.
- For the 2020-2021 Delivery Year, the decision will be deferred until next year's Plan.

Table 7-8 summarizes the proposed capacity procurement for Ameren Illinois.

7.2.1.3 MidAmerican

The IPA notes that the magnitude of the proposed capacity procurements for MidAmerican is small relative to its capacity requirements, as shown in Table 7-5. The IPA, consistent with the discussion regarding the procurement strategy for ComEd, recommends that MidAmerican procure 100% of its forecasted capacity deficit through its RTO's capacity market, the MISO PRA. MidAmerican forecasted load and capability is presented in Table 7-6 below.

[136] Actual procurement volumes may not match percentage targets.

Table 7-6: Summary of MidAmerican Load and Capability (MW)

	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023
Coincident Peak Load	435	436	438	440	441
Reserves	34	34	34	34	34
Coincident Peak Load with Reserves	469	470	472	474	476
Total Net Capability	381	381	381	381	381
Deficit to Be Procured in MISO PRA	88	89	91	93	95

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 2018 Procurement Plan to assure reliability over the planning horizon. For the 2018-2019 Delivery Year, the IPA recommends no changes from the previously approved strategy.[137] Starting with the 2019-2020 Delivery Year, the IPA recommends procuring Ameren Illinois capacity requirements through IPA-administered RFPs and through the MISO PRA, as shown below in Table 7-7 below. The percentages in this Table represent procurement targets; the actual procurement volumes may be lower.

Table 7-8: Summary of Capacity Procurement for Ameren Illinois[138]

June 2018-May 2019 (Upcoming Delivery Year)[139]	June 2019-May 2020	June 2020-May 2021
25% RFP in Sep. 2016 50% RFP in Fall 2017 Remaining balance, MISO PRA*	25% RFP in Spring 2018 25% RFP in Fall 2018 Remaining balance, MISO PRA**	To Be Determined In Next Year's Plan MISO PRA***

* MISO Auction is expected to clear in April 2018.
** MISO Auction is expected to clear in April 2019.
***MISO Auction is expected to clear in April 2020.

7.2.2.2 ComEd

For ComEd, the IPA concludes that it does not need to include any extraordinary measures in the 2018 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 7-9: Summary of Capacity Procurement for ComEd

June 2018-May 2019 (Upcoming Delivery Year)	June 2019-May 2020	June 2020-May 2021	June 2021-May 2022
100% PJM RPM Auctions*	100% PJM RPM Auctions*	100% PJM RPM Auctions*	100% PJM RPM Auctions**

137 Procurements approved in the 2016 and 2017 Procurement Plans.

138 Table shows the incremental percentage of capacity requirements to be procured in the indicated procurement events.

139 Percentages approved under prior Procurement Plans (which may not necessarily reflect actual procurement volumes).

* PJM RPM Base Residual Auctions for 2018-2019, 2019-2020, and 2020-2021 have already cleared.

** The 2021-2022 Base Residual Auction will likely be held in May 2018.

7.2.2.3 MidAmerican

For MidAmerican, the IPA concludes that it does not need to include any extraordinary measures in the 2018 Procurement Plan to assure reliability over the planning horizon. The IPA recommends that MidAmerican continue to procure 100% of its capacity deficit for the 2018-2019, 2019-2020 and 2020-2021 delivery years through the MISO PRAs as indicated below.

Table 7-10: Summary of Capacity Procurement for MidAmerican

June 2018-May 2019 (Upcoming Delivery Year)	June 2019-May 2020	June 2020-May 2021
100% of capacity deficit through MISO PRA*	100% of capacity deficit through MISO PRA**	100% of capacity deficit through MISO PRA***

* MISO Auction is expected to clear in April 2018.
** MISO Auction is expected to clear in April 2019.
***MISO Auction is expected to clear in April 2020.

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.*[140]

Section 8-103B(g)(4.5) contains a similar requirement, requiring that Ameren Illinois and ComEd, "in submitting proposed plans and funding levels" to meet the state's new energy efficiency portfolio standard targets adopted through Public Act 99-0906, "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." [141] This updated requirement now "continues until December 31, 2026."[142]

ComEd provided information regarding its existing demand response programs for 2017-2018 which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 72,000 customers with a load reduction potential of 86 MW (ComEd Rider AC).

[140] 220 ILCS 5/8-103(c).

[141] 220 ILCS 5/8-103B(g)(4.5).

[142] Id.

- 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 915 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 8.2 MW of price response potential.
- Peak Time Savings (PTS) Program: This program is required by Section 16-108.6(g) of the PUA and was approved by the ICC in Docket No. 12-0484. The PTS program is an opt-in, market-based demand response program for customers with smart meters. Under the program, customers receive bill credits for kWh usage reduction during curtailment periods. The program commenced in 2015 with 56,000 customers, and has grown to 233,000 customers in 2017. ComEd sold 76 MW of capacity from the program into the PJM capacity auction for the 2018-2019 Delivery Year, increasing to 85 MW in the 2019-2020 Delivery 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 Rewards program (Rider PTR). According to Ameren Illinois, the program currently has approximately 40,000 customers and Ameren Illinois sold 7.5 MW of related capacity in the MISO PRA for the 2017-2018 Delivery 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. At the time of gross system peak, the SummerSaver program was in effect in the amount of 2 MW. In addition, there is a potential for load displacement due to curtailment of customers on an interruptible rate. There was no curtailment event in effect at the time of gross system peak.

The IPA does not propose any procurement of demand response programs from eligible retail customers in the 2018-2019 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," and as the IPA is not aware of any simple, straightforward way of definitively determining whether a non-competitive class customers take supply from the utility or an alternative retail electric supplier for purposes of any demand response aggregation, 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 Rewards (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.[143] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[144] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act[145], Section 1-75(d) describes two special cases: the "initial clean coal facility"[146] 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"). 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.

[143] 20 ILCS 3855/1-75(d).

[144] 20 ILCS 3855/1-75(d)(1).

[145] 20 ILCS 3855/1-10.

[146] Id.

8 Procurement Process Design

The procedural requirements for the procurement process are detailed in the Illinois Public Utilities Act at Section 16-111.5.[147] 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.

The IPA has procured RECs to meet the RPS obligations for Ameren Illinois, ComEd and more recently MidAmerican as part of the IPA's past annual procurement plans. As discussed further in Chapter 2, Public Act 99-0906 made changes to the IPA's procurement process. Among these changes, starting with this Plan the procurement of RECs will be separated from the annual procurement plan and covered under a new long-term renewable resources procurement plan. The IPA's procurement process going forward will continue to procure standard wholesale products for the utilities' eligible retail customers through the annual procurement plans.

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[148], 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.*

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

[148] The IPA 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.

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

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

(4) Request for proposals competitive procurement process.

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

(5) A plan for implementing contingencies

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

8.1 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, 2016, and 2017 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 2018 Procurement Plan would be the twelfth iteration of IPA-run procurement events, when including the Spring 2017 procurement events[149] and the planned Fall 2017 procurement events for the procurement of capacity for Ameren Illinois, the procurement of standard energy products for all of the utilities, and the distributed generation RECs procurement. 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, 2016, and 2017 procurement events, potential bidders submitted only limited comments on the proposed changes to the forms.

In the procurement events conducted for energy blocks since 2012 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 procurement events were similar to the Ameren Illinois contract documents.

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 contracts used in the 2017 procurement

[149] The Spring 2017 procurement events included: the April 3rd procurement of standard energy blocks and the April 28th procurement of DG RECs.

events be the starting point for the contracts used in the energy 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.

8.2 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."[150] Additionally in April, 2014 the IPA adopted 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.[151]

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.

In developing its procurement approach, the IPA has 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 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

[150] 20 ILCS 3855/1-75(h).

[151] 83 Ill. Admin. Code. §§ 1200.110, 1200.220.

to the IPA for payment of the Supplier Fees). This is the approach that was used in the 2014, 2015, 2016, and 2017 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 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.

8.3 Second Procurement Event

The IPA recommends that procurement events be held in the spring and fall of 2018 for purchase of energy blocks under the 2018 Procurement Plan. The components of the energy 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 2018 procurement event includes the procurement of standard energy products for MidAmerican, Ameren Illinois and ComEd.

8.4 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 July 13, 2017 the ICC Staff posted a public notice for the informal hearing for the purpose of receiving comments regarding the procurement process for the procurement events that were held during the summer and fall of 2016 and the spring of 2017. The summer 2016 event involved the procurement of RECs from distributed renewable energy generation devices. The Fall 2016 procurements involved the procurement of standard energy products to meet the requirements of ComEd's, Ameren Illinois', and MidAmerican's eligible retail customers for November 2016 through May 2017 and MISO Zonal Resource Credits capacity products for Ameren Illinois. The Spring 2017 procurement events included the purchase of a portion of the three utilities' energy requirements to meet eligible retail customers' needs for the 2017-2018, 2018-2019, and 2019-2020 delivery years, as well as the purchase of distributed generation RECs for ComEd, MidAmerican and Ameren Illinois.

Initial comments for the informal hearing were due to the Commission by July 28, 2017 and Reply Comments were due August 4, 2017. Initial Comments were received from Bates White Economic Consulting ("Bates

White"), the ICC's Procurement Monitor, on July 27, 2017. No Reply Comments were received. With regard to procurement process design for energy and capacity procurements, the primary Bates & White recommendation focused on delaying or "rolling over" procurements for small quantities into the next procurement event to save on procurement administration costs and improve the robustness of the competition among bidders. Based on the concern that a solicitation for a small quantity would result in limited or no bidder participation, Bates White recommended that a minimum quantity threshold be established such that if the amount of the solicitation for a particular product were to fall below that threshold, then the IPA, Commission Staff, the Procurement Administrator, and the Procurement Monitor could decide not to hold the procurement for that product. While the IPA appreciates Bates White's recommendation to roll over procurements for small quantities, the IPA would prefer to keep the current procurement process—which it considers to be effective, successful and consistent with the procurement framework for all utilities as detailed in this Plan— unchanged for the 2018 Plan. Under the current process, the costs associated with administering the procurement of incremental small quantities is insignificant, and a protocol exists for addressing the event that a solicitation does not procure the target quantities of a product.

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

Appendices (Overview)

Appendices are available separately at:

www.illinois.gov/sites/ipa/Pages/2018-Appendices.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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