2017

ELECTRICITY PROCUREMENT PLAN

2017 Plan Filed for

Illinois Commerce Commission Approval

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

Table of Contents

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

Tables

Figures

1 Executive Summary

This is the ninth electricity and renewable resource procurement plan (the "Plan," "Procurement Plan," or "2017 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 and renewable resource supply for the "eligible retail customers" of Ameren Illinois Company ("Ameren Illinois"), Commonwealth Edison ("ComEd"), and MidAmerican Energy Company ("MidAmerican"). Following MidAmerican's first-time participation in the 2016 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 2017 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 2017-2018 energy delivery year and lasts through the 2021-2022 delivery year.

The 2016 Procurement Plan, approved by the Commission in Docket No. 15-0541, 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), a spring renewables procurement, and an early summer distributed generation procurement. In addition, the 2016 Plan involved a capacity procurement for Ameren Illinois held as a Fall 2016 procurement event. The 2016 Plan also called for a minor change to the energy hedging strategy to bring the hedging level for October 2016 to 75% of average load at the time of the spring procurement event and to 100% in the fall procurement event. For the 2017 Procurement Plan, the IPA recommends a continuation of the energy procurement strategies proposed in the 2016 Procurement Plan.

1.1 Power Procurement Strategy

The Plan proposes to continue using the risk management and procurement strategy that the IPA has historically utilized: hedging load by procuring on and off-peak blocks of forward energy in a three-year laddered approach. 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 environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[2]

The IPA's hedging strategy for the 2017 Procurement Plan is consistent with the strategy used for the 2016 Plan. The IPA continues to recommend the procurement of standard energy in blocks of 25MW. The risk management strategy also continues to bifurcate the first delivery year into periods with different hedging levels—with June hedged at 100% of average load, July and August hedged to 106% of average on-peak load

[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 2017 procurement planning process.

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

and 100% of average off-peak load, fall hedged to 100% of average load, and the balance of the year hedged to 75% of average load at the time of the spring procurement event. The IPA also recommends that the Commission approve a fall energy procurement event to bring the hedging level for the balance of the first delivery year (October through May) to the fully hedged level (100% of load). Consistent with other recent procurement plans, the IPA also recommends hedging 50% of the expected load for the second delivery year, and 25% of the expected load for the third delivery year. The IPA recommends the procurement of half of these volumes in the Spring 2017 procurement event and the balance in the Fall 2017 procurement event.

Additionally, for Ameren Illinois' 2018-2019 planning year, the IPA recommends purchasing 75% of its forecasted capacity requirements in bilateral transactions and 25% from the MISO Planning Resource Auction ("PRA").[3] For future years' Ameren Illinois capacity requirements, the IPA will defer a decision for the 2019-2020 planning year and beyond until next year's Plan. For ComEd, consistent with the strategy adopted in prior plans, the IPA proposes that forecast capacity requirements be secured by ComEd through the PJM Reliability Pricing Model and Capacity Performance processes. For MidAmerican, consistent with the approach taken in the 2016 Plan, the IPA recommends that its forecast capacity shortfall be secured by MidAmerican through the annual MISO PRA.[4]

Aside from the various proposals above, the IPA recommends that capacity, 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[5]

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

Table 1-2: Summary of Capacity Procurement for ComEd

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

[3] 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.

[4] 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); in the case of capacity, MidAmerican's shortfall is relatively small (15.2% to 16.3% of its capacity requirement).

[5] Table 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[6]

June 2017-May 2018 (Upcoming Planning Year)[7]	June 2018-May 2019	June 2019-May 2020
75% RFP in Fall 2016 25% MISO PRA	25% RFP in Fall 2016 50% RFP in Fall 2017 25% MISO PRA	To Be Determined In Next Year's Plan

Table 1-4: Summary of Capacity Procurement for MidAmerican

June 2017-May 2018 (Upcoming Planning Year)	June 2018-May 2019	June 2019-May 2020
100% of expected shortfall (approximately 15.2% of the capacity requirements) from MISO PRA	100% of expected shortfall (approximately 15.8% of the capacity requirements) from MISO PRA	100% of expected shortfall (approximately 16.3% of the capacity requirements) from MISO PRA

1.2 Renewable Energy Resources

The load forecast provided by Ameren Illinois indicates that while existing renewable energy resources under contract meet that utility's overall renewable resource obligations for the upcoming delivery year, they do not fully meet or exceed the Renewable Portfolio Standard obligations for solar photovoltaics or for distributed generation. The load forecasts submitted by ComEd and MidAmerican indicate that existing renewable energy resources under contract do not meet those utilities' overall renewable energy resource obligations for the upcoming delivery year or the specific obligations for wind, photovoltaics, or distributed generation.

Accordingly, the IPA recommends conducting a Spring 2017 procurement event for general renewable energy credits ("RECs") (ComEd and MidAmerican only), wind RECs (ComEd and MidAmerican only), and solar RECs (all utilities) using the Renewable Resources Budget. The IPA also proposes two procurements for distributed generation RECs using hourly ACP funds for Ameren Illinois and ComEd, and using the Renewable Resources Budget for MidAmerican. Scheduling of the procurements will be finalized based upon whether the IPA undertakes a contingency procurement in April, 2017 as contemplated in the Agency's the Supplemental Photovoltaic Procurement Plan and other factors. For Ameren Illinois and ComEd, the distributed generation procurement budget will be equal to the amount of hourly ACP funds collected by each utility as of December 31, 2016 for any procurement undertaken prior to June 30, 2017 and updated to the May 31, 2017 balance for any procurement after July 1, 2017, minus the value of contracts awarded through the 2015, 2016, and 2017 distributed generation REC procurements[8] and any hourly ACP funds committed to the purchase of curtailed RECs stemming from the 2010 long-term power purchase agreements ("LTPPAs") should the March updated load forecasts indicate the need for a curtailment.[9]

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

[7] Procurement approved in the 2015 Procurement Plan.

[8] As the second 2017 distributed generation REC procurement's budget would be impacted by contracts committed to in the first 2017 distributed generation REC procurement.

[9] While the IPA will endeavor to conduct its DG procurements as soon as practicable after Plan approval as requested by commenters on the Draft Plan, because the first of the two DG procurements will almost certainly occur after the March load forecasts are received, those load forecasts will be used to inform a DG procurement budget.

Table 1-5 summarizes the IPA's proposed supply-side recommendations as described in this Plan:

Table 1-5: Summary of Procurement Plan Recommendations Based on July 15, 2016 Utility Load Forecast (Quantities to be Adjusted Based on the March and July 2017 Load Forecasts):

	Delivery Year / Planning Year	Energy	Capacity	Renewable Resources	Transmission and Ancillary Services
AMEREN ILLINOIS	2017-2018	Up to 625MW forecasted requirement (Spring Procurement) Up to 225MW additional forecasted requirement (Fall Procurement)	75% RFP in Sep. 2016 25% MISO PRA	One-year SRECs procurement up to 43.1GWh Five-year DG REC procurement up to 7.0GWh	Will be purchased from MISO
	2018-2019	Up to 150MW forecasted requirement (Spring Procurement) Up to 125MW forecasted requirement (Fall Procurement)	25% RFP in Sep. 2016 50% RFP in Fall 2017 25% MISO PRA	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2019-2020	Up to 125MW forecasted requirement (Spring Procurement) Up to 125MW forecasted requirement (Fall Procurement)	To Be Determined In Next Year's Plan	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2020-2021	No energy procurement required	No further action at this time	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2021-2022	No energy procurement required	No further action at this time.	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
COMED	2017-2018	Up to 2,225MW forecasted requirement (Spring Procurement) Up to 800MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	One-year wind REC procurement up to 500.0GWh One-year SREC procurement up to 107.9GWh Five- year DG REC procurement up to 20.1GWh	Will be purchased from PJM
	2018-2019	Up to 500MW forecasted requirement (Spring Procurement) Up to 500MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from PJM
	2019-2020	Up to 475 MW forecasted requirement (Spring Procurement) Up to 450MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from PJM
	2020-2021	No energy procurement required	100% PJM RPM Auctions	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from PJM
	2021-2022	No energy procurement required	No further action at this time	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from PJM

MIDAMERICAN	2017-2018	Up to 100MW forecasted requirement (Spring Procurement) Up to 75MW additional forecasted requirement (Fall Procurement)	100% of expected shortfall from MISO PRA	One-year wind REC procurement up to 49.2GWh One-year SREC procurement up to 3.9GWh Five- year DG REC procurement up to 0.5GWh	Will be purchased from MISO
	2018-2019	Up to 25MW forecasted requirement (Spring Procurement) Up to 25MW forecasted requirement (Fall Procurement)	100% of expected shortfall from MISO PRA	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2019-2020	No energy procurement required	100% of expected shortfall from MISO PRA	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2020-2021	No energy procurement required	No further action at this time	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2021-2022	No energy procurement required	No further action at this time	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO

1.3 Incremental Energy Efficiency

This plan is the fifth year for inclusion of incremental energy efficiency programs pursuant to Section 16-111.5B of the Public Utilities Act. As with past plans, the IPA recommends inclusion of the programs submitted by the utilities that pass the Total Resource Cost and have not been determined to be duplicative of other programs. Those programs can be found in Chapter 9. The IPA also recommends that the Commission approve and adopt the Section 16-111.5B Workshop Consensus Items as set forth in Section 9.3.

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 2016.
2. Approve two energy procurement events scheduled for Spring 2017 and Fall 2017. The energy amounts to be procured in the spring will be based on the updated March 15, 2017 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 (and capacity for Ameren Illinois) amounts to be procured in the fall will be based on the July 15, 2017 updated base 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. The March 15, 2017 and the July 15, 2017 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 Item 2 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 Item 2 above, then the July 2016 load forecast will be used for the applicable procurement event.

4. Approve procurement by ComEd, Ameren Illinois, and MidAmerican of capacity, network transmission service and ancillary services from their respective RTO.
5. Approve a Fall 2017 capacity procurement for Ameren Illinois.
6. Approve pro-rata curtailment of ComEd and/or Ameren Illinois' 2010 long-term power purchase agreements for renewable energy in the unlikely event that the updated March 2017 load forecast indicates that such a curtailment is necessary. This forecast will form the basis for pro-rata curtailment of long term renewable contracts assuming consensus is reached among the parties identified in Item 3 above. Otherwise, the July 2016 forecast will form the basis for curtailment.
7. Approve a Spring 2017 procurement of RECs using the renewable resources budget for the prompt delivery year to allow the utilities to meet their RPS requirements other than for distributed generation for Ameren Illinois and ComEd. The volume for the procurement will be determined based upon the "Remaining Target" quantities resulting from the utilities' March, 2017 load forecasts and limited to the funds available according to the utilities' updated renewable resource budgets.
8. Approve two procurements of distributed generation RECs using the Renewable Resources Budget for MidAmerican, and using already collected hourly ACP funds for Ameren Illinois and ComEd, minus the total dollar value committed from prior distributed generation REC contracts. For Ameren Illinois and ComEd, the budget will also reflect any hourly ACP funds committed to the purchase of curtailed RECs stemming from the 2010 long-term power purchase agreements.
9. Approve specific consensus items from the 2016 energy efficiency stakeholder workshops related to the implementation of Section 16-111.5B of the PUA that are set forth in Section 9.3.
10. Approve the Section 16-111.5B incremental energy efficiency programs identified in Chapter 9.

The Illinois Power Agency respectfully files its 2017 Procurement Plan, which the IPA believes is compliant with all applicable laws, for Commission approval and requests approval of the specific action items listed above.

2 Legislative/Regulatory Requirements of the Plan

This Section of the 2017 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.

2.1 IPA Authority

The Illinois Power Agency ("IPA" or "Agency") was established in 2007 by Public Act 95-0481 in order to ensure that ratepayers, specifically customers in service classes that have not been declared competitive and who take service from the utility's bundled rate ("eligible retail customers"),[10] benefit from retail and wholesale competition. The objective of the Act was to improve the process to procure electricity for those customers.[11] 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."[12] The General Assembly also articulated "investment in energy efficiency and demand-response measures, and to support development of clean coal technologies and renewable resources" as additional goals.[13]

Each year, the IPA must develop a "power procurement plan" and conduct a competitive procurement process to procure supply resources as identified in the final procurement plan, as approved by the Commission pursuant to Section 16-111.5 of the Public Utilities Act ("PUA").[14] 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.[15] 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"[16] and "Procurement Administrator."[17] The Illinois Commerce Commission ("ICC" or "Commission") is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[18]

2.2 Procurement Plan Development and Approval Process

Although the 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 2017 Procurement Plan began on July 15, 2016. On that date, each Illinois utility that procures electricity through the IPA (ComEd, Ameren Illinois, and MidAmerican) 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.

Next, the IPA prepares a draft Procurement Plan. On August 15, 2016, that 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

[10] 220 ILCS 5/16-111.5(a).
[11] 20 ILCS 3855/1-5(2)-(4).
[12] 20 ILCS 3855/1-5(1).
[13] 20 ILCS 3855/1-5(4).
[14] 20 ILCS 3855/1-20(a)(2), 1-75(a).
[15] 20 ILCS 3855/1-20(a)(1). MidAmerican elected to participate in the 2016 Procurement Plan and will continue to participate in the 2017 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.")
[16] 20 ILCS 3855/1-75(a)(1).
[17] 20 ILCS 3855/1-75(a)(2).
[18] 220 ILCS 5/16-111.5(b), (c)(2).

IPA releases its draft plan. The 2017 Plan comment period concluded on September 14, 2016. 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 procurement plan.[19] Written comments were received from Ameren Illinois, Carbon Solutions Group, Citizens Utility Board, ComEd, the Environmental Law and Policy Center, Exelon Generation, the Staff of the Illinois Commerce Commission, the Office of the Attorney General of Illinois, the Illinois Solar Energy Association, the Illinois Solar Energy Association's Business Members, MidAmerican, the Natural Resources Defense Council, Power TakeOff, a collection of Renewables Suppliers, the Illinois Chapter of the Sierra Club, SRECTrade, and Wind on the Wires.

Objections to this Plan must be filed with the Commission within five days after the filing of the Plan.[20] Typically, the presiding Administrative Law Judge sets the dates for Responses and Replies to Objections shortly after the docket opens, and 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 confirming or modifying the Plan within 90 days after it is filed by the IPA.[21] With a filing date for the 2017 Plan of September 27, 2016, this year's deadline for approval will fall on December 27, 2016.[22]

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."[23]

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 (such as renewable/clean coal purchase requirements or mandates from previous Commission Orders). To that end, the Procurement Plan must contain an hourly load analysis, which includes: multi-year historical analysis of hourly loads; switching trends and competitive retail market analysis; known or projected changes to future loads; and growth forecasts by customer class.[24] 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.[25] 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,[26] 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.[27]
- 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

[19] 220 ILCS 5/16-111.5(d)(2). Public hearings on the draft 2017 Plan took place on September 6 in Springfield, September 7 in Chicago, and September 9 in Moline. No comments were offered by the public at any of the three public hearings.
[20] 220 ILCS 5/16-111.5(d)(3).
[21] Id.
[22] 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 2016 is currently a regular open meeting scheduled for December 20, 2016, with a meeting also scheduled in the week prior for December 14, 2016.
[23] 220 ILCS 5/16-111.5(d)(4).
[24] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).
[25] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).
[26] 220 ILCS 5/16-111.5(b)(3).
[27] 220 ILCS 5/16-111.5(b)(i), (b)(iii).

generating resources.[28] 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.[29]

- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[30]
- Assess the price risk, load uncertainty, and other factors associated with the proposed portfolio measures, including, to the extent possible, the following factors: contract terms; time frames for security products or services; fuel costs; weather patterns; transmission costs; market conditions; and the governmental regulatory environment.[31] 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. [32]
- Include renewable resource and 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."[33] This listing has been understood by the Commission to be non-exhaustive and non-static.[34] 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."[35]

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,[36] 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.[37] 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

[28] 220 ILCS 5/16-111.5(b)(3)(iv).
[29] Id.
[30] 220 ILCS 5/16-111.5(b)(3)(v).
[31] 220 ILCS 5/16-111.5(b)(3)(vi).
[32] 220 ILCS 5/16-111.5(b)(4).
[33] 220 ILCS 5/16-111.5(b)(3)(iv).
[34] 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").
[35] Id.
[36] 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").
[37] *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).

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."[38]

2.5 Renewable Energy Resources

2.5.1 Renewable Portfolio Standard

The General Assembly has acknowledged the importance of including cost-effective renewable resources in a diverse electricity portfolio.[39] "Renewable energy resources" is defined in the Illinois Power Agency Act as (1) energy and its associated renewable energy credit or (2) renewable energy credits alone from qualifying sources such as wind, solar thermal energy, photovoltaic cells and panels, biodiesel, and other generating technologies as identified in the IPA Act.[40] Section 1-75(c)(1) of the IPA Act requires that a minimum percentage of each utility's total supply to serve the load of eligible retail customers shall be generated from cost-effective renewable energy resources; by June 1, 2017, that requirement is at least 13.0% of each utility's total supply, with the requirement increasing by 1.5% each year until reaching 25% in 2025.[41]

Section 1-75(c)(1) of the IPA Act also features sub-target goals for the procurement of renewable energy resources by specific generating technologies. For the current (2017) Procurement Plan, to the extent cost-effective resources are available, the IPA is directed to procure at least 75% of renewable energy resources used to meet overall renewable energy resource requirements from wind generation, 6% from photovoltaics, and 1% from distributed renewable energy generation devices.[42] Renewable energy resources procured from distributed generation devices to meet this requirement may also count towards the required percentages for wind and solar photovoltaics.[43] Stated differently, if the IPA procures the required 1% distributed generation ("DG") renewable energy resources from photovoltaics, those procured resources may also count toward the 6% solar photovoltaics sub-target, leaving 5% solar photovoltaics to be procured from other sources.

In both Docket No. 14-0588 and Docket No. 15-0541 (approving the Agency's 2015 and 2016 Plans), the Commission confronted the question of whether, given that the overall renewable energy resource requirements for the upcoming delivery year were already met (via existing long-term contracts), procurements should still be conducted to satisfy the sub-target percentage goals specific to generating technologies.[44] In both proceedings, the Commission approved the Agency's proposal to conduct a procurement of renewable energy credits specifically from photovoltaic systems to meet those sub-targets over the objections of ComEd and Ameren Illinois (who viewed the procurement as "unnecessary" given that overall REC procurement targets were met), stating that "the plain language of Section 1-75(c)(1) requires technology-specific targets by dates certain."[45]

Section 1-75(c)(1) sets renewables targets and technology-specific sub-targets based on "a minimum percentage of each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act."[46] With respect to ComEd and Ameren Illinois, "each utility's total supply

[38] Docket No. 14-0588, Final Order dated December 17, 2014 at 156.
[39] 20 ILCS 3855/1-5(5)-(6).
[40] 20 ILCS 3855/1-10. See also Docket No. 10-0563, Final Order dated December 21, 2010 at 83 ("Section 1-10 defines 'renewable energy resources' as either energy and its associated renewable energy credit or renewable energy credits from renewable energy, such as wind or solar thermal energy. As noted in Section 1-10 a REC is a renewable energy resource and therefore fully meets the requirement of Section 1-20 of the IPA Act requiring the procurement of renewable energy.")
[41] 20 ILCS 3855/1-75(c)(1).
[42] Id.
[43] Id.
[44] See generally Docket No. 14-0588, Final Order dated December 17, 2014 at 286 (and associated discussion); Docket No. 15-0541, Final Order dated December 16, 2015 at 126-127.
[45] Docket No. 15-0541, Final Order dated December 16, 2015 at 126-127. Alternatively, in past procurement plan proceedings, the Commission has also approved Agency proposals to not conduct renewable resource procurements despite sub-targets not scheduled to be met due to concerns about the availability of renewable resource budget funds or the scarce amount of resources required to be procured relative to the procurement's administrative costs. (See generally Docket Nos. 12-0544, 13-0546).
[46] 20 ILCS 3855/1-75(c)(1).

to serve the load of eligible retail customers" is addressed through the IPA's procurement planning process. Alternatively, MidAmerican "may elect to procure power and energy for all or a portion of its eligible Illinois retail customers in accordance with the applicable provisions set forth in this Section and Section 1-75 of the Illinois Power Agency Act,"[47] raising the question of whether the renewables targets enumerated in Section 1-75(c) automatically apply to MidAmerican's entire eligible retail customer load, or only to that portion of its eligible retail customer load for which the IPA develops its procurement plan. The Commission settled this issue in Docket No. 15-0541, stating that "the statutes should be interpreted such that the renewable resources targets should only relate to that portion of the 'total supply' procured for MidAmerican's jurisdictional eligible retail customers that is included in the 2016 Procurement Plan."[48]

All renewable energy resources procured, including those to meet sub-target requirements, must still be "cost-effective" under the law. The IPA Act's definition of "cost-effective" has two key features: first, for different renewable resources, the Procurement Administrator creates "benchmarks based on market prices for renewable energy resources in the region" against which all bids are measured.[49] No bid exceeding the established confidential benchmark price may be recommended for procurement. Second, and in addition to the benchmarks, the total cost of renewable energy resources procured for any single year shall be reduced by an amount necessary to limit the annual estimated average net increase due to the costs of these resources to no more than the greater of:

- 2.015% of the amount paid per kilowatt-hour by eligible retail customers during the year ending May 31, 2007; or
- The incremental amount per kilowatt-hour paid for these resources in 2011.[50]

These values are now fixed for Ameren Illinois, ComEd, and MidAmerican, The greater of the two is the 2007 calculation, which constitutes 0.18054 ¢/kWh for Ameren Illinois, 0.18917 ¢/kWh for ComEd, and 0.12415 ¢/kWh for MidAmerican. When these values are multiplied against a utility's forecast eligible retail customer load, it creates a budget amount commonly referred to as that utility's "renewable resources budget," which constitutes the maximum that may be spent on renewable resource procurement in a given year under Section 1-75(c)(1) of the IPA Act (additional money may be spent from the renewable energy resources fund for from alternative compliance payments paid by hourly rate customers).

Cost-effective renewable energy resources are subject to geographic restrictions. The IPA must first procure from resources located in Illinois or in states that adjoin Illinois.[51] If cost-effective renewable energy resources are not available in Illinois or adjoining states, the IPA must seek cost-effective renewable energy resources from "elsewhere."[52]

The IPA's 2016 Plan called for the pre-authorization from the Commission of a curtailment of long-term renewable PPAs, pursuant to the language of the contract, should the Spring 2016 load forecasts indicate that the eligible retail customer rate cap would be exceeded.[53] As discussed in later chapters, with significant amounts of load having switched back to ComEd supply and a modest amount of load switched back to Ameren Illinois supply, the likelihood that existing long-term power purchase agreements may need to be

[47] 220 ILCS 5/16-111.5(a) (emphasis added).
[48] Docket No. 15-0541, Final Order dated December 16, 2015 at 131.
[49] 20 ILCS 3855/1-75(c)(1).
[50] 20 ILCS 3855/1-75(c)(2)(E).
[51] 20 ILCS 3855/1-75(c)(3).
[52] Id.
[53] This process involves the IPA, Commission Staff, the utilities, and the Commission's Procurement Monitor reviewing and approving the spring load forecast used to determine whether curtailment is necessary. In past procurement plan approval proceedings, this approach was contested by parties who contended that the Spring load forecast approval process should be open to stakeholder comment and require an additional step for Commission approval. In Docket No. 15-0541, the Commission found that the existing process "has worked well and has led to favorable results in the procurement process" and that those parties repeatedly challenging that process were "Collaterally Estopped from presenting this argument in future procurement dockets." Docket No. 15-0541, Final Order dated December 16, 2015 at 79.

curtailed for the 2017-2018 delivery year is very low in the case of ComEd and modest in the case of Ameren Illinois.[54] MidAmerican has not entered into any long-term contracts of this nature.

As referenced above, in addition to funds from eligible retail customers, alternative compliance payments collected by the utility from customers taking service under the utility's hourly pricing tariff "increase [IPA] spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year."[55] As part of the 2015 and 2016 Plans, the existing balances of these funds were committed to procure distributed generation renewable energy resources under 5-year contracts, with the balance of funds available for the distributed generation procurement reduced by any amounts necessary to be spent on RECs from long-term renewable PPA holders that could not be purchased by eligible retail customers due to Commission-authorized curtailments necessitated by the statutory 2.015% rate impact cap.[56]

2.5.2 Distributed Generation Resources Standard

As noted above, within the Renewable Portfolio Standard are sub-targets for the procurement of wind (75%), photovoltaics (6%), and distributed generation (1%). Procurement of renewable energy resources from distributed renewable energy generation devices is to be conducted on an annual basis through multi-year contracts of no less than five years, and shall consist solely of renewable energy credits.[57]

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

- Powered by wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;
- Interconnected at the distribution system level of either an electric utility, alternative retail electric supplier, municipal utility, or a rural electric cooperative;
- Located on the customer side of the customer's electric meter and is primarily used to offset that customer's electricity load; and is
- Limited in nameplate capacity to no more than 2,000 kW.[58]

To the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25 kW in nameplate capacity.[59]

The IPA's 2015 Plan featured the first distributed generation-specific procurement approved by the Commission, conducted using hourly customer alternative compliance payment funds previously collected by Ameren Illinois and ComEd, culminating in a procurement held on October 14, 2015.[60] A similar proposal was included in the 2016 Plan, culminating in a second DG procurement event on June 23, 2016 (which included the procurement of DG RECs for MidAmerican as well as Ameren Illinois and ComEd). Resulting contracts from both procurements are for 5 years and may be from any qualifying distributed generation technology. As renewable energy resources procured from distributed generation devices may also count towards the required percentages for wind and solar photovoltaics, the Agency will track the attributes of systems under contract for future REC deliveries as a result of the recent DG procurements and use that information to inform the amount to be procured in future renewables, wind, photovoltaics, and distributed generation

[54] See Section 3.2.3 for further discussion of Ameren Illinois' "low" scenario load forecast.
[55] 20 ILCS 3855/1-75(c)(5).
[56] Docket No. 14-0588, Final Order dated December 17, 2014 at 6; Docket No. 15-0541, Final Order dated December 16, 2015 at 10. As curtailments were ultimately not necessary for the 2015-2016 and 2016-2016 delivery years, no funds will be spent on curtailed RECs.
[57] 20 ILCS 3855/1-75(c)(1).
[58] 20 ILCS 3855/1-10.
[59] 20 ILCS 3855/1-56(b).
[60] For background on the assessment and collection of hourly customer alternative compliance payments, see 20 ILCS 3855/1-75(c)(5). Also, as MidAmerican had not elected to participate in the 2015 Procurement Plan, this initial DG procurement was conducted only for ComEd and Ameren Illinois.

procurements (including procurements for the 2017-2018 delivery year). Chapter 8 contains additional information on how the Agency plans to address the distributed generation and other technology-specific sub-target goals.

2.5.3 Renewable Energy Resources Fund

Separate from the renewable energy procurements approved as part of the Agency's annual procurement plan are procurements made by the IPA from the Renewable Energy Resources Fund ("RERF"). Created through Section 1-56 of the Illinois Power Agency Act, the RERF is a special fund in the Illinois State Treasury administered by the Illinois Power Agency to procure renewable energy resources.[61] Unlike with procurements made to satisfy the requirements of Section 1-75(c) of the IPA Act, procurements made from the RERF are not proposed as part of the Agency's annual plan and do not require Commission approval, and the resulting counterparty for such procurements is the State of Illinois (and not the utilities).[62] Resources procured using the RERF thus cannot be used to meet the utilities' Section 1-75(c) renewable energy resources procurement targets.

The RERF is funded through payments made by Alternative Retail Electric Suppliers ("ARES") to satisfy statutory renewable energy resource procurement obligations manifest in Section 16-115D of the Public Utilities Act.[63] The RERF does not consist of payments made by customers taking supply from their electric utility. Instead, for customers taking supply from an ARES, the ARES is responsible for making an alternative compliance payment for no less than 50% of its compliance obligation,[64] with its payment rate determined by results from the procurement of renewable energy resources using the renewable resources budget (including any previously-entered into contracts, such as the LTPPAs).[65] These alternative compliance payments ("ACPs") are generally made in conjunction with an ARES's self-procurement of the remainder of its renewable energy resource obligation to meet compliance with state's renewable energy portfolio standard.[66]

In recognition of the constraints present in attempting to conduct procurements from the RERF without more express statutory authorization,[67] Public Act 98-0672 created new subsection 1-56(i) of the IPA Act requiring the Illinois Power Agency to develop a plan for conducting a supplemental procurement of renewable energy credits from solar photovoltaics ("SRECs") using up to $30 million from the RERF.[68] The IPA's Supplemental Photovoltaic Procurement Plan was filed with the Commission on October 28, 2014 and approved on January 21, 2015. As called for in the Supplemental Plan, the IPA conducted its first supplemental photovoltaic procurement in May 2015 with a budget of $5 million, its second procurement in November 2015 with a budget of $10 million, and its third procurement in March 2016 with a budget of $15 million.[69] All three procurements resulted in the commitment of the entirety of the respective procurement budgets.

2.6 Energy Efficiency Programs or Measures

Section 16-111.5B of the PUA outlines requirements related to including new or expanded cost-effective energy efficiency programs in the Procurement Plan. The Procurement Plan must include an assessment of opportunities to expand programs under the utilities' existing Commission-approved energy efficiency plans

[61] 20 ILCS 3855/1-56(a).
[62] See generally Docket No. 12-0544, Final Order dated December 19, 2012 at 112-113; Docket No. 15-0541, Final Order dated December 16, 2015 at 147.
[63] 220 ILCS 5/16-115D(d)(4).
[64] 220 ILCS 5/16-115D(b).
[65] 220 ILCS 5/16-115D(d)(1).
[66] In past years, the vast majority of ARES have chosen to pay no more than the minimum percentage (50%) in alternative compliance payments, relying on self-procurement for the remainder.
[67] For further discussion of these constraints, see the IPA's Supplemental Photovoltaic Procurement Plan at 3-4.
[68] See 20 ILCS 3855/1-56(i).
[69] Information about the results of the IPA's supplemental photovoltaic procurements may be found at https://www.ipa-energyrfp.com/supplemental-pv-procurement-section/.

or to implement additional cost-effective energy efficiency programs or measures.[70] To assist in this effort, the utilities are required to provide, along with their load forecasts, an "assessment of cost-effective energy efficiency programs or measures that could be included in the Procurement Plan."[71] This assessment is required to include the following:

- A comprehensive energy efficiency potential study for the utility's service territory that was completed within the past 3 years.[72]
- Beginning in 2014, the most recent analysis submitted pursuant to Section 8-103A of the PUA and approved by the Commission under subsection (f) of Section 8-103 of the PUA.[73]
- Identification of new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 and that would be offered to all retail customers whose electric service has not been declared competitive under Section 16-113 of the PUA and who are eligible to purchase power and energy from the utility under fixed-price bundled service tariffs, regardless of whether such customers actually do purchase such power and energy from the utility.[74]
- Analysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service.[75]
- Analysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply.[76]
- An energy savings goal, expressed in megawatt-hours, for the year in which the measures will be implemented.[77]
- For each expanded or new program, the estimated amount that the program may reduce the agency's need to procure supply.[78]

Both Ameren Illinois and ComEd have provided this information, which is included in the Appendices to this Procurement Plan along with their load forecast information. Alternatively, because MidAmerican does not fall under the purview of Section 8-103 of the PUA,[79] many of the requirements of Section 16-111.5B are not applicable to it; similar to an approach taken with the development of the 2016 Plan (and approved by the Commission in Docket No. 15-0541), MidAmerican has instead provided this information to the extent applicable and offered a statement regarding inapplicability where it is not.[80]

These assessments were delivered to the IPA on July 15, 2016 to aid the Agency in the development of its 2017 Procurement Plan. The PUA requires the Agency to include in its Procurement Plan those energy efficiency programs and measures that it determines are cost-effective, and the utilities are directed to factor in the associated energy savings to the load forecast.[81] If the Commission approves the procurement of this additional efficiency, it shall reduce the amount of power to be procured under the Procurement Plan and shall direct the utility to undertake the procurement of the efficiency resources.[82]

[70] See 220 ILCS 5/16-111.5B(a)(2). Additionally, pursuant to Section 16-111.5B(a)(1), the Agency's analysis required under Section 16-111.5(b)(2) must provide "the impact of energy efficiency building codes or appliance standards, both current and projected." This information is contained in Appendices to the Plan.
[71] 220 ILCS 5/16-111.5B(a)(3).
[72] 220 ILCS 5/16-111.5B(a)(3)(A).
[73] 220 ILCS 5/16-111.5B(a)(3)(B).
[74] 220 ILCS 5/16-111.5B(a)(3)(C).
[75] 220 ILCS 5/16-111.5B(a)(3)(D).
[76] 220 ILCS 5/16-111.5B(a)(3)(E).
[77] 220 ILCS 5/16-111.5B(a)(3)(F).
[78] 220 ILCS 5/16-111.5B(a)(3)(G).
[79] See 220 ILCS 5/8-103(h) ("This Section does not apply to an electric utility that on December 31, 2005 provided electric service to fewer than 100,000 customers in Illinois"); Docket No. 15-0541, Final Order dated December 16, 2015 at 68.
[80] See Docket No. 15-0541, Final Order dated December 16, 2015 at 67-68.
[81] 220 ILCS 5/16-111.5B(a)(4).
[82] 220 ILCS 5/16-111.5B(a)(5).

For purposes of meeting this statutory requirement, "cost-effective" means that the assessed measures pass the total resource cost test as defined in the IPA Act:[83]

> *"Total resource cost test" or "TRC test" means a standard that is met if, for an investment in energy efficiency or demand-response measures, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the program to the net present value of the total costs as calculated over the lifetime of the measures. A total resource cost test compares the sum of avoided electric utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided natural gas utility costs, to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side program, to quantify the net savings obtained by substituting the demand-side program or supply resources. In calculating avoided costs of power and energy that an electric utility would otherwise have had to acquire, reasonable estimates shall be included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases.*[84]

Each year, new issues relating to the implementation of Section 16-111.5B are raised in the Commission proceedings approving the IPA's annual plan. Resolution (or at least further discussion) of these issues is often deferred to workshop processes ordered by the Commission for the months immediately following the conclusion of the docket. Further discussion of the energy efficiency-related workshops required from the Order approving the 2016 Plan and the contested issues addressed therein, as well as the "energy efficiency programs and measures [the IPA] determines are cost-effective" and thus fit for inclusion in this Plan, may be found in Chapter 9.

Additionally, past years' disputes have resulted in a series of Commission-mandated workshops leading to consensus language being reached among stakeholders. Workshops held in 2016 resulting in an updating of those consensus items and the development of new consensus language around previously contested issues. Specific consensus items are included in Chapter 9 (Prior Year Consensus Items) and in the attached SAG Workshop Subcommittee Report (Appendix H), and the IPA expressly requests that such language be approved by the Commission with the intention that it be binding upon the planning of, implementation of, reporting on, and evaluation, measurement, and verification of savings of the energy efficiency programs approved as part of the 2017 Plan, and applied prospectively to inform the requests for proposals developed by the utilities pursuant to Section 16-111.5B(a)(3) for the solicitation of programs to be included in the 2018 Procurement Plan.

2.7 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."[85] Under the PUA, cost-effective demand-response measures may be procured whenever the cost is lower than procuring comparable capacity products, if the product and company offering the product meet minimum standards.[86] Specifically:

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;

[83] See 220 ILCS 5/16-111.5B(b) ("For purposes of this Section, the term 'energy efficiency' shall have the meaning set forth in Section 1-10 of the Illinois Power Agency Act, and the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act.); 220 ILCS 5/8-103(a) ("As used in this Section, 'cost-effective' means that the measures satisfy the total resource cost test.").
[84] 20 ILCS 3855/1-10.
[85] 220 ILCS 5/16-111.5(b)(3)(ii).
[86] Id.

- 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;[87]
- The products must provide for customers' participation in the stream of benefits produced by the demand-response products;
- The provider must have a plan for the reimbursement of the utility for any costs incurred as a result of the failure of the provider to perform its obligations;[88]; 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.[89]

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.[90] 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.[91] These programs are discussed further in Section 7.4, where demand response resource choices are examined.

2.8 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.[92] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[93] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[94] Section 1-75(d) describes two special cases: the "initial clean coal facility"[95] 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").[96] 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.[97] 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.[98] The FutureGen Alliance's Board of Directors "approved a resolution, dated January 6, 2016, ceasing all FutureGen Project development efforts"[99] 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

[87] 220 ILCS 5/16-111.5(b)(3)(ii)(A)-(B).
[88] 220 ILCS 5/16-111.5(b)(3)(ii)(C)-(D).
[89] 220 ILCS 5/16-111.5(b)(3)(ii)(E).
[90] 220 ILCS 5/16-108.6(g).
[91] 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.
[92] 20 ILCS 3855/1-75(d).
[93] 20 ILCS 3855/1-75(d)(1).
[94] 20 ILCS 3855/1-10.
[95] Id.
[96] 20 ILCS 3855/1-75(d)(5).
[97] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2014 IL App (1st) 130544, July 22, 2014.
[98] See, e.g., http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead.
[99] Supplemental Brief of Appellee FutureGen Industrial Alliance, Inc. on the Issue of Mootness, dated January 13, 2016, at 1.

Commission's Order approving the 2013 Procurement Plan concerning FutureGen 2.0 sourcing agreements and related authority.[100]

2.9 2015-2016 Legislative Proposals and Related Developments

The 99th Illinois General Assembly (inducted in January 2015 and concluding in January 2017) has seen the introduction of a number of legislative proposals that would significantly change the scope or direction of the Illinois Power Agency's planning and procurement processes. Introduced legislation has included proposals to require the Agency to procure zero-emission credits to provide additional revenue to nuclear power generating facilities in Illinois at risk of closure, increase targets in the state's renewable energy portfolio standard and focus the Agency's efforts on procuring renewable energy resources from newly developed projects, eliminate the Section 16-111.5B mechanism for including incremental energy efficiency programs in IPA procurement plans (while expanding electric utility energy efficiency requirements under Section 8-103 of the PUA), and require the Agency to develop low-income and community solar programs to encourage the development of additional solar photovoltaics projects while providing new pathways for photovoltaic project participation.[101]

As of the filing of this Plan with the Commission, the Agency understands that these proposals—and, possibly, additional proposals that could impact the IPA's procurement authority[102]—are still being actively negotiated by interested stakeholders. Additional legislative session dates for 2016 are currently scheduled for November 15-17 and November 29-December 1, and further dates could be added should unfinished business remain. At this time, it is unclear what changes (if any) will be made to the Agency's powers and responsibilities through legislation in the 99th General Assembly. The Agency will continue to actively track the status of these bills (and provide technical feedback on any such proposals whenever possible) and any other legislation that could change its powers, duties, and objectives.

In addition, on August 3, 2015, the United States Environmental Protection Agency ("U.S. EPA") released its Clean Power Plan rules promulgated pursuant to Section 111(d) of the Clean Air Act. These rules require states to develop strategies intended to reduce carbon dioxide emissions from power plants. On February 9, 2016 the U.S. Supreme Court stayed implementation of the Clean Power Plan pending judicial review.[103] 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 issued in litigation has delayed the timing for the state compliance plan development. Assuming a favorable outcome of the litigation for the U.S. EPA, the development of the Illinois state compliance plan may generate additional legislation of relevance to the Agency.

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

[101] The latest and most comprehensive proposal can be found in amendments to Senate Bill 1585, with the most recent amendment to that bill having been filed on May 27, 2016.

[102] See http://www.chicagobusiness.com/article/20160910/ISSUE01/309109997/why-is-nuke-giant-exelon-touting-a-subsidy-for-coal-fired-power

[103] 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.

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."[104] 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 incremental amounts of electricity,[105] thus making it also subject to statutorily mandated renewable resources procurement targets for its eligible retail customers in Illinois.[106] 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.[107]

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.*[108]

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:

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[104] 220 ILCS 5/16-111.5(a).

[105] 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.

[106] 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 second procurement process in which MidAmerican elected to have the IPA procure power and energy for a portion of its Illinois jurisdictional load.

[107] 220 ILCS 5/16-111.5(b)(1).

[108] 220 ILCS 5/16-111.5(d)(1).

- Ameren Illinois Company Load Forecast for the period June 1, 2017 – May 31, 2022 (See Appendix B)
- Electric Energy Efficiency Compliance with 220 ILCS 5/16-111.5B. This document also contained six Appendices. (See Appendix B. Note, Appendix 4 [Bidder Confirmations] and Appendix 6 [Detailed Bid Analysis] were marked confidential and are not included in Appendix B as part of this Plan.) Ameren Illinois also separately provided to the IPA its most recent energy efficiency potential study, and on a confidential basis, each Section 16-111.5B bid received.
- Spreadsheets of the expected (base), high, and low load forecasts.
- Supplemental spreadsheets detailing the renewable portfolio standard targets and budgets under each scenario, capacity needs under each scenario, and the impact on the expected (base) load forecast of incremental energy efficiency programs. (Summarized in Appendix E)

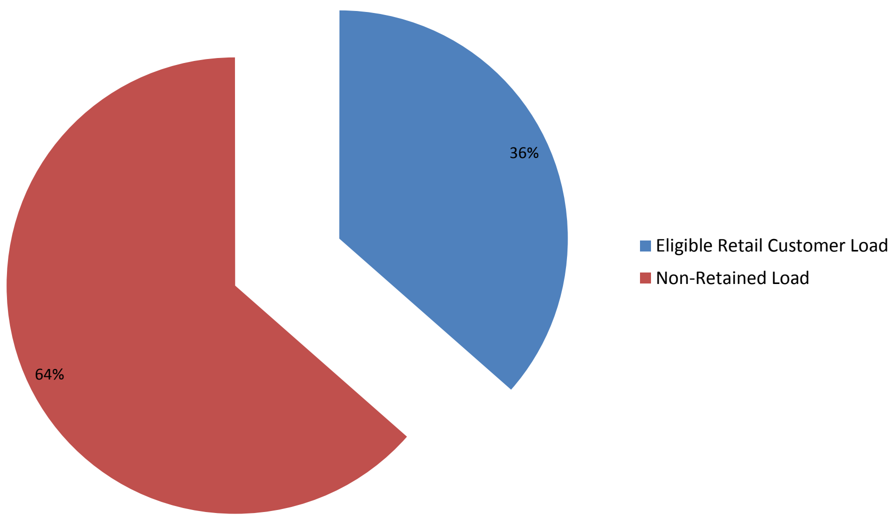
Ameren Illinois uses a combination of statistical and econometric modeling approaches to develop its customer class specific load forecast models. A Statistically Adjusted End-use approach is used for the residential and commercial customer classes. This approach combines the econometric model's ability 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.[109]

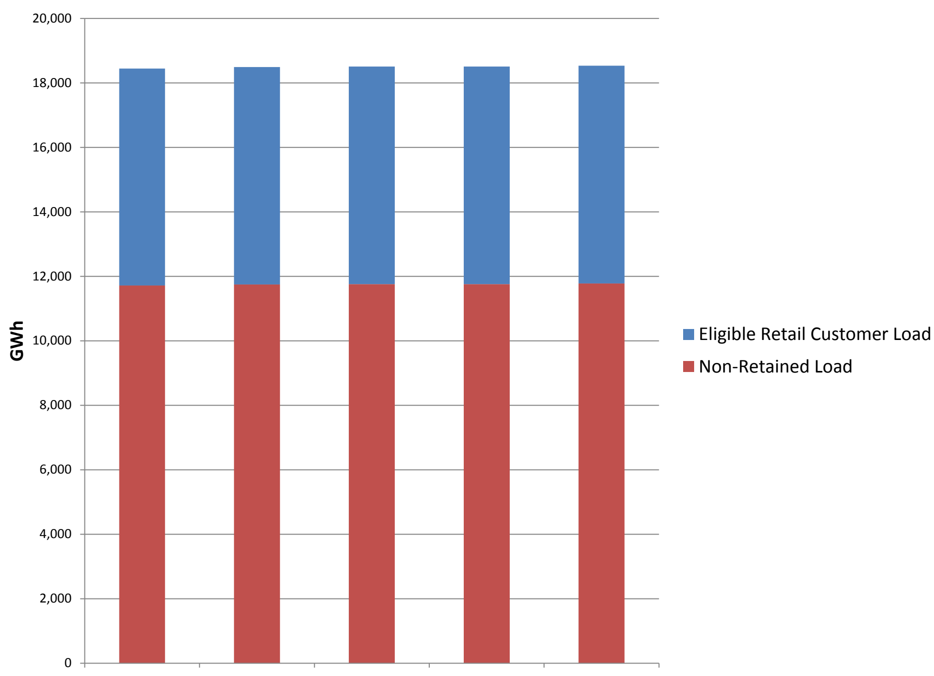
[109] Ameren Illinois assigns load profile classifications at the point of service level and only to points of service that are metered. The classifications are as follows: DS1 – Residential, DS2 – Non-Time of Use Commercial & Industrial with demands less than 150 kW, DS3 – Time of Use Commercial & Industrial 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 3-1: Ameren Illinois' Forecast Retail Customer Load Breakdown, Delivery Year 2017-2018



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.

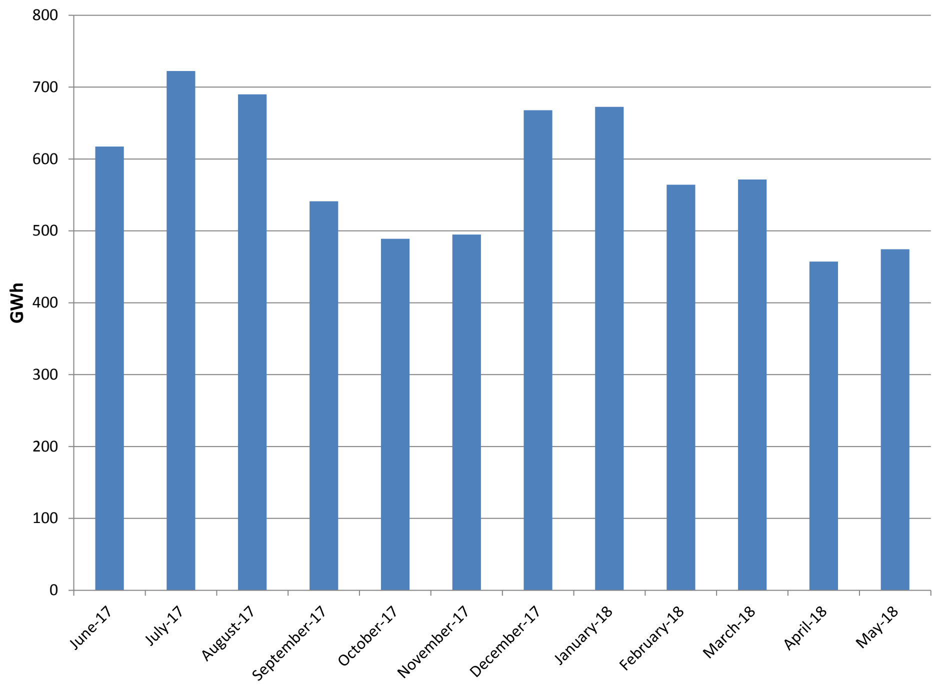
Figure 3-2: Ameren Illinois' Forecast Retail Customer Load by Delivery Year



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), municipal aggregation, or other Alternative Retail Electric Suppliers ("ARES"). 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 forecast load attributed to Rider HSS, municipal aggregation, and other ARES customers, is subtracted from the total system load forecast. The result is the forecasted load to be supplied by Ameren 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 forecast 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 increase 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	0.920	1.080
DS2	0.883	1.117
DS5	0.920	1.080

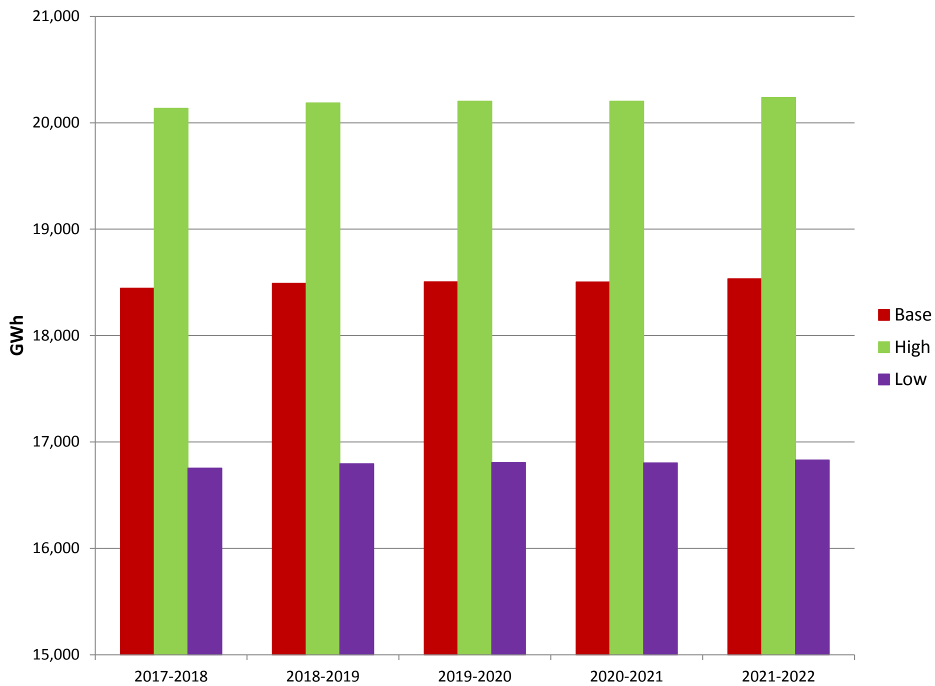
In regression models, residuals indicate the difference between the predicted and actual values. Patterns associated with residuals may indicate the impact of non-specified variables. Because the excursion cases are based on the statistics of the residuals, they reflect the influence of variables not 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 9% lower than the base case and the high case is about 9% higher than the base case.

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



3.2.3 Switching

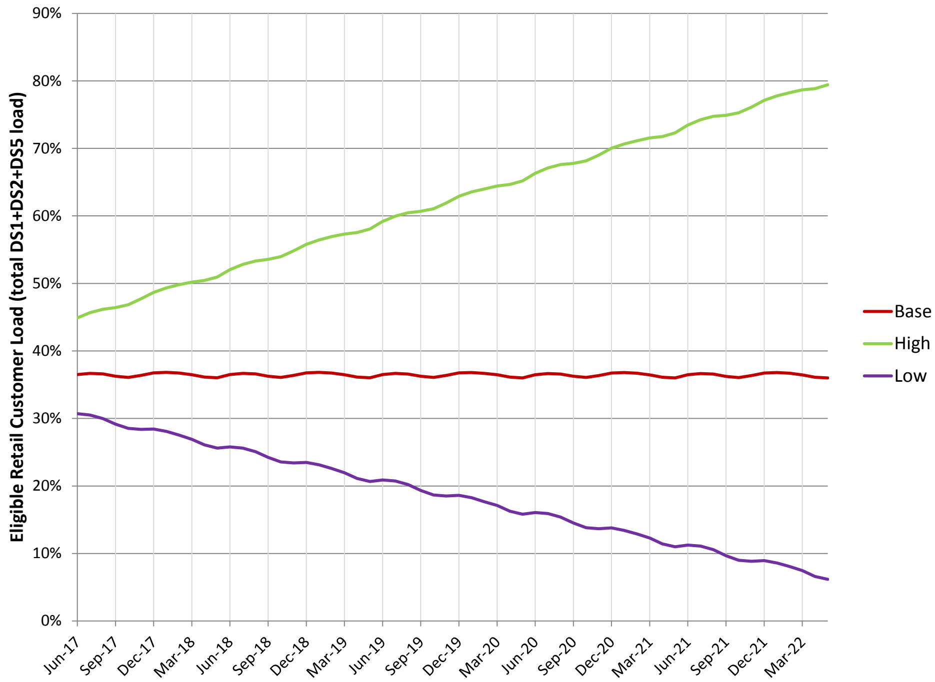
According to Ameren Illinois, customer switching to alternative suppliers, in particular through municipal aggregation, is the greatest driver of load uncertainty. Switching through April 2016 has resulted in approximately 62-65% of residential and small commercial load seeking service from alternative suppliers. 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, according to 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. Residential and small commercial switching rates under the low switching and a corresponding high load scenario are forecasted to be 47% and 50%, respectively, in May 2018, 39% and 43%, respectively, in May 2019, and 18% and 21%, respectively, by the end of the planning horizon.

Conversely, should future Ameren Illinois tariff price 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 72% and 75%, respectively, in May 2018, 76% and 80%, respectively, in May 2019, and 91% and 94%, 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.

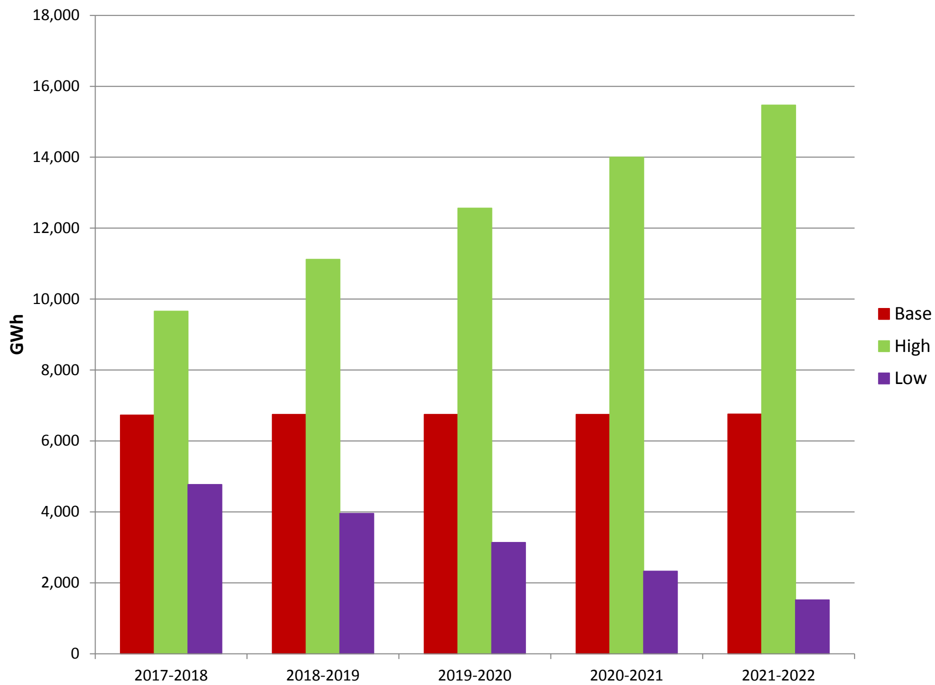
Figure 3-5: Utility Load Retention in Ameren Illinois' Forecasts



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

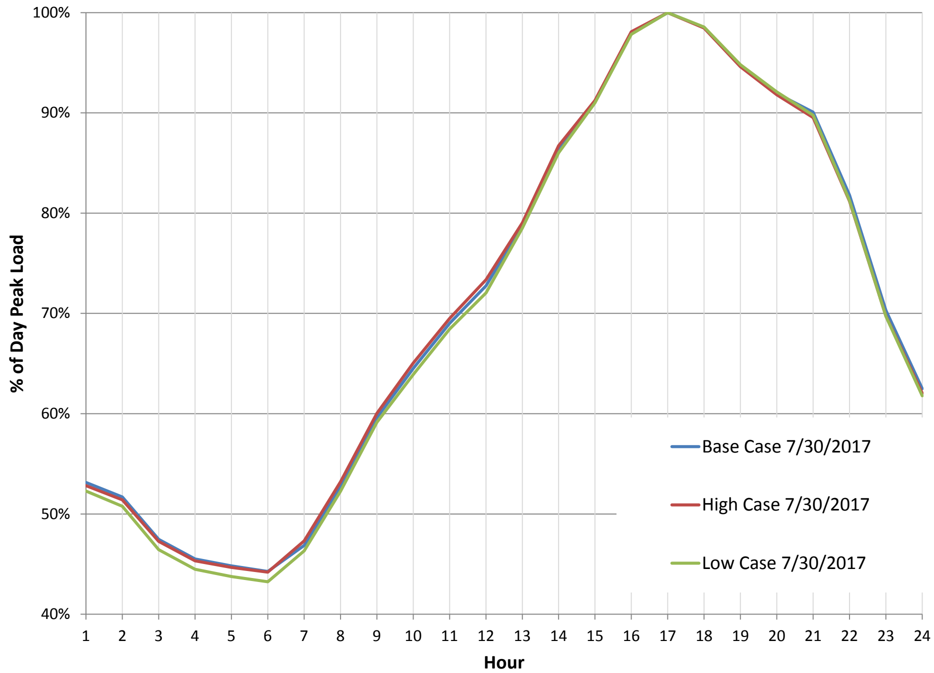
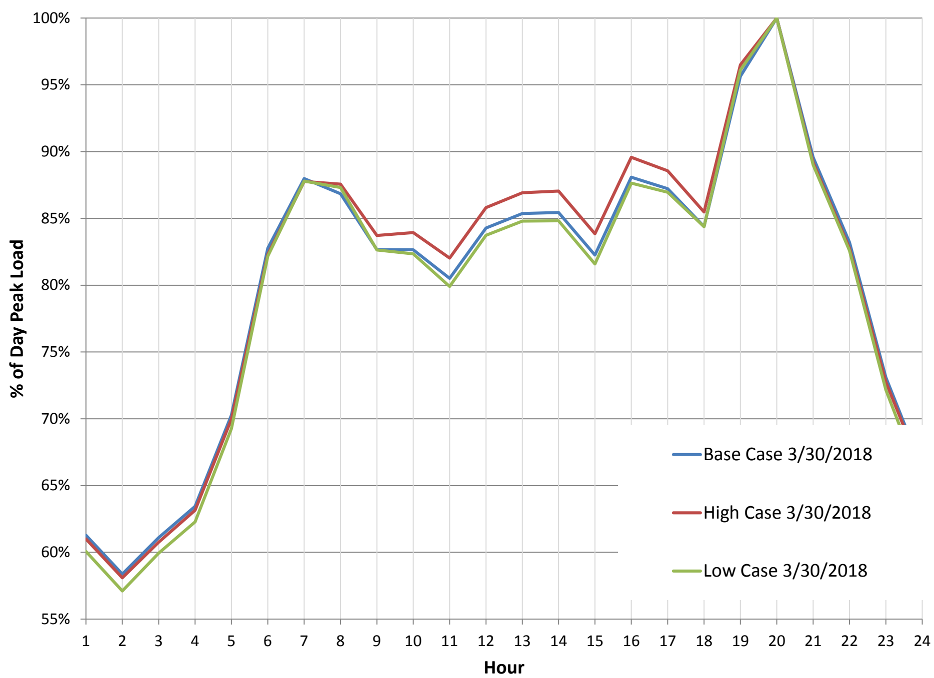
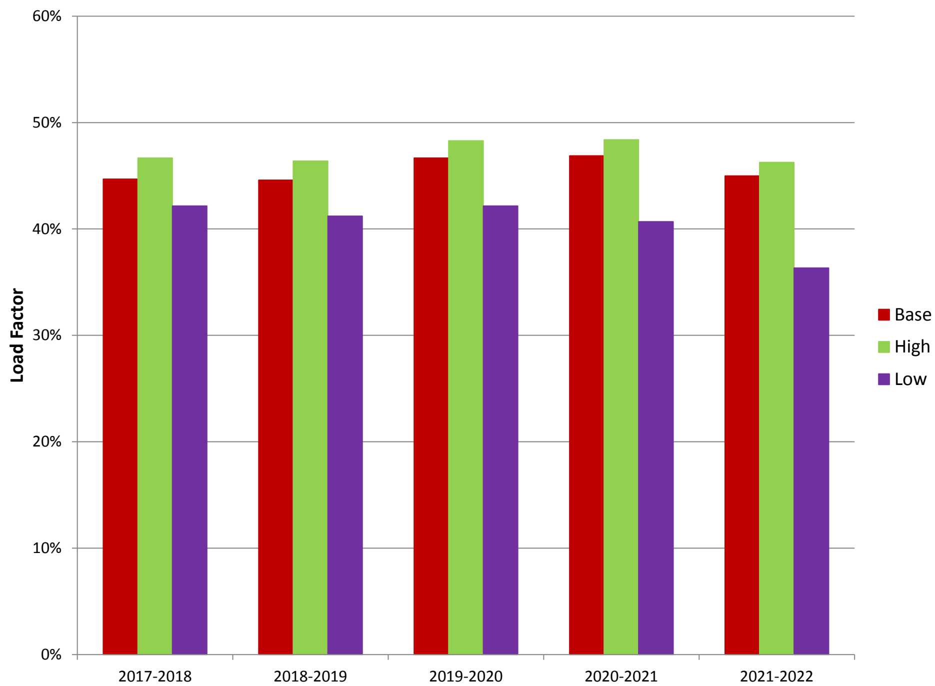


Figure 3-8: Sample Daily Load Shape, Spring Day in Ameren Illinois' Forecasts



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

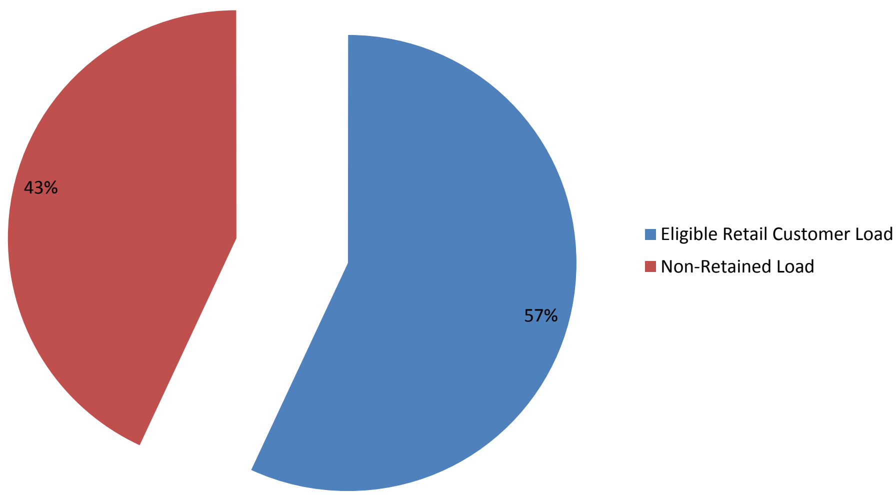
In compliance with Section 16-111-5(d)(1) of the Public Utilities Act, ComEd provided the IPA the following documents for use in preparation of this plan:

- *Load Forecast for Five-Year Planning Period June 2017 – May 2022.* This document also contained Appendices A-D. Four of the Appendices are included in the main document, while one (ComEd Appendix C) with supplemental information on Section 16-111.5B incremental energy efficiency programs was included as five additional separate documents. (See Appendix C. Note, ComEd also provided an additional document entitled, *Third Party Efficiency Program Results of 2016 Bid Review* which was marked confidential and is not included in Appendix C.).
- 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 Retail Customer Load Breakdown, Delivery Year 2017-2018



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 downs 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 Retail Customer Load by Delivery Year

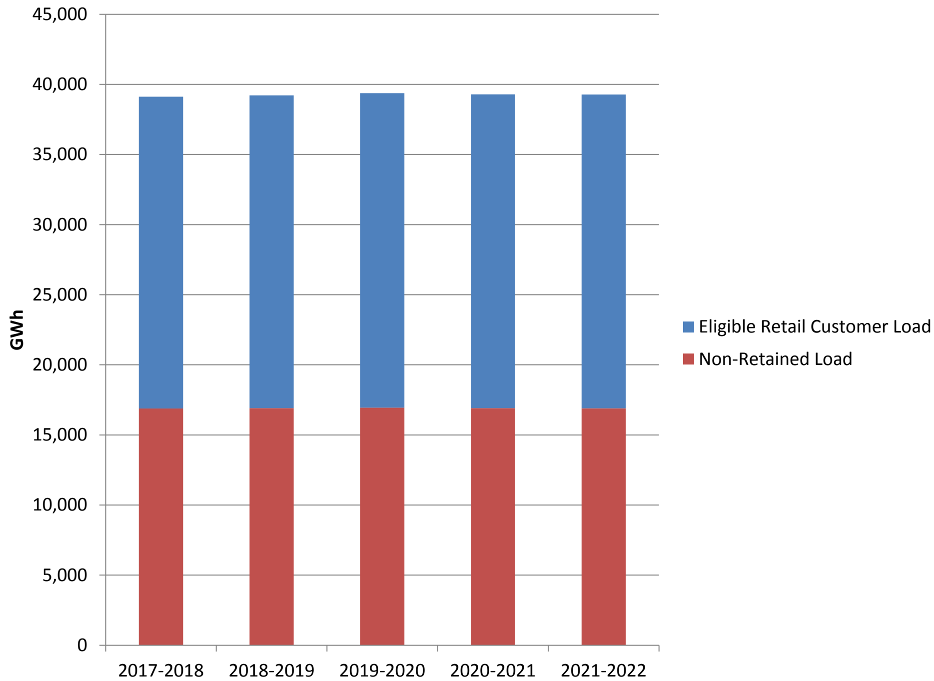
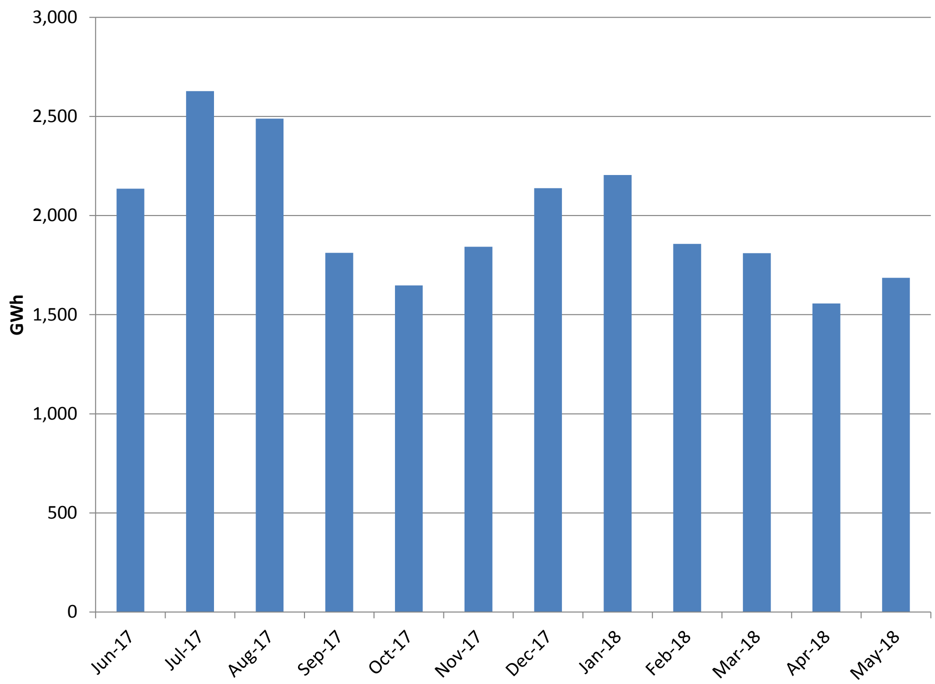


Figure 3-12 provides a monthly breakdown of the base-case forecast of ComEd's eligible retail customer load, that is, the load of customers who are forecast to take bundled supply under this Procurement Plan.

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

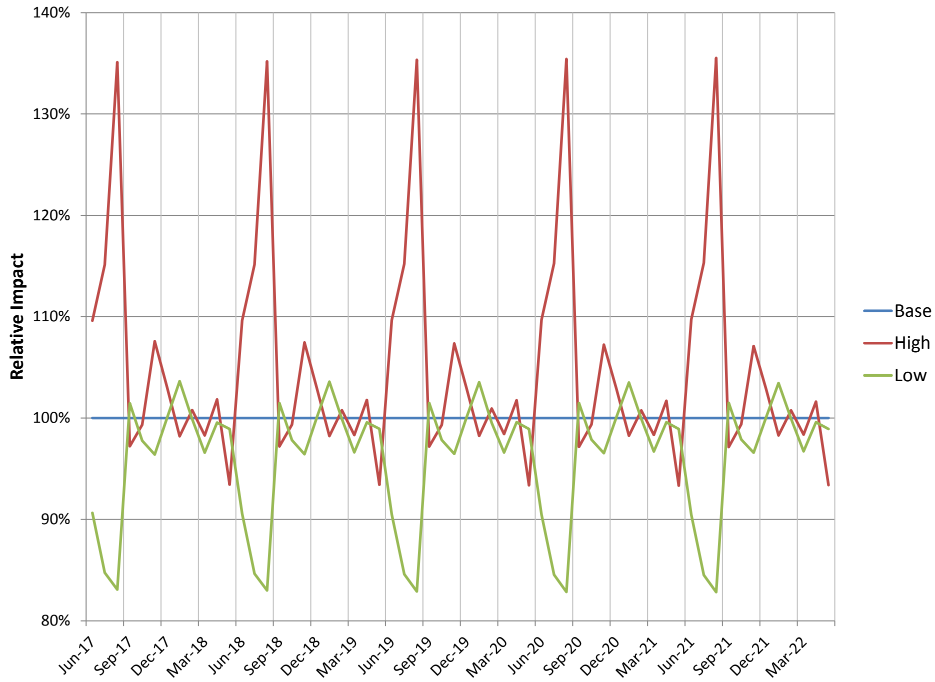
ComEd's base case load forecast is driven by a Zone Model that includes both macroeconomic variables (Gross Metropolitan Product for Chicago and other metropolitan areas within ComEd's service territory, household income) and demographics (household counts). ComEd did not use this model to define "high" 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

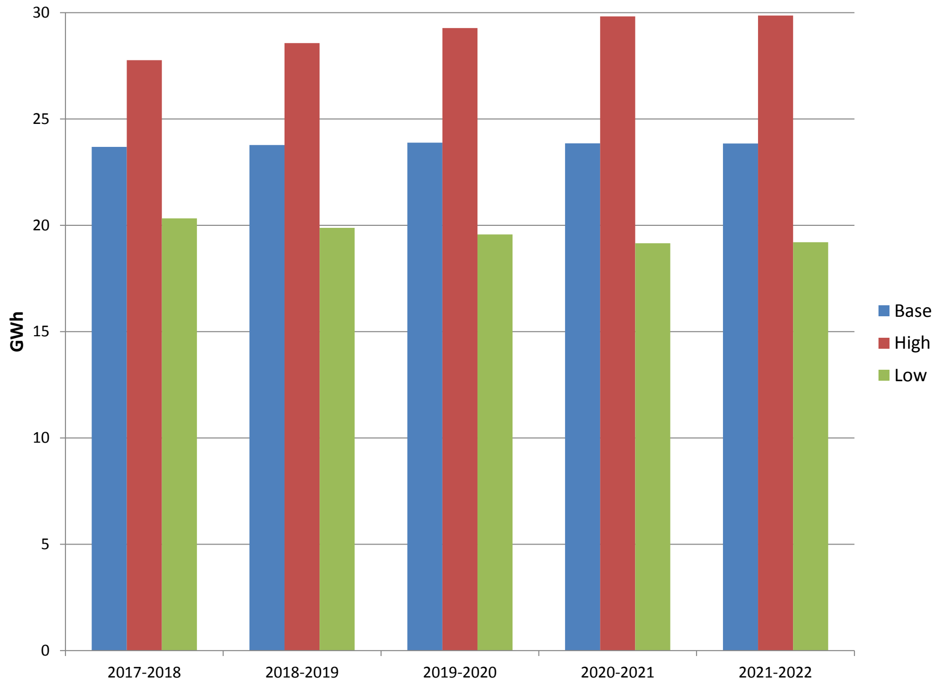


3.3.3 Switching

The high switching (low load) case assumes residential ARES usage to be at 85% (vs. the 60% base case assumption) in the years 2017 and 2018 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 2016. That is a very small increase from the 357 communities reported last year. In addition, it is assumed that small commercial switching increases initially by 1.2% and then by another 2.4% over the next 2 years.

The low switching (high load) case assumes additional communities opt out of municipal aggregation in the years 2017 and 2018 such that residential ARES usage declines to approximately 35% in the years 2017 and 2018. This coincides with an initial 1.2% decrease and a further decline by another 2.4% in small commercial switching over the next 2 years. 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 summer day, both the base case and low case are less peaky than the high case; and 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

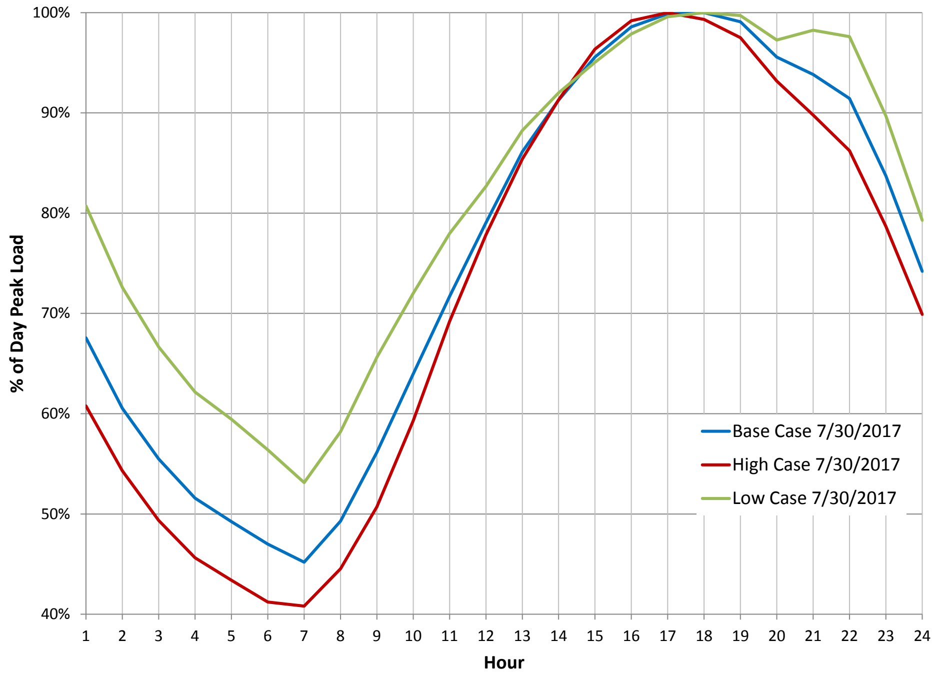
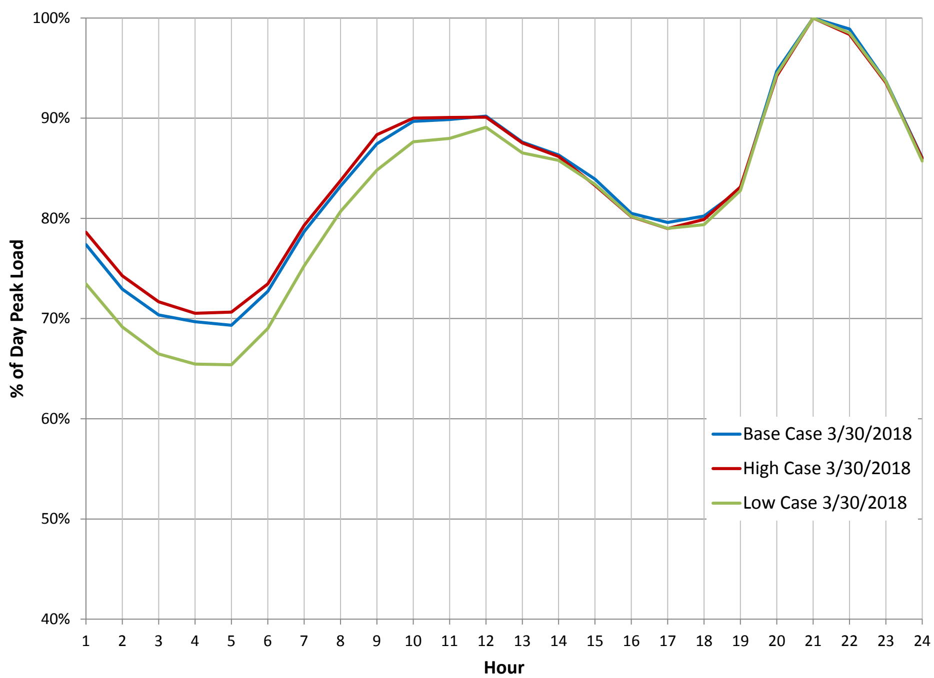
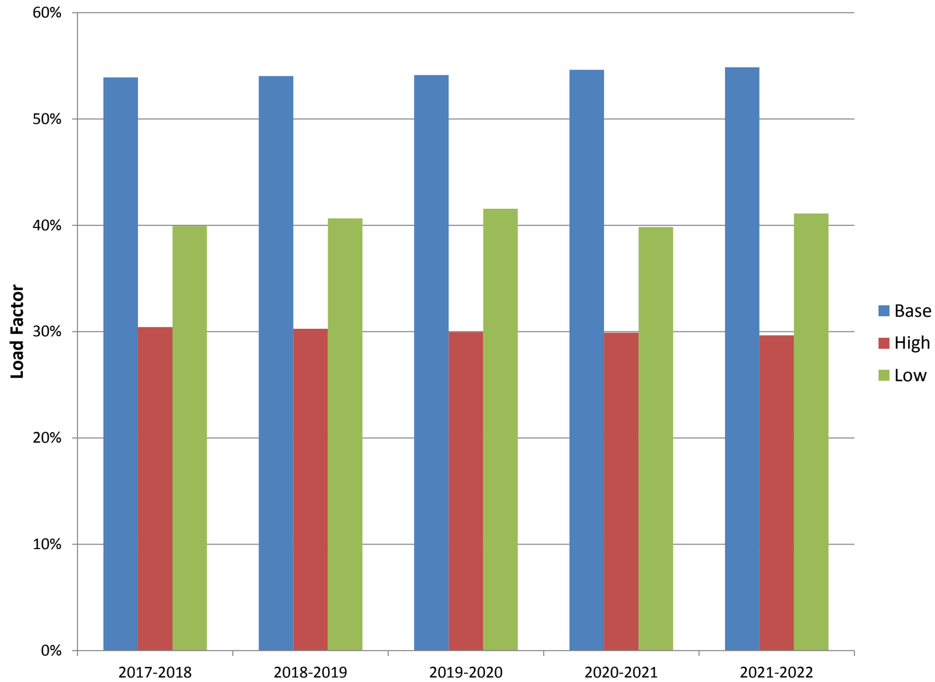


Figure 3-16: Sample Daily Load Shape, Spring Day in ComEd's Forecasts



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:

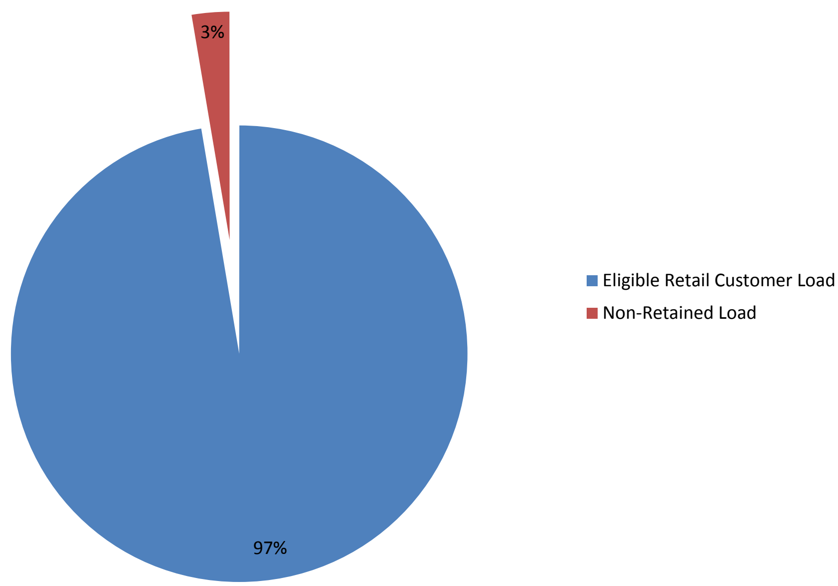
- *Methodology for Illinois Electric Customers and Sales Forecasts: 2017-2026.* This document contained a discussion of load forecast methodology for all MidAmerican scenarios and supporting data for the base scenario forecast. The load forecast included a multi-year historical analysis of hourly load 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.
- *MidAmerican Energy Company: Election to Procure Power and Energy for a Portion of its Eligible Illinois Retail Customers, Procurement Year – 2017.* This document provided energy efficiency disclosures required under Section 16-111.5B of the PUA and further information relating to MidAmerican's load forecasts and energy efficiency, and was sent along with MidAmerican's latest energy efficiency potential study and information related to energy efficiency programs currently operating in the MidAmerican service territory.
- 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 2017-2018



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

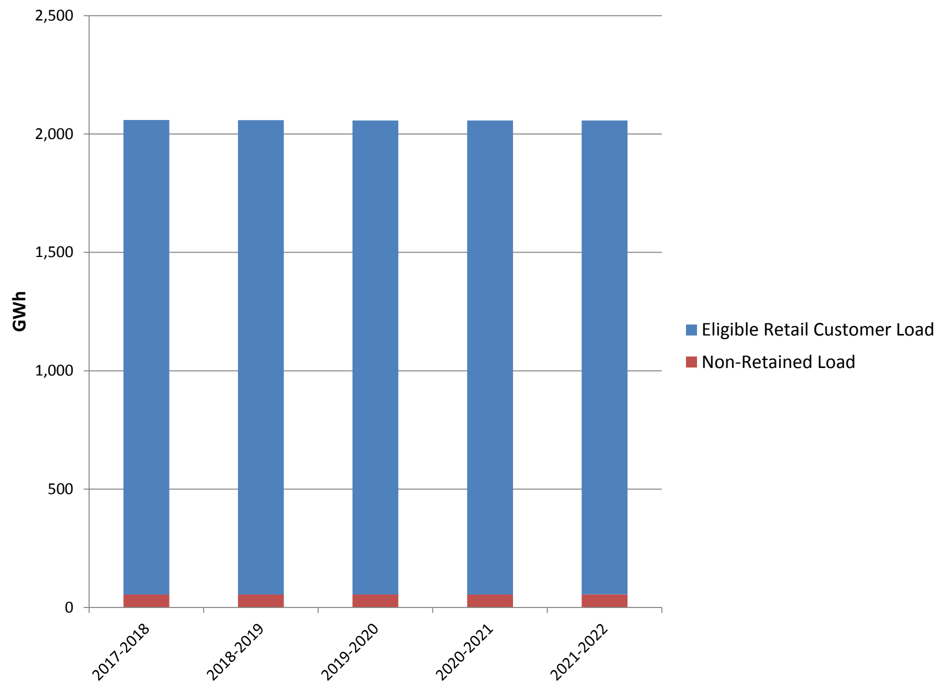
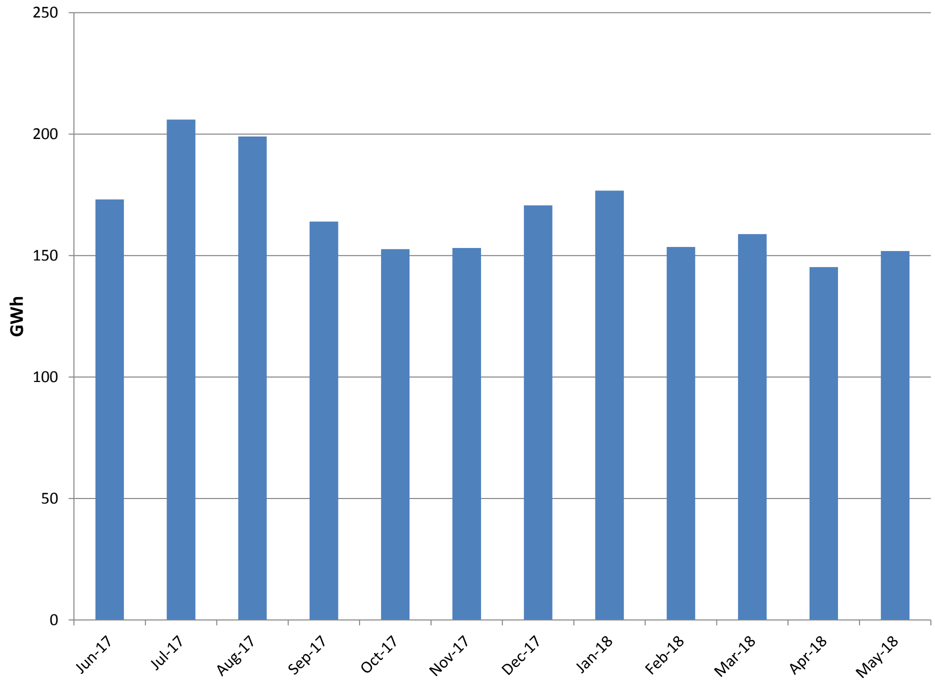


Figure 3-20 provides a monthly breakdown of the base case forecast of MidAmerican retained eligible retail customer load, that is, the load of customers on bundled supply to be considered under this Procurement Plan.

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 and the 95% confidence interval around the non-coincident gross peak demand forecast. The load forecasting software used for the sales, customers use per customer and non-coincident peak demand forecasts, provided the upper and lower bounds of a 95% confidence interval around each monthly forecast value. 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.

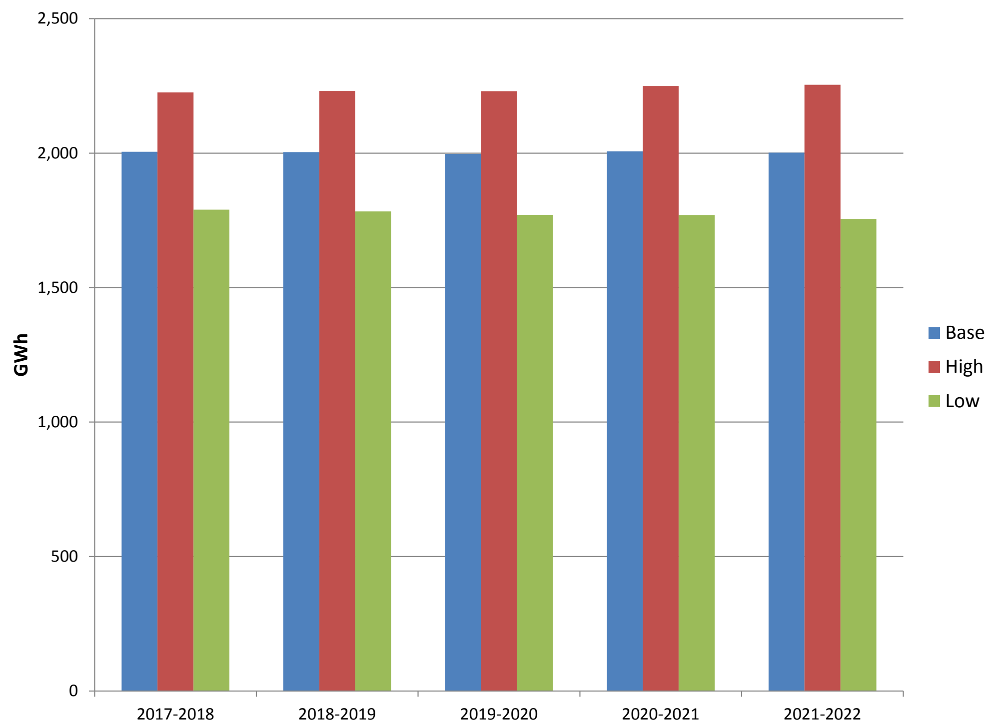
3.4.2 Weather

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

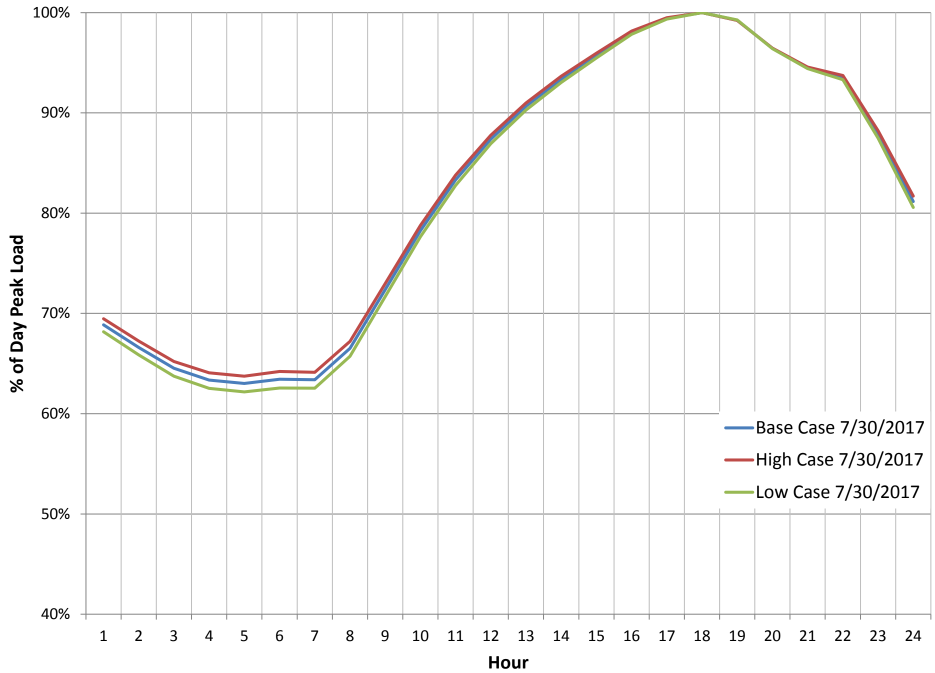
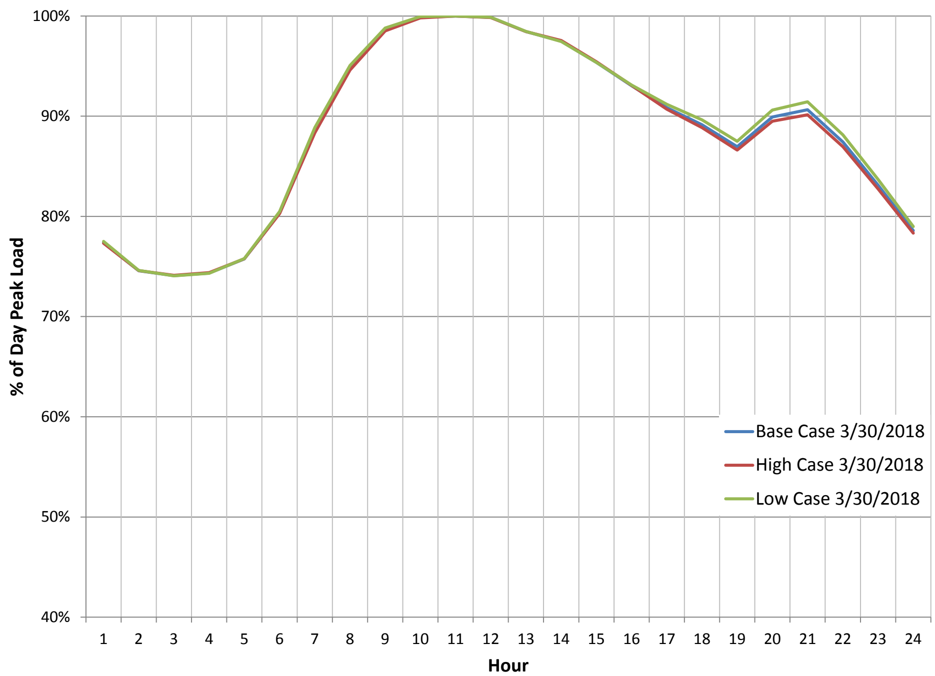
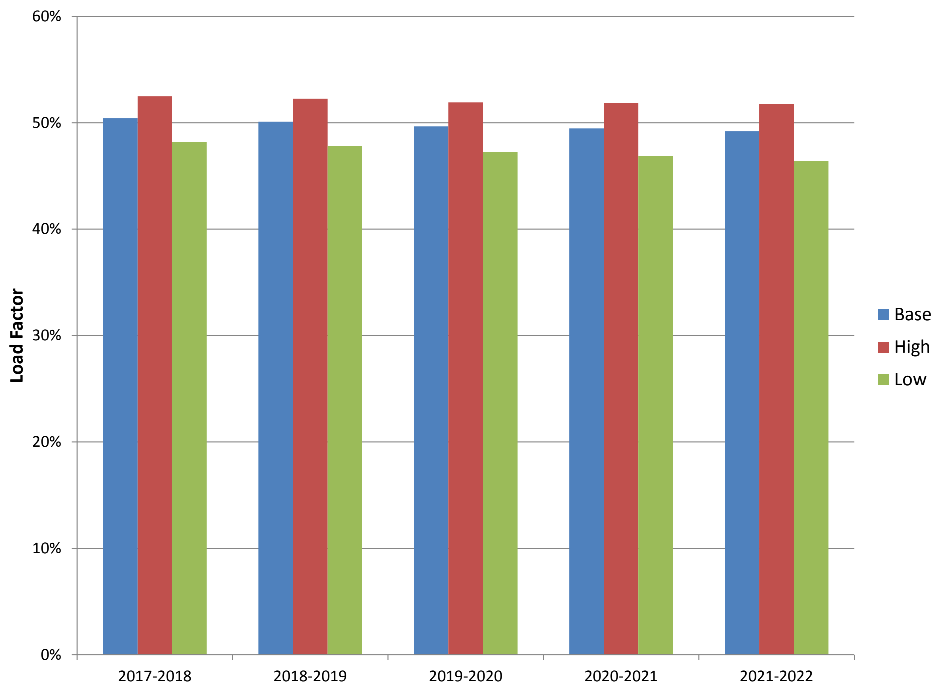


Figure 3-23: Sample Daily Load Shape, Spring Day in MidAmerican's Forecasts



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 46-52% 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 ±9% 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

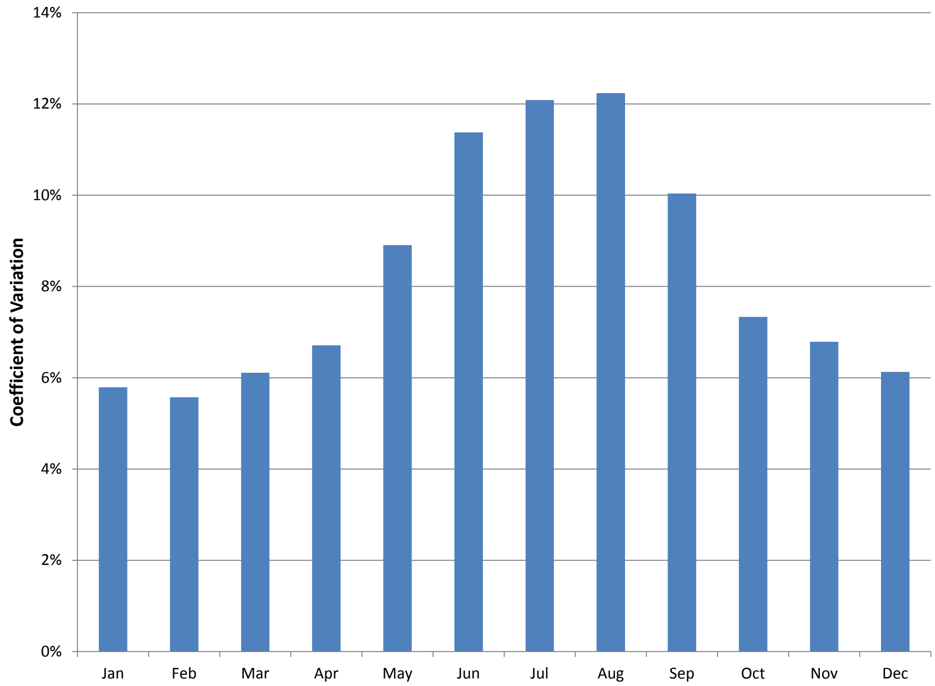
On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The discussion of high and low scenarios in Sections 3.2.2, 3.3.2, and 3.4.2 notes the way that Ameren Illinois, ComEd, and MidAmerican 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.

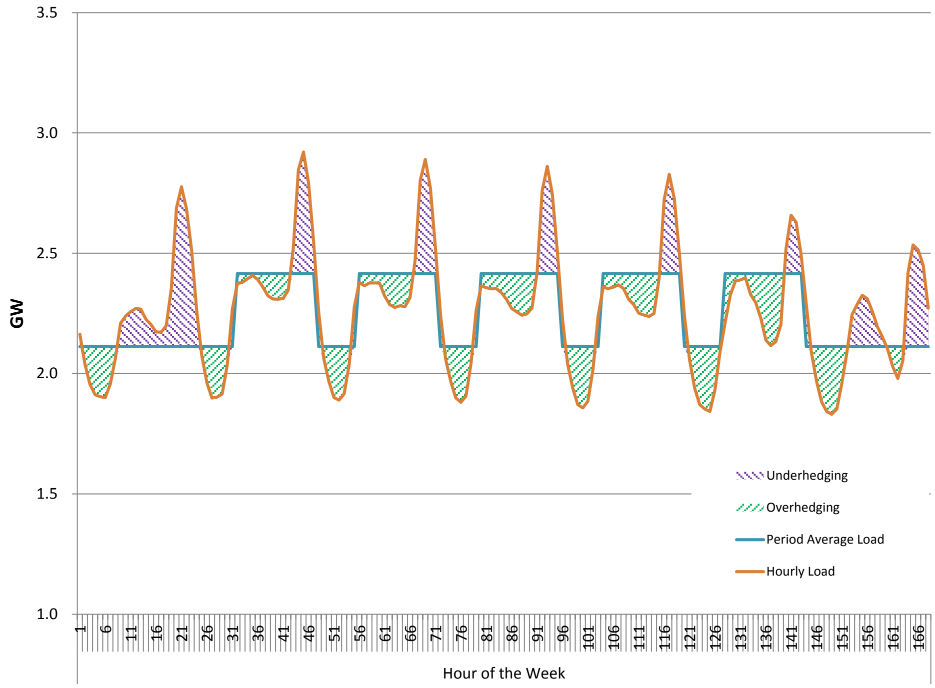
Figure 3-25 illustrates this disconnect by showing, for each month, the average historical "daily coefficient of variation" for peak period loads. This figure is based on historical ComEd loads from 2009 through 2015, normalized to the monthly base case forecasts in the first delivery year. To calculate 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[110] will have switched away from Ameren Illinois fixed price tariff by the end of the 2017-2018 delivery year. This level represents an increase in the switching statistics from the 58% assumed in the July 2015 forecasts and is informed by higher than forecasted actual switching through April 2016 driven in part by communities deciding to renew their municipal aggregation programs with alternative suppliers. Savings opportunities that existed prior to 2014 drove the growth in residential switching, and the trend has continued in 2016. A temporary decline in switching to ARES in 2015 may be attributed to the effect of the polar vortex and various municipal aggregation communities suspending their programs. ComEd projects 43% switching to ARES by potentially eligible retail customers by the end of the 2017-2018 delivery year, which represents a decline from the 46.2% switching rate assumed in the July 2015 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.[111]

[110] "Potentially-eligible retail customer load" refers to the load of those customers eligible to take bundled service from the utility.
[111] For more information on choices offered by ARES, see the 2016 Annual Report of the ICC Office of Retail Market Development at http://www.icc.illinois.gov/downloads/public/2016%20ORMD%20Section%2020-110%20report.pdf.

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 that currently exists between the utility price to compare[112] and representative ARES prices[113] available to eligible utility customers. It appears that, currently, ARES fixed price offers for a similar term to the utility price do not 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[114] and Utility Price to Compare

Utility Territory	Utility Price to Compare (¢/kWh)	Representative ARES Price (¢/kWh)
Ameren Illinois (Zone I)	6.51	6.69
Ameren Illinois (Zone II)	6.51	6.73
Ameren Illinois (Zone III)	6.51	6.71
ComEd	6.39	7.12

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 also created a requirement for ComEd and Ameren Illinois to offer cost-effective energy efficiency and demand response measures to all customers.[115] Both Ameren Illinois and ComEd have incorporated the impacts of these statutory and spending-capped efficiency goals, as applied to eligible retail customers, as well as achieved and projected savings in the forecasts that are included with this Procurement Plan. Chapter 9 of this plan discusses the proposed incremental energy efficiency programs that have been submitted pursuant to Section 16-111.5B. These programs are reflected in the load forecasts. Pursuant to a separate provision in the Public Utilities Act,[116] MidAmerican also has energy efficiency programs operating in its Illinois service territory. MidAmerican expects that the projected energy efficiency program impact would be consistent with the historical levels; therefore, no adjustment was made to the forecasting models.

[112] July 2016 utility cost to compare from http://www.pluginillinois.org/MunicipalAggregation.aspx.
[113] Representative ARES prices are an average of 12-month fixed price offers from ARES available at http://www.pluginillinois.org/OffersBegin.aspx as of September 27, 2016.
[114] Offers without an explicit premium renewable component.
[115] See P.A. 95-0481 (Section originally codified as 220 ILCS 5/12-103).
[116] See 220 ILCS 5/8-408.

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

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.[117] As of the first quarter of 2016, the U.S. DOE listed 201 operational battery-based storage systems with a total capacity of 405 MW operating in the U.S. Illinois was listed as having 12 projects with 73 MW in operation, placing it among the leaders in states with battery storage projects currently in operation. However, it is too early to forecast the impact on load forecasts, and the Agency notes that there are not clear provisions in Illinois law to encourage the adoption of these technologies. The Agency will continue monitor the development of the 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. The IPA also recommends that the Commission approve the additional incremental energy efficiency programs and measures as presented in Chapter 9. The March 2017 load forecasts should also reflect those newly approved programs.

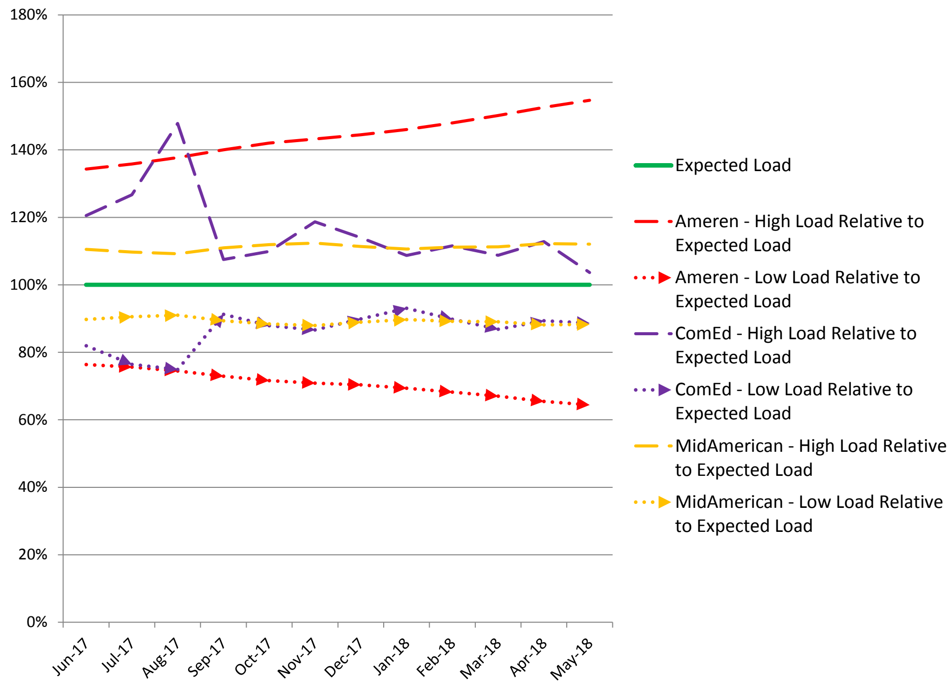
3.6.2 High and Low Excursion Cases

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 71% and 144% of the base case forecast, respectively, during the 2017-2018 delivery year. Comparatively, for the same period, ComEd's low and high load forecasts are on average equal to 86% and 116% 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 89% and 111%, 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.

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

Figure 3-27: Comparison of Ameren Illinois, ComEd, and MidAmerican High and Low Forecasts for Delivery Year 2017-2018



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 purchased 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.[118] 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.[119] The 2016 Procurement Plan included procurement of energy supply to meet the needs of MidAmerican's eligible retail customers as well as those of ComEd and Ameren Illinois. 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 2017-2018 delivery year will be targeted for procurement. The fall procurement event will bring the targeted hedge levels to 100% for October through May of the 2017-2018 delivery year. A portion of the targeted hedge levels for the 2018-2019 and the 2019-2020 delivery years of 50% and 25%, respectively, will be acquired spread on an equal basis in the spring and fall procurement events.

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.[120]

Under the current utility load forecasts, which contemplate relatively flat customer switching, curtailment of the Ameren Illinois and ComEd LTPPAs is unlikely for the 2017-2018 delivery year. MidAmerican is not covered by either LTPPAs or Rate Stability procurements.

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.[121]

[118] See 2014 IPA Procurement Plan at 93.
[119] http://www2.illinois.gov/ipa/Pages/Prior_Approved_Plans.aspx.
[120] P.A. 97-0616 also mandated associated REC procurements, but these REC procurements do not impact the (energy) resource portfolio.
[121] Docket No. 12-0544, Final Order dated December 19, 2012 at 228-237; see also Docket No. 13-0034, Final Order dated June 26, 2013 ("Phase II" approving sourcing agreement as required in Docket No. 12-0544).

However, DOE funding support for FutureGen 2.0 has been suspended, terminating development of the project.

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.

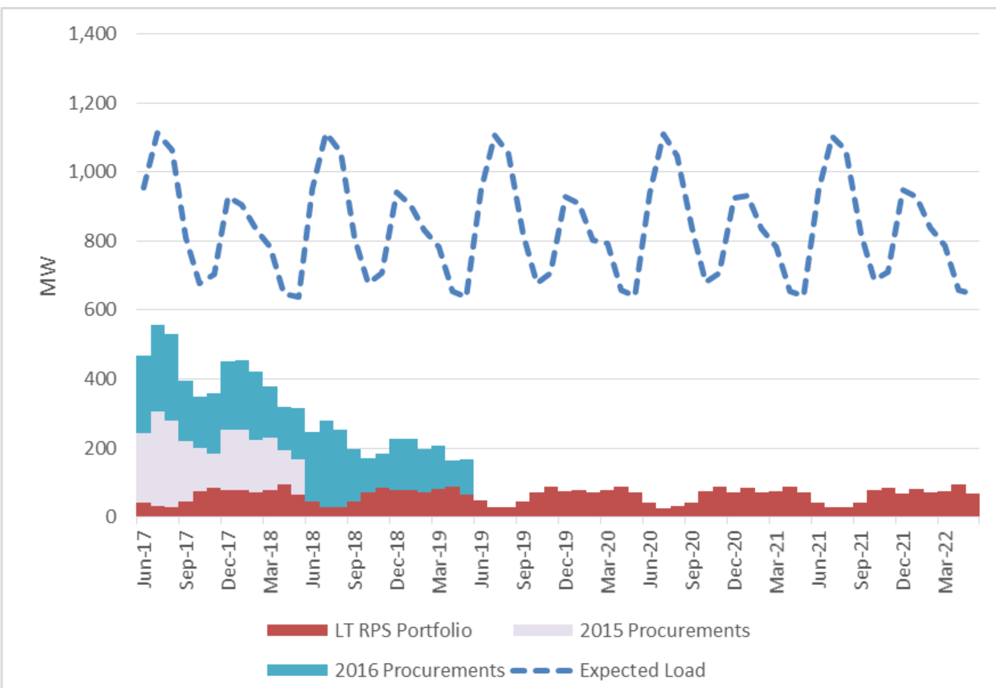
4.1 Ameren Illinois Resource Portfolio

Figure 4-1 shows the current supply gap in the Ameren Illinois supply portfolio for the five-year, June 2017 through May 2022, planning period, using the base case on-peak forecast described in Chapter 3.

Ameren Illinois' existing supply portfolio, including long-term renewable resource contracts, is not sufficient to cover the projected load for the 2017-2018 delivery year. Additional energy supply will be required for the entire 5-year planning period. Approximately 62% of the Ameren Illinois residential 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 2017-May 2022 Period - Base Case Load Forecast



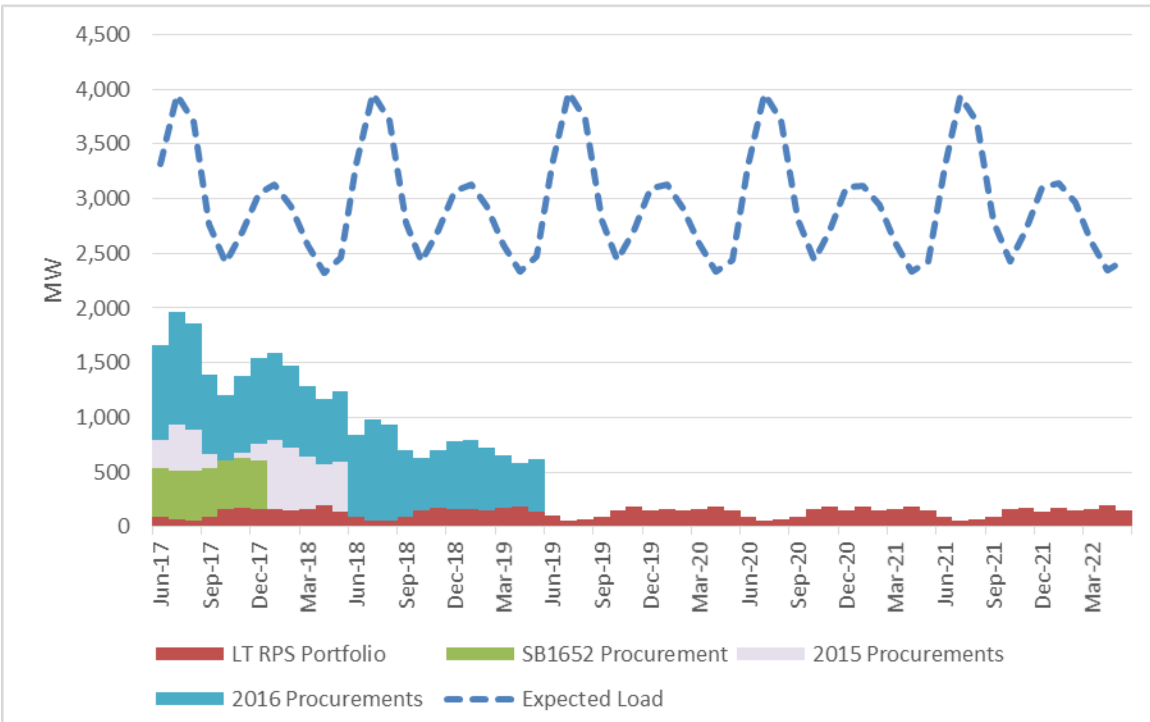
Under the base case load forecast scenario, the average supply gap for peak hours of the 2017-2018 delivery year is estimated to be 421 MW, the peak period average supply gap for the 2018-2019 delivery year is estimated to be 629 MW, and the average peak period supply gap for the 2019-2020 delivery year is estimated to be 772 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 2017-May 2022 planning period, using the base case load on-peak forecast described in Chapter 3.

ComEd's current energy resources will not cover eligible retail customer load starting in June 2017. The average supply gap during peak hours for the 2017-2018 delivery year under the base case load forecast is estimated to be 1,505 MW. The average supply gap during peak hours for the 2018-2019 and 2019-2020 delivery years is estimated to be 2,251 MW and 2,856 MW respectively.

Figure 4-2: ComEd's On-Peak Supply Gap - June 2017-May 2022 period - Base Case Load Forecast



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 capacity from MidAmerican's resources ("Illinois Historical Resources").

In reviewing the load forecast and resource portfolio information supplied by MidAmerican for the 2017 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. The maximum generation output during each hour is then capped at the maximum of the generation capacity or the forecasted demand level, whichever is lower. The IPA recommends removing this cap for the 2017 Procurement Plan. Removing the cap represents an incremental improvement and would entail no effort to implement.[122]

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 2016 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 forecast 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.

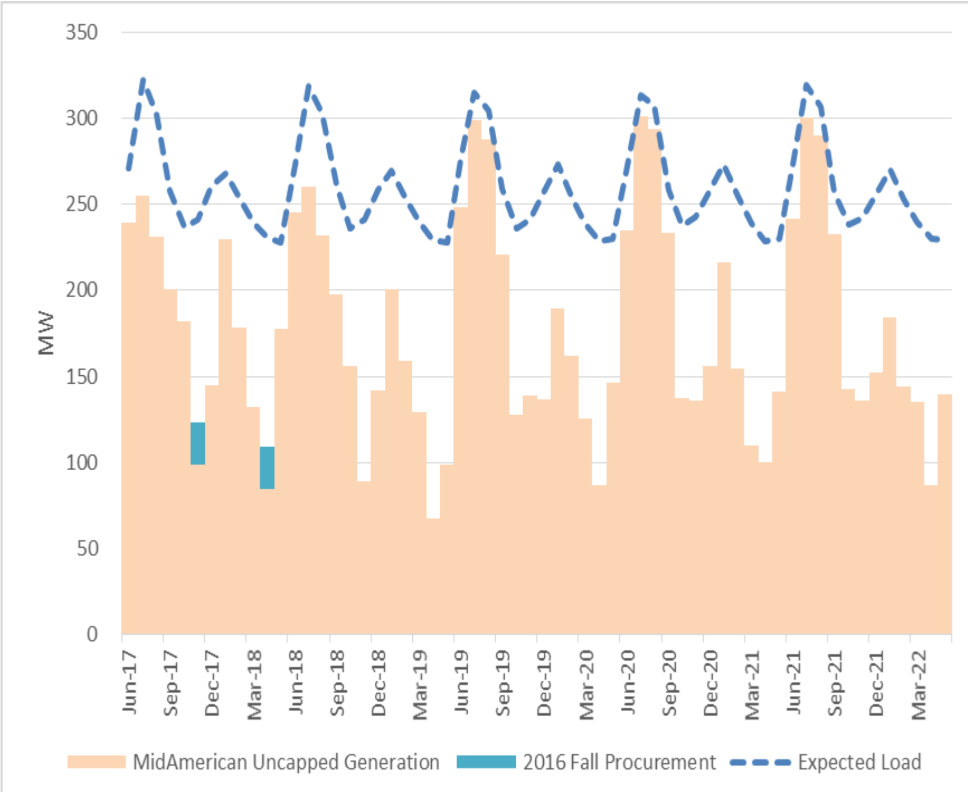
The IPA believes that the methodology used with regards to MidAmerican's supply procurement is reasonable given this correlation and that the overall hedging levels and laddered procurement approach are consistent with the proposed approach for Ameren Illinois and ComEd. The IPA understands that the basic methodology adopted in the 2016 Procurement Plan and continued in this Plan has produced hedge volumes that successfully matched the supply/load balance for June and July, 2016. 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, 2022. 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. 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 2017-2018 delivery year under the base case load forecast is estimated to be 80 MW. The average supply gap during peak hours for the 2018-2019 delivery year is 95 MW and for the 2019-2020 delivery year the supply gap is 79 MW.

[122] Tables G-5 and G-6 in Appendix G show monthly capped and uncapped generation dispatch and residual values for peak and off-peak periods

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



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 Section 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 to establish and enforce reliability standards with the goal of ensuring the reliability of the American bulk power system.
- Midcontinent ISO ("MISO"), which operates the transmission grid in most of central and southern Illinois, serving Ameren Illinois and MidAmerican.
- PJM Interconnection ("PJM"), which operates the transmission grid in Northern Illinois, serving ComEd.

From 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 2021-2022 timeframe.

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.[123] 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.[124] The commitment period is also referred to as a Planning Year.[125] In addition to the BRAs, up to three incremental auctions are held, at intervals 20, 10, and 3 months prior to the Planning Year. The 1st, 2nd, and 3rd Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement.[126] 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 for such Planning Year.

Just prior to the beginning of each Planning Year, the Final Zonal Net Load Price, which is the price paid by Load Serving Entities ("LSEs") for capacity procured as part of RPM in PJM, is calculated. This price is

123 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 ("the Capacity Performance Filing"). 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 implemented for the 2018-2019 and 2019-2010 planning years, with transitional capacity performance incremental auctions conducted for the 2016-2017 and 2017-2018 planning years to facilitate improved resource performance during those years by allowing a portion of capacity to be rebid in a new procurement. Implementation of Capacity Performance has generally resulted in increased capacity clearing prices, in particular for the ComEd zone.

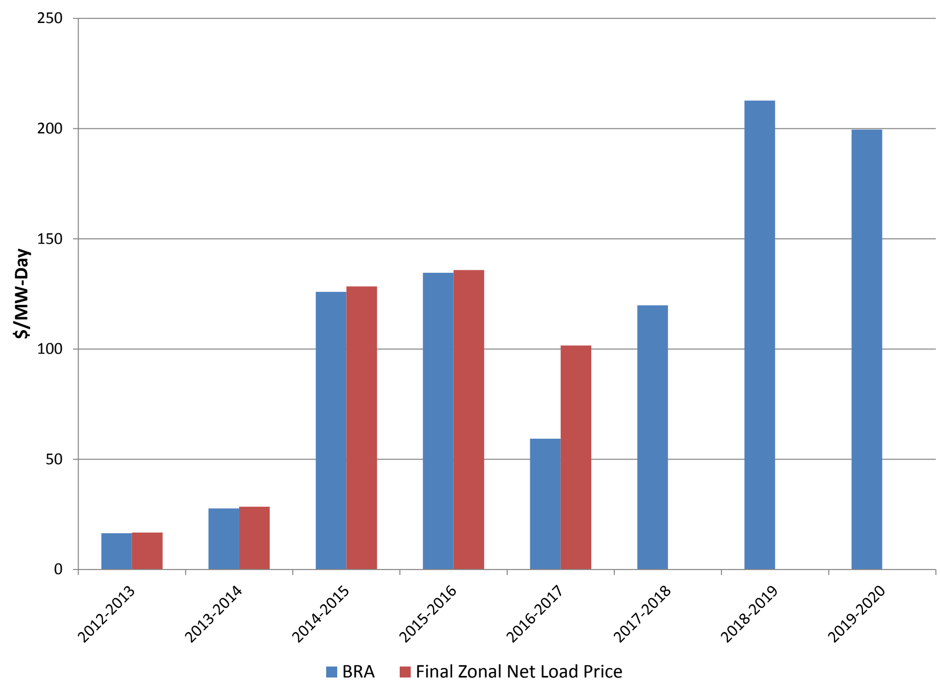
124 Note that the BRA for the 2018-2019 Planning Year was delayed from May, 2015 to August, 2015.

125 A Planning Year is June 1 through May 31 of the following year. Planning Year is used in this Plan in relation to capacity procurement.

126 Deferred short-term resource procurement only applies prior to the 2018-2019 Planning Year.

determined based on the results of the BRA and subsequent incremental auctions for a given Planning 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 and the Final Zonal Net Load Price as shown in Figure 5-1. However, while Figure 5.1 shows little variation between the BRA clearing price and the Final Zonal Net Load Price for the Planning Years through 2015-2016, Planning Year 2016-2017 shows a significant variation between the prices. This is because the Final Zonal Net Load Price for 2016-2017 includes the incremental costs of that year's transitional Capacity Performance Incremental Auction ("CPIA").[127] A similar variation in the prices is expected for the 2017-2018 Planning Year after the costs for that Planning Year's CPIA are taken into account.[128] Figure 5.1 also shows increases in the preliminary BRA prices for Planning Years 2018-2019 and 2019-2020, which can also be primarily attributed to the implementation of the capacity performance product.[129]

Figure 5-1: PJM RPM (ComEd Zone) Capacity Price for Planning Years 2012-2013 to 2019-2020[130]



As shown in Figure 5-2Figure 5-2, PJM is projected to have sufficient resources to meet load plus required reserve margins for the Delivery Years 2016-2017 to 2021-2022, with projected reserve margins above the 15.5% target reserve margin in 2016-2017 and the 15.7% target reserve margin for the remaining Delivery Years. For the 2016-2017 Delivery Year, the reserve margin is approximately 10% above the target reserve margin, peaks at approximately 16% above the target reserve margin in 2018-2019 and then drops to approximately 12% above the target reserve margin for the 2021-2022 Planning Year.

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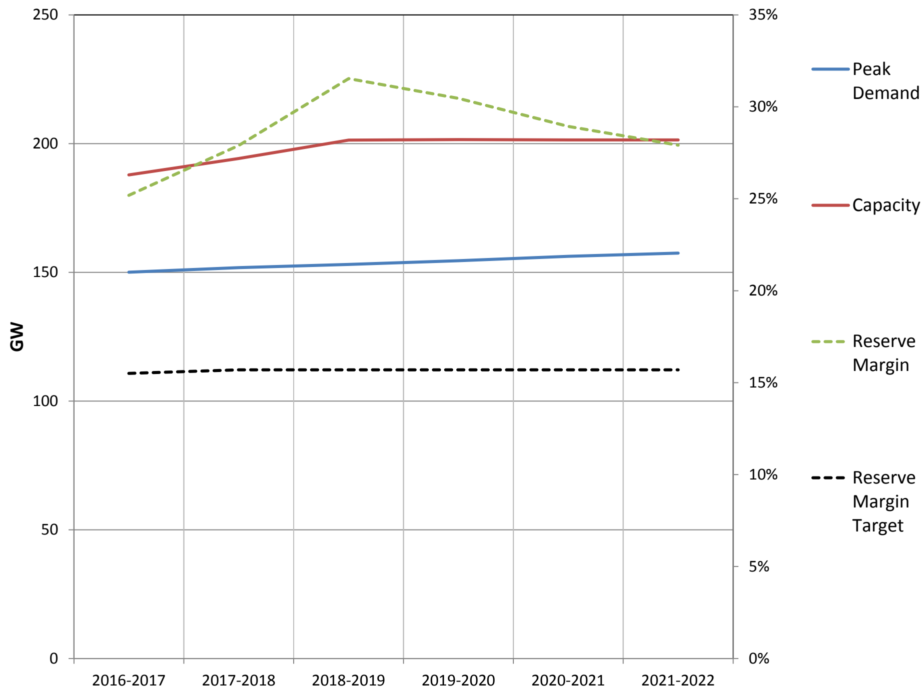
[127] The BRA clearing price for the ComEd zone for 2016-2017 was $59.37/MW-Day. 60% of resources procured in the 2016-2017 CPIA were Capacity Performance Resources. The preliminary incremental cost component for the 2016-2017 CPIA was $38.17/MW-Day and the final incremental cost component was $39.86/MW-Day. 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.

[128] 70% of resources procured in the 2017-2018 CPIA were Capacity Performance Resources.

[129] In 2018-2019 and 2019-2020 the ComEd Zone was modeled as a separate Locational Deliverability Area ("LDA"), and in both years the results showed that it was a constrained LDA. Binding constraints therefore also contributed to the higher clearing price. In 2018-2019 and 2019-2020, 80% of resources procured were Capacity Performance Resources.

[130] 2016-2017 is the latest Planning Year for which the Final Zonal Net Load Price has been calculated. It will be calculated for future Planning Years as the start of the year approaches.

Figure 5-2: PJM NERC Projected Capacity Supply and Demand for Planning Years 2016-2017 to 2021-2022



Source: NERC 2015 Long Term Reliability Assessment ("NERC 2015 LTRA")

The MISO Resource Adequacy Construct, specified in Module E-1 of its Tariff,[131] 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")[132] for the Planning Year. An LSE's total resource adequacy obligation is referred to as the Planning Reserve Margin Requirement ("PRMR"). On June 11, 2012 the Federal Energy Regulatory Commission ("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 fourth PRA are provided in Section 5.2.

As shown in Figure 5-3, based upon the NERC 2015 LTRA, on a region-wide basis MISO is expected to have sufficient resources to meet load plus required reserve margin for the Planning Years 2016-2017 to 2020-2021 with projected reserve margins above the 14.3% target reserve margin. However, in 2021-2022 MISO is projected to have insufficient resources to meet load plus required reserve margin. For the 2016-2017 Planning Year, the reserve margin is approximately 2% above the target reserve margin, dropping to approximately 0.4% above the target reserve margin for the 2020-2021 Planning Year. As also shown in Figure 5-3, NERC's analysis mirrors MISO's analysis presented in the 2015 MISO Transmission Expansion Planning ("MTEP") report, which addresses resource adequacy. The MISO assessment, however, forecasts the reserve margin dropping below the target reserve margin a year earlier in 2020-2021. MISO explains that the difference is primarily due to how each assessment accounts for certain types of resources as well as how the reserve margin is calculated. In particular, MISO notes that the MTEP report does not include "low-certainty"

[131] 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.
[132] 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 their jurisdiction, then that state-set PRM would be adopted by MISO for jurisdictional LSEs in such state.

resources; whereas the NERC assessment includes these resources in the overall supply pool.[133] In 2020-2021 there are 2.3 GW of "low-certainty" resources which MISO did not include in its base case. If MISO had included these resources in 2020-2021, the MISO assessment would have been above the target reserve margin, similar to the NERC assessment. MISO also explains that the MISO and NERC assessments differ in how the reserve margin percent is calculated. MISO's calculation of the reserve margin counts DR as a resource while the NERC assessment has DR calculated on the demand side. MISO however notes that while the reserve margin percent will be slightly different, the absolute GW shortfall/surplus is the same between the two assessments.

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

- 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 by the utilities and, as such, do not cause immediate concern.
- The change in LTRA results was driven primarily by the combination of an increase in resources committed to serving MISO load and a decrease in load forecasts.
- The increase in committed resources reflects action taken by MISO LSEs and state regulators to address potential capacity shortfalls.
- MISO projects that each zone within the MISO footprint will have sufficient resources within their boundaries to meet the local clearing requirements, or the amount of their local resource requirement, which must be contained within their boundaries.
- 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 to support this transfer. 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.
- MISO limited the transfer of capacity from the South region to the North/Central region to 1,000 MW.[134] Any capacity in the south above its requirements and 1,000 MW was therefore excluded from the MISO-wide capacity reserves in the assessment, since this capacity was assumed unavailable for the North/Central region's capacity needs.

MISO projects that reserve margins will continue to tighten over the next five years, approaching the target reserve margin. Operating at the reserve margin creates a new operating reality for MISO members where the use of all resources on the system and emergency operating procedures are more likely. This could lead to a projected dependency in the use of load-modifying resources such as behind-the-meter generation and DR.

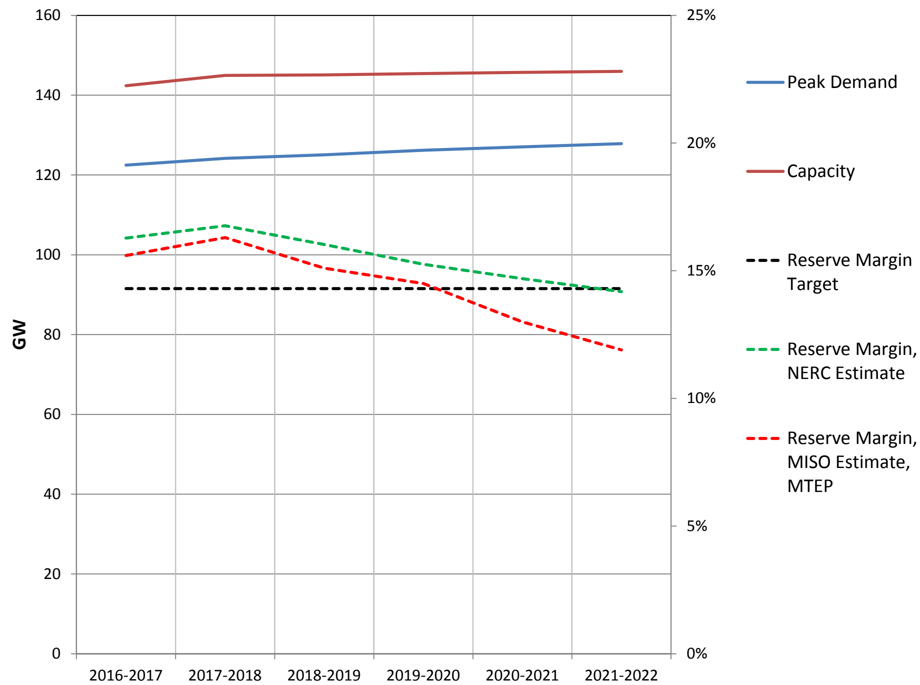
The LTRA results represent a point-in-time forecast, and the NERC assessment notes that MISO expects these figures to change significantly as future capacity plans are solidified by LSEs and states. In the MTEP MISO also notes that 91% of the load in the MISO footprint is served by utilities with an obligation to serve. This obligation is reflected as a part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Need ("CPCN"). MISO further notes that five years is sufficient lead time for LSEs to plan, build and operate new resources to meet the projected

[133] "Low-Certainty" resources are those resources that have some indication of not being available to serve load in a given Planning Year (*i.e.* the certainty of them being able to serve load is low). In other words, while "low-certainty" resources may be available to serve MISO load, they do not have any firm commitments to do so. Most "low-certainty" resources are potential retirements or suspensions.

[134] The 2016 Procurement Plan provided details on the 1,000 MW contract path limit and the dispute between MISO and SPP regarding flows above the contract path limit. On January 21, 2016 FERC approved a Settlement Agreement between MISO, SPP and other parties that resolved the disputed issues. It should be noted that, as explained in the 2016 Procurement Plan, the transmission system can support flows above this 1,000 MW contract path and these flows are allowed in the operational time frame.

shortfall. However, the IPA notes that because Illinois is a retail-choice state where LSEs do not own generation, this construct may not apply as clearly to Illinois.

Figure 5-3: MISO NERC Projected Capacity Supply and Demand for the Planning Years 2016-2017 to 2021-2022



Source: NERC 2015 Long Term Reliability Assessment, MISO 2015 MTEP Book 2 Resource Adequacy

5.2 MISO Resource Adequacy Update

A key component of the MISO Module E-1 RAR is the establishment of Local Resource Zones ("LRZs"). The MISO region currently has 10 LRZs. Local Reliability Requirements ("LRRs") are set for each LRZ to establish the minimum amount of Planning Resources needed to maintain MISO's LOLE within each LRZ, without consideration of Planning Resources outside of the LRZ that could be accessed through transmission ties. MISO also establishes a Local Clearing Requirement ("LCR") for each LRZ, which is the minimum amount of Planning Resources required to be sourced within the LRZ while fully utilizing the Capacity Import Limit ("CIL") for the LRZ. Capacity Export Limits ("CEL") are also established for each LRZ. A market participant can qualify a Planning Resource, and convert the Unforced Capacity of the Planning Resource into Zonal Resource Credits ("ZRCs"). ZRCs are MW units of Planning Resources that have been converted into a credit that can be used to meet PRMR directly through offers or self-schedules in the PRA, or commitments in a Fixed Resource Adequacy Plan ("FRAP"). Market participants can also buy and sell ZRCs through bilateral arrangements. MISO will impose a Capacity Deficiency Charge ("CDC")[135] on an LSE that has not demonstrated at the close of the PRA, that it has sufficient capacity resources to meet its PRMR. MISO held the fourth PRA in April 2016.

The RTO-based reliability assessments examined in the previous 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 2017 Procurement Plan to assure reliability over the planning horizon.

[135] The value of the CDC is currently set at 2.748*Cost of New Entry ("CONE").

MISO, in consultation with its stakeholders, has been developing proposed changes to the MISO Resource Adequacy Construct. Key aspects of these proposed changes include:

- MISO is proposing several changes to their Resource Adequacy Construct which could potentially result in a more stable capacity market.[136] These changes include (i) the introduction of seasonal considerations to ensure transparency of resource adequacy across all seasons and provide flexibility to market participants, and (ii) addressing the locational construct to reduce volatility in the key inputs to the PRA. Increased stability may, or may not, be at a higher price than the current construct.
- MISO is proposing a competitive retail solution to specifically address the resource adequacy needs of Illinois and Michigan, the states within MISO that have competitive retail choice.[137] To the extent the solution results in the addition of new resources or the avoidance of existing resource retirement and coupled with the pending addition of new transmission lines in the region, it seems logical that the reliability of electric service for consumers in Illinois would be enhanced. As proposed, the competitive retail solution also includes a bright line test where all demand in Zone 4 subject to competitive retail access will be required to participate in the competitive retail solution. Advocates of the competitive retail solution believe it will address the needs of Illinois and Michigan without harm to the other states within MISO. Opponents believe it will increase capacity prices and/or volatility and will do so with no assurance that reliability will be enhanced.

If implemented, the proposed changes to the MISO resource adequacy construct could, in time, eliminate the need to enter into bilateral transactions altogether. The IPA also notes the lack of bilateral hedging of capacity in PJM where the RPM construct serves as an effective capacity auction for LSE's serving load in the PJM region.

5.2.1 Future Capacity Procurement Strategy for Ameren Illinois

The IPA recognizes that the proposed changes to the MISO capacity construct have received considerable debate among stakeholders and given the wide range of opinion, and the IPA believes it is currently unclear whether the proposed changes will result in a more stable capacity market in the near term. It is possible, however, that the proposed changes, when implemented, will reduce capacity price volatility, and could help ensure the reliability of electric service. As a result, the IPA bilateral capacity procurement approach may not have any apparent advantage over the future PRA approach. In light of the uncertainty around the proposed changes to the MISO resource adequacy construct, the IPA recommends deferral of the decision regarding hedging capacity for Ameren Illinois for the 2019-2020 planning year until next year's Plan.

5.2.2 2015-2016 PRA Results Follow-Up

FERC has taken several actions on the complaints filed regarding the results of the MISO 2015-2016 PRA. The complaints were filed by the Illinois Attorney General ("IL AG"),[138,] Public Citizen, Inc. ("Public Citizen"),[139] Southwestern Electric Cooperative ("SWEC"),[140] and the Illinois Industrial Energy Consumers ("IIEC").[141] A summary of the complaints was provided in the 2016 Procurement Plan.[142] The actions can be summarized as follows:

- Shortly after the conclusion of the 2015-2016 PRA, FERC's Office of Enforcement began a non-public, informal investigation under Part 1b of FERC's regulations into whether market manipulation or other potential violations of FERC orders, rules and regulations, occurred before or during the 2015-2016 PRA.

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136 See Section 5.2.5 for a more detailed discussion of the changes.

137 See Section 5.2.6 for a more detailed discussion of the changes.

138 FERC Docket EL15-71-000.

139 FERC Docket EL15-70-000.

140 FERC Docket EL15-72-000.

141 FERC Docket EL15-82-000.

142 See Pages 60-61.

On October 1, 2015, pursuant to the Federal Power Act sections 201, 307, and 309 (as amended by the Energy Policy Act of 2005), and Part 1b of FERC's regulations, FERC authorized the Office of Enforcement to conduct a non-public, formal investigation, with subpoena authority, regarding violations of FERC's regulations, including section 1c.2 (Prohibition of electric energy market manipulation) that may have occurred in connection with, or related to, the 2015-2016 PRA.[143] That investigation is ongoing. On October 20, 2015, FERC staff held a Technical Conference to obtain additional factual information about the following issues: (i) implementation of the current mitigation procedures and reference level calculations, (ii) alternatives to the current mitigation procedures and reference level calculations, (iii) the determination of LCR and CIL, and (iv) the basis for zonal boundaries.[144]

- On December 31, 2015, FERC issued an Order ("the Order") granting in part and denying in part the complaints filed by the IL AG, Public Citizen, SWEC and IIEC. FERC denied the complaints in part and found that complainants had not shown MISO Tariff provisions to be unjust and unreasonable or unduly discriminatory or preferential regarding changes to zonal boundaries, MISO Tariff provisions regarding MISO's capacity construct, and the stakeholder process. FERC directed MISO to submit two compliance filings to revise its Tariff within 30 and 90 days of the Order.

- FERC directed MISO to set the Initial Reference Level for capacity at $0/MW-day.

- FERC directed MISO to determine technology-specific default avoidable costs, which will be based on a formula MISO must develop and add to the Tariff. Recognizing that it would have been difficult for MISO to develop default technology-specific avoidable costs in time for the 2016-2017 PRA, FERC directed MISO to propose such Tariff revisions within 90 days of the date of the order to be implemented prior to the 2017-2018 PRA.[145]

- FERC directed MISO to file Tariff revisions on compliance to ensure that MISO's calculation of CILs accurately reflects counter-flows resulting from capacity exports to neighboring regions. FERC also agreed with an alternative approach and recommendation for calculating CILs provided by the MISO IMM which better reflected the counter flows that capacity exports provide. FERC directed MISO to work with the MISO IMM to file necessary Tariff revisions to implement this recommendation on compliance within 30 days of the date of the Order, to be implemented in time for the 2016-2017 PRA. If MISO had concerns that this directive may result in adverse impacts on reliability, FERC instructed MISO to submit in its compliance filing a demonstration of these concerns and its recommended alternative proposal to be implemented in time for the 2016-2017 PRA.

- FERC denied the complaints with respect to zonal boundaries and did not direct MISO to combine Zones 4 and 5. Nevertheless, FERC encouraged MISO to continue to work with its stakeholders to ensure its zonal boundaries reflect the physical realities of the transmission system.

- In late January and early February of 2016, several parties (including MISO) filed requests for rehearing and/or clarification of the Order.[146]

- In MISO's 30-Day Compliance Filing to the Order ("1st Compliance Filing"), which was filed on January 29, 2016, contemporaneously with the request for rehearing, MISO addressed FERC's compliance directives. i.e. setting the Initial Reference Level at $0/MW-Day, adding language to the Tariff regarding generation resources with facility-specific reference levels, revising the CIL calculation to remove the impact of exports, and revising the LCR calculation to include the benefits of exporting units in supporting local

[143] Investigation into MISO Zone 4 Planning Resource Auction Market Participant Offers, 153 FERC ¶ 61,005 (2015) (Order Initiating Formal Investigation). An order converting an informal, non-public investigation to a formal, non-public investigation does not indicate that FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation.
[144] Notice of Technical Conference, Docket No. EL15-70-000, *et al.*, at 2-3 (Oct. 1, 2015).
[145] The 90 day compliance filing was extended to June 28, 2016 at the request of MISO and the MISO IMM.
[146] The other parties who filed requests for rehearing were IIEC, IL AG, SWEC, and Electricity Power Association ("EPSA").

resource requirements. Consistent with their request for rehearing MISO proposed to reduce each Zone's LCR by the amount of capacity under MISO's functional control that is exported outside of MISO's footprint (i.e., non-pseudo-tied exports). MISO proposed the following formula to calculate LCR:

LCR = LRR – CIL – non-pseudo-tied exports[147]

- In an order issued on March 18, 2016, ("the 1st Compliance Filing Order") FERC accepted MISO's 1st Compliance Filing, subject to a further compliance filing. FERC also granted MISO's request for clarification and IIEC's and IL AG's request for clarification with respect to going-forward costs and denied all other requests for clarification and rehearing. In the 1st Compliance Filing Order FERC accepted MISO's 1st Compliance Filing to set the Initial Reference Level to $0/MW-Day and also found that MISO had generally complied with the other directives. In the 1st Compliance Filing Order FERC also accepted MISO's proposed revisions to its Tariff, which modifies the formula MISO uses to calculate LCRs.

- In the 1st Compliance Filing Order FERC also granted clarification with respect to concerns raised by IIEC and IL AG regarding whether sunk costs are included in going-forward costs. Specifically, FERC clarified that, for purposes of calculating facility-specific reference levels, going-forward costs do not include sunk costs.

- On April 18, 2016 MISO submitted a compliance filing ("2nd Compliance Filing") to address FERC's directives in the 1st Compliance Filing Order. MISO provided FERC recommended Tariff language changes to comply with FERC's directive to make it clearer that it is the MISO IMM's responsibility to verify opportunity costs used in facility-specific reference levels. MISO also provided revised Tariff language to comply with FERC's directive to clarify that the CIL values posted by MISO on November 1st of each year shall be considered preliminary and subject to change. Also, as directed by FERC, MISO has reflected the revised CIL methodology in the Tariff. The 2nd Compliance Filing is still under FERC's review.

5.2.3 Zonal Deliverability Benefits Filing

MISO has made Tariff changes to the method for allocating Zonal Deliverability Benefits ("ZDBs"). Under the MISO PRA construct, Resources, represented by ZRCs, are paid the Auction Clearing Price in the LRZ where they are located and load, represented by the PRMR pays the Auction Clearing Price in the LRZ where the PRMR resides. Price separation can occur between these zones due to the locational requirements of the PRA when one or more LRZs are importing lower priced capacity from one or more other LRZs within MISO. This can cause MISO to collect more revenue from load than it pays to resources. ZDBs occur as a result of this price separation.

On January 27, 2016, MISO filed with FERC a new methodology for allocating ZDBs. In their filing, MISO noted that the old methodology, which allocated ZDBs pro-rata in an LRZ based upon an LSE's PRMR in comparison with all LSEs' PRMR (i.e. primarily allocating ZDBs based upon the amount of PRMR), may not best reflect the price separation exposure of LSEs from a PRA auction result and is insufficiently precise to preclude undesirable allocations under certain situations. This is because under the MISO PRA mechanism, price separation can occur due to binding constraints in the PRA. Individual LRZs within MISO can have equal Auction Clearing Prices due to the same binding constraint and therefore have the same price separation risk. The old allocation methodology was indifferent to the amount of imports or the price separation between LRZs, making it not effective when there are multiple importing LRZs that all clear at the same Auction Clearing Price due to the same binding constraint.

[147] A pseudo-tied generation resource is one located physically in one reliability authority area but treated electrically as being in another reliability authority area. Pseudo-tied exports are exports from these resources. For example, a MISO resource pseudo-tied to PJM would be a resource physically located in MISO but treated as though it was electrically in PJM. PJM will have dispatch control of the resource even though it is physically located in MISO.

On March 15, 2016, FERC issued a deficiency letter to MISO and requested additional information. On March 25, 2016, MISO submitted a response to FERC's deficiency letter. On April 29, 2016, FERC issued a Letter Order accepting the new method for allocating ZDBs.

5.2.4 Proposed Seasonal and Locational Changes to the MISO Resource Adequacy Construct

MISO is proposing seasonal and locational changes to the MISO Resource Adequacy Construct. The seasonal changes are meant to ensure the transparency of resource adequacy across all seasons and provide flexibility to market participants. The locational changes are meant to reduce volatility in the key inputs to the PRA. Implementation of the seasonal and locational changes is currently scheduled for Planning Year 2019-2020.[148]

<u>Seasonal Changes</u>

Table 5-1 provides a comparison of what is currently proposed versus the status quo.

Table 5-1: Seasonality Proposal Key Differences - Current versus Proposed

Resource Adequacy Requirement Construct	Current State	Proposed
	Annual	Seasonal
Number of Seasons	Summer Based	Two Seasons: Summer and Winter • Summer (June – Sept.) • Winter (October – May)
Capacity Accreditation	Annual	Seasonal: Summer and Winter) • Availability and interconnection service for each season
Demand	Summer Peak Load	Summer and Winter Peak Loads
PRA Deliverables	Annual PRM, LRR, CIL, and CEL	Seasonal: • Summer and Winter PRM • Summer and Winter LRR • Summer and Winter CEL
PRA Design	• Single Auction with Annual Offers • One Annual Auction Clearing Price	• Single Auction with Seasonal Offers • Summer and Winter Auction Clearing Prices
LOLE	Annual LOLE - 0.1 Days/Year	• Summer LOLE - 0.1 Days/Year • Winter LOLE - 0.01 Days/Year

<u>Locational Changes</u>

The MISO Proposal can be summarized as follows:

- Stability

Regarding the need to stabilize locational requirements, MISO notes that unwarranted drivers have been identified for both (i) the PRM and (ii) the CIL and CEL analysis which factor into the LCR analysis. MISO is therefore proposing to stabilize specific inputs and reduce the year over year volatility. Examples of variables contributing to volatility include (i) Load Forecast Uncertainty ("LFU"), (ii) dispatch and load in planning models, (iii)generation retirements, and (iv)new transmission. It is reasonable for the variations in load and generation characteristics to influence the study and its results, but variations in LFU as well as in the external non-firm support may be due to modeling, rather than actual system conditions, and, according to

[148] Based on presentations made to the August 3, 2016 Resource Adequacy Subcommittee ("RASC") meeting, MISO expects to post an updated Design Document of the proposal in the November / December 2016 timeframe.

MISO, changes based on these variations may not be warranted, potentially creating unnecessary and inappropriate volatility. MISO recommends stabilizing the PRM and CIL/CEL by holding external non-firm support constant, reduce volatility in LFU calculation, and require a trigger before re-calculating CIL/CEL

- Creation of External Zones for external Capacity Resources

MISO is proposing the creation of External Resource Zones to appropriately represent and correctly account for the impact of resources outside of MISO on the PRA and to accredit these External Resources in a similar manner to resources internal to MISO and outside of a particular zone. External Resources would no longer count directly towards LCR. External Resources would however be able to directly count towards CIL and CEL. External Resource Zones would facilitate consistency in treatment of external and internal resources through eliminating external resources being modeled in a zone in which they are not physically located. Consideration will be made for Coordination Members. Resources in Coordination Member areas will continue to be considered as part of the MISO zone in which the Transmission Service sinks at the border. A Coordination Member is an entity with a reciprocal tariff with MISO that includes reliability coordination subject to emergency procedures it has developed with MISO. It has also agreed to operate its system in a similar manner, including the agreement to share reserves with MISO during emergency conditions.

- Improved Hedging Mechanisms to Manage Price Separation

To improve hedging mechanisms to manage price separation, MISO recommends implementing Capacity Transfer Rights ("CTRs"). CTRs will be made primarily available to LSEs that enter into long-term supply arrangements and that have firm long-term Transmission Service. This results in allocating the value of the transmission system to LSEs which recognizes that the cost of constructing and maintaining the grid has largely been borne by LSEs. Supply arrangements include ownership of an asset or contractual rights that are at least 5 years in duration. CTRs will be valued based on their "sink" and "source." The value of a CTR is the greater of zero and the "sink" auction clearing price minus the "source" auction clearing price.[149] CTRs will be funded using only excess revenue collected from the PRA (ZDBs). As a result, some CTRs may not be fully funded.

[149] Electrical system modeling uses a "source point" to simulate where electricity it is generated and a "sink point" where it is consumed.

Table 5-2 provides a comparison of what is proposed versus the status quo.

Table 5-2: Locational Considerations Proposal Key Differences - Current versus Proposed

	Current State	Proposed
Stability	Volatility in PRM, CIL and CEL values.	Limit Volatility in PRM, CIL and CEL values: • PRM: Limit volatility caused by unwanted variation in LFU and external non-firm support and provide "bands" or ranges of certainty around out year PRM values. • CIL and CEL: New values re-calculated based on triggers such as threshold impacts of transmission and generation.
External Zones	No External Zones currently modeled.	Create External Zones for resources outside MISO.
Hedges	Zonal Deliverability Hedges	Capacity Transfer Rights.

5.2.5 Resource Adequacy in Restructured Competitive Markets

MISO is proposing the implementation of a competitive retail solution ("CRS") to specifically address the unique resource adequacy needs in restructured competitive retail markets including Illinois and Michigan. MISO proposes to phase in the implementation of the CRS starting in 2018-2019.[150]

MISO's current proposal (yet to be filed with the FERC) has the following features:

- Full Forward Capacity Procurement for Retail Choice Load, Separate from Existing PRA Process.[151]
  - Two structurally separate auctions
    - A new 3-year Forward Resource Auction ("FRA") to procure capacity needs of Retail Choice Load where state or local planning processes are absent.
      - FRA would use a Sloped Demand Curve pricing method.[152]
      - Forward procurement (cleared supply) will be "self-scheduled" into the PRA similar to resources procured by regulated LSEs.
    - Maintains existing PRA and FRAP option for Non-Retail Choice Load.
  - Different Demand Curves Serve Different Needs.
    - FRA will use a "Target Reliability Range" ("TRR") (i.e., Downward Sloping Demand Curve).
      - Sloped Demand Curve will only be used in the FRA.
    - PRA continues to use Vertical Demand Curve to meet balancing needs of LSEs through FRAP and auction clearing for Non-Retail Choice Load.
      - All demand will be modeled using Vertical Demand Curve.
      - Maintains PRA as residual imbalance trading platform.
- Load Participation – Bright-Line Test

[150] On August 8, 2016 MISO Staff informed the Markets Committee of the Board of Directors that MISO will delay the filing date of the CRS proposal from late August, 2016 to November, 2016.
[151] Initial MISO design used hybrid procurement with a sloped demand curve used for both partial forward and residual prompt auctions.
[152] MISO final design utilizes previously FERC-approved demand curve construct (PJM) as basis for design. MISO IMM and multiple stakeholders called for the use of a downward-sloping demand curve to improve price formation for Retail Choice regions.

- Bright-Line Test for Demand.
  - Demand subject to competitive retail access will be required to participate in CRS (subject to evaluation for materiality).
- Materiality Clause
  - Revised test to be based on PRMR instead of LCR
    - Potential Participating Demand's PRMR must be less than 0.5% of the total system wide PRMR.[153]
    - Threshold will be based on having a negligible impact to the system-wide LOLE.
    - Demand evaluated for materiality year over year.
    - Demand that is identified as material will be subject to participation obligations of the FRA and Forward FRAP.
- Elimination of Opt-In Mechanism
  - The Bright-Line Test is the sole determinant of demand participation in CRS.
- Opt-Out Mechanism (Forward FRAP)
  - Fixed requirement.
  - Requires 4 year notification to opt into FRA.
  - Ability for states to establish a compensation mechanism similar to PJM Fixed Resource Requirements ("FRR").

- Participation – Supply
  - Market Power Monitoring and Mitigation.
    - Resources physically located within an LRZ with Participating Demand will be subject to existing Module D provisions for the FRA.
    - Resources physically located outside an LRZ (s) with Participating Demand may elect to participate.
    - MISO will work with IMM to identify and develop additional mechanisms as necessary.
  - Safe Harbor
    - LSEs serving non-Participating Demand that have resources in an LRZ with Participating Demand may exempt those resources from evaluation for physical withholding.
    - Up to the most recent PRMR from the last cleared PRA.
    - Requires attestation from an officer of the company.
    - Includes a process to account for adjustments due to new resource exit and increases in forecasted demand.
    - Adjustments are subject to review by MISO.

Table 5-3 provides a comparison of what is proposed under the MISO proposal versus the status quo.

[153] For example, if the system wide PRMR is 136,000, the Materiality Threshold is 136,000*0.005 = 680 MW. If the coincident peak demand reported by the EDC is 400 MW, and the PRM is 7%, the PRMR is 400*1.07 = 428 MW. Application of materiality test: 428 MW is not greater than or equal to 680 MW – therefore LRZ will not have demand represented in FRA.

Table 5-3: Competitive Retail Solution Proposal Key Differences - Current versus Proposed

	Current State	Proposed
Capacity Auctions	PRA	Two Structurally Separate Auctions: • 3-Year FRA for Retail Choice Load in CRAs. • PRA for Non-Retail Choice Load
Auction Demand Curves	Vertical Demand Curve for PRA	• Sloped Demand Curve for FRA • Vertical Demand Curve for PRA
Load Participation	• No Bright Line Test for Load • Load can opt out through FRAP	• Bright-Line Test for Load. • CRA Load will be required to participate subject to Materiality Clause. • Bright-Line Test is sole determination of participation in CRS. • Load can opt out through FRAP.
Supply Participation	All resources subject to market power and mitigation procedures (Module D).	• Resources physically located within an LRZ with Participating Demand will be subject to existing Module D provisions for the FRA. • Resources located outside an LRZ (s) with Participating Demand may elect to participate. • Safe Harbor provisions for LSEs serving Non-Participating Demand that have resources in an LRZ with Participating Demand (LSEs may exempt those resources from evaluation for physical withholding).

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."[154]

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.*[155]

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. Section 6.1.4 describes types of contracts and hedges that can be used to manage supply risk. Those products may be thought of as being used to build a supply portfolio. Section 6.4 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 6.6.2 addresses the cost and uncertainty impacts of these risk factors. Risk is often taken to mean the amount by which costs differ from initial estimates. Utility energy pricing in Illinois for Ameren Illinois and ComEd customers is based on estimates and cost differences are trued up after the fact through the Purchased Electricity Adjustment ("PEA").[156] Prior to the 2016-2017 delivery year, MidAmerican provided power and energy to its eligible Illinois customers from MidAmerican owned generation. The energy pricing for MidAmerican customers in Illinois has been recovered through base rates regulated by the Illinois Commerce Commission. Starting with the 2016-2017 delivery year, MidAmerican pricing for its Illinois customers also includes the energy obtained in IPA procurements, and that will be reflected through a cost recovery process similar to what is used by Ameren Illinois and ComEd. Section 6.5 provides a historical summary of the Ameren Illinois and ComEd PEA rates as a guide to the historical impact of risk factors. 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 demand management.

6.1 Risks

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

[154] 20 ILCS 3855/1-20(a)(1).
[155] 220 ILCS 5/16-111.5(b)(3)(vi).
[156] 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's Rider PER (Purchased Electricity Recovery).

6.1.1 Volume Risk

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

6.1.2 Price Risk

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

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 prior years. 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 that the current price of an ARES or municipal aggregation offer. 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.

6.1.3 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 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.

6.1.4 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 Load Serving Entity's ("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.

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 which 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 was 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 the energy, capacity and renewable resources that is not met by the allocated MidAmerican resources. Following the approach started for the 2016 Plan, under the 2017 Procurement Plan, the IPA will procure the net requirements between MidAmerican's eligible retail customer load and the MidAmerican controlled generation allocated to its Illinois customers.

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, That is, generators supply their energy to the RTO, and the RTO delivers energy to LSEs and customers. The RTO ensures the physical delivery of power. The cost of managing this delivery, including the cost of managing reliability risks, is passed on to the LSEs financially. The risks faced by LSEs in supplying energy to customers are mostly financial. The LSE still needs to manage certain operational risks such as scheduling and settlement. There are other, non-financial risks associated with electricity retailing, such as customer billing or accounts payable risks, but those are not associated with the supply portfolio.

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

6.3 Types of Supply Hedges

The 2014 Procurement Plan contained a detailed description of a number of different types of supply hedges, listed below. One point made in that Plan is that hedges available in the market are not perfect; the risks listed in Section 6.1 cannot all be hedged away except perhaps through a specially tailored "full requirements" hedge contract, whose price premium may not be acceptable in return for that degree of risk reduction.[157]

[157] 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.

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

- As-available
- Baseload
- Dispatchable

Unit-Independent Hedges.

- 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.[158] 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.[159] 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.[160] The most natural evidence of competitiveness is the breadth of participation, although other evidence may be possible as well.

Hedges most suitable for use by the Agency would be those standardized products that are well-understood, and preferably widely-traded. If a product has liquid trading markets, or is similar to other products with liquid markets, a bidder can control its risk exposure. Availability of information on current prices and the price history of similar products help bidders provide more competitive pricing, and help the Procurement Administrator produce a realistic benchmark. Prior to its 2014 Procurement Plan, the IPA had generally restricted its hedging to the use of standard forward hedges in 50 MW increments. The IPA began using 25 MW increments and a 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

[158] 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." ICC 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.

[159] 220 ILCS 5/16-111.5(b), (e), (f).

[160] 220 ILCS 5/16-111.5(f).

contracts and option contracts, could be subject to future litigation. Markets for products that are specifically designed for the IPA's requirements, such as full requirements contracts or over-the-counter options, will likely have limited transparency. The IPA's procurement structure requires a benchmarking and approval process and may not be compatible with such a low level of transparency.

Futures contracts at the PJM Northern Illinois Hub and the MISO Illinois Hub 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 less liquid than near term contracts, however. The Agency would seek to obtain competitive pricing on such contracts if it were to incorporate them in its portfolio. However, it may 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's 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."[161] 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.
- 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 to FERC Order 717.[162]
- 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 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 Purchased Electricity Adjustment ("PEA") functions as a financial balancing mechanism to assure that electricity supply charges match supply costs over time. The balance is reviewed monthly and the charge rate is adjusted accordingly. The PEA can be a debit or credit to address the difference between the revenue

[161] 220 ILCS 5/16-111.5(b)(4).
[162] 125 FERC ¶ 61,064, Oct. 16, 2008.

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 and ComEd. MidAmerican will recover the costs of power and energy procured by the IPA through tariffs Implementing Rider PE – Purchased Electricity which were approved by the ICC in February 2016.[163]

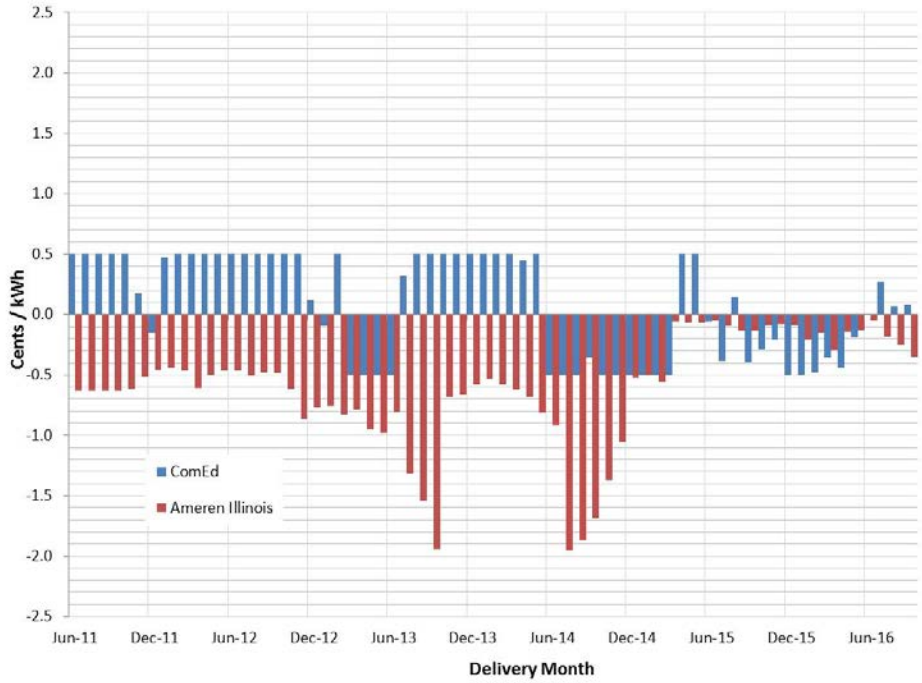
The PEA provides some guidance as to the amount by which the complete set of risk factors caused the cost of energy supply to differ from the estimate—in other words, the impact of risk. Figure 6-1 shows how the PEAs for Ameren Illinois and ComEd have changed over the last five years. While Ameren Illinois's 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), and recently have shown more volatility. ComEd has voluntarily limited its PEA to move between +0.5 cents/ kWh and -0.5 cents/kWh, and the figure shows that ComEd's PEA has oscillated between those limits.

In April 2014, the Commission approved an adjustment to ComEd's PEA that allows the accumulated balance of deferrals associated with the computation of the PEA each June to be rolled into the base default service rate for the next year and the associated balance to be reset to zero. 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 2016, but reflected credits for most of the recent months ending in June 2016.

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 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 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.

[163] See Docket No. 15-0564, Final Order dated February 24, 2016.

Figure 6-1: Purchased Electricity Adjustments in Cents/kWh, June 2011 – September 2016



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

6.6 Estimating Supply Risks in the IPA's Historic 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 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 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 2016 Plan.

The procurement schedule balances procurement overhead costs, price risk, and load uncertainty. If the amounts to be hedged in any year are small, the Agency could decide to avoid the procurement overhead and not schedule a procurement event (as in 2013). The Agency has not used options, unit specific contracts (except for the LTPPAs 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.[164] The results 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

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

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 2017 Plan from the approach established in the 2015 Plan and utilized again for the 2016 Plan.

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 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. 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 DR and EE resources similarly to other capacity providing resources for operational planning purposes.

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 DR 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.[165] Chapter 7 of this plan provides details and additional discussion regarding demand response resources.

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