

2022



ELECTRICITY PROCUREMENT PLAN

**2022 Draft Plan for Public
Comment**

August 16, 2021

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

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1 Executive Summary

This is the fourteenth electricity procurement plan (the “Plan,” “Procurement Plan,” “2022 Plan,” or “2022 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 the plan, including those set forth in previous orders of the Illinois Commerce Commission (“Commission” or “ICC”).

The Plan addresses the provision of electricity for the “eligible retail customers” of Ameren Illinois Company (“Ameren Illinois”), Commonwealth Edison Company (“ComEd”), and MidAmerican Energy Company (“MidAmerican”). Following MidAmerican’s participation for its sixth time in the 2021 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 2022 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 2022-2023 Delivery Year² and lasts through the 2026-2027 Delivery Year.

The 2021 Procurement Plan, as approved by the Commission in Docket No. 20-0717, called for the energy requirements for Ameren Illinois, ComEd, and MidAmerican to be procured by the IPA through two block energy procurements (Spring 2021 and Fall 2021). In addition, the 2021 Plan included two capacity procurements for Ameren Illinois (Spring 2021 and Fall 2021). The 2021 Procurement Plan also recommended a continuation of the energy procurement strategies proposed in the 2020 Procurement Plan. The 2022 Procurement Plan recommends a further continuation of those strategies.

Renewable energy resources are now procured through procurements and programs subject to a separate planning process. Those include procurements and programs described in the Agency’s Long-Term Renewable Resources Procurement Plan (“Long-Term Plan”) and subsequent updates to the Long-Term Plan.

Section 16-111.5(b)(5)(ii)(B) of the PUA calls for that Long-Term Plan to be updated, and possibly revised, every two years “in conjunction with the Agency’s other planning and approval processes” to the extent practicable. The initial Long-Term Plan was developed by the Agency in 2017 and approved by the Commission on April 3, 2018 in Docket No. 17-0838. A revised Long-Term Plan was approved by the Commission on February 18, 2020 in Docket No. 19-0995, and a final revised Long-Term Plan edited to conform with the Commission’s Order was filed and published on April 20, 2020.³ Concurrent with the release of this draft 2022 Electricity Procurement Plan, the Agency has also released a draft of the Second Revised Long-Term Plan for public comment.

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 2022 procurement planning process.

² As defined by Section 1-10 of the IPA Act, a delivery year lasts from June 1 until May 31 of the following year. (20 ILCS 3855/1-10).

³ The Agency subsequently petitioned the Commission to reopen the Revised Long-Term Plan to address the potential of an RPS funding shortfall and the ICC approved the Revised Long-Term Plan on Reopening on May 27, 2021. A final Revised Long-Term Plan on Reopening was filed on June 7, 2021. See https://www2.illinois.gov/sites/ipa/Pages/Renewable_Resources.aspx for more information on the Long-Term Plans.

1.1 Power Procurement Strategy

The 2022 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 ladder 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.”⁴

The IPA’s energy hedging strategy for the 2022 Procurement Plan is consistent with the strategy used for the 2021 Plan. That strategy involves the procurement of hedges in 2022 to meet a portion of anticipated eligible retail customer energy supply requirements for a three-year period and includes two block energy procurement events, one in the Spring and the second in the Fall. Details of this procurement strategy can be found in Section 7.1.

Additionally, for Ameren Illinois, for the 2023-2024 Delivery Year, the IPA recommends continuing the strategy of procuring up to 50% of its forecasted capacity requirements in bilateral transactions and the remaining balance through the MISO Planning Resource Auction (“PRA”).⁵ For the 2024-2025 Delivery Year, the IPA recommends procuring up to 25% of its forecasted capacity requirements in bilateral transactions in 2022, with the balance of forecast capacity requirement to be determined in the 2023 Electricity Procurement Plan. For ComEd, consistent with the strategy adopted in prior plans, the IPA proposes that its capacity requirements be secured by ComEd through the PJM Reliability Pricing Model process. Following the approach taken in the 2021 Plan, the IPA recommends that MidAmerican’s forecasted capacity deficit be secured by MidAmerican through the annual MISO PRA.⁶

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

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

Table 1-1: Summary of Energy Hedging Strategy for all Utilities⁷

Spring 2022 Procurement			Fall 2022 Procurement		
June 2022-May 2023 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	October 2022-May 2023	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%

⁴ 20 ILCS 3855/1-20(a)(1).

⁵ 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.

⁶ 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).

⁷ Table 1-1 shows the cumulative percentage of targeted load to be hedged by the conclusion of the indicated procurement events.

Table 1-2: Summary of Capacity Procurement for Ameren Illinois^{8 9}

June 2022-May 2023	June 2023-May 2024	June 2024-May 2025
12.5% RFP in Spring 2020 25% RFP in Fall 2020 37.5% in Spring 2021 50% in Fall 2021 100%, MISO PRA	12.5% in Spring 2021 25% in Fall 2021 37.5% in Spring 2022 50% in Fall 2022 100%, MISO PRA	12.5% in Spring 2022 25% in Fall 2022 Remainder to be determined in 2023 Plan

Table 1-3: Summary of Capacity Procurement for ComEd

June 2022-May 2023 (Upcoming Delivery Year)	June 2023-May 2024	June 2024-May 2025	June 2025-May 2026
100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions

Table 1-4: Summary of Capacity Procurement for MidAmerican

June 2022-May 2023 (Upcoming Delivery Year)	June 2023-May 2024	June 2024-May 2025
100% of expected deficit through MISO PRA	100% of expected deficit through MISO PRA	100% of expected deficit through MISO PRA

1.2 Renewable Energy Resources

Through the passage of Public Act 99-0906, “the Agency shall no longer include the procurement of renewable energy resources in the annual procurement plans” and “shall instead develop a long-term renewable resources procurement plan.”¹⁰ Thus, the procurement of Renewable Energy Resources was included in the IPA’s Long-Term Renewable Resources Procurement Plan rather than this Plan. The IPA’s Initial Plan was approved by the Commission in April of 2018, and its First Revised Plan was approved in February of 2020. Concurrent with the release of this draft 2022 Electricity Procurement Plan, the Agency has also released a draft of the Second Revised Long-Term Plan for public comment.

⁸ Table 1-2 shows the cumulative up-to percentage of capacity targeted to be procured by the conclusion of the indicated procurement event.

⁹ Procurement percentage targets for the 2022-2023, and 2023-2024 Delivery Years conducted in 2021 were approved under the 2021 Procurement Plan. Actual procurement volumes may not match percentage targets.

¹⁰ 20 ILCS 3855/1-75(a).

1.3 Procurement Recommendations

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

Table 1-5: Summary of Procurement Plan Recommendations Based on July 15, 2021 Utility Load Forecast (Quantities to be Adjusted Based on the March and July 2022 Load Forecasts)

	Delivery Year	Energy	Capacity ^{11,12}	Transmission and Ancillary Services
Ameren Illinois	2022-2023	Up to 625 MW forecasted requirement (Spring Procurement)	Up to 12.5% in Spring 2020 Up to 25% RFP in Fall 2020 Up to 37.5% in Spring 2021 Up to 50% RFP in Fall 2021	Will be purchased from MISO
		Up to 225 MW additional forecasted requirement (Fall Procurement)	Remaining balance from MISO PRA	
	2023-2024	Up to 150 MW forecasted requirement (Spring Procurement)	Up to 12.5% RFP in Spring 2021 Up to 25% RFP in Fall 2021 Up to 37.5% in Spring 2022 Up to 50% RFP in Fall 2022	Will be purchased from MISO
		Up to 125 MW forecasted requirement (Fall Procurement)	Remaining balance from MISO PRA	
	2024-2025	Up to 125 MW forecasted requirement (Spring Procurement)	Up to 12.5% RFP in Spring 2022 Up to 25% RFP in Fall 2022 ¹³	Will be purchased from MISO
		Up to 125 MW forecasted requirement (Fall Procurement)	Remaining balance to be determined in 2023 Plan	
ComEd	2025-2026	No energy procurement required	No further action at this time	Will be purchased from MISO
	2026-2027	No energy procurement required	No further action at this time.	Will be purchased from MISO
	2022-2023	Up to 2,350 MW forecasted requirement (Spring Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
		Up to 850 MW additional forecasted requirement (Fall Procurement)		
	2023-2024	Up to 525 MW forecasted requirement (Spring Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
		Up to 525 MW forecasted requirement (Fall Procurement)		
MidAmerican	2024-2025	Up to 500 MW forecasted requirement (Spring Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
		Up to 500 MW forecasted requirement (Fall Procurement)		
	2025-2026	No energy procurement required	100% PJM RPM Auctions	Will be purchased from PJM
	2026-2027	No energy procurement required	No further action at this time	Will be purchased from PJM
	2022-2023	Up to 75 MW forecasted requirement (Spring Procurement)	100% of expected deficit from MISO PRA	Will be purchased from MISO
		No additional energy procurement needed (Fall Procurement)		
MidAmerican	2023-2024	No energy procurement needed (Spring Procurement)	100% of expected deficit from MISO PRA	Will be purchased from MISO
		No additional energy procurement needed (Fall Procurement)		
	2024-2025	No energy procurement required	100% of expected deficit from MISO PRA	Will be purchased from MISO
	2025-2026	No energy procurement required	No further action at this time	Will be purchased from MISO
MidAmerican	2026-2027	No energy procurement required	No further action at this time	Will be purchased from MISO

¹¹ Cumulative percentage of capacity targeted to be procured by the conclusion of the indicated procurement event.

¹² Procurement percentage targets for the 2022-2023, and 2023-2024 Delivery Years conducted in 2021 were approved under the 2021 Procurement Plan. Actual procurement volumes may not match percentage targets.

¹³ Additional Procurements for the 2024-2025 Delivery Year will be considered in the 2023 Procurement Plan.

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 2021.
2. Approve two energy procurement events scheduled for Spring 2022 and Fall 2022. The energy amounts to be procured in the spring will be based on the updated March 15, 2022 base case load forecasts developed by Ameren Illinois, MidAmerican, and ComEd, in accordance with the hedging levels stated in this Plan, and as ultimately approved by the ICC. The energy amounts to be procured in the fall will be based on the July 15, 2022 base case load forecasts developed by Ameren Illinois, MidAmerican, and ComEd, in accordance with the hedging levels stated in this Plan, and as ultimately approved by the ICC.
3. Approve two capacity procurement events for Ameren Illinois scheduled for Spring 2022 and Fall 2022. The up-to capacity amounts to be procured in the spring will be based on the updated March 15, 2022 base case load forecast developed by Ameren Illinois in accordance with the hedging levels stated in this Plan, and as ultimately approved by the ICC. The up-to capacity amounts to be procured in the fall will be based on the July 15, 2022 base case load forecast developed by Ameren Illinois, in accordance with the hedging levels stated in this Plan, and as ultimately approved by the ICC. In the event that legislative changes and/or regulatory decisions render the proposed 2023-2024 and/or 2024-2025 capacity procurements for Ameren Illinois unnecessary and that there is consensus to cancel either procurement among the IPA, ICC Staff, Procurement Monitor and Ameren Illinois, the affected procurements would be cancelled.
4. The March 15, 2022 and the July 15, 2022 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. To allow for the filing of forecast updates, a utility which has not intervened in this Plan's approval docket will be allowed to make an informational filing for its March 15, 2022 forecast update with the ICC. In the event that the parties do not reach consensus (or reach consensus that the updated load forecast should not be used) on an updated load forecast required in Items 2 and 3 above, then the most recent consensus load forecast will be used for the applicable procurement event. If those parties are unable to reach consensus on either of the updated load forecasts required in Items 2 and 3 above, then the July 2021 load forecast will be used for the applicable procurement event.
5. Approve procurement by ComEd, Ameren Illinois, and MidAmerican of capacity, network transmission service and ancillary services from each utility's respective Regional Transmission Organization ("RTO").

The Illinois Power Agency respectfully publishes this draft 2022 Procurement Plan for public comment and invites the affected utilities and any interested parties to submit comments on the Plan to the Agency by September 15, 2021.

2 Legislative/Regulatory Requirements of the Plan

This Section of the 2022 Procurement Plan describes the legislative and regulatory requirements applicable to the Agency's annual Procurement Plan, including compliance with previous Commission Orders. The Statutory Compliance Index (Appendix A) provides a complete cross-index of regulatory/legislative requirements and the specific sections of this Plan that address each requirement identified.

Public Act 99-0906, which became effective on June 1, 2017, substantially modified what elements are to be included in the IPA's annual "power procurement plan." Starting with the 2018 Procurement Plan, the IPA no longer includes the procurement of renewable energy resources as part of the annual procurement plan.¹⁴ The procurement of renewable energy resources to comply with the Illinois Renewable Portfolio Standard ("RPS") requirements in Section 1-75(c) of the IPA Act is instead addressed through the IPA's separately-developed Long-Term Renewable Resources Procurement Plan.

Public Act 99-0906 also included revisions to the state's energy efficiency portfolio standard (found in Section 8-103 of the PUA) as well as the elimination of the mechanism through which incremental energy efficiency programs were included in IPA procurement plans under Section 16-111.5B of the PUA.¹⁵ The 2022 Procurement Plan is focused only on the procurement of standard wholesale power products to meet the needs of the Ameren Illinois, ComEd and MidAmerican eligible retail customers.

2.1 IPA Authority

The IPA was established in 2007 by Public Act 95-0481 to ensure that ratepayers, specifically customers in service classes that have not been declared competitive and who take service from the utility's bundled rate ("eligible retail customers"),¹⁶ benefit from retail and wholesale competition. The original objective of the IPA Act was to improve the process to procure electricity for those customers.¹⁷ 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."¹⁸ The IPA Act thus directs the IPA to "[d]evelop electricity procurement plans" and conduct competitive procurement processes to bring resources under contract in a manner consistent with those findings.

Each year, the IPA thus must develop a "power procurement plan" and conduct a competitive procurement process to procure supply resources as identified in its procurement plan as approved by the Commission pursuant to Section 16-111.5 of the PUA.¹⁹ The purpose of the power procurement plan is to secure the wholesale electric power products 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.²⁰ The 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"²¹ and

¹⁴ See 20 ILCS 3855/1-75(a); 220 ILCS 5/16-111.5(b)(5).

¹⁵ See 220 ILCS 5/16-111.5B(a)(5) ("The requirements set forth in paragraphs (1) through (5) of this subsection (a)" – i.e., the solicitation, inclusion, and approval of incremental energy efficiency programs in IPA procurement plans – "shall terminate after the filing of the procurement plan in 2015, and no energy efficiency shall be procured by the Agency thereafter. Energy efficiency programs approved previously under this Section shall terminate no later than December 31, 2017.").

¹⁶ 220 ILCS 5/16-111.5(a).

¹⁷ See 20 ILCS 3855/1-5(2)-(4).

¹⁸ 20 ILCS 3855/1-5(1).

¹⁹ See 20 ILCS 3855/1-20(a)(2), 1-75(a).

²⁰ 20 ILCS 3855/1-20(a)(1). MidAmerican elected to participate in IPA Procurement Plans starting in 2016 and will continue to participate in the 2021 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.")

²¹ 20 ILCS 3855/1-75(a)(1).

“Procurement Administrator.”²² The Commission is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired “Procurement Monitor.”²³

Public Act 99-0906, effective June 1, 2017, modified the IPA’s procurement planning process in part through the introduction of new requirements impacting the Agency. These requirements include the development of a separate zero emission standard procurement plan and the procurement of zero-emission credits from zero-emission generators (i.e., nuclear power plants);²⁴ the development of a separate long-term plan for the procurement of renewable energy resources (which includes the development of an adjustable block program to procure renewable energy credits from distributed generation and community solar projects; and the development of a low-income solar program using, in part, money held in the Renewable Energy Resources Fund);²⁵ and the elimination of the statutory requirement that the Agency include cost-effective incremental energy efficiency programs in its annual power procurement plan.²⁶

At the time of publishing this draft 2022 Procurement Plan, new omnibus energy legislation in Illinois is still being debated and negotiated. Based on a review of drafts of that legislation, the IPA’s procurement responsibilities related to renewable energy credits could expand significantly, and the Agency may be tasked with the development of a new procurement plan for the procurement of carbon mitigation credits from at-risk nuclear facilities. Some drafts have included changes to Section 16-111.5 of the PUA in ways that could alter procurement strategies and bid evaluation for the Agency’s energy procurement processes, although those proposed changes do not appear to be significant enough to require the withdrawal of this plan and the development of an entirely new annual procurement plan under a new timeline. As of August 16, 2021, the fate of these legislative proposals or timing of their enactment remains unclear.

2.2 Procurement Plan Development and Approval Process

Although elements of the 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 2022 Procurement Plan began on July 15, 2021. 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.

After the receipt of load forecasts from the utilities, the IPA next prepares a draft Procurement Plan. The Draft 2022 Plan was made available for public review and comment on August 16, 2021.²⁷ The Public Utilities Act provides for a 30-day comment period starting on the day the IPA releases its draft plan. The 2021 Plan comment period is scheduled to conclude on September 15, 2021. In prior years, during the 30-day comment period, the Agency has held in-person public hearings within each participating utility’s service area to receive public comment on the draft Procurement Plan. Due to the ongoing COVID-19 pandemic, the Agency will hold public hearings for the 2022 Plan virtually in lieu of the separate meetings in each utility’s service area.²⁸

After the receipt of comments, and within 14 days after the conclusion of the comment period, the IPA “shall revise the procurement plan as necessary based on the comments received” and file that revised Plan with the

²² 20 ILCS 3855/1-75(a)(2).

²³ 220 ILCS 5/16-111.5(b), (c)(2).

²⁴ See 20 ILCS 3855/1-75(d-5).

²⁵ See 20 ILCS 3855/1-75(c); Docket No. 17-0838.

²⁶ See 220 ILCS 5/16-111.5B.

²⁷ August 15, 2021 falls on a Sunday. The Agency therefore released the Draft 2022 Plan for comment on the next business day, Monday, August 16, 2021 in accordance with the Statute on Statutes (5 ILCS 70).

²⁸ The virtual public hearings on the draft 2022 Plan are planned for 12:00 p.m. (Ameren Illinois), 1:00 p.m. (ComEd), and 2:00 p.m. (MidAmerican) on Friday September 3, 2021, and will be held in conjunction with public hearings on the Agency’s draft Second Revised Long-Term Renewable Resources Procurement Plan. For more information on how to offer public comment at this hearing, please see the cover letter and hearing notice that accompanies this draft Plan at <https://www2.illinois.gov/sites/ipa/Pages/Plans-Under-Development.aspx>.

Commission.²⁹ The IPA's 2022 Plan is scheduled to be filed with the Commission no later than September 29, 2021. Within 5 days after the Procurement Plan is filed with the Commission, parties may file Objections to the Plan.³⁰

Under the PUA, 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."³¹

2.3 Procurement Plan Requirements

At its core, the Procurement Plan consists of three pieces: (1) a forecast of how much energy (and in some cases capacity) is required by eligible retail customers; (2) the supply currently under contract; and (3) what type and how much supply must be procured to meet load requirements and to satisfy all other legal requirements associated with the Procurement Plan. To that end, the Procurement Plan must contain an hourly load analysis, which includes: multi-year historical analysis of hourly loads; switching trends and competitive retail market analysis; known or projected changes to future loads; and growth forecasts by customer class.³² 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.³³ 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,³⁴ 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.³⁵
- Include the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year that, separately or in combination, will meet the portion of the load requirements not met through pre-existing contracts or in the case of MidAmerican, including allocations to eligible Illinois customers of energy and capacity from company owned generating resources.³⁶ 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.³⁷
- Detail the proposed term structures for each wholesale product type included in the portfolio of products.³⁸
- 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.³⁹ The load forecasts for the 2022 Plan also take into account the estimated impact of the COVID-19 pandemic on the eligible customers' electricity demand. For those portfolio measures that are identified as having significant price risk, the Plan shall identify alternatives to those measures.

²⁹ See 220 ILCS 5/16-111.5(d)(2).

³⁰ 220 ILCS 5/16-111.5(d)(3).

³¹ 220 ILCS 5/16-111.5(d)(4).

³² 220 ILCS 5/16-111.5(b)(1)(i)-(iv).

³³ 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).

³⁴ 220 ILCS 5/16-111.5(b)(3).

³⁵ 220 ILCS 5/16-111.5(b)(i), (b)(iii).

³⁶ 220 ILCS 5/16-111.5(b)(3)(iv).

³⁷ Id.

³⁸ 220 ILCS 5/16-111.5(b)(3)(v).

³⁹ 220 ILCS 5/16-111.5(b)(3)(vi).

- 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.⁴⁰
- Include demand-response products, as discussed below.

2.4 Standard Product Procurement

As noted in Section 2.3, the IPA Act provides examples of “standard wholesale products.”⁴¹ This listing has been understood by the Commission to be non-exhaustive and non-static.⁴² Instead, as articulated by the Commission in approving the 2015 Plan, “[w]henver 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.”⁴³

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,⁴⁴ 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.⁴⁵ With respect to demand-side products, in approving the 2015 Plan the Commission determined that block super-peak energy efficiency products proposed for procurement by the Agency “should not be procured at this time,” but left open the possibility that “as demand-side markets evolve and energy efficiency products become more standardized, the Commission could envision a time in which these products might satisfy Section 16-111.5 of the PUA.”⁴⁶

2.5 Demand Response Products

The IPA may include cost-effective demand response products in its Procurement Plan. The Procurement Plan must include the particular “mix of cost-effective, demand-response products for which contracts will be executed during the next year, to meet the expected load requirements that will not be met through preexisting contracts.”⁴⁷ 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.⁴⁸ Specifically:

⁴⁰ 220 ILCS 5/16-111.5(b)(4).

⁴¹ 220 ILCS 5/16-111.5(b)(3)(iv).

⁴² 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”).

⁴³ Id.

⁴⁴ While not adopting the Illinois Competitive Energy Association’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”).

⁴⁵ 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).

⁴⁶ Docket No. 14-0588, Final Order dated December 17, 2014 at 156.

⁴⁷ 220 ILCS 5/16-111.5(b)(3)(ii).

⁴⁸ Id.

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;⁴⁹
- The products must at least satisfy the demand-response requirements of the regional transmission organization market in which the utility's service territory is located, including, but not limited to, any applicable capacity or dispatch requirements;⁵⁰
- The products must provide for customers' participation in the stream of benefits produced by the demand-response products;⁵¹
- 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;⁵²; 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.⁵³

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 approved the utility's Advanced Metering Infrastructure ("AMI") Plan.⁵⁴ ComEd's PTR program was provisionally approved in Docket No. 12-0484, and Ameren Illinois' PTR program was likewise provisionally approved in Docket No. 13-0105.⁵⁵ These programs are discussed further in Section 7.4, where demand response resource choices are examined.

Public Act 99-0906 made significant revisions to the energy efficiency and demand response portfolio standard found in Section 8-103 of the Public Utilities Act, creating new requirements that became effective on January 1, 2018. On June 30, 2017, ComEd filed its 2018-2021 Energy Efficiency and Demand Response Plan; for its demand response goal, ComEd proposed to implement a demand response program element that would fund the enrollment into its air conditioning ("AC") cycling program of any purchasers of qualified smart thermostats from ComEd's other residential program elements.⁵⁶ Ameren Illinois also filed its Energy Efficiency and Demand-Response Plan on June 30, 2017; Ameren Illinois proposed to achieve demand response reductions and meet its obligations under Section 8-103B(g)(4.5) through the peak demand reduction coincident to the electric energy efficiency savings proposed in its plan.⁵⁷ These Plans were both approved by the Commission on September 11, 2017.⁵⁸

Ameren Illinois and ComEd filed new energy efficiency plans as required by March 1, 2021 to cover the 2022-2025 period.⁵⁹ Ameren once again proposed to achieve its demand response goal through coincident peak demand reduction achieved by the energy efficiency portfolio; this proposal was approved by the Commission on July 22, 2021.⁶⁰ Like Ameren, ComEd also proposed to utilize the same approach as in its prior plan to achieve its demand response goal. The Commission approved ComEd's proposal to continue to meet its demand response goals through its residential and income-eligible energy efficiency programs on June 24, 2021.⁶¹

⁴⁹ 220 ILCS 5/16-111.5(b)(3)(ii)(A).

⁵⁰ 220 ILCS 5/16-111.5(b)(3)(ii)(B).

⁵¹ 220 ILCS 5/16-111.5(b)(3)(ii)(C).

⁵² 220 ILCS 5/16-111.5(b)(3)(ii)(D).

⁵³ 220 ILCS 5/16-111.5(b)(3)(ii)(E).

⁵⁴ 220 ILCS 5/16-108.6(g).

⁵⁵ 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.

⁵⁶ See Docket No. 17-0312, Final Order dated September 11, 2017 at 19.

⁵⁷ See Docket No. 17-0311, Final Order dated September 11, 2017 at 46-47.

⁵⁸ The Commission's approval of the Ameren Illinois plan in Docket No. 17-0311 was appealed by the People of the State of Illinois, through the Office of the Attorney General, to the Illinois Appellate Court, Fourth District under Case No. 4-17-0870.

⁵⁹ 220 ILCS 5/8-103B(f)(2).

⁶⁰ See Docket No. 21-0158, Final Order dated July 22, 2021 at 15.

⁶¹ See Docket No. 21-0155, Final Order dated June 24, 2021 at 12, 25.

2.6 Clean Coal Portfolio Standard

The IPA Act contains an aspirational goal that cost-effective clean coal resources will account for 25% of the electricity used in Illinois by January 1, 2025.⁶² As a part of the goal, the Plan must also include electricity generated from clean coal facilities.⁶³ While there is a broader definition of “clean coal facility” contained in the definition section of the IPA Act,⁶⁴ Section 1-75(d) describes two special cases: the “initial clean coal facility”⁶⁵ 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”).⁶⁶ Currently, there is no facility meeting the definition of an “initial clean coal facility” or a “retrofit clean coal facility” that the IPA is aware of, that has announced plans to begin operations within the next five years. A discussion of the considerations and challenges associated with possible clean coal procurements is contained in Section 7.5.

In Docket No. 12-0544, the Commission approved inclusion of the FutureGen 2.0 project as a “retrofit clean coal facility” starting in the 2017-2018 Delivery Year; that administrative approval and the associated cost recovery mechanism were subsequently appealed, and initially upheld by the Illinois First District Appellate Court.⁶⁷ With an appeal still pending before the Illinois Supreme Court, the U.S. Department of Energy (“U.S. DOE”) announced in February 2015 that federal funding for the project would be suspended.⁶⁸ The FutureGen Alliance’s Board of Directors “approved a resolution, dated January 6, 2016, ceasing all FutureGen Project development efforts”⁶⁹ and FutureGen exercised its right to terminate the prior-approved FutureGen 2.0 Sourcing Agreements with ComEd and Ameren Illinois. The Illinois Supreme Court subsequently dismissed the pending appeal of the appellate court’s decision as moot through a May 2016 ruling, vacating the judgment of the appellate court without expressing an opinion on its merits while refraining from vacating those portions of the Commission’s Order approving the 2013 Procurement Plan concerning FutureGen 2.0 sourcing agreements and related authority.⁷⁰

2.7 Recent Legislative Proposals and Related Developments

Under changes made to Section 1-75(c) of the IPA Act and Section 16-111.5 of the PUA through Public Act 99-0906, the Agency’s responsibility for renewable energy resource procurement has transitioned from meeting percentage-based renewables requirements applicable to eligible retail customer load to meeting similar percentage-based requirements for all retail customer load.⁷¹ As part of this transition, the IPA was tasked with developing a separate Long-Term Renewable Resources Procurement Plan through which it proposed procurements and programs to meet these new targets,⁷² conducting “initial forward procurements” of renewable energy credits from new utility-scale wind projects and new utility-scale solar and brownfield site photovoltaic projects,⁷³ developing an adjustable block program to support the development of new distributed photovoltaic generation and community solar projects,⁷⁴ and developing a low-income solar incentive program to support the development of a low-income solar marketplace.⁷⁵ The Agency’s initial Long-

⁶² 20 ILCS 3855/1-75(d).

⁶³ 20 ILCS 3855/1-75(d)(1).

⁶⁴ 20 ILCS 3855/1-10.

⁶⁵ Id.

⁶⁶ 20 ILCS 3855/1-75(d)(5).

⁶⁷ Commonwealth Edison Co. v. Ill. Commerce Comm’n, et al., 2014 IL App (1st) 130544, July 22, 2014.

⁶⁸ See, e.g., <http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead>.

⁶⁹ Supplemental Brief of Appellee FutureGen Industrial Alliance, Inc. on the Issue of Mootness, dated January 13, 2016, at 1.

⁷⁰ Commonwealth Edison Co. v. Ill. Commerce Comm’n, et al., 2016 IL 118129, May 19, 2016.

⁷¹ See 20 ILCS 3855/1-75(c)(1)(B). Among other changes, the revised law also now features quantitative targets for the procurement of renewable energy credits from new generating facilities as well. (See 20 ILCS 3855/1-75(c)(1)(C)).

⁷² See 20 ILCS 3855/1-75(c)(1)(A); 220 ILCS 5/16-111.5(b)(5).

⁷³ 20 ILCS 3855/1-75(c)(1)(G).

⁷⁴ See 20 ILCS 3855/1-75(c)(1)(K).

⁷⁵ See 20 ILCS 3855/1-56(b)(2).

Term Renewable Resources Procurement Plan was approved by the Commission in Docket No. 17-0838 on April 3, 2018; it has subsequently been revised, and that Revised Plan was approved by the Commission on February 18, 2020 through Docket No. 19-0995. A draft Second Revised Long-Term Plan was published concurrent with publishing this Draft 2022 Procurement Plan.

Incremental energy efficiency programs and renewable energy resource procurement provided for the bulk of contested issues in past IPA Plan approval proceedings. As those issues are now handled through separate proceedings and processes not involving the IPA, the number of contested issues and intensity of arguments in attaining approval of the IPA's annual procurement plans has been reduced, with just two contested issues for the 2018 Plan, no contested issues for the 2019 Plan, and only one contested issue for the 2020 Plan approval proceeding. There were, once again, no contested issues for the 2021 Plan.

During the Spring 2021 session of the 102nd Illinois General Assembly, the ILGA debated new omnibus energy legislation including a significant overhaul and expansion of the state's Renewable Portfolio Standard, new standalone renewable energy resource procurement initiatives (such as a coal-to-solar renewable energy credit procurement), the development of a carbon mitigation credit planning and procurement process to support at-risk nuclear power plants, and an increased focus on diversity, equity, and labor standards across the IPA's planning and procurement activities.

While the Agency understands that most new responsibilities would be handled through separate planning processes, changes of this magnitude would unquestionably carry impacts on the development of the Agency's annual procurement plans. Additionally, some drafts have included changes to Section 16-111.5 of the PUA in ways that could alter procurement strategies and bid evaluation for the Agency's energy procurement processes, although those proposed changes do not appear to be significant enough to require the withdrawal of this plan and the development of an entirely new annual procurement plan under a new timeline.

As of the publishing of this draft 2022 Procurement Plan, these proposals remain under consideration, and the Agency has no timetable for if or when these proposals will be enacted. The Agency will continue to monitor legislative discussions and be an active participant in any hearings, negotiations, working groups, or other discussions in which its interests or jurisdiction are implicated.

On a national level, litigation and federal policy decisions have continued to shape the United States Environmental Protection Agency's ("U.S. EPA") approach to limiting CO₂ emissions from coal-fired power plants. On August 3, 2015, the U.S. EPA released its Clean Power Plan rules promulgated pursuant to Section 111(d) of the Clean Air Act, requiring states to develop strategies intended to reduce carbon dioxide emissions associated with electricity generation. On February 9, 2016, the U.S. Supreme Court stayed implementation of the Clean Power Plan pending judicial review.⁷⁶ Under the Clean Power Plan, initial state compliance plans were scheduled to be due to the U.S. EPA by September 6, 2016, but the stay delayed the timing for the state compliance plan development. In March 2017, President Trump issued an Executive Order seeking to revise or terminate the Clean Power Plan,⁷⁷ and on October 16, 2017, U.S. EPA published a Proposed Rule to repeal the Clean Power Plan.⁷⁸ On December 28, 2017, U.S. EPA published an Advance Notice of Proposed Rulemaking with the purpose of soliciting public comment on a new rule to regulate greenhouse gas ("GHG") emissions from existing electric generating units, written comments were due by February 26, 2018.⁷⁹ On July 9, 2018 a draft of a new rule, which would replace the Clean Power Plan, was sent to the White House for review.⁸⁰

⁷⁶ 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>.

⁷⁷ See, e.g., <https://www.nytimes.com/2017/03/28/climate/trump-executive-order-climate-change.html>; <https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economy-1>.

⁷⁸ See <https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0355-0002>.

⁷⁹ See <https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0545-0001>; <https://www.regulations.gov/docketBrowser?rpp=25&so=DESC&sb=commentDueDate&po=0&dct=PS&D=EPA-HQ-OAR-2017-0545>.

⁸⁰ Proctor, D., "EPA Sends Replacement for Clean Power Plan to Trump," www.powermag.com/category/coal/, July 10, 2018.

The U.S. EPA released its proposed rulemaking, titled the “Affordable Clean Energy” (“ACE”) rule, on August 21, 2018.⁸¹ On June 19, 2019, the EPA issued the final rule to replace the Clean Power Plan. The ACE rule established emissions guidelines for states to use for developing limits to CO₂ emissions from coal-fired power plants which identifies coal plant heat rate improvements as the best system of emission reduction (BSER).⁸² The ACE rule is generally less stringent as compared with the Clean Power Plan (which would have imposed limitations on emissions from power plants to be achieved through switching power plant fuels from coal to natural gas, increasing generation from renewable resources, or requiring new coal-fired plants to meet low CO₂ emissions limits only possible through the use of carbon capture technology).⁸³

Litigation regarding the ACE rule commenced in August 2019 when a coalition of 23 state Attorneys General filed a lawsuit in the D.C. Circuit Court of Appeals challenging the ACE rule.⁸⁴ On March 23, 2020 the D.C. Circuit issued a revised brief schedule. All parties were required to submit their final briefs by August 13, 2020, with oral argument held on October 8, 2020.⁸⁵ On January 19, 2021, the D.C. Circuit vacated the ACE Rule and remanded it to the EPA. The decision vacating the ACE did not reinstate the CPP.⁸⁶ The Biden Administration is currently developing a comprehensive proposal for addressing the country’s climate change issues which will likely also address the emissions from electric power plants.

Additionally, the Agency is actively monitoring developments at the Federal Energy Regulatory Commission (“FERC”) regarding capacity market constructs for PJM and MISO, the two Regional Transmission Organizations that Illinois is part of, including the recent FERC Order on PJM capacity market design. These are discussed further in Chapter 5 below.

⁸¹ Emissions Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program, 83 Fed. Reg. 44746 (August 31, 2018); see also <https://www.epa.gov/stationary-sources-air-pollution/proposal-affordable-clean-energy-ace-rule>.

⁸² See: <https://www.epa.gov/stationary-sources-air-pollution/affordable-clean-energy-rule>.

⁸³ “Goodbye, Clean Power Plan: Stanford researchers discuss the new energy rule,” Stanford Woods Institute for the Environment, June 21, 2019.

⁸⁴ See, e.g.: <http://biomassmagazine.com/articles/17436/oral-arguments-held-in-challenge-to-epaundefineds-ace-rule>.

⁸⁵ Congressional Research Service Report R46482, “EPA’s Affordable Clean Energy Rule and Related Issues: Frequently Asked Questions,” August 13, 2020.

⁸⁶ U.S. EPA, Office of Air and Radiation, Memorandum: Status of Affordable Clean Energy Rule and Clean Power Plan, February 12, 2021.

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.”⁸⁷ 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 in Illinois, has elected to have the IPA procure electricity⁸⁸ for a portion of its load.⁸⁹ 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.⁹⁰

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.⁹¹

The forecasts are prepared by the utilities, but the Procurement Plan is ultimately the responsibility of the Agency. The 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 Plan, except where noted, the retail load is taken to include an allowance for losses. In other words, it represents the volume of energy that each utility must schedule to meet the load of its eligible retail customers at the RTO level (MISO for Ameren Illinois and MidAmerican, and PJM for ComEd).

3.2 Summary of Information Provided by Ameren Illinois

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

- Ameren Illinois Company Load Forecast for the period June 1, 2022 – May 31, 2027 (See Appendix B)
- Spreadsheets of the expected (base), high, and low load forecasts. (Summarized in Appendix E)

⁸⁷ 220 ILCS 5/16-111.5(a).

⁸⁸ 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.

⁸⁹ 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 seventh annual procurement process in which MidAmerican elected to have the IPA procure power and energy for a portion of its Illinois jurisdictional load.

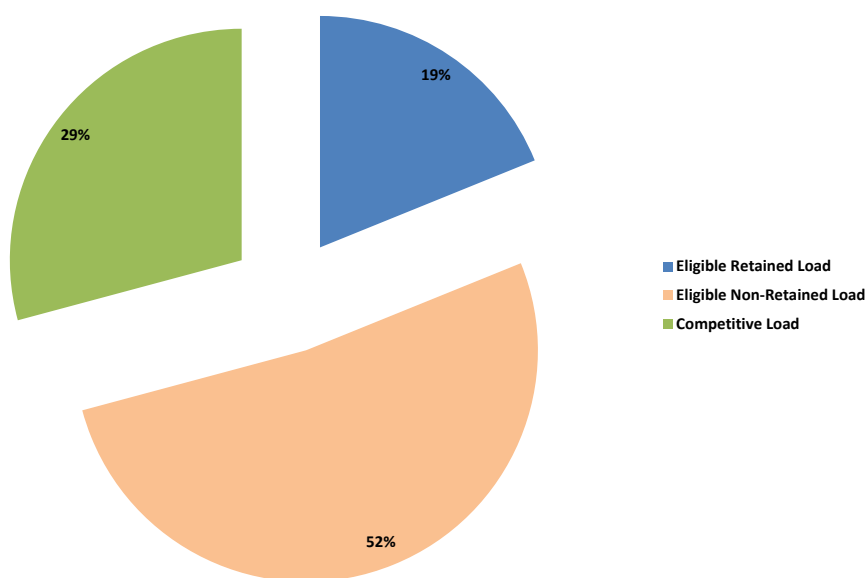
⁹⁰ 220 ILCS 5/16-111.5(b)(1).

⁹¹ 220 ILCS 5/16-111.5(d)(1).

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

Industrial and public authority classes are modeled using a traditional econometric approach that correlates monthly sales, weather, seasonal variables, and economic conditions. The Lighting load class is modeled using either exponential smoothing or econometric models. Figure 3-1 shows Ameren's retail load forecasted annual energy usage percentage.⁹²

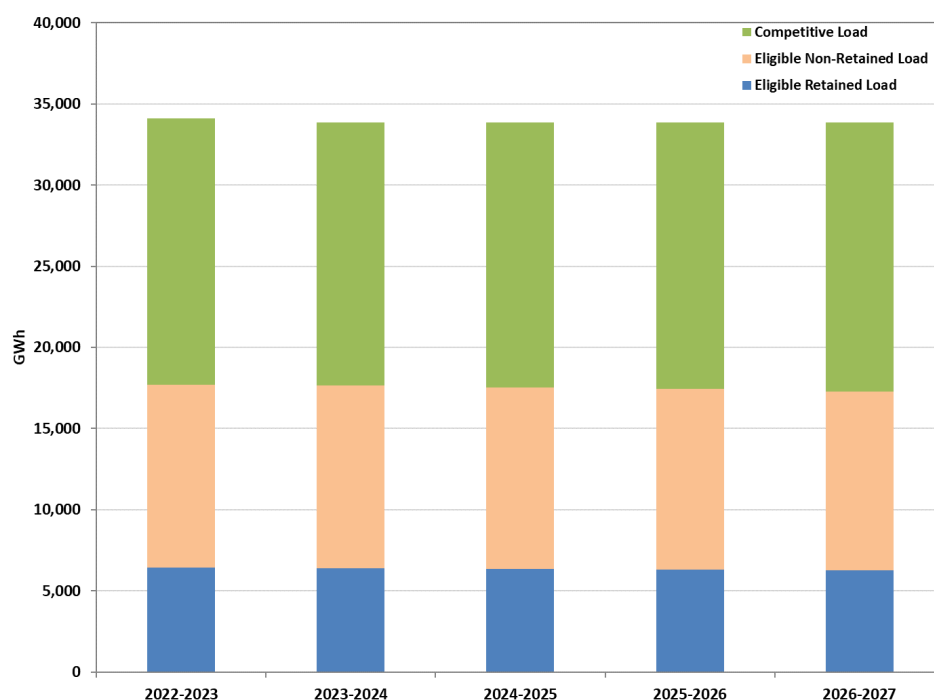
Figure 3-1: Ameren Illinois' Forecast Retail Customer Load Breakdown, Delivery Year 2022-2023⁹³



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 of its retail customer load.

⁹² 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: DS-1 – Residential, DS-2 – Non-Time of Use Commercial & Industrial with demands less than 150 kW, DS-3 – Time of Use Commercial & Industrial with demands between 150 kW and 1,000 kW, DS-4 – Time of Use Commercial & Industrial with demands above 1,000 kW, and DS-5 – Lighting. The DS-3 and DS-4 classes are fully competitive, meaning that customers in these classes must receive supply from ARES or Ameren Illinois real time pricing. Customers in the DS-1, DS-2 and DS-5 classes are eligible to take fixed-price supply service from Ameren Illinois or an ARES.

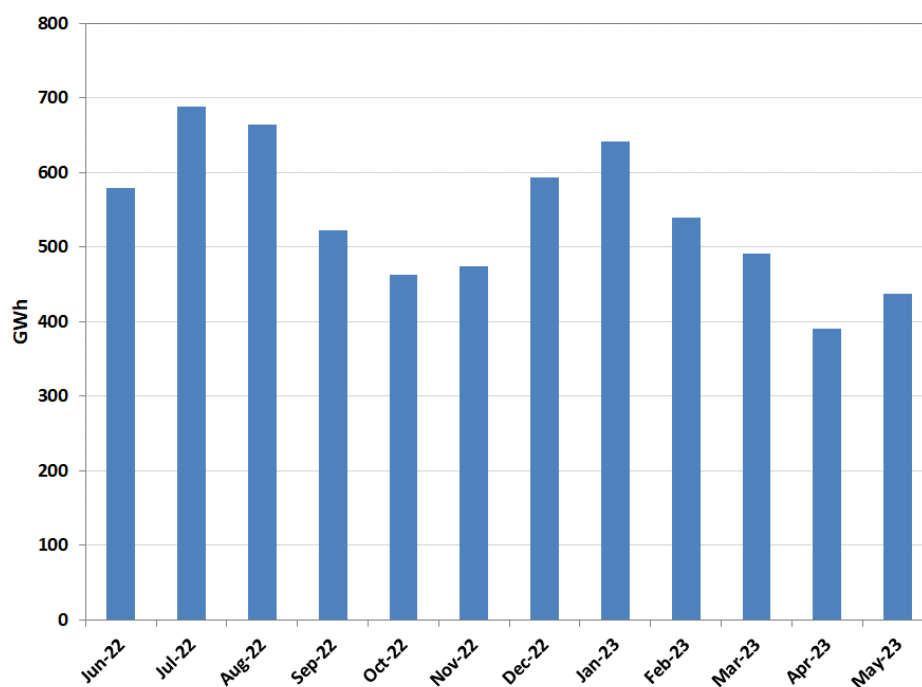
⁹³ For the 2022-2023 Delivery Year, Ameren Illinois' projected total Retail Load is 35,071,637 MWh, where the Eligible Retained Load accounts for 6,430,836 MWh, the Eligible Non-Retained Load accounts for 17,715,133 MWh, and the Competitive Load accounts for 10,925,668 MWh. The amount for the projected total Retail Load was provided by Ameren in their July 2021 response to the IPA Data Request for the update of the Final Revised Long-Term Plan.

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) and Alternative Retail Electric Suppliers, including municipal aggregation.⁹⁴ Ameren Illinois establishes the current customer switching trend line utilizing actual switching data by customer class. Qualitative judgment is used to make adjustments to the switching trend line. The portion of the forecasted load attributed to Rider HSS, municipal aggregation customers, and other ARES customers, is subtracted from the total system load forecast. The result is the forecasted load to be supplied by Ameren Illinois.

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

⁹⁴ Municipal aggregation of residential and small commercial retail customer load for contracting with ARES is authorized by the IPA Act, 20 ILCS 3855/1-92.

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

*Total load, prior to netting QF supply.

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

3.2.1 Macroeconomics

The Ameren Illinois base case load forecast is based on a statistically adjusted end-use forecast that combines technological coefficients (efficiencies of various end-use equipment) and econometric variables (income levels and energy prices). Ameren Illinois did not define “high” and “low” cases by varying the econometric (or other) variables. Instead, Ameren Illinois looked at the statistics of the residuals from the model fit, and the high and low cases are based on a 95% confidence interval. For the residential electric customer class, Ameren Illinois currently projects a 5-year compound annual growth rate of -1.2%. For commercial customers, the growth rate for Ameren Illinois is projected to be -0.3%. While for industrial customers, the growth rate for Ameren Illinois is projected to be 2.3%.

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 below shows the current rates for the low and high cases for each of the three rate classes.

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

Rate Class	Low Case	High Case
DS-1	0.94	1.07
DS-2	0.94	1.07
DS-5	0.93	1.07

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 average impact of weather, and macroeconomic effects, which is proportionally the same in each hour.

The low case is about 7% lower than the base case and the high case is about 7% higher than the base case. The difference between the high, low, and base cases are the variation Ameren Illinois attributes to macroeconomic effects and weather variables.

3.2.3 Switching

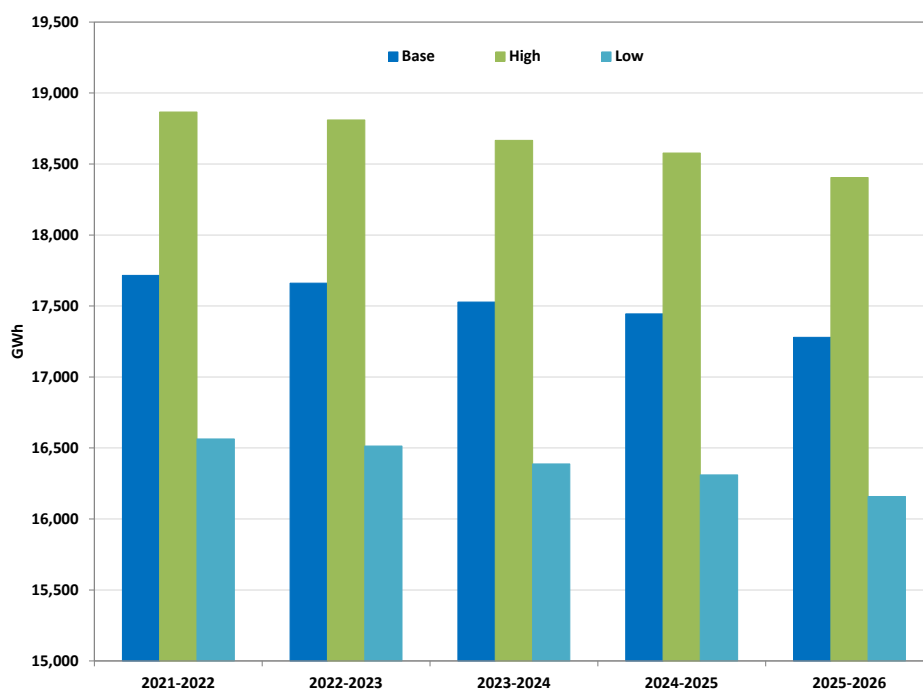
According to Ameren Illinois, customer switching to alternative retail electric suppliers, in particular through municipal aggregation, is the greatest driver of load uncertainty. As of May 1, 2021, customer switching has resulted in approximately 61% of residential and 69% small commercial load taking service from alternative retail electric suppliers rather than from Ameren’s default service. Ameren Illinois expects that the amount of load supplied by ARES will remain flat across the planning horizon. A number of municipal aggregation contracts are set to expire in July 2022, January 2023, December 2023 and January 2024, and Ameren’s load forecast presumes that those municipalities will renew their contracts.⁹⁵ Additionally, as shown in Table 3-2 presented in the next Section, ARES offerings to individual customers, in general, are higher than the default utility rate.

Ameren Illinois has also developed additional switching scenarios that address high and low switching scenarios for this planning period. A low switching scenario envisions a situation where a larger return of residential and, to a lesser extent, commercial customers, is realized. These scenarios reflect various switching rates which are the reflection of the percentage of load that is being served by alternative retail electric suppliers. Residential and small commercial switching rates under the low switching and a corresponding high load scenario are forecasted to be 53% and 61%, respectively, in May 2022, 46% and 54%, respectively, in May 2023, and 17% and 25%, respectively, by the end of the planning horizon.

Conversely, should future Ameren Illinois tariff rates exceed customers’ perceived value of ARES contracts, a higher switching scenario is possible. Thus, Ameren Illinois’ high switching and a corresponding low load scenario assumes that residential and small commercial switching rates will approach 66% and 74%, respectively, in May 2022, 71% and 79%, respectively, in May 2023, and 90% and 98%, respectively, by the end of the planning horizon.

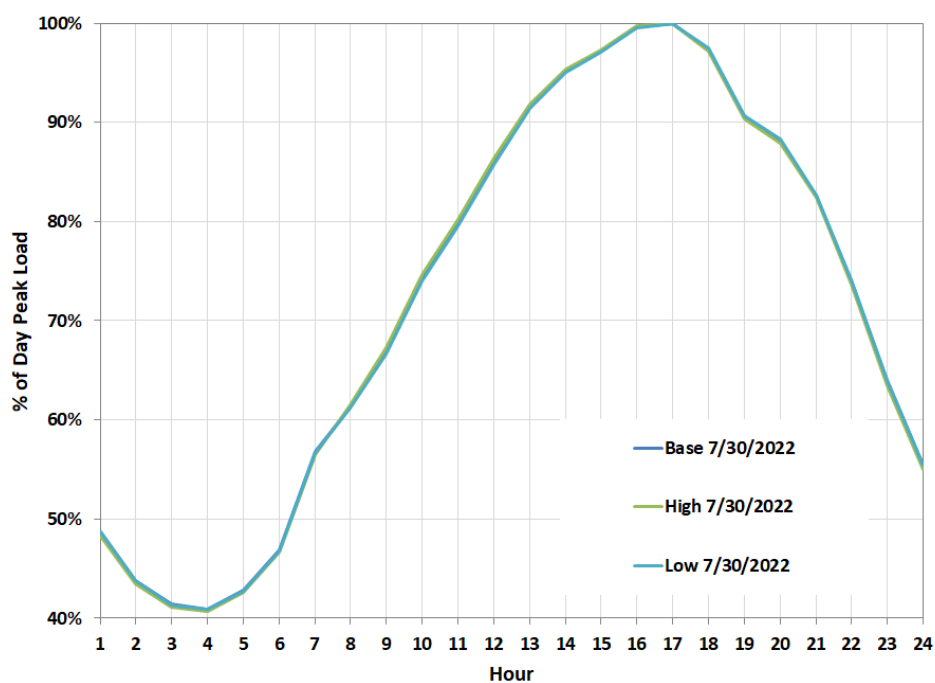
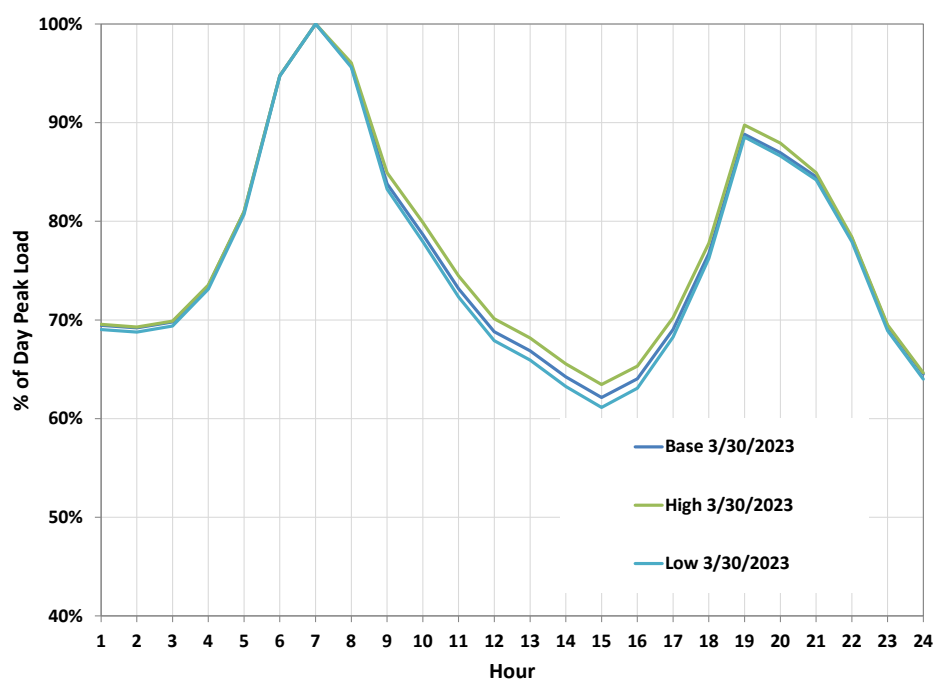
The difference in switching rates is the most significant factor driving the differences among the scenarios. Figure 3-4 shows the forecasted Ameren Illinois supply obligation in each case. The Base Case assumes the expected switching, the High Load assumes low switching, and the Low Load assumes high switching.

⁹⁵ If some, or all, of these municipalities do not renew their contracts and customers return to default service, that additional load will be reflected in the March 2022 load forecasts and procurement volumes adjusted accordingly.

Figure 3-4: Supply Obligation in Ameren Illinois' Forecasts

3.2.4 Load Shape and Load Factor

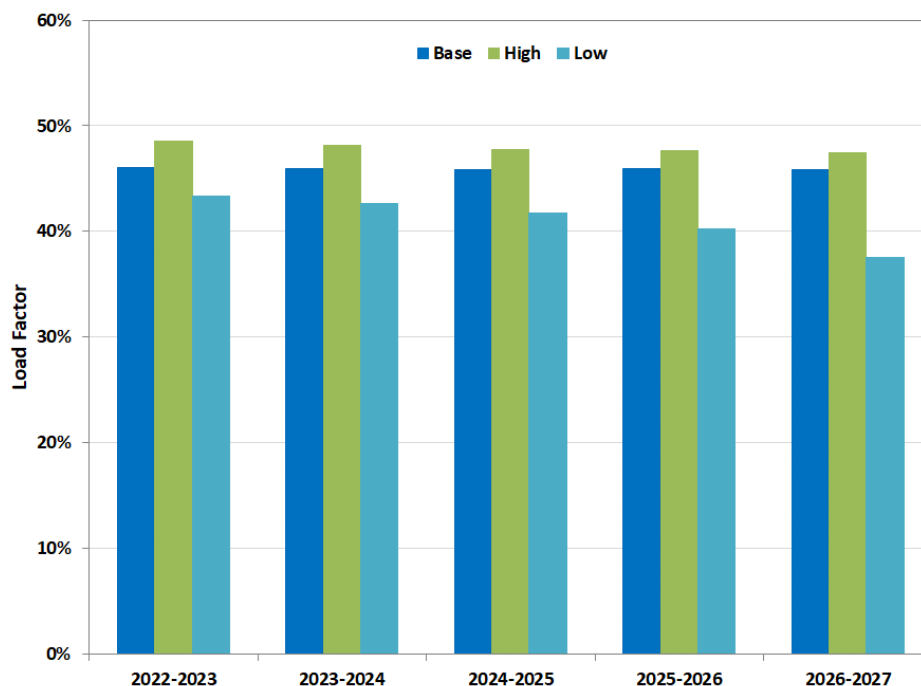
Figure 3-5 and Figure 3-6 display the hourly profile of Ameren Illinois supply obligation in each case (relative to the daily maximum load). Figure 3-5 illustrates a summer day and Figure 3-6 a spring day. In these figures the curves are normalized so that the highest value in each is 1. There is little difference between the profiles of the high, low, and base cases.

Figure 3-5: Sample Daily Load Shape, Summer Day in Ameren Illinois' Forecasts**Figure 3-6: Sample Daily Load Shape, Spring Day in Ameren Illinois' Forecasts**

A load shape can be called “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. 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 3-7 shows that the low case has the lowest load factors, while Figure 3-5 and Figure 3-6 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 3-7: Load Factor in Ameren Illinois' Forecasts



3.3 Summary of Information Provided by ComEd

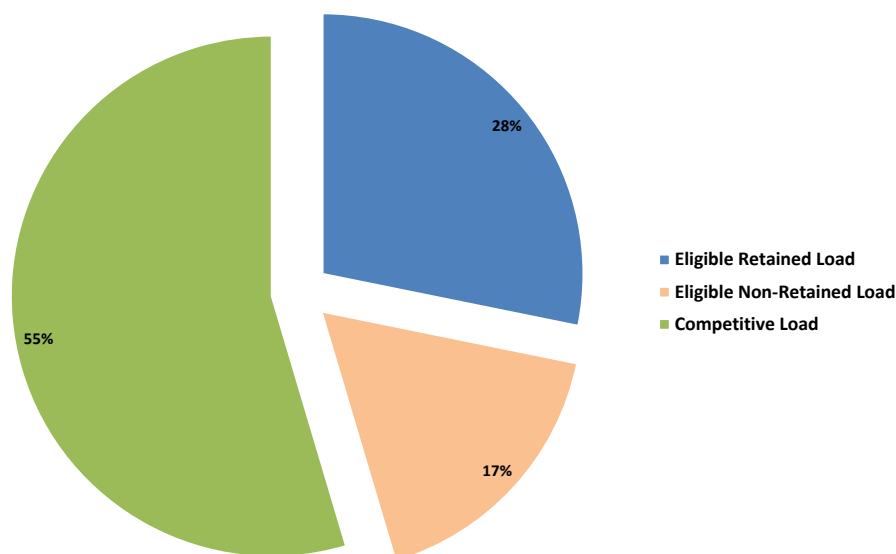
In compliance with Section 16-111.5(d)(1) of the Public Utilities Act, ComEd provided the IPA the following documents for use in preparation of this Plan:

- *Load Forecast for Five-Year Planning Period June 2022 – May 2027.* (See Appendix C) This document also contained several appendices.
- Information supporting the load forecasts including spreadsheets of load profiles, hourly load strips, model inputs, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix F)⁹⁶

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 3-8 shows ComEd's retail load forecasted annual energy usage percentage.

⁹⁶ In its July 15, 2021 Load Forecast, ComEd also included a brief discussion of the distributed generation penetration effect in its service territory.

Figure 3-8: ComEd's Forecast Retail Customer Load Breakdown, Delivery Year 2022-2023⁹⁷

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 3-9, is based on the rate of customer switching in the past, expected increases in residential ARES service, and the anticipated additional migration of 0 to 100 kW customers to ARES and municipal aggregation. The figure breaks down the total forecast of retail customer load in the same way as Figure 3-8 does for a single year.

⁹⁷ For the 2022-2023 Delivery Year, ComEd's projected total Retail Load is 85,389 GWh, where the Eligible Retained Load accounts for 23,907 GWh, the Eligible Non-Retained Load accounts for 14,598 GWh, and the Competitive Load accounts for 46,885 GWh. The amount for the projected total Retail Load was provided by ComEd in their July 2021 response to the IPA Data Request for the update of the Final Revised Long-Term Plan.

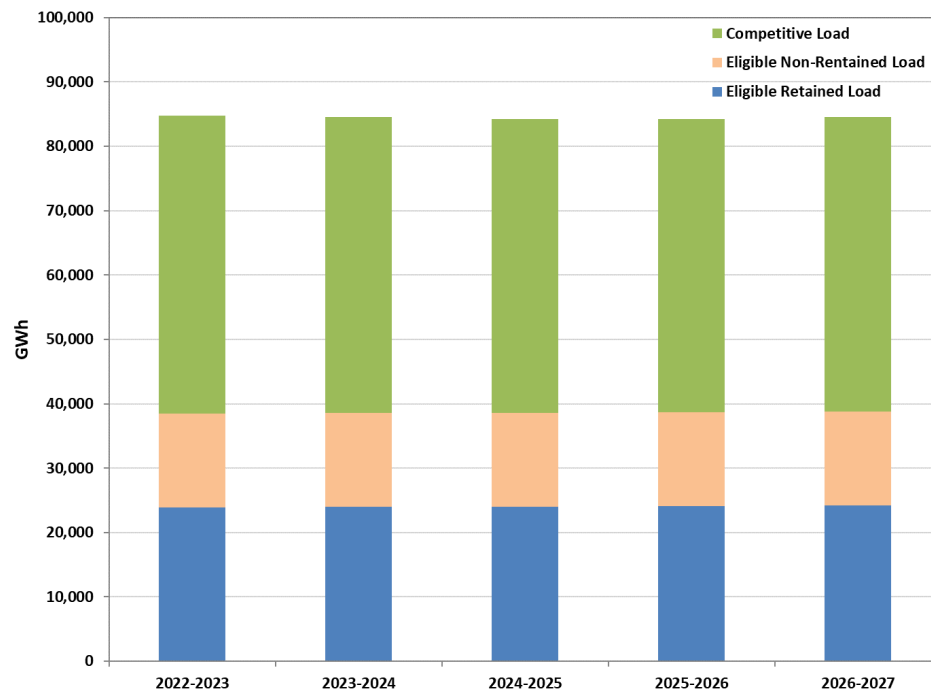
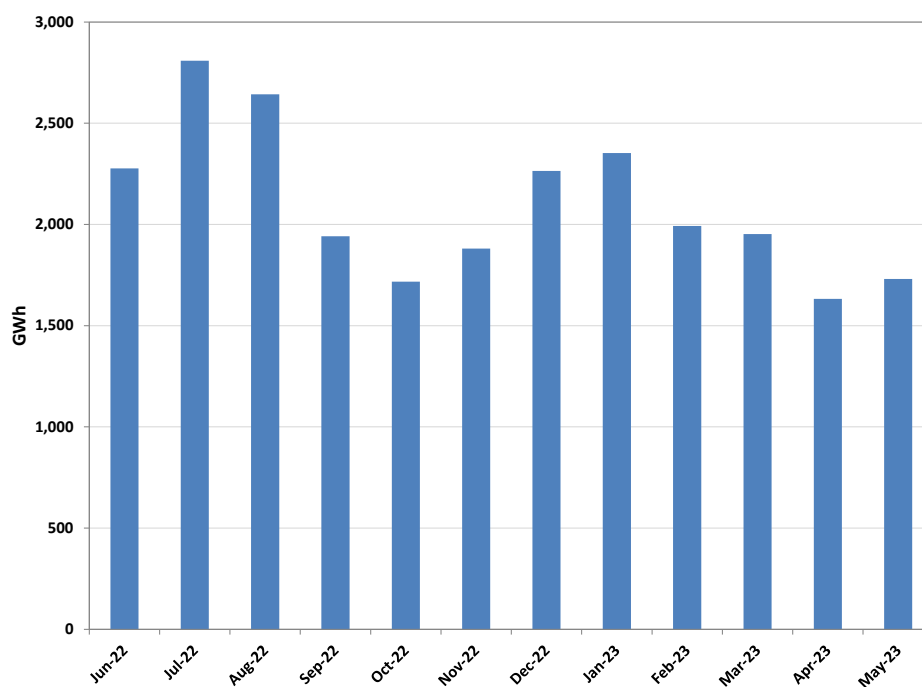
Figure 3-9: ComEd's Forecast Retail Customer Load by Delivery Year

Figure 3-10 provides a monthly breakdown of the base-case forecast of ComEd's eligible retail customer load, that is, the load of customers who are forecasted to take bundled supply under this Procurement Plan.

Figure 3-10: ComEd's Forecast Eligible Retained 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

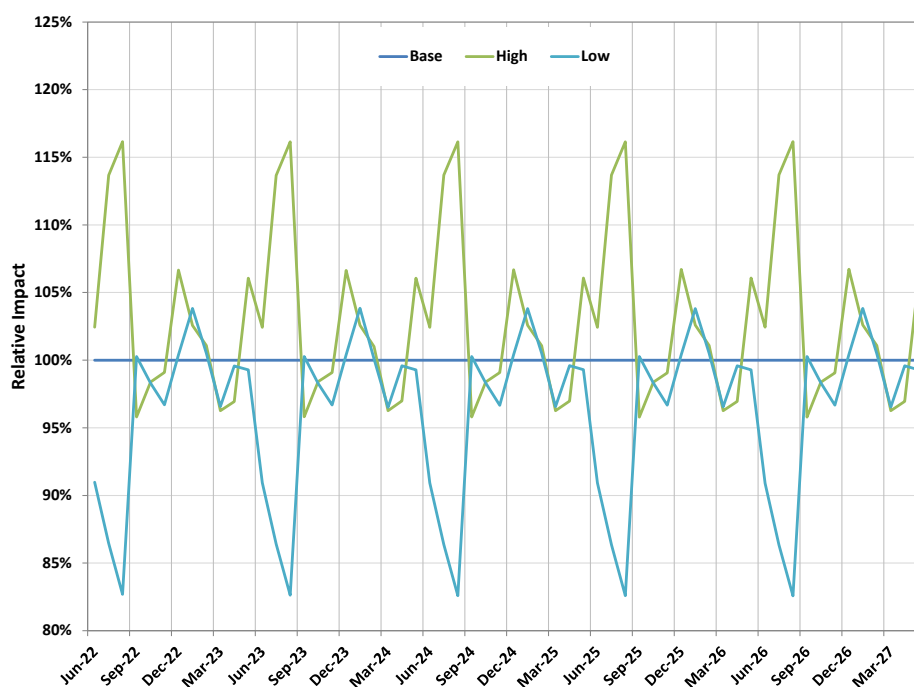
ComEd's base case load forecast is driven by a Zone Model that includes both macroeconomic variables (Gross Metropolitan Product for Chicago and other metropolitan areas within ComEd's service territory, household income) and demographics (household counts). ComEd did not use this model to define "high" 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 case (because the growth rate in the base case is projected to be flat to negative, 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 high weather and low weather cases on residential and small commercial load, relative to the base case forecast. The weather impacts are provided as percentages that summarize the hourly impacts of the effect of temperature on load.

Figure 3-11 shows the impact of weather on load by month. The figure compares the high and low weather usage factors to the base forecast weather usage factors in the form of ratios to the base case to gauge the relative impacts.

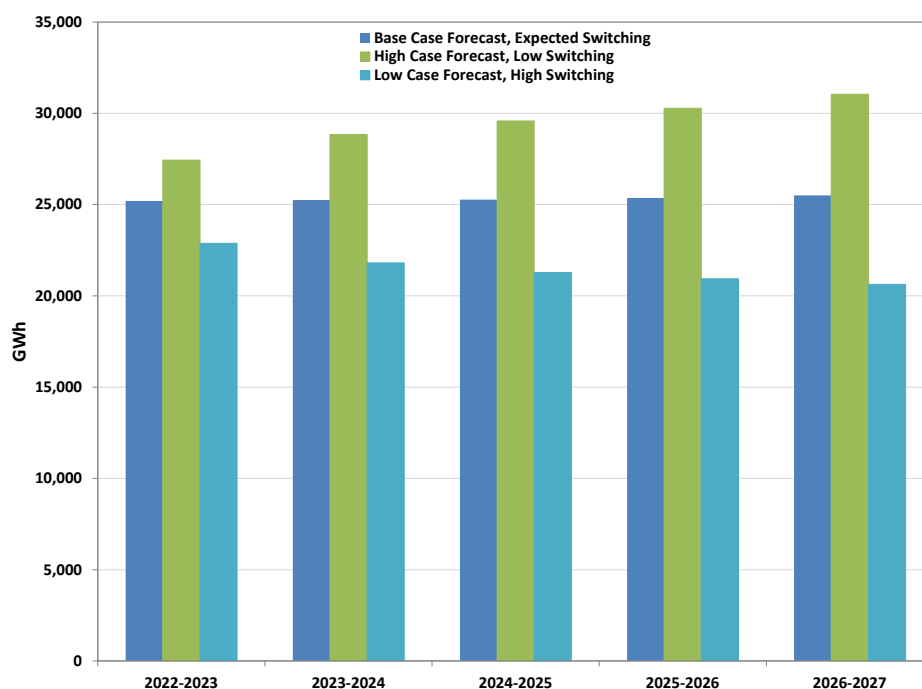
Figure 3-11: The Impact of Weather in ComEd's Forecasts

3.3.3 Switching

The high switching (low load) case assumes residential, watt-hour, and 0 to 100 kW blended service⁹⁸ usage will be reduced by 4% from the expected load level over the course of the calendar years 2022 and 2023 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 359 communities within the ComEd service territory that had approved aggregation as of June of 2021, with 228 of those communities actively being served through municipal aggregation (an increase from 226 in June 2020). The percentage of potentially eligible retail customers taking blended service in this switching scenario is 58% (based on usage) as of December 2023 compared to 62% in the expected load forecast.

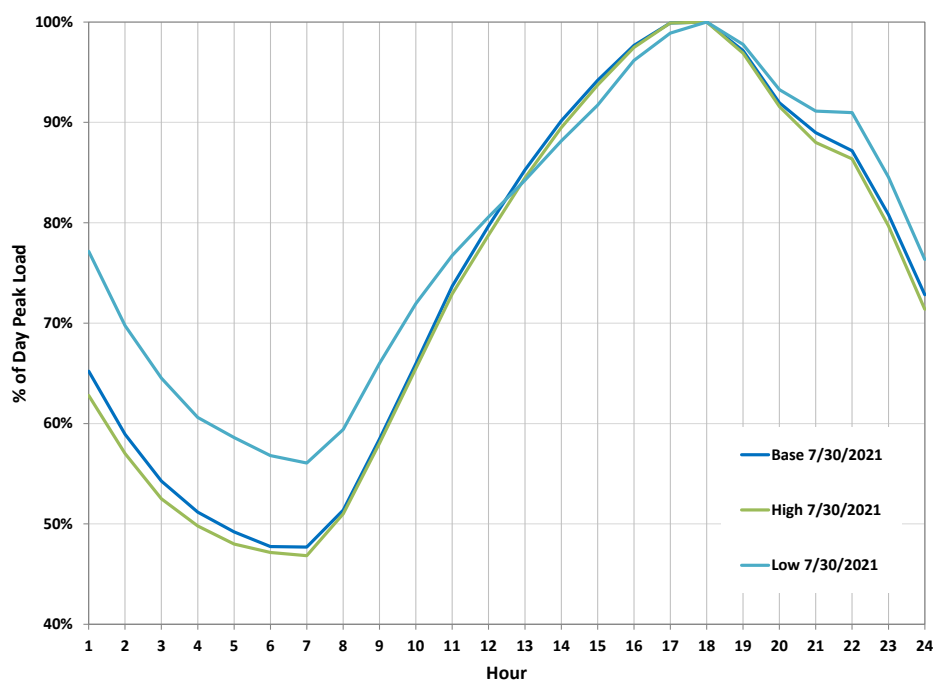
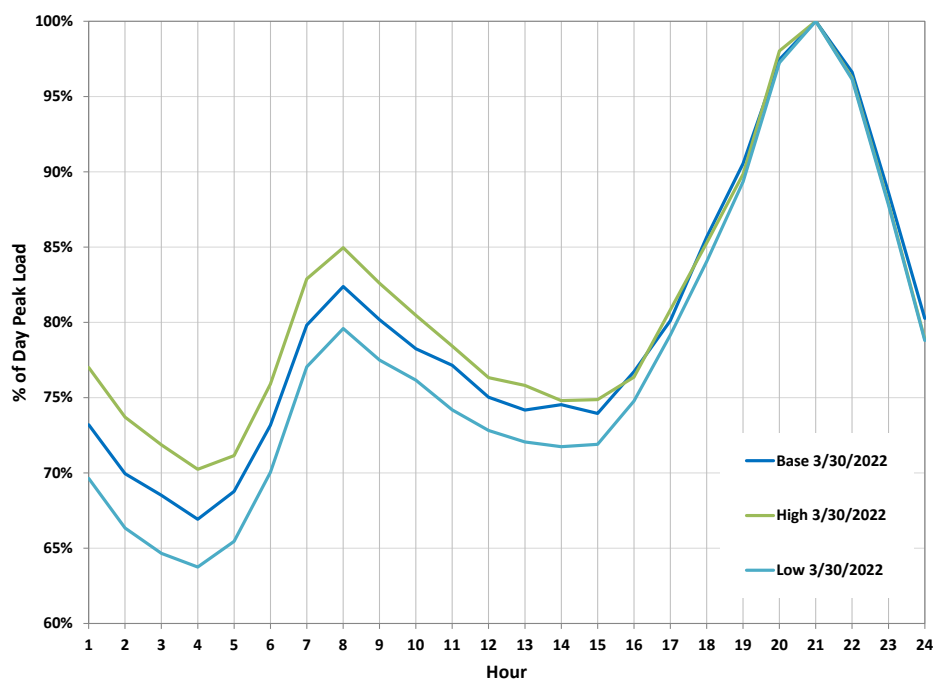
The low switching (high load) case assumes additional communities opt out of municipal aggregation in the years 2021 and 2022 such that residential usage increases by 4% from the expected load level over the course of the calendar years 2022 and 2023. The percentage of potentially eligible retail customers taking blended service in this switching scenario is 58% (based on usage) as of December 2023 compared to 62% in the expected load forecast. Figure 3-12 shows the forecasted ComEd supply obligation in each case. The Base Case assumes the expected switching, the High Load assumes low switching, and the Low Load assumes high switching.

⁹⁸ "Blended service" refers to eligible retail customers that purchase power and energy from ComEd under fixed-price bundled service tariffs.

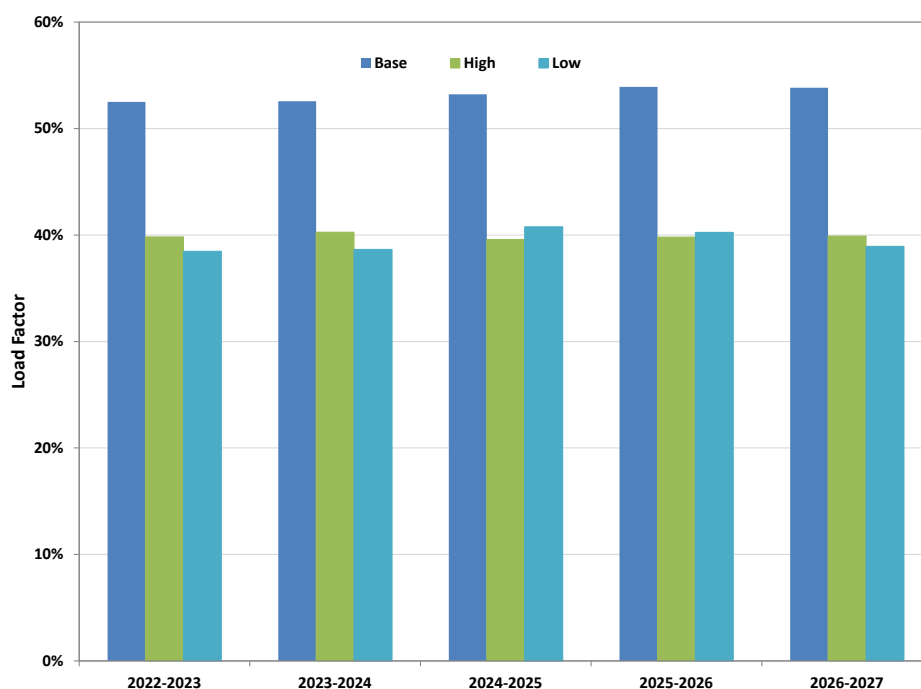
Figure 3-12: Supply Obligation in ComEd's Forecasts

3.3.4 Load Shape and Load Factor

Figure 3-13 and Figure 3-14 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-13 illustrates a summer day, and Figure 3-14 a spring day. There is no significant difference between the profiles of the high case and the base case on a summer day, but the low case is flatter. During the sample spring day, the base case is peakier than the high case, and the low case is slightly peakier than the base case.

Figure 3-13: Sample Daily Load Shape, Summer Day in ComEd's Forecasts**Figure 3-14: Sample Daily Load Shape, Spring Day in ComEd's Forecasts**

The annual load factors are shown in Figure 3-15. 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 3-15: Load Factor in ComEd's Forecasts

3.4 Summary of Information Provided by MidAmerican

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

- Methodology for the 2022-2031 Illinois Electric Customers and Sales Forecasts.* This document contained a discussion of load forecast methodology for all MidAmerican scenarios and supporting data for the base scenario forecast. The load forecast included a multi-year historical analysis of hourly load data, forecasted load and capability along with the impact of demand side and renewable energy initiatives. MidAmerican's load forecast was further broken down by revenue class, projected kWh usage and sales, which factored in economic and demographic variables along with weather variables based on weather data. Additionally, the load forecast accounted for sales forecasts based on variables and model statistics along with the non-coincident electric gross peak demand forecast and represents all of the eligible retail customer classes, except the customer being served by an ARES. MidAmerican methodology also includes the discussion of the energy efficiency and switching trends. Pursuant to Section 16-111.5(d)(1), MidAmerican's load forecast covered a five-year procurement planning period. (See Appendix D)
- Spreadsheets of load profiles, hourly load strips, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix G)

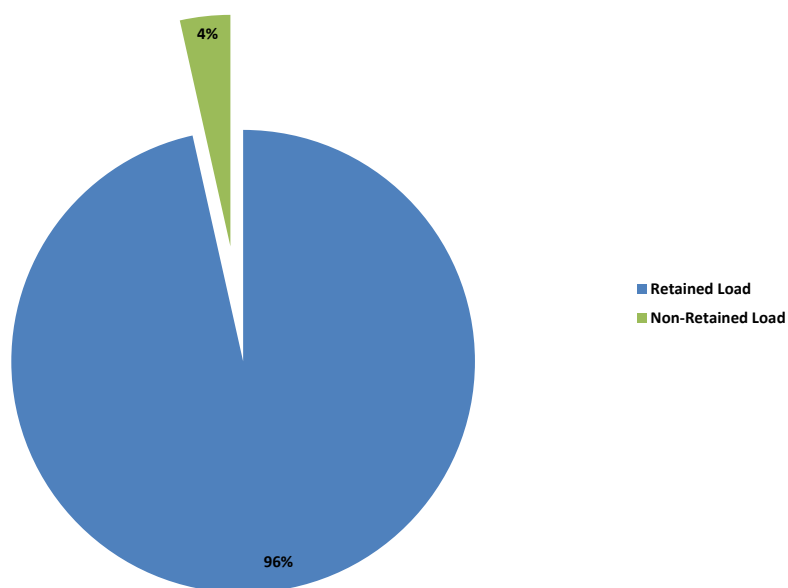
MidAmerican forecasts load by using econometric models on a monthly basis. For the residential, commercial and public authority classes, sales are determined by multiplying customers by use per customer. For the industrial class, sales are modeled directly. For the street lighting class, sales are forecast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

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

MidAmerican has one active alternative retail supplier in its Illinois service territory. MidAmerican has no customer classes that have been declared competitive. Figure 3-16 shows Ameren's retail load forecasted annual energy usage percentage. 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 the ARES).

Figure 3-16: MidAmerican's Forecast Retail Customer Load Breakdown, Delivery Year 2022-2023⁹⁹



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 3-17, 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 retail customer load, in the same way as Figure 3-16 does for a single year.

⁹⁹ For the 2022-2023 Delivery Year, MidAmerican's projected total Retail Load is 2,040,151 MWh, where the Eligible Retained Load accounts for 1,951,906 MWh and the Eligible Non-retained Load accounts for 88,246 MWh. The amount for the projected total Retail Load was provided by MidAmerican in their July 2021 response to the IPA Data Request for the update of the Final Revised Long-Term Plan.

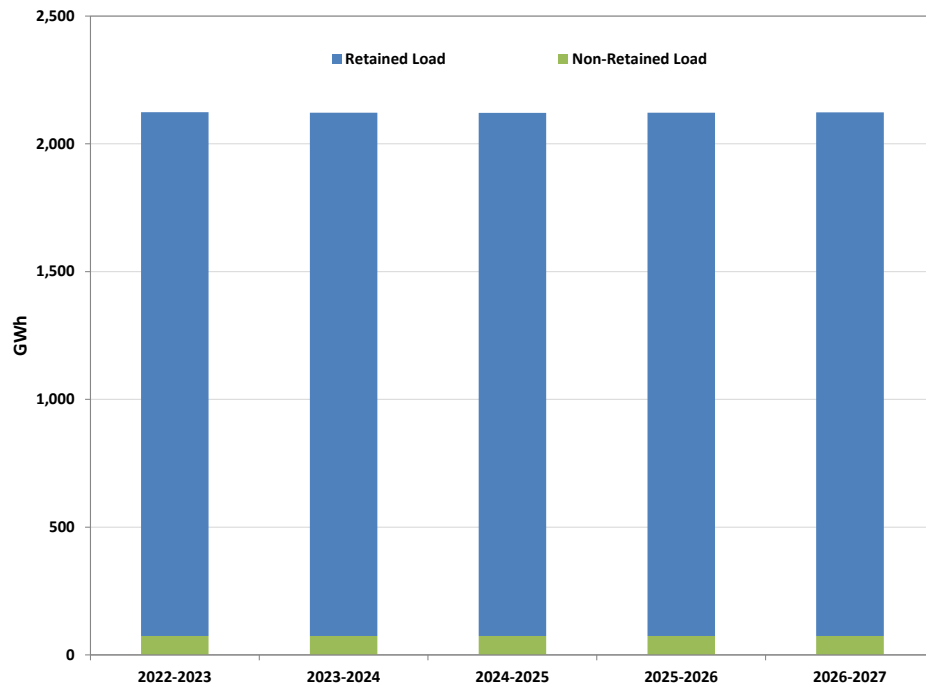
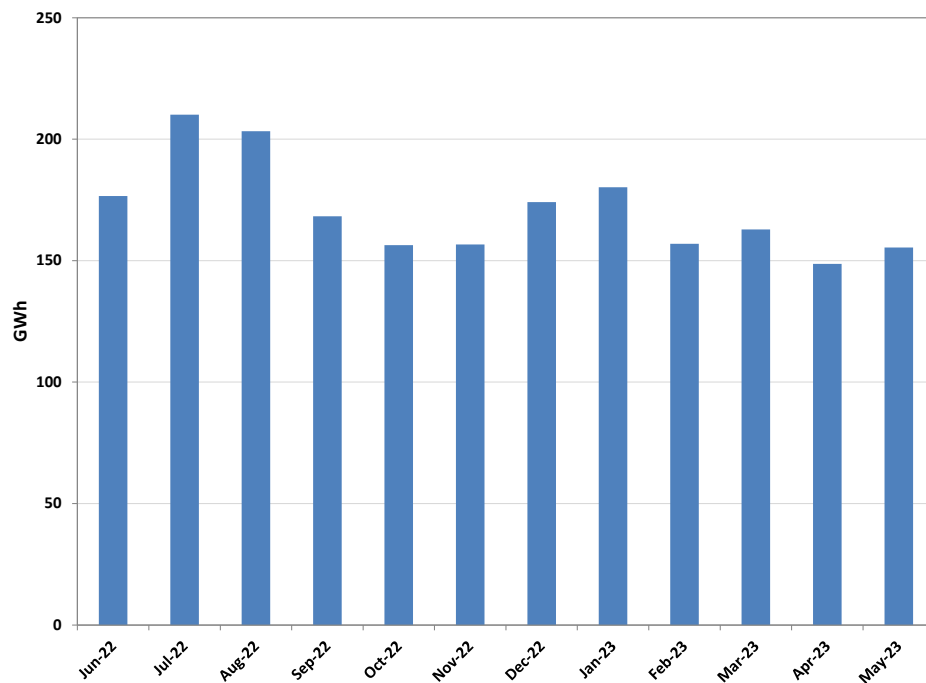
Figure 3-17: MidAmerican's Forecast Retail Customer Load by Delivery Year

Figure 3-18 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 3-18: MidAmerican's Forecast Retained Eligible Retail Customer Load by Month

MidAmerican provided a Base-Case load forecast and two excursion cases: a Low-Case forecast and a High-Case forecast. The required low and high hourly load forecast scenarios were created by taking the 95%

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

3.4.1 Macroeconomics

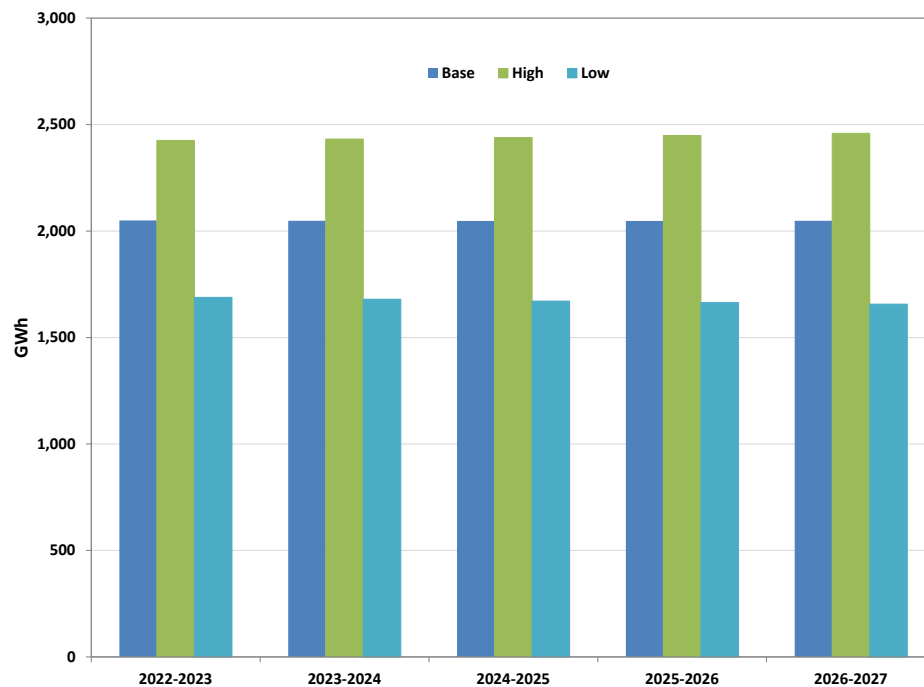
MidAmerican's Base Case load forecast utilized economic and demographic data that were obtained from IHS Markit, Inc. Data for other variables of the model, such as customer numbers, sales and other customer related data, were taken from internal company data sources. For MidAmerican's Illinois service 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. The street lighting load was forecast using trending forecast techniques. In the customer revenue classes, the current customer numbers were assumed to remain constant while the corresponding energy sales were projected to grow approximately 0.05% annually in Illinois.

3.4.2 Weather

The Base Case temperature assumptions in the hourly load forecast model were not changed for the scenarios. The Base 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.

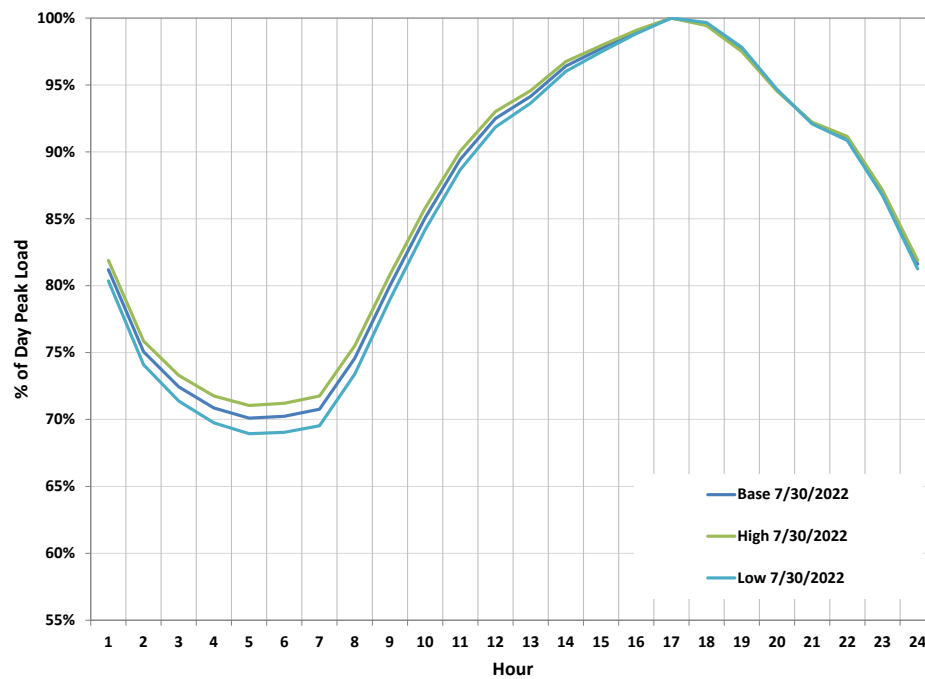
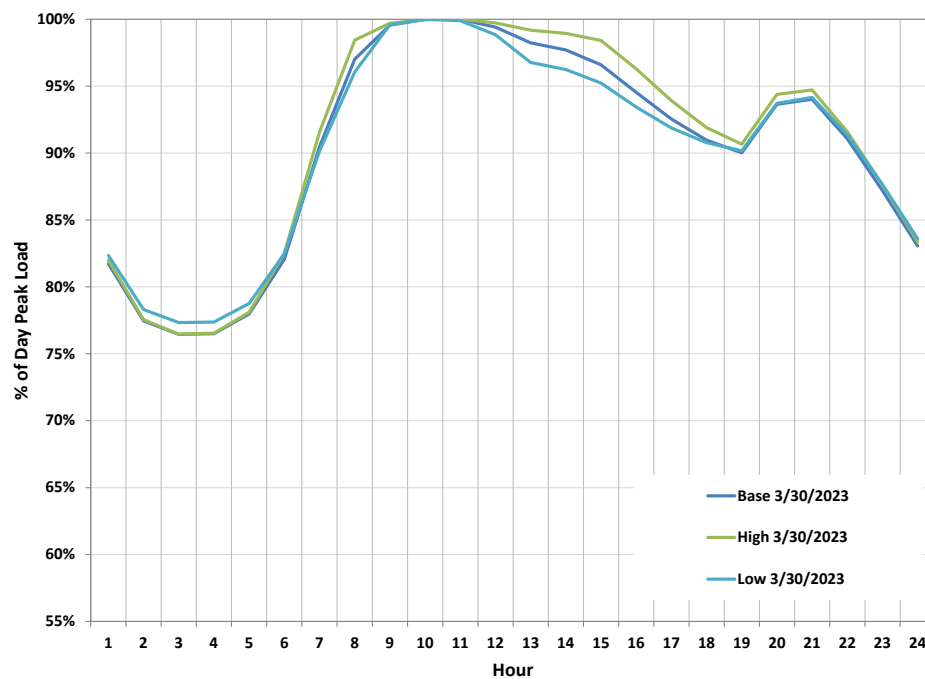
3.4.3 Switching

The Base Case forecasts for retail switching sales, customers, and demand in MidAmerican Illinois service territory were not changed in the scenarios. Figure 3-19 shows MidAmerican's supply obligation in each case. As noted above, all three cases assume the Base Case assumptions for weather and switching, with the difference between the Base, High, and Low cases being attributable to macroeconomics i.e. economic and demographic variables.

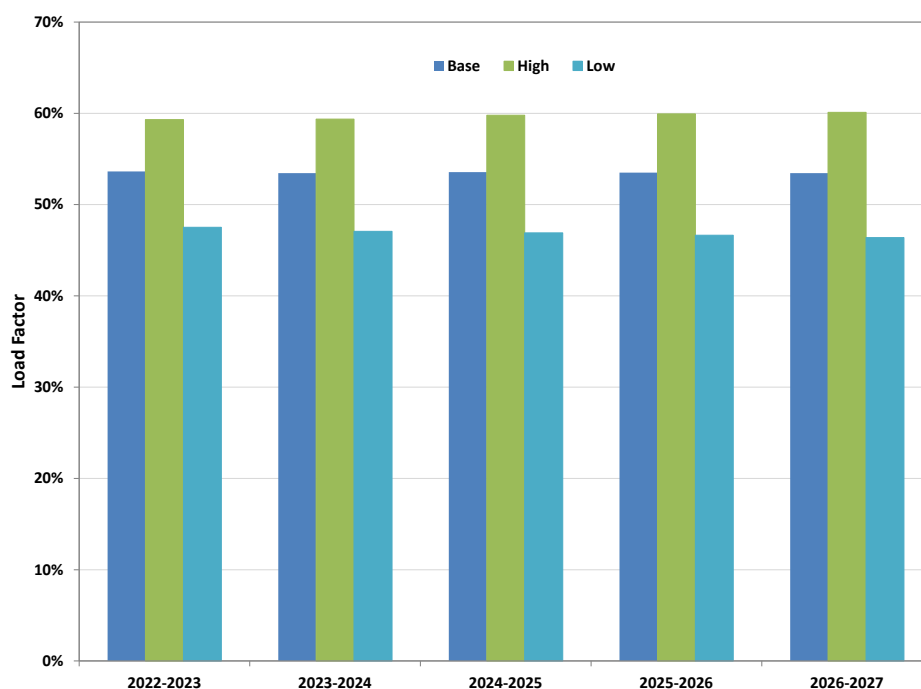
Figure 3-19: Supply Obligation in MidAmerican's Forecasts

3.4.4 Load Shape and Load Factor

Figure 3-20 and Figure 3-21 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-20 illustrates a summer day, and Figure 3-21 shows a spring day. There is no meaningful difference between the base, low, and high load shapes on a sample summer day. During the sample spring day, the base case is peakier than the high case, and the low case is peakier than the base case.

Figure 3-20: Sample Daily Load Shape, Summer Day in MidAmerican's Forecasts**Figure 3-21: Sample Daily Load Shape, Spring Day in MidAmerican's Forecasts**

The annual load factors are shown in Figure 3-22. As expected, the base, the high, and the low case load factors are consistent, being within the 46-60% range.

Figure 3-22: 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. As a result, 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 classes 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 $\pm 7\%$ 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 $\pm 2\%$ in load growth should provide 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 forecasts, 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.

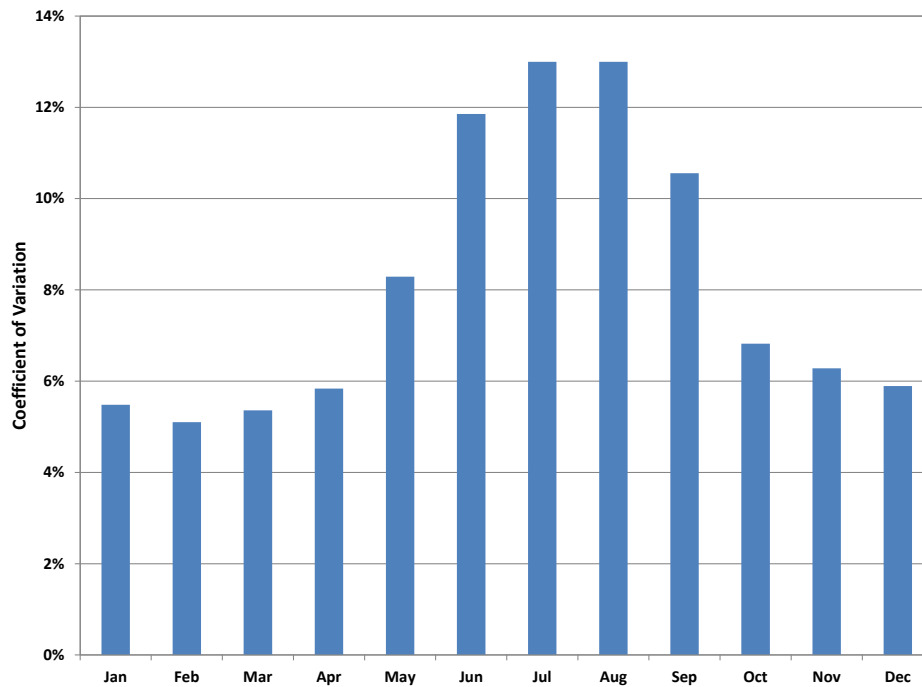
3.5.2 Weather

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.

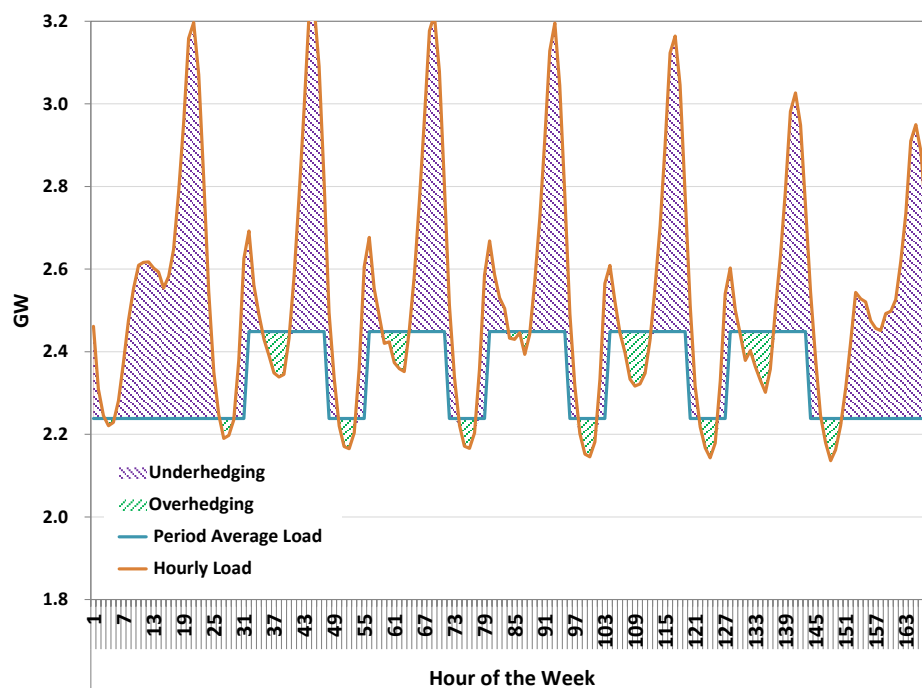
3.5.3 Load Profiles

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 3-23 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 2020, 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 3-23: 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 3-24, below.

Figure 3-24: 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 61% of potentially-eligible retail customer load¹⁰⁰ will have switched away from Ameren Illinois default fixed price tariff service by the end of the 2021-2022 Delivery Year. This level is consistent with the 61% switching statistics in the July 2021 forecasts. Ameren expects that the amount of load supplied by ARES will remain flat across the planning horizon. Ameren's forecast of flat ARES load is explained in its forecast methodology, which explains that "the vast majority of municipal aggregation contracts" up for renewal were, in fact, "renewed after their recent expiration."¹⁰¹ The load forecast uncertainty is affected by "...the aggressiveness of ARES marketing campaigns, the fate of municipal aggregation initiatives going forward, customer response and perhaps most importantly, the headroom between ARES contracts and AIC fixed price tariffs." Ameren Illinois' current default service price is lower than comparable ARES prices for individual customers. ComEd projects that 38% of potentially-eligible retail load will have switched to ARES service by the end of the 2022-2023 Delivery Year, which represents a decrease from the 41% switching rate assumed in the July 2020 forecasts. 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 (typically at a premium price), month-to-month variable pricing (frequently with an initial rate lower than utility service, but no guarantee of that lower price being maintained after an initial period), longer-term fixed prices, options to match prices in the future, options to extended contract terms, and options to adjust prices retroactively.¹⁰² 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 on overall customer switching trends, Ameren Illinois and ComEd switching forecasts have been dominated by municipal aggregation. While the IPA recognizes that many ARES focus on individual residential switching, the IPA is not aware of a significant number of residential customers leaving default service to take ARES service outside of a municipal aggregation program. As shown in Table 3-2, this is currently the case because of the appreciable difference between the utility price to compare and representative ARES prices available to eligible utility customers.¹⁰³ It appears that, currently, ARES fixed price offers for a 12-month term are higher than the respective utility summer rates and do not appear to offer savings or benefits to individual residential customers.¹⁰⁴ 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.

¹⁰⁰ "Potentially-eligible retail customer load" refers to the load of those customers eligible to take bundled service from the utility.

¹⁰¹ See Appendix B to this report.

¹⁰² For more information on choices offered by ARES, see the 2021 Annual Report of the ICC Office of Retail Market Development at <https://www.icc.illinois.gov/downloads/public/2021%20ORMD%20Section%202020-110%20Report.pdf>.

¹⁰³ Representative ARES prices are an average of 12-month fixed price offers from ARES available at <https://www.pluginillinois.org/OffersBegin.aspx>. The utility Price to Compare is exclusive of the Purchased Electricity Adjustment, which as discussed in Section 6.5 has been a consistent credit in recent years for Ameren Illinois and ComEd customers. Therefore the difference shown may be understated.

¹⁰⁴ Based on the price data in Table 3-2, Ameren Illinois retail customers taking a representative fixed-price supply service offer from an ARES in September 2021 would pay approximately 29% more than if they were to take default supply service from the utility. ComEd retail customers would pay approximately 21% more. The utility prices are effective June 2021 through September 2021.

Table 3-2: Representative ARES Fixed Price Offers and Utility Price to Compare¹⁰⁵

Utility Territory	Utility Price to Compare (¢/kWh)	Representative ARES Price (¢/kWh)
Ameren Illinois (Rate Zone I)	4.82	6.23
Ameren Illinois (Rate Zone II)	4.82	6.21
Ameren Illinois (Rate Zone III)	4.82	6.25
ComEd	6.78	8.19

3.5.5 Hourly Billed Customers

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

3.5.6 Energy Efficiency

Public Act 95-0481 created a requirement for ComEd and Ameren Illinois to offer cost-effective energy efficiency and demand response measures to all customers,¹⁰⁶ with updates to those savings targets adopted through Public Act 99-0906. Both Ameren Illinois and ComEd have incorporated into their forecasts the expected impacts of these updated measures (as applied to eligible retail customer load).

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

3.5.7 Demand Response

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

3.5.8 Emerging Technologies

An emerging technology that could have a significant impact on the Illinois power market as well as the IPA’s future procurement plans is energy storage—in particular, lithium-ion (“Li-ion”) battery storage integrated with solar PV distributed generation. Based on storage data compiled by the U.S. Department of Energy, as of July 2020, there were 52 operational battery-based storage systems with a total capacity of 358.43 MW operating in PJM and 15 systems totaling 22.68 MW operating in MISO; the majority of these systems in terms of capacity were utility scale systems. Illinois was listed as having 12 projects with 144.06 MW in operation and under construction.¹⁰⁷ The overwhelming majority of these projects are based on Li-ion chemistry.

While utility scale energy storage technology continues to be developed and deployed, distributed solar PV integrated with distributed storage offers significant potential to enhance the benefits and spur the

¹⁰⁵ Offers without an explicit premium renewable component. Monthly service fees and early termination fees are ignored.

¹⁰⁶ See P.A. 95-0481 (Section originally codified as 220 ILCS 5/12-103).

¹⁰⁷ U.S. Department of Energy Global Energy Storage Database, <https://www.sandia.gov/ess-ssl/global-energy-storage-database/>, downloaded July 27, 2021.

development of solar distributed generation. However, the costs of Li-ion batteries for use with distributed solar PV systems (such as residential rooftop solar) remain high relative to the value proposition for residential and small commercial solar PV applications, even with the average cost of battery storage declining by 89% from 2010 to 2020.¹⁰⁸ While the average cost of battery storage using Li-ion batteries is forecast to continue to decline it is too early to forecast the impact on load forecasts associated with distributed solar PV integrated with battery storage.

The Agency notes that while Public Act 99-0906 encourages the development of distributed solar PV, there are not clear provisions in Illinois law to encourage the adoption of integrated storage technologies. Proposed state legislation would encourage the development of integrated energy storage in Illinois, including storage co-located at shuttered coal plant sites alongside new utility-scale solar projects, but no such proposals have yet been enacted as of the date of this draft Plan's publishing. The Agency will continue to monitor the development of the energy storage market in the coming years.

3.5.9 COVID-19 Impacts on Utilities' Load Forecasts

In reviewing the load forecast documentation, each of the utilities briefly mention that they have included consideration of the impacts of COVID-19 in their forecasts. ComEd does not specifically identify the impacts but adjusted the forecast methodology to account for changes in load due to the pandemic. ComEd included new independent variables within the traditional models used in filings before 2020 which estimate the GWh impact by customer class from dynamics like social distancing, mandated business closures, and remote work. Ameren indicates that between 2020 and 2021 residential sales increased 5% and C&I sales decreased 10% to 15%. The Ameren forecast assumes a u-shaped recovery with residential sales stabilizing at slightly above pre-COVID-19 levels and small commercial load at lower than pre-COVID levels. MidAmerican has incorporated the sales impacts into the retail kWh sales forecast and the peak demand forecast. The forecast includes a downturn in retail sales in 2023 through 2025, then a gradual increasing trend by 2026.

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. The Ameren Illinois and ComEd forecasts include already approved energy efficiency programs, and MidAmerican's forecast includes verified energy efficiency program impacts as well.

3.6.2 High and Low Excursion Cases

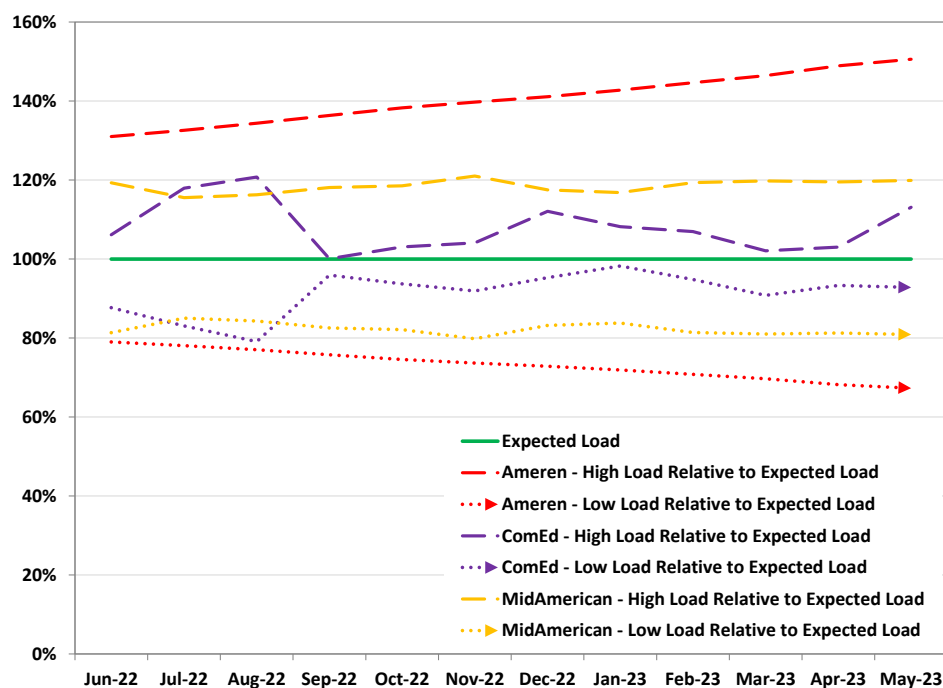
The high and low cases represent useful examples of potential load variability. Although they are primarily driven by variation in switching, Ameren Illinois correctly notes that this is the major uncertainty in its outlook. The switching variability, especially in Ameren Illinois' high and low forecasts,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

As illustrated in Figure 3-25, the Ameren Illinois low and high load forecasts are on average equal to 73% and 141% of the base case forecast, respectively, during the 2022-2023 Delivery Year. Comparatively, for the same period, ComEd's low and high load forecasts are on average equal to 91% and 108% of the base forecast, respectively. This reflects the differences in switching assumptions used by the two utilities. MidAmerican's low and high load forecast deviations from the base case are flat and symmetrical being equal to 82% and 118%, respectively. The reference case forecasts for retail switching were not changed in Mid American's high and low load forecasts.

¹⁰⁸ Battery Pack Prices Cited Below \$100/kWh for the First Time in 2020, While Market Average Sits at \$137/kWh - December 16, 2020

<https://about.bnef.com/blog/battery-pack-prices-cited-below-100-kwh-for-the-first-time-in-2020-while-market-average-sits-at-137-kwh/>

Figure 3-25: Comparison of Ameren Illinois, ComEd, and MidAmerican High and Low Load Forecasts for Delivery Year 2022-2023



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 3-24, load is variable while the hedging instrument (standard block energy) features a constant delivery of energy. The spot price at which the unhedged volumes are covered is positively correlated with load. However, as explained below, the high and low cases are less suitable for such a risk analysis.

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

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

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

4 Existing Resource Portfolio and Supply Gap

Starting with the 2014 Procurement Plan, the IPA has procured energy supply in standard 25 MW on-peak and off-peak blocks. This energy block size was reduced from the previous level of 50 MW to more accurately match procured supply with eligible retail customer load.¹⁰⁹ 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.¹¹⁰

The 2021 Procurement Plan included the procurement of energy supply to meet the needs of ComEd's and Ameren Illinois' eligible retail customers, as well as that portion of MidAmerican's eligible retail customer load not met through its allocation of existing generation. The current plan will continue the procurement of energy supply for each of the three utilities.

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

The current IPA energy 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 2022 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 2022-2023 Delivery Year will be targeted for procurement. The Fall 2022 procurement event will bring the targeted hedge levels to 100% for October through May of the 2022-2023 Delivery Year. A portion of the targeted hedge levels for the 2023-2024 and the 2024-2025 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:

- 20-year bundled REC and energy purchases (also known as the 2010 long-term power purchase agreements or "LTTPAs"), starting in June 2012, made by Ameren Illinois and ComEd in December 2010 pursuant to the Final Order in Docket No. 09-0373.¹¹¹
- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017.¹¹²

¹⁰⁹ See 2014 IPA Procurement Plan at 93.

¹¹⁰ http://www2.illinois.gov/ipa/Pages/Prior_Approved_Plans.aspx.

¹¹¹ With the changes to the Renewable Resources Budget contained in Public Act 99-0906, curtailment of the Ameren Illinois and ComEd LTTPAs (as occurred for ComEd in 2013 and 2014) is extremely unlikely. MidAmerican is not a counterparty to the LTTPAs.

¹¹² P.A. 97-0616 also mandated associated REC procurements, but these REC procurements did not impact the (energy) resource portfolio. Additionally, twenty-year power purchase agreements between Ameren Illinois and ComEd and the FutureGen Industrial Alliance, Inc. were directed by the Commission order approving the Agency's 2013 Procurement Plan. (See Docket No. 12-0544) However, U.S. DOE funding support for FutureGen 2.0 was suspended, and in early 2016, the project's development was ultimately terminated.

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

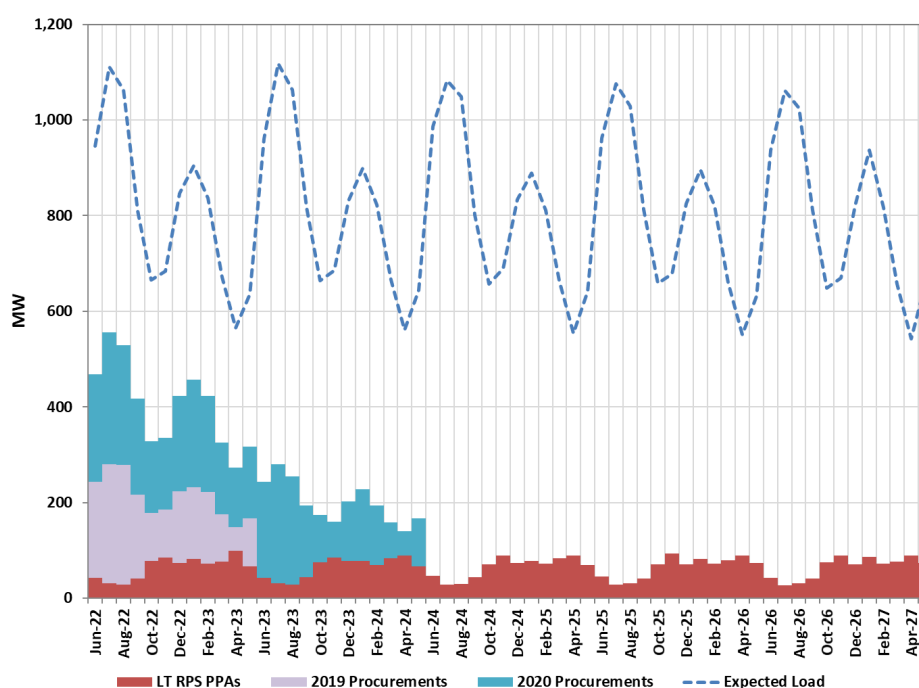
4.1 Ameren Illinois Resource Portfolio

Figure 4-1 shows the current supply gap in the Ameren Illinois supply portfolio for the five-year, June 2022 through May 2027, planning period, using the base case on-peak forecast described in Chapter 3.

Ameren Illinois' existing supply portfolio, including long-term renewable energy resource contracts, is not sufficient to cover the projected load for the 2022-2023 Delivery Year. Additional energy supply will be required for the entire 5-year planning period. Approximately 59% of the Ameren Illinois eligible load has switched to ARES suppliers. The Ameren Illinois base case scenario load forecast assumes that switching will be flat across the current planning horizon.

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

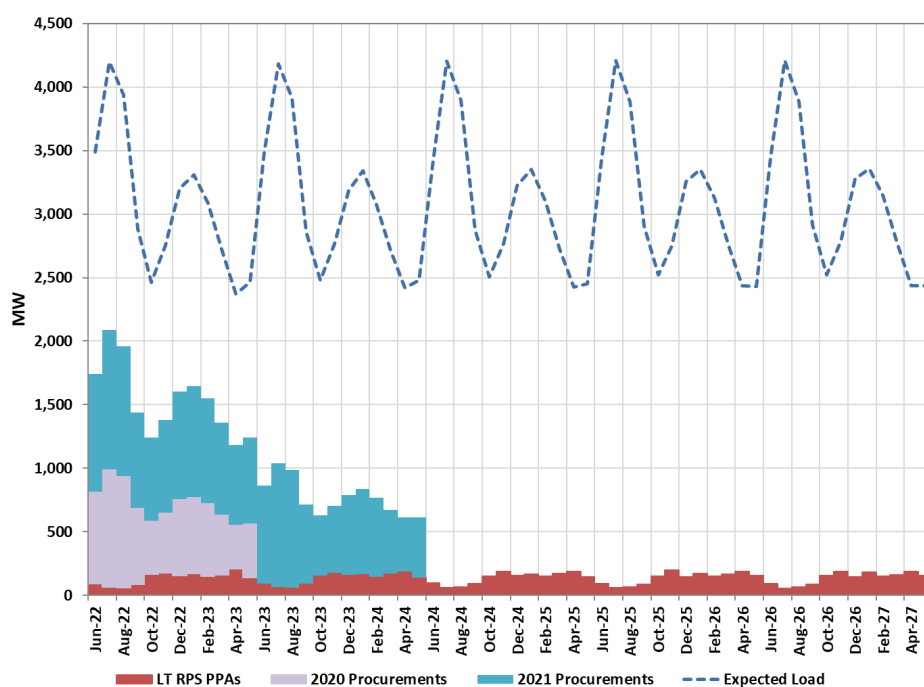
Figure 4-1: Ameren Illinois' On-Peak Supply Gap - June 2022-May 2027 Period - Base Case Load Forecast



Under the base case load forecast scenario, the average supply gap for peak hours of the 2022-2023 Delivery Year is estimated to be 407 MW, the peak period average supply gap for the 2023-2024 Delivery Year is estimated to be 612 MW, and the average peak period supply gap for the 2024-2025 Delivery Year is estimated to be 740 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 2022-May 2027 planning period, using the base case load on-peak forecast described in Chapter 3. As of May 2021, approximately 58.0% of total usage in ComEd's 0 to 100 kW class was served by retail electric suppliers.

Figure 4-2: ComEd's On-Peak Supply Gap - June 2022-May 2027 period - Base Case Load Forecast

As with Ameren Illinois, ComEd's current energy resources will not cover eligible retail customer load starting in June 2022. The average supply gap during peak hours for the 2022-2023 Delivery Year under the base case load forecast is estimated to be 1,538 MW. The average supply gap during peak hours for the 2023-2024 and 2024-2025 Delivery Years is estimated to be 2,305 MW and 2,943 MW respectively.

4.3 MidAmerican Resource Portfolio

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

MidAmerican revised the methodology used for its generation supply forecast starting with the forecast information submitted for the 2019 Plan. The prior forecast methodology utilized production cost models to dispatch the Illinois Historical Resources whenever the expected cost to generate electricity is less than the expected cost of acquiring it in the market. The revised methodology is based on the utilization of MISO Unforced Capacity ("UCAP") from the baseload Illinois Historical Resources to determine the generation available to meet MidAmerican's Illinois eligible load.¹¹³

MidAmerican's revised methodology utilizes the full capability of each baseload generation asset, represented by the UCAP MW values as determined by MISO for each year's Planning Resource Auction. The UCAP values de-rate generating unit capabilities by considering historical forced outage rates and operating conditions under summer peak conditions. This methodology was utilized for the 2020 and 2021 Plans. The IPA, for the 2022 Plan, recommends no changes to the determination of monthly on-peak and off-peak block energy requirements. MidAmerican's generation supply forecast is based on the UCAP values for each of the following baseload resources:

- Coal resources including: Neal Unit #3, Neal Unit #4, Walter Scott Unit #3, Louisa Generating Station, and Ottumwa Generating Station.

¹¹³ MidAmerican allocates 10.86% of the UCAP ratings of its baseload units for Illinois Historical Generation.

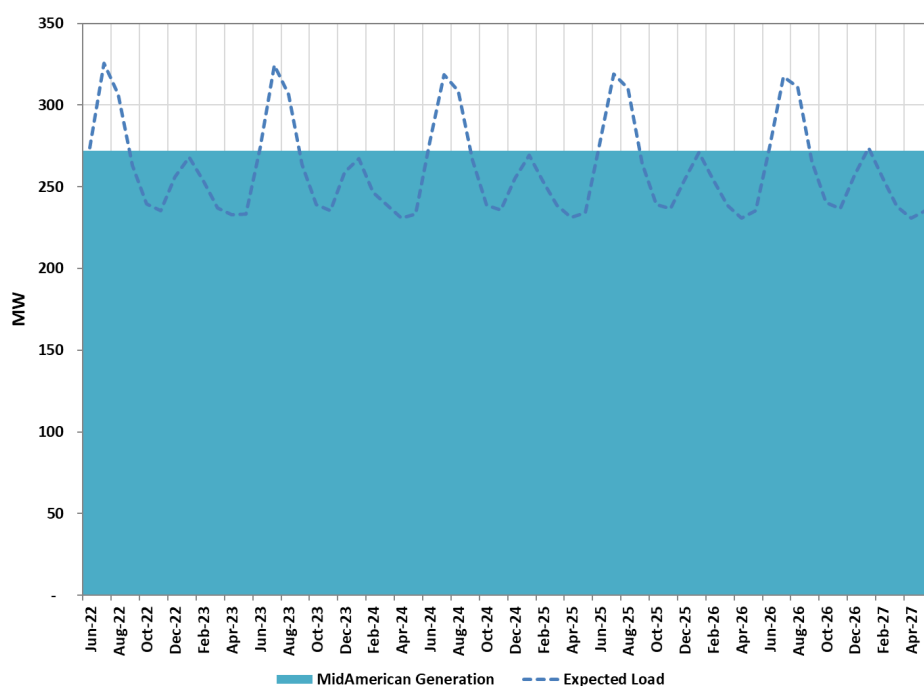
- Nuclear Resources: Quad Cities Nuclear Power Station.

The supply capability that is determined is netted against the forecast of MidAmerican Illinois load to calculate the monthly on-peak and off-peak shortfalls which will be met with energy block purchases in the IPA procurements. In determining the amount 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 2021 Procurement Plan approved by the Commission.

The IPA believes that the methodology used with regards to MidAmerican's supply procurement is reasonable and that the overall hedging levels and laddered procurement approach are consistent with the proposed approach for Ameren Illinois and ComEd. The IPA and MidAmerican will continue to monitor the actual performance of this approach and will revisit it in future procurement plans, if warranted.

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 surplus during peak hours for the 2022-2023 Delivery Year under the base case load forecast is estimated to be 12 MW. The average supply surplus during peak hours for the 2023-2024 Delivery Year is 12 MW and for the 2024-2025 Delivery Year the supply surplus is 11 MW.

Figure 4-3: MidAmerican's On-Peak Supply Gap - June 2022-May 2027 period - Base Case Load Forecast



5 PJM and MISO Resource Adequacy Outlook and Uncertainty

As a result of retail choice in Illinois, the resource adequacy challenge (i.e., 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 Chapter 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 this Chapter analyzes several studies of resource adequacy that are publicly available from different planning and reliability entities. These entities include:

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

While definitive and detailed analyses of the impact of COVID-19 on electricity demand in Illinois are not currently available, all three utilities reported that they included consideration of the impacts of COVID-19 in their forecasts. Ameren specifically noted that between 2020 and 2021, residential electricity sales have increased by approximately 5% and commercial and industrial sales have decreased by 10%-15%.

From the review and analysis 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 the PJM region. MISO, on the other hand, could be short of the resources necessary to meet the target reserve margin on a region-wide basis starting in the 2025-2026 timeframe.

The analysis in Section 5.1.3 of the planning resources available to meet the locational capacity requirement (“LCR”) in Zone 4 (Ameren Illinois) shows that:

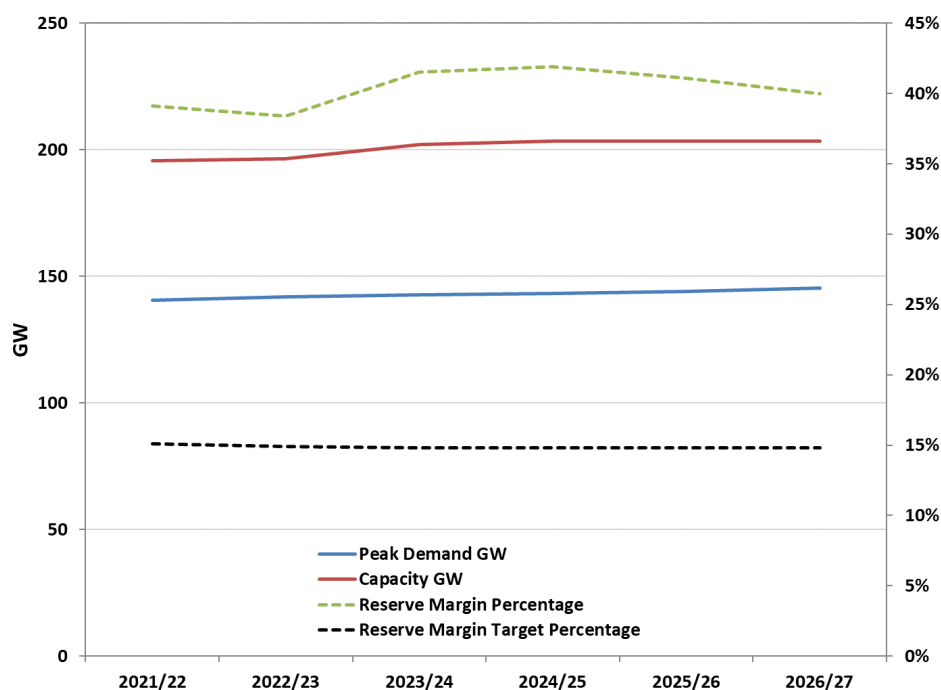
- If all new planning resources are taken into account, the available capacity in Zone 4 will be able to meet the LCR for the study period. In 2026-2027 the difference between available capacity and the LCR (“the LCR Margin”) is 2,288 MW, a drop of 32% (1,074 MW) from the previous year. The LCR Margin was at its highest in 2014-2015 at 7,637 MW.
- If only generators with a signed generator interconnection agreement (“GIA”), that are under construction, are assumed as the new planning resources, the LCR Margin in 2026-2027 drops to 862 MW.
- If the retirement date of the Newton Power Plant is moved up two years from 2027 to 2025, the LCR Margin in 2026-2027 further tightens and drops to only 305 MW.

5.1 Resource Adequacy Projections

5.1.1 PJM RTO

As shown in Figure 5-1, based upon the 2020 NERC Long-Term Reliability Assessment (“2020 NERC LTRA”), PJM is projected to have sufficient resources to meet load plus required reserve margins for the Delivery Years 2021-2022 to 2026-2027, with projected reserve margins above the 14.9% target reserve margin. For the 2021-2022 Delivery Year, the reserve margin is 24% above the target reserve margin and is 25.2% above the target reserve margin for the 2026-2027 Delivery Year.

Figure 5-1: PJM / NERC Projected Capacity Supply and Demand for Delivery Years 2021-2022 to 2026-2027



Source: 2020 NERC LTRA

5.1.2 MISO RTO

As shown in Figure 5-2, based upon the 2020 NERC LTRA, on a region-wide basis MISO is expected to have sufficient resources to meet load plus required reserve margin for the Delivery Years 2021-2022 to 2024-2025 with projected reserve margins above the 18.0% target reserve margin. However, in 2025-2026, MISO will have insufficient resources to meet load plus a target reserve margin. For the 2021-2022 Delivery Year, the reserve margin is approximately 5.8% above the target reserve margin, declining to 0.3% above the target reserve margin for the 2024-2025 Delivery Year, and finally dropping to 1% below the target reserve margin for the 2025-2026 Delivery Year.

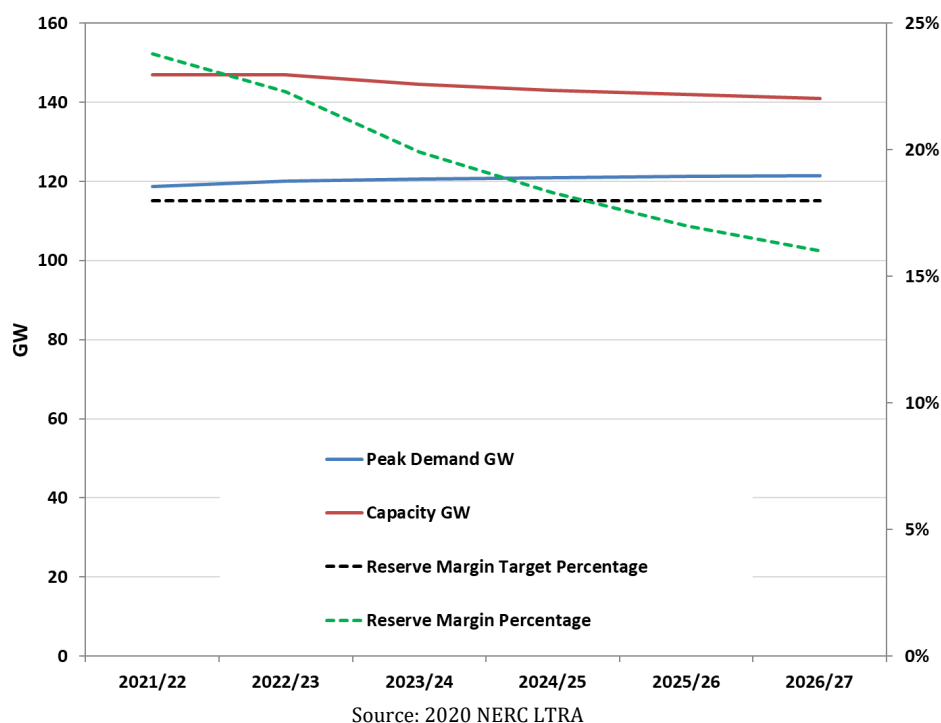
The 2020 NERC LTRA makes the following observation:

- The MISO area is projected to have resources in excess of the regional requirement through 2024-2025.

The observation in the 2020 NERC LTRA is consistent with statements made by MISO in their 2020 Transmission Expansion Plan ("2020 MTEP"). In the 2020 MTEP MISO notes that, based on the 2020 survey conducted by the Organization of MISO States and MISO, the region will have adequate but tighter reserve margins, and that continued action will be needed to ensure resource adequacy in the extended outlook. MISO further notes that resource adequacy risk can be avoided by firming up the commitment of additional potential resources by load serving entities.¹¹⁴ As shown in the year to year IPA procurement plans, as more information on the supply outlook has become available to load serving entities, the supply outlook has generally been more positive. For example, in the 2020 Electricity Procurement Plan, the reserve margin shortfall was projected to occur in 2023-2024.

¹¹⁴ See 2020 MTEP report at <https://cdn.misoenergy.org/MTEP20%20Full%20Report485662.pdf> at pages 31 and 32.

Figure 5-2: MISO / NERC Projected Capacity Supply and Demand for the Delivery Years 2021-2022 to 2026-2027



The RTO-based, region-wide reliability assessments examined in this section are important measures of resource reliability in Illinois because the Illinois electric grid operates within the control of these two RTOs. However, the IPA notes that resource adequacy in Zone 4, the Local Resource Zone (“LRZ”) covering the state of Illinois, is more pertinent because the MISO resource adequacy mechanism, through MISO’s capacity auction --- the planning resource auction,¹¹⁵ has a requirement that, in order to meet resource adequacy requirements, a certain amount of resources has to be located within Zone 4. With several generation units having recently retired within Zone 4,¹¹⁶ and more planned for retirement, the IPA believes it has become necessary to analyze the adequacy of planning resources in Zone 4 to meet the locational requirement as further described in section 5.1.3 below.

5.1.3 Analysis of the Adequacy of Zone 4 Planning Resources to meet the Local Clearing Requirement

5.1.3.1 Impact of Local Clearing Requirement on Resource Adequacy

The MISO Tariff defines the Local Clearing Requirement (“LCR”) as the minimum amount of Unforced Capacity (“UCAP”) for an LRZ that is required to meet its Loss of Load Expectation (“LOLE”) while fully using the Zonal

¹¹⁵ An overview of the planning resource auction is provided in section 5.2.2.

¹¹⁶ In June 2019, the Illinois Pollution Control Board (“IPCB”) issued a Proposed Second Notice Order with amendments to the Multi-Pollutant Standard in 35 Ill. Adm. Code § 225.233. The proposed amendments include mass-based caps for SO₂ and NO_x as well as elimination of 2,000 megawatts of coal-fired electric generating capacity by December 31, 2019. See IPCB Docket No. R18-20, Second Notice Order dated June 20, 2019, <https://pcb.illinois.gov/documents/dsweb/Get/Document-100685>. On August 22, 2019, Vistra Energy, the ultimate owner of all of downstate Illinois’ coal-fired power plants, announced that four coal-fired plants – Coffeen (915 MW), Duck Creek in the city of Canton (425 MW), Havana (434 MW), and Hennepin (294 MW) – would be closed by the end of 2019 to comply with the IPCB’s ruling. On September 16, 2019, Vistra additionally announced that the E.D. Edwards coal-fired plant (585 MW) near Peoria would be closed by the end of 2022 as part of a settlement of a federal Clean Air Act lawsuit in the Central District of Illinois. Vistra retired the Coffeen plant on November 1, 2019, Duck Creek on December 15, 2019, Havana on November 1, 2019, and Hennepin on November 1, 2019. See <http://www.chicagotribune.com/news/environment/ct-illinois-coal-plant-shutdowns-20190822-5m5icfssrbdldgrggp6rd65brm-story.html>; <http://www.chicagotribune.com/news/environment/ct-illinois-coal-plant-closing-20190916-3ql3ch4c3vhmfcznlot5z2zt4-story.html>

Import Ability (“ZIA”) for such LRZ and accounting for controllable exports.¹¹⁷ UCAP is the amount of capacity in MW assigned to a planning resource after accounting for its forced outage rate or historic availability.¹¹⁸ The UCAP required to meet LCR has to be located within the zone. LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand. The requirement is set such that the loss of load is no greater than 0.1 days in one year.¹¹⁹ ZIA is the ability of an LRZ to import capacity from areas outside of that LRZ.¹²⁰

The impact of the shortage of resources to meet the LCR was evidenced in the results of the 2020-2021 planning resource auction. In that auction, Zone 7 (Michigan) cleared at the cost of new entry, a high price relative to the other zones, due to insufficient capacity to meet the LCR.¹²¹ The IPA also notes that in the 2015-2016 planning resource auction, Zone 4 cleared at a high price due to the need to meet the LCR. However, in that case the high price was not due to a shortage of resources to meet the LCR but was due to a bidder submitting an extraordinarily high offer, and because that offer was needed to meet the LCR, it set the clearing price for Zone 4. As explained in the 2016 and 2017 Plans, FERC ordered changes to the MISO tariff to address the flaws in the planning resource auction rules, and therefore prevent a similar occurrence in the future.

The analysis in this section is therefore focused on assessing whether there are sufficient planning resources to meet the Zone 4 LCR, and therefore prevent what occurred in Zone 7 taking place in Zone 4. The analysis covers the years 2021-2022 through 2026-2027, with 2021-2022 as the base year.

5.1.3.2 Historical Analysis of Available UCAP and LCR

To get an understanding of how much capacity has historically been available to meet the LCR, the IPA reviewed the input data and results of all the planning resource auctions since the inception of the auction in 2013-2014. The results of the analysis are presented in Figure 5-3.

The results of the analysis show that:

- The available UCAP in 2013-2014 was 12,869 MW. The available UCAP in 2021-2022, the most recent delivery year, is 9,506 MW, a 3,363 MW (26%) reduction from 2013-2014. The average available UCAP for the nine delivery years is 11,257 MW.
- The LCR had its highest value in 2014-2015 at 8,879 MW and its lowest value in 2018-2019 at 4,960 MW. The average LCR for the nine delivery years is 6,517 MW.
- The difference between the available UCAP and the LCR (“the LCR Margin”) was at its highest in 2013-14 at 7,637 MW and at its lowest in 2021-2022 at 3,056 MW. The average LCR Margin for the nine delivery years is 4,740 MW.

While there has been a 26% reduction in the LCR Margin, the results show that for the nine delivery years there was no shortage of available UCAP to meet the LCR. The available UCAP of 9,506 MW in 2021-2022 (the base year), will be the starting capacity for the analysis of available UCAP for years 2022-2023 through 2026-2027.

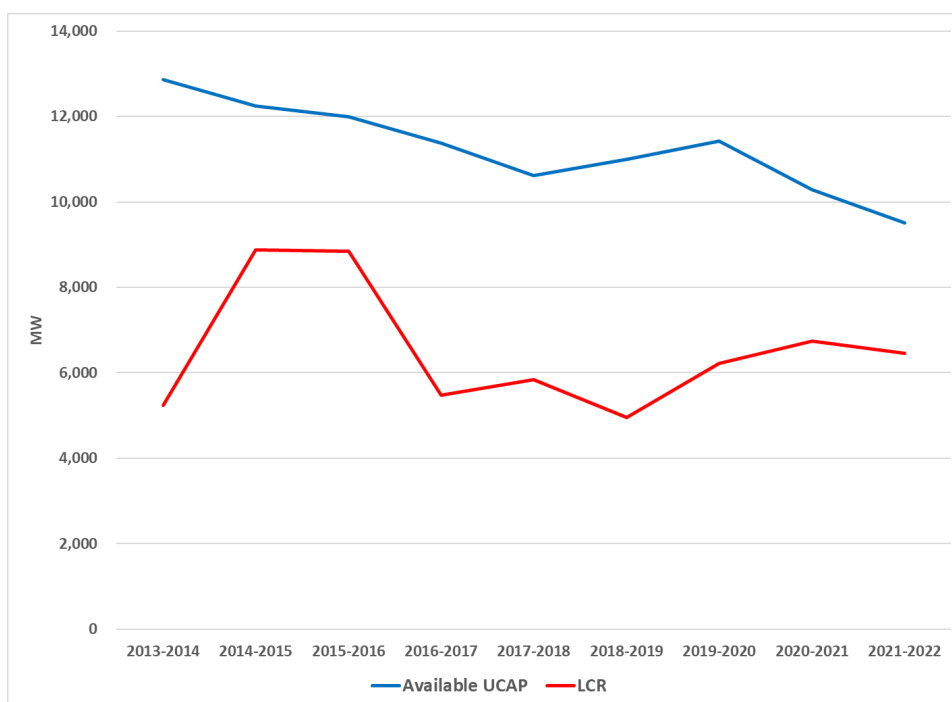
¹¹⁷ See MISO Tariff at <https://docs.misoenergy.org/legalcontent/TariffAsFiledVersion.pdf>

¹¹⁸ Id.

¹¹⁹ Id.

¹²⁰ Id.

¹²¹ More detail on clearing prices in the planning resource auction is provided in section 5.2.2.

Figure 5-3: Comparison of Available UCAP and LCR

Source: MISO Planning Resource Auction Input Data and Results¹²²

5.1.3.3 Recent and Planned Retirements

As noted in section 5.1.2, a number of generation units owned by Vistra have retired. The IPA reviewed MISO documents, contacted MISO,¹²³ and confirmed that all the Vistra units listed in section 5.1.2, and reproduced in Table 5-1, as well as the Dallman units, have been included in the 2021-2022 LOLE Study Report¹²⁴ which prepared the inputs for the 2021-2022 planning resource auction, and the inputs for the 2020 NERC LTRA.

Table 5-1 shows all the recent retirements which have been approved by MISO.

¹²² See Planning Resource Auction documents at:

<https://www.misoenergy.org/planning/resource-adequacy/#nt=%2Fplanningdoctype%3APRA%20Document&t=10&p=0&s=&sd=>

¹²³ On May 15, 2021 the IPA requested that MISO confirm whether the 2021-2022 Loss of Load Expectation Study Report took into account the Zone 4 unit retirements listed in Table 5-1. In an email dated May 17, 2021, MISO confirmed that all the unit retirements listed in Table 5-1 were removed from the model for the 2021-2022 Loss of Load Expectation Study Report.

¹²⁴ The 2021-2022 LOLE Study Report can be found at:

<https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf>

Table 5-1: Recent Retirements in Zone 4

Unit Name	Installed Capacity (MW)	Fuel Type	Retirement Date
Coffeen Units 1 and 2	1,101	Coal	November 1, 2019
Hennepin Units 1 and 2	366	Coal	November 1, 2019
Havana Unit 6	543	Coal	November 1, 2019
Duck Creek Unit 1	517	Coal	December 15, 2019
Dallman Units 31 & 32	180	Coal	March 1, 2021
Total	2,707		

Source: MISO list of approved generator retirements¹²⁵

The retirements in Table 5-1 include the Vistra units and two units (Dallman Units 31 and 32) owned by City Water, Light and Power ("CWLP") in Springfield, Illinois.¹²⁶ The Dallman units were recommended for retirement in CWLP's Integrated Resource Plan¹²⁷ and the retirements were approved by the Springfield Illinois City Council on February 4, 2020.¹²⁸ The approved CWLP retirements also include Dallman Unit 33, which is scheduled for retirement by September 2023.¹²⁹

Vistra has also announced the retirement of additional coal units in their portfolio in Illinois. In a press release issued on September 29, 2020, Vistra noted that, as part of their CO₂ reductions through coal retirements, they would be retiring the Edwards Power Plant by year end 2022, the Baldwin Power Plant by year end 2025, the Joppa Power Plant by year end 2025, and the Newton Power Plant by year end 2027.¹³⁰ In another press release issued on April 6, 2021, Vistra noted that they had decided to move up the retirement of the Joppa Power Plant to September 1, 2022, three years earlier than previously disclosed.¹³¹ Vistra noted that the revised retirement date is part of an agreement Vistra has reached in order to settle a complaint brought by the Sierra Club in 2018 before the Illinois Pollution Control Board concerning allegations of environmental exceedances occurring prior to Vistra's ownership. Table 5-2 lists the planned retirements by Vistra and CWLP.

Table 5-2: Planned Retirements in Zone 4

Plant / Unit Name	Installed Capacity (MW)	Fuel Type	Retirement Date
Edwards Power Plant	585	Coal	By Year-End 2022
Joppa Power Plant	1,002	Coal	September 1, 2022
Dallman Unit 33	192	Coal	By September, 2023
Baldwin Power Plant	1,185	Coal	By Year-End 2025
Newton Power Plant	615	Coal	By Year-End 2027
Total	3,579		

¹²⁵ See [http://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS Posting of Approved Generator Retirements \(Public\) 2021-04-29.pdf](http://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS%20Posting%20of%20Approved%20Generator%20Retirements%20(Public)%202021-04-29.pdf)

¹²⁶ MISO also confirmed that Dallman Unit 33 was also included in the 2021-2022 LOLE study report and is therefore part of the 2021-2022 base year capacity of 9,506 MW.

¹²⁷ See [https://cwlp.com/Documents/CWLP IRP Report Final digital.pdf](https://cwlp.com/Documents/CWLP_IRP_Report_Final_digital.pdf)

¹²⁸ <https://www.sierraclub.org/press-releases/2020/02/springfield-il-city-council-votes-retire-three-coal-units-city-s-dallman>

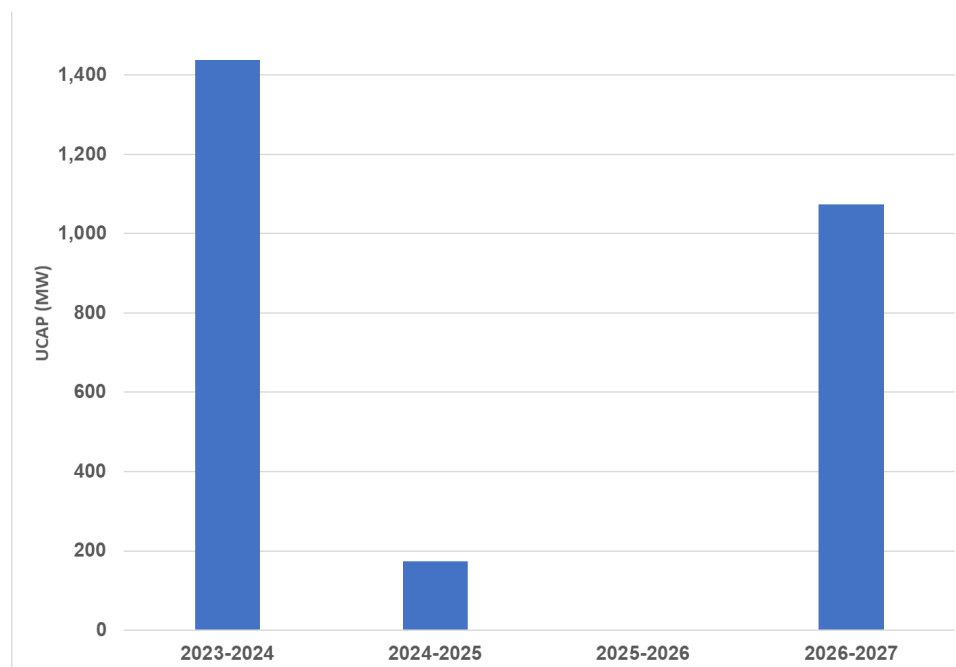
¹²⁹ CWLP confirmed the retirement of Dallman Unit 33 by September 2023.

¹³⁰ <https://investor.vistracorp.com/2020-09-29-Vistra-Accelerates-Pivot-to-Invest-in-Clean-Energy-and-Combat-Climate-Change>

¹³¹ <https://investor.vistracorp.com/2021-04-06-Joppa-Power-Plant-to-Close-in-2022-as-Company-Transitions-to-a-Cleaner-Future>

The retirements in Table 5-1 and Table 5-2 are expressed in installed capacity (“ICAP”). ICAP is the amount of capacity in MW assigned to a planning resource before accounting for its forced outage rate or historic availability.¹³² To convert to UCAP the IPA used a class average forced outage rate of 9.36% as recommended by MISO in the inputs to the 2021-2022 LOLE study report.¹³³ Figure 5-4 shows the planned retirements, expressed in UCAP, and presented by delivery year.

Figure 5-4: Planned Retirements by Delivery Year



The placement of retirements by delivery year is based on the impact of the retirement on the summer peak of the delivery year. For example, Edwards Power Plant’s retirement date is by year end 2022, which means it will have an impact on the summer peak of delivery year 2023-2024. The same applies to the Joppa Power Plant. The Newton Power Plant’s retirement date is outside the study period as its impact will be in 2027-2028. The IPA has conducted a sensitivity analysis of the retirement which is described in section 5.1.3.4.

5.1.3.4 New Planning Resources

To estimate the planned generation capacity for the study period, the IPA reviewed and analyzed the MISO interconnection queue for planned generation capacity in Zone 4.¹³⁴ The analysis showed that the planned generation capacity was at different stages of the MISO interconnection process as follows:

- The planned generation capacity consists of solar generation, wind generation, gas fired generation, and battery storage.
- The planned generation capacity can be presented in two groups --- generation capacity that has signed a GIA and is under construction, and generation capacity that is still active in the interconnection queue and

¹³² See MISO Tariff at <https://docs.misoenergy.org/legalcontent/TariffAsFiledVersion.pdf>

¹³³ See <https://cdn.misoenergy.org/2021-2022%20Pooled%20EFORD%20Class%20Averages488564.xlsx>

¹³⁴ The MISO queue can be found at: https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/gi-interactive-queue/

is at either Phase 1 or Phase 3 of the MISO interconnection process. There is currently no planned generation capacity in Phase 2.¹³⁵

- There is a total of 12,261 MW of ICAP under development from 2022-2023 through 2025-2026.
- From 2022-2023 through 2024-2025, a total of 1,479 MW of ICAP has signed a GIA and is under construction. 69% is solar capacity, and 31% is wind capacity.
- From 2022-2023 through 2025-2026, a total of 10,782 MW of ICAP is still active in the queue at either Phase 1 or Phase 3 of the DPP. 62% (6,726 MW) is solar capacity, 24% (2,591 MW) is wind capacity, 13% (1,365 MW) is gas-fired capacity, and 1% (100 MW) is battery storage capacity. Phase 1 constitutes 83% (8,942 MW) of the total MW, with the remaining 17% (1,840 MW) in Phase 3. Phase 1 resources, which are still in the early stages of the interconnection process, consist of 38 solar projects (6,526 MW), 8 wind projects (1,991 MW), 2 battery storage projects (100 MW), and 1 gas-fired project (325 MW). Phase 3 resources, which are at an advanced stage of the interconnection process, consist of 3 wind projects (600 MW), 1 gas-fired project (1,040 MW), and 1 solar project (200 MW).

Table 5-3 presents the new planning resources by delivery year.

Table 5-3: New Planning Resources in Zone 4

	2022-2023	2023-2024	2024-2025	2025-2026
GIA/Under Construction (MW ICAP)	879	500	100	
Active in the Queue (MW ICAP)	5,111	2,199	3,072	400
Total New Planning Resources (MW ICAP)	5,989	2,699	3,172	400

To convert the ICAP to UCAP the capacity credit for wind and solar was applied, and the forced outage rates for gas fired generation and battery storage were applied as follows:

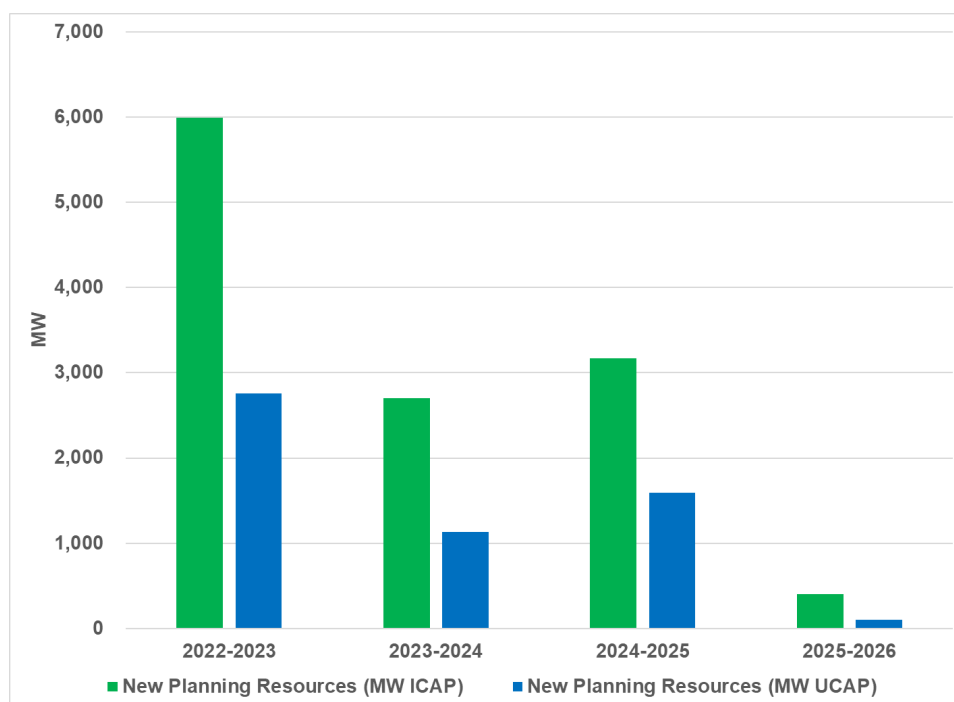
- In MISO the capacity credit for wind and solar is determined annually and published in the Wind and Solar Capacity Credit Report.¹³⁶ Based on the 2021-2022 Wind and Solar Capacity Credit Report, the capacity credit for wind in Zone 4 is 10.5% and the capacity credit for solar is 50%.
- Gas fired generation was converted to UCAP using its class average forced outage rate of 4.76% and Battery Storage was treated as Pumped Storage and assigned a class average forced outage rate of 9.36%.¹³⁷

Figure 5-5 provides a side-by-side comparison of the ICAP and UCAP of the new planning resources.

¹³⁵ MISO's interconnection process has three study phases referred to as Definitive Planning Phases (DPP). Under Phase 1 of the DPP a preliminary system impact study is conducted. Under Phase 2 of the DPP, a revised system impact study and an initial facilities study are conducted. Under Phase 3 of the DPP, a final system impact study and a final facilities study are conducted. After the three study phases an interconnection customer can proceed to the signing of a GIA, followed by construction. Details of the DPP are provided in MISO's Tariff at <https://docs.misoenergy.org/legalcontent/TariffAsFiledVersion.pdf>.

¹³⁶ The 2021-2022 Wind and Solar Capacity Credit Report can be found at: <https://cdn.misoenergy.org/2021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf>

¹³⁷ See <https://cdn.misoenergy.org/2021-2022%20Pooled%20EFORD%20Class%20Averages488564.xlsx>

Figure 5-5: New Planning Resources in Zone 4

As noted above, the new planning resources are at various stages of progress through the MISO interconnection queue. There is uncertainty as to how much of the total capacity will actually go into service. While MISO does not publish statistics on the progress of queue positions through the interconnection queue, in particular how much of the total capacity that started the queue process actually went into service, PJM does. Based on PJM's statistics only 25% of the capacity that started the interconnection process ends up signing a GIA, and only 14% actually goes into service.¹³⁸

The resource adequacy survey that is conducted jointly between the Organization of MISO States and MISO ("OMS-MISO Survey") looked into the treatment of new planning resources that are in the queue in particular the amount of capacity that must be credited to a resource based on its progress through the queue. In the early years of the OMS-MISO Survey only resources with a signed GIA were considered as new planning resources for the purposes of the survey and included in the survey totals.¹³⁹ Stakeholders recommended including all new planning resources but with a weight applied to a resource's capacity to reflect its progress through the MISO interconnection queue. MISO proposed some weights which have been refined from year to year. For the 2021 OMS-MISO survey, the following weights were applied to new planning resources.¹⁴⁰

- Not Started / Phase 1 = 10%
- Phase 2 = 75% for non-intermittent resources; 50% for Intermittent resources
- Phase 3 / GIA in Progress = 90%

If a resource has not yet started the study phase or is in Phase 1, a 10% weight is applied to the resource's capacity. For example, if a resource's UCAP is 100 MW, the resource will only be credited with 10 MW. If a unit is either in Phase 3 or has started the GIA process, a 90% weight is applied to the resource's capacity.

¹³⁸ See <https://www.pjm.com/-/media/committees-groups/committees/pc/2020/20200512/20200512-pc-info-only-pjm-queue-status-update.ashx>

¹³⁹ See <https://cdn.misoenergy.org/20170208%20RASC%20Item%2002f%20OMS%20MISO%20Survey%20Improvements87474.pdf>

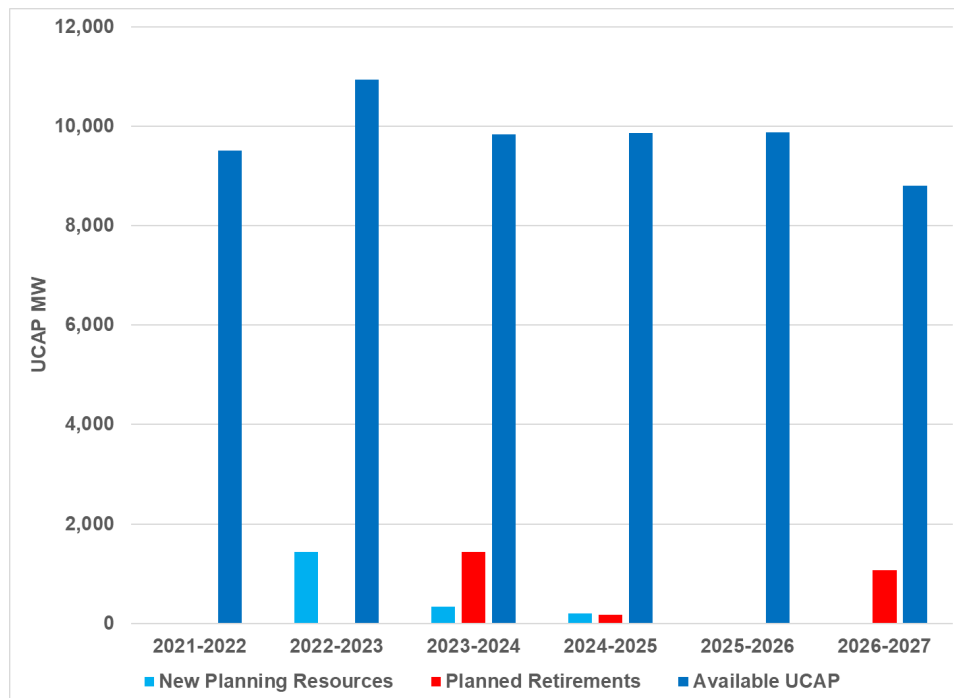
¹⁴⁰ See <https://cdn.misoenergy.org/20210611%20OMS%20MISO%20Survey%20Workshop%20Presentation559144.pdf>

The IPA believes that it is appropriate to apply weights to new planning resources based on their progress through the MISO interconnection process, similar to the OMS-MISO Survey. As noted above, the new planning resources in Zone 4 that are active in the MISO queue, but without a signed GIA, are either in Phase 1 or Phase 3. The IPA applied weights to these resources based on the values used in the OMS-MISO survey. Table 5-4 shows the Available UCAP in Zone 4, net of planned retirements, after the weights were applied to the new planning resources. Figure 5-6 presents the same information. As noted above, 2021-2022 represents the base year.

Table 5-4: Available UCAP in Zone 4

	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
Base Year UCAP (MW)	9,506					
New Planning Resources UCAP (MW)		1,432	339	205	10	
Planned Retirements UCAP (MW)			1,438	174		1,074
Available UCAP (MW)	9,506	10,938	9,838	9,869	9,879	8,805

Figure 5-6: Available UCAP in Zone 4



5.1.3.5 Local Clearing Requirement

The formula for determining the LCR is as follows:

$$\text{LCR} = \text{Local Reliability Requirement (LRR)} - \text{ZIA} - \text{Controllable Exports}^{141}$$

LRR is the minimum amount of UCAP for an LRZ to meet its LOLE, without considering transmission ties to systems outside of the LRZ. The LRR is determined by MISO using a probability simulation model, by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. There currently is no forecast

¹⁴¹ See Business Process Manual for Resource Adequacy at:

<https://cdn.misoenergy.org/BPM%20011%20-%20Resource%20Adequacy110405.zip>

from MISO of the LRR for the full study period (2022-2023 through 2026-2027). The ZIA is determined annually by MISO using a power flow model. There also is no forecast of the ZIA for the study period. Controllable exports are exports made by MISO resources within a zone that have firm capacity commitments to non-MISO load. MISO may commit and dispatch controllable exports during an emergency. Controllable exports are business decisions made by market participants on an annual basis and are therefore difficult to forecast.

Since there is no MISO forecast for LCR for the study period, the IPA used an estimate based on historical values of the LCR. Based on the analysis of the data presented in Figure 5-3, the LCR averaged 6,517 MW for the 9-year period of the planning resource auction. The average of the most recent two delivery years is 6,597 MW which is only 1.2% higher than the 9-year average. The IPA used the 9-year average for the estimate of the LCR for the study period. The LCR is kept constant from 2022-2023 through 2026-2027.

5.1.3.6 Comparison of Available UCAP and the LCR

Table 5-5 and Figure 5-7 show a comparison of the Available UCAP in Zone 4 and the LCR.

Table 5-5: Comparison of Available UCAP and LCR

	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
Available UCAP (MW)	9,506	10,938	9,838	9,869	9,879	8,805
LCR (MW)	6,450	6,517	6,517	6,517	6,517	6,517
UCAP Less LCR ("LCR Margin") (MW)	3,056	4,421	3,321	3,352	3,362	2,288

Figure 5-7: Comparison of Available UCAP and LCR

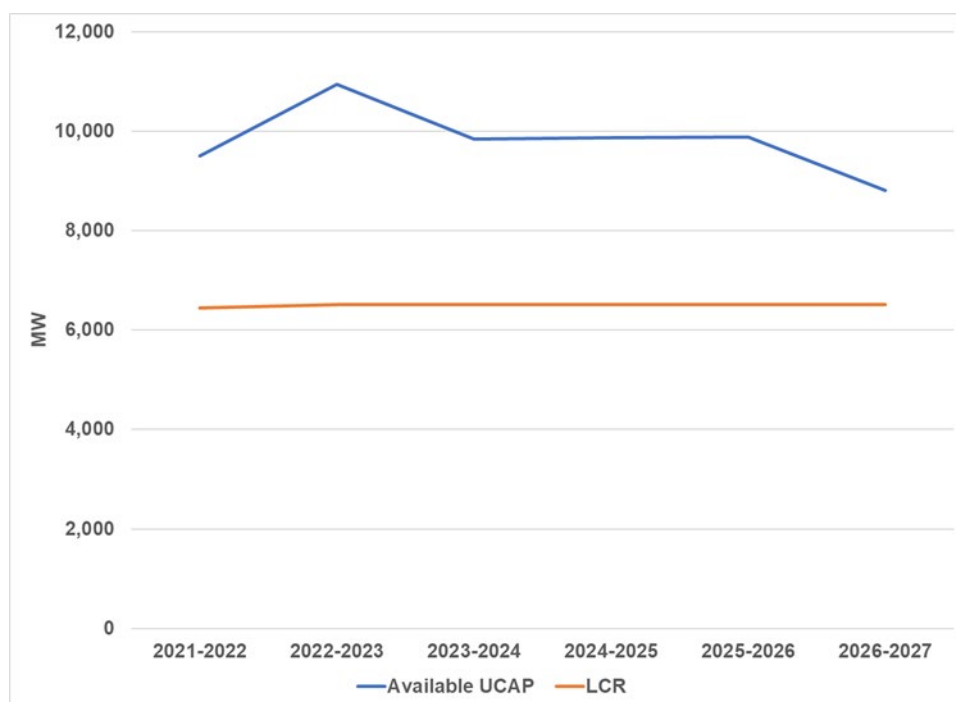


Table 5-4 and Figure 5-7 show that the Available UCAP in Zone 4 will be able to meet the LCR for the study period. In 2026-2027 the LCR is 2,288 MW, and the LCR Margin drops by 32% (1,074 MW) from the previous year.

As noted above, there is uncertainty in the amount of new planning resources that will ultimately go into service. To further test the adequacy of resources to meet the LCR, the IPA performed a sensitivity analysis

(Sensitivity Analysis A), which assumes that only resources with a signed GIA and under construction will get in-service. The results of the analysis are shown in Figure 5-8. The results show that the LCR Margin in 2026-2027 drops to 862 MW from 2,288 MW. The LCR Margin is, however, still above the LCR.

The IPA conducted another sensitivity (Sensitivity Analysis B) to test the timing of retirements. As noted, earlier Vistra originally announced that the Joppa Power Plant would retire by the end of 2025. However, Vistra later announced that they had decided to retire the unit on September 1, 2022, three years earlier than previously disclosed. Currently the Newton Power Plant is scheduled to be retired by the end of 2027 and is currently outside the study period. Sensitivity Analysis B tests the impact of moving the retirement date of the Newton Plant two years up to the end of 2025. The results of the analysis are shown in Figure 5-9. The results of the analysis show that the LCR Margin further tightens and drops to only 305 MW. The LCR Margin is still above the LCR.

Figure 5-8: Sensitivity Analysis A – Only Resources with Signed GIA and Under Construction

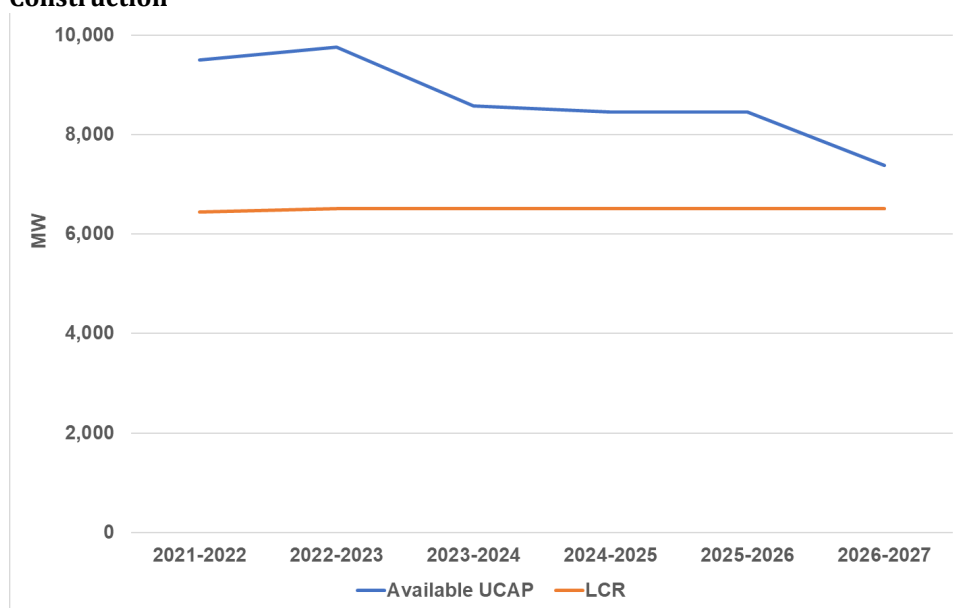
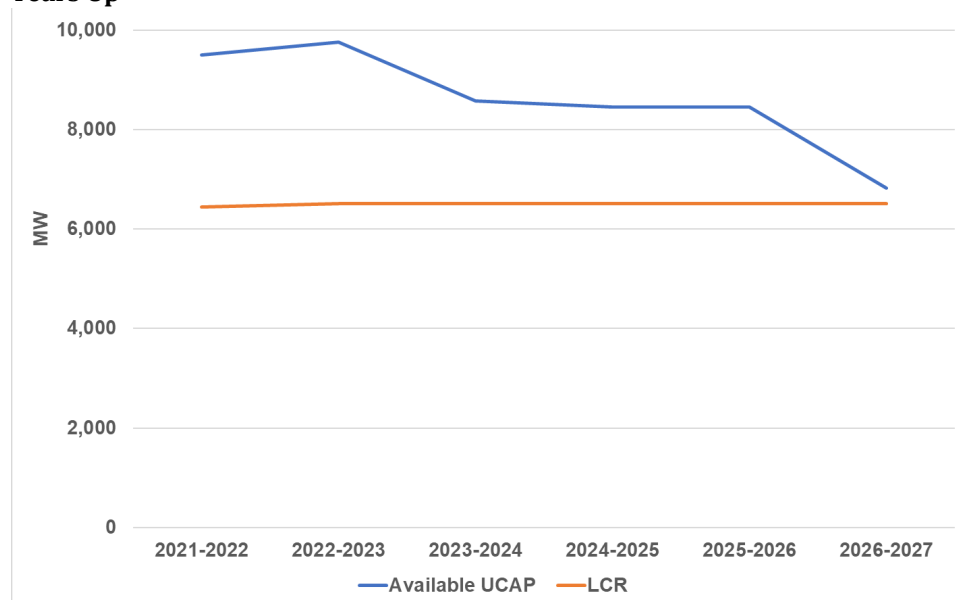


Figure 5-9: Sensitivity Analysis B – Newton Power Plant Retirement Moved Two Years Up



5.1.3.7 The IPA's Review of the 2021 OMS-MISO Survey

The IPA notes that the 2021 OMS-MISO survey released their survey results on June 11, 2021.

The IPA reviewed the survey results for Zone 4 and notes that the results of the survey's LCR analysis are consistent with the IPA's analysis in that there is enough Available UCAP to meet the LCR for the study period. However, the OMS-MISO survey also did an analysis of Available UCAP to meet the Planning Reserve Requirement, which shows that if the supply consists of only committed capacity in 2022 and 2026 Available UCAP in Zone 4 will not be able to meet the Planning Reserve Margin Requirement, but if the supply consists of all planned generation resources (what the OMS-Survey refers to as Potential New Capacity), the Available UCAP will be able to meet the Planning Reserve Margin Requirement. Since 2014-2015, Zone 4 has relied on both Available UCAP and imports to meet the Planning Reserve Margin Requirement. Zone 4 imports for the 8 year period through 2021-2022 averaged 1,115 MW. Zone 4, even when it had enough Available UCAP to meet the Planning Reserve Margin Requirement, still imported from neighboring zones based on clearing dynamics. For example, in 2019-2020 the Available UCAP was 11,429 MW, which was higher than the Planning Reserve Margin Requirement of 9,792 MW, yet Zone 4 imported 1,187 MW while clearing 8,606 MW of the 11,429 MW of Available UCAP. 2021-2022 was the first year that Zone 4's Available UCAP (9,506 MW --- the base year for the IPA's analysis) was below the Planning Reserve Margin Requirement of 9,853 MW. However, Zone 4 imported 1,521 MW, while clearing 8,332 MW of the 9,506 MW. Therefore, if Zone 4 only considered Available UCAP, the zone would not have been able to meet the Planning Reserve Margin even in 2021-2022 and would have cleared at the cost of new entry.

If the IPA's analysis had been based on comparing Available UCAP to the Planning Reserve Margin Requirement, without considering imports into Zone 4, the results would be consistent with the results of the OMS-MISO Survey. The IPA however believes that the analysis of the Available UCAP to meet the LCR is a more relevant analysis for Zone 4.

5.1.3.8 Conclusions

- If all new planning resources were taken into account, the Available UCAP in Zone 4 would be able to meet the LCR for the study period. In 2026-2027 the LCR Margin is 2,288 MW, a drop of 32% (1,074 MW) from the previous year. The LCR Margin remains above the LCR.
- If only generators with a signed GIA, and under construction are assumed as the new planning resources, the LCR Margin in 2026-2027 drops to 862 MW. The LCR Margin is still above the LCR.

- If the retirement date of the Newton Power Plant is moved up two years from 2027 to 2025, the LCR Margin in 2026-2027 further tightens and drops to only 305 MW. The LCR Margin is still above the LCR.

The IPA concludes that it does not need to include any extraordinary measures in the 2022 Procurement Plan to assure reliability over the five-year planning horizon. However, the IPA plans to continue to monitor the resource adequacy in Zone 4. The IPA notes the contributions of wind and solar capacity to meeting resource adequacy in Zone 4. As noted before, the new planning resources with a signed GIA and under construction consist entirely of wind and solar capacity. Most of these are projects from the IPA's competitive procurements. The majority of the resources which are active in the interconnection queue at either Phase 1 or Phase 3 are also wind and solar resources which were part of the IPA's RPS procurements. In all, wind and solar capacity constitutes 88% of all the new planning resources that have been considered in this analysis and which are critical to meeting resource adequacy in Zone 4. The IPA notes that as the LCR margin tightens, and depending on what gets enacted in new RPS reforms, the development of renewable resources, in particular wind and solar, is going to be key to resource adequacy in Zone 4.

5.2 RTO Administered Organized Capacity Auctions

Electric power systems should have sufficient capacity resources to meet peak load requirements plus a planning reserve margin to maintain resource adequacy and ensure reliable system operations. Regional transmission organizations like PJM and MISO operate centralized competitive capacity markets to help ensure resource adequacy and reliability. This section provides a brief overview and a regulatory update of these organized capacity markets.

5.2.1 PJM Reliability Pricing Model

In PJM, capacity is largely procured through the PJM-organized 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.¹⁴² RPM is a forward capacity auction through which generators offer capacity to serve the obligations of load-serving entities. The primary capacity auctions, Base Residual Auctions ("BRAs"), are held each May, three years prior to the commitment period. In the RPM construct, the commitment period is referred to as a "Delivery Year". In this Plan, "Delivery Year" is also used in relation to all capacity and energy procurements.¹⁴³ In addition to the BRAs, up to three incremental auctions are held, at intervals of 20, 10, and 3 months prior to the Delivery Year. The 1st, 2nd, and 3rd Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement.¹⁴⁴ A Conditional Incremental Auction may be conducted, if and when necessary, to secure commitments of additional capacity to address reliability criteria violations arising from the delay of a backbone transmission upgrade that was modeled in the BRA.

Just prior to the beginning of each Delivery Year, the Final Zonal Net Load Price, which is the price paid by LSEs for capacity procured as part of the RPM, is calculated. This price is determined based on the results of the BRA and subsequent incremental auctions for a given year. As the procurement of the majority of the capacity via the RPM is done during the BRA, there is little variation between the BRA clearing price (Preliminary Zonal Capacity Price) and the Final Zonal Net Load Price as shown in Figure 5-10. However, while Figure 5-10 shows little variation in the ComEd zone between the BRA clearing price and the Final Zonal Net Load Price for the

¹⁴² On June 9, 2015, FERC accepted PJM's proposal to establish a new capacity product, a Capacity Performance Resource, on a phased-in basis, to ensure that PJM's capacity market provides adequate incentives for resource performance during emergency conditions (FERC Docket No. ER15-623 et al., 151 FERC ¶ 61,208). Resources that are committed as capacity performance resources will be paid incentives to ensure that they deliver the promised energy and reserves when called upon in emergencies. Capacity Performance has been fully implemented for the 2018-2019, 2019-2020, 2020-2021, and 2021-2022 Delivery Years, with transitional capacity performance incremental auctions conducted for the 2016-2017 and 2017-2018 years to facilitate improved resource performance during those years by allowing a portion of capacity to be rebid as Capacity Performance Resources in a new procurement. Implementation of Capacity Performance has generally resulted in increased capacity clearing prices, in particular for the ComEd zone.

¹⁴³ As noted above, a Delivery Year is June 1 through May 31 of the following year. The use of "Delivery Year" in this Plan also applies to the MISO RTO where the term "Planning Year" is normally used.

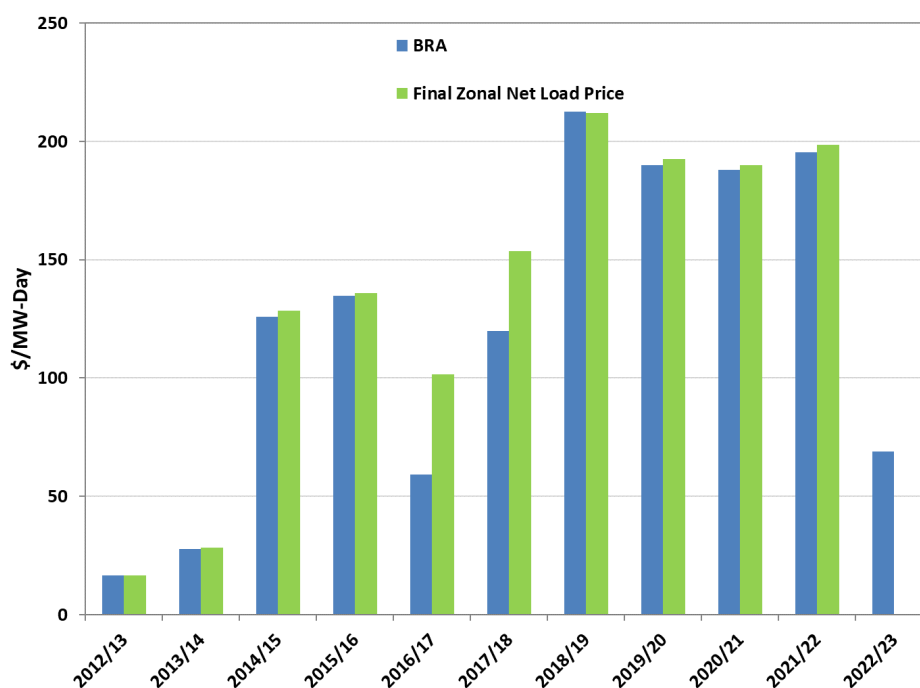
¹⁴⁴ Deferred short-term resource procurement only applies prior to the 2018-2019 Delivery Year.

Delivery Years through 2015-2016, Delivery Years 2016-2017 and 2017-2018 show a significant variation between the prices. This is because the Final Zonal Net Load Price for 2016-2017 and 2017-2018 includes the incremental costs of each year's transitional Capacity Performance Incremental Auction ("CPIA").¹⁴⁵

Figure 5-10 also shows higher BRA prices in the ComEd zone for Delivery Years 2018-2019 through 2022-2023 relative to 2017-2018, which are attributable to the transition to full implementation of the Capacity Performance product (i.e. Capacity Performance Resources bidding in the BRA) as well as transmission constraints in the ComEd LDA.¹⁴⁶

Figure 5-10 also shows little variation between the BRA clearing price and the Final Zonal Net Load Price for the 2018-2019, 2019-2020, 2020-2021, and 2021-2022 Delivery Years which, as noted before, is consistent with procuring the majority of the capacity during the BRA.

Figure 5-10: PJM (ComEd Zone) Capacity Price for Delivery Years 2012-2013 to 2022-2023¹⁴⁷



¹⁴⁵ The BRA clearing price (Preliminary Zonal Capacity Price) for the ComEd zone for 2016-2017 was \$59.37/MW-Day. 60% of resources procured in the 2016-2017 CPIA were Capacity Performance Resources. The preliminary incremental cost component for the 2016-2017 CPIA was \$38.17/MW-Day and the final incremental cost component was \$39.86/MW-Day. After factoring in the adjustments to account for the results of the 1st, 2nd, and 3rd incremental auctions, the Final Zonal Net Load Price was \$101.62/MW-Day, a 71% increase from the BRA clearing price. 70% of resources procured in the 2017-2018 CPIA were Capacity Performance Resources. The BRA clearing price for the ComEd zone for 2017-2018 was \$119.81/MW-Day. The preliminary incremental cost component for the 2017-2018 CPIA was \$27.69/MW-Day and the final incremental cost component was \$29.97. After factoring in the adjustments to account for the results of the 1st, 2nd, and 3rd incremental auctions, the Final Zonal Net Load Price for 2017-2018 was \$153.61/MW-Day, a 28% increase from the BRA clearing price.

¹⁴⁶ In 2017-2018, 2018-2019, 2019-2020, 2020-2021, 2021-2022, and 2022-2023, the ComEd Zone was modeled as a separate Locational Deliverability Area ("LDA"), and in all years starting with 2018-2019, the results showed that it was a constrained LDA. Binding constraints therefore also contributed to the higher clearing price although 2022-2023 cleared at a significantly lower price than the previous year due to a lower load forecast and reserve requirement, and overall lower prices from resources participating in the BRA. In 2018-2019 and 2019-2020, 84% of resources procured were Capacity Performance Resources. In 2020-2021 and 2021-2022, 100% of resources procured were Capacity Performance Resources.

¹⁴⁷ 2021-2022 is the latest Delivery Year for which the Final Zonal Net Load Price has been calculated. It will be calculated for future Delivery Years as the start of the year approaches..

As explained in more detail in the 2020 Electricity Procurement Plan,¹⁴⁸ FERC has issued a number of orders that will significantly change PJM's RPM in the future. As noted in the 2020 Electricity Procurement Plan, in an order¹⁴⁹ issued on June 29, 2018, FERC ruled that an important component of PJM's RPM, the Minimum Offer Price Rule ("MOPR"), was unjust and unreasonable because it does not address the impact of state-subsidized existing resources on the capacity market.

FERC instituted a proceeding¹⁵⁰ under Section 206 of the Federal Power Act to find a replacement for the current MOPR.

On October 2, 2018, PJM filed a proposal that had two main features: (i) an expanded MOPR that would apply to all fuel and technology types as well as to existing and new resources, and (ii) a Resource Carve-Out ("RCO") that would allow resources subject to the MOPR to receive capacity market payments without bidding into the PJM capacity market.¹⁵¹

On December 19, 2019, FERC issued an Order in FERC Docket No. EL18-178-000. In its Order, FERC expanded the MOPR to apply to all fuel and technology types (new and existing resources). The expanded MOPR also includes new and existing demand response, energy efficiency, storage and all resources owned by vertically-integrated utilities. Essentially, with certain exceptions, all existing and new resources receiving a state subsidy would not be allowed to offer capacity bids below the applicable MOPR floor. FERC directed PJM to develop applicable MOPR floors for new and existing resources using 100% of the cost of new entry and net avoided cost, respectively. FERC also rejected the RCO option. FERC directed PJM to submit a compliance filing within 90 days, including a proposed schedule for future capacity auctions.

On March 18, 2020 PJM submitted its compliance filing in response to FERC's December 19, 2019 Order.¹⁵² In its filing, PJM submitted revisions to their tariff to modify the application of the MOPR to address state subsidies and their impact in the PJM capacity market. The PJM filing also provided a timetable for conducting the BRA for the 2022-2023 Delivery Year. Specifically, PJM proposed to complete all pre-auction activities and open the BRA for the 2022-2023 Delivery Year within six and a half months after the date of FERC's acceptance of PJM's compliance filing. In order to accommodate a request made by the Organization of PJM States to delay the BRA to May 2021,¹⁵³ PJM proposed that, in the event that legislation directly applicable to new elections of the Fixed Resource Requirement Alternative¹⁵⁴ is enacted before June 1, 2020, and upon request of a state public utility commission acting in its official capacity, PJM would have the limited ability to extend the schedule for the BRA to no later than March 31, 2021.

¹⁴⁸ See pages 46-48 of 2020 Electricity Procurement Plan at <https://www2.illinois.gov/sites/ipa/Documents/2020%20Final%20Electricity%20Procurement%20Plan/IPA%20Final%202020%20Electricity%20Procurement%20Plan.pdf>

¹⁴⁹ Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act, 163 FERC ¶ 61,236, FERC Docket No. EL16-49-000 et al, June 29, 2018.

¹⁵⁰ FERC Docket No. EL18-178-000.

¹⁵¹ Initial Submission of PJM Interconnection, L.L.C, FERC Docket No. EL18-178-000 (Consolidated), October 2, 2018.

¹⁵² Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RPM Auction Deadlines, and Request for An Extended Comment Period of At Least 35 Days, FERC Docket No. EL18-178-000, March 18, 2020.

¹⁵³ See letter from the Organization of PJM States, Inc., to the PJM Board of Managers, at <https://www.pjm.com/-/media/about-pjm/who-we-are/publicdisclosures/20200219-opsi-letter-re-scheduling-next-base-case-residual-auction.ashx?la=en>.

¹⁵⁴ The Fixed Resource Requirement Alternative allows an LSE to opt out of participating in the PJM capacity auction and satisfy its obligation to commit unforced capacity by submitting a capacity plan.

On April 16, 2020, FERC issued an Order addressing requests for rehearing of its December 19, 2019 Order.¹⁵⁵ In that Order, FERC largely upheld their December 19, 2019 Order. FERC also directed PJM to make another compliance filing within 45 days of the date of the Order (i.e., by June 1, 2020). On June 1, 2020, PJM submitted the second compliance filing addressing the issues raised in FERC's Order which include, but are not limited to (i) modifying the March 18, 2020 filing to include separate provisions for the pre-existing MOPR and the new MOPR for capacity resources with a state subsidy, (ii) clarifying that state default service procurements are state subsidies, and proposing language that will allow for the continuation of normal commercial activity associated with state default service auctions while safeguarding against any revenues that would distort the competitiveness of the RPM auctions, (iii) updating the March 18, 2020 filing to clarify that subsidized capacity resources procured in a bilateral transaction cannot be used to replace a non-subsidized capacity resource's capacity commitment, and (iv) revising the proposed tariff language to be consistent with FERC's clarification in the April 16, 2020 Order that zonal net revenues are to be used for calculating default offer price floors for new capacity resources and that resource-specific net revenues should be used for calculating default net avoidable cost rate values for existing resources.¹⁵⁶

On October 15, 2020, FERC issued an Order largely accepting PJM's June 1, 2020 compliance filing, denying the compliance filing in part, and directed PJM to submit another compliance filing within 30 days of the Order.¹⁵⁷ In that Order, FERC indicated that the date for the upcoming 2022-2023 Base Residual Auction could not be set until an Order on the pending Energy and Ancillary Services ("E&AS") compliance filing was resolved.¹⁵⁸

On November 12, FERC approved PJM's E&AS compliance filing,¹⁵⁹ clearing the path for PJM to establish the dates for the upcoming RPM auctions, as well as the deadlines for the associated pre-auction activities. One day later, on November 13, 2020, PJM submitted its compliance filing required under the October 15, 2020 FERC Order from the MOPR proceeding. In that compliance filing, PJM noted that, consistent with FERC's Order, PJM had not set the date for the next Base Residual Auction as it was still awaiting FERC's Order on PJM's E&AS compliance filing. PJM further noted, now that FERC had accepted PJM's E&AS compliance filing, PJM would proceed in establishing the dates for the upcoming RPM auctions, as well as the deadlines for the associated pre-auction activities. PJM set May 19, 2021 as the date for the 2022-2023 Base Residual Auction.

On April 6, 2021 the PJM Board issued a letter to PJM stakeholders asking them to pursue several topics related to the capacity market. One of the topics included "Implementing changes to the Minimum Offer Price Rule (MOPR) to ensure the capacity market accommodates state policy choices related to resource mix, as well as long established self-supply business models, while adequately mitigating buyer-side market power".¹⁶⁰ In the letter the PJM Board further noted that the issue of critical importance, which the PJM stakeholders should address first, is the MOPR and its future application in the capacity market. The Board also noted that, although FERC has not formally spoken on the issue, a recent FERC technical conference focused heavily on the MOPR, and the FERC Chair has provided clear publicly stated guidance that he wants this issue addressed as soon as practicable. Given the importance of the issue the PJM Board requested that the discussion to modify the MOPR should be advanced via the Critical Issue Fast Path (CIFP) accelerated stakeholder process mechanism to try and achieve stakeholder consensus that would inform a PJM Board decision on a potential filing with FERC.

PJM instituted a CIFP-MOPR stakeholder process which discussed various proposals for modifying the MOPR.¹⁶¹ On July 27, 2021 the PJM Board approved the PJM proposal which had received majority stakeholder

¹⁵⁵ Order on Rehearing and Clarification, FERC Docket No. EL18-178-002, April 16, 2020.

¹⁵⁶ Second Compliance Filing Concerning Application of The Minimum Offer Price Rule, FERC Docket No. ER18-1314-006, June 1, 2020.

¹⁵⁷ Order on Compliance, Granting Waiver Request, Addressing Arguments raised on Rehearing, and Setting aside Prior Order, in Part, FERC Docket No. EL18-1314-006 (Consolidated), October 15, 2020.

¹⁵⁸ For E&AS filing, see PJM Compliance Filing, FERC Docket No. EL19-58-003, August 5, 2020.

¹⁵⁹ FERC approved the E&AS compliance filing in an Order issued on November 12, 2020 --- See Order on Compliance, FERC Docket EL19-58-003.

¹⁶⁰ <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210406-board-letter-regarding-capacity-market-minimum-offer-price-rule-and-initiation-of-the-critical-issue-fast-path-process.ashx>

¹⁶¹ <https://www.pjm.com/committees-and-groups/cifp-mopr>.

support and instructed PJM to prepare the PJM proposal for filing with FERC.¹⁶² PJM filed their proposal with FERC on July 30, 2021.¹⁶³ PJM's proposal will replace the current MOPR provisions in the PJM Tariff. The PJM proposal, which is to be effective starting with the 2023-2024 delivery year, is meant to protect the PJM capacity market from buyer-side market power and state actions that directly interfere with capacity auction clearing prices, while accommodating state public policies and self-supply models. Under PJM's proposal the MOPR will be applied to generation capacity resources that exercise Buyer-Side Market Power¹⁶⁴ and generation capacity resources that receive Conditioned State Support.¹⁶⁵ PJM will require capacity market sellers to certify 1) whether, at the time of certification, their generation capacity resource is receiving or expected to receive Conditioned State Support, and 2) that the capacity market seller acknowledges and understands that the exercise of Buyer-Side Market Power is not permitted in PJM's RPM auctions and the seller does not intend to submit a sell offer for their generation capacity resource as an exercise of Buyer-Side Market Power.

5.2.2 Overview of MISO Planning Resource Auction

The MISO Resource Adequacy Construct, specified in Module E-1 of its Tariff,¹⁶⁶ 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")¹⁶⁷ for the Delivery Year. An LSE's total resource adequacy obligation is referred to as the Planning Reserve Margin Requirement ("PRMR"). On June 11, 2012, FERC conditionally approved MISO's proposal to enhance its RAR by establishing an annual construct based upon meeting reliability requirements on a locational basis, including the use of an annual Planning Resource Auction or PRA. MISO implemented the Module E-1 RAR, which became fully effective on June 1, 2013.

On December 15, 2017, MISO filed the currently effective provisions of its Tariff governing resource adequacy in MISO with FERC, informing FERC that their filing did not change any of the current Tariff provisions regarding MISO's resource adequacy requirements, and requesting that FERC reaffirm that these provisions are just and reasonable.¹⁶⁸ On February 28, 2018, FERC issued an order accepting MISO's filing.¹⁶⁹ MISO's Independent Market Monitor ("IMM"), however, asserted that "it does not believe that the Auction outcomes have been just and reasonable because the prices produced through the Auction have departed from any reasonable measure of an efficient capacity price level."¹⁷⁰ The MISO IMM further stated that "it expects prices to continue to clear at near-zero prices due to attributes of MISO's construct including the vertical demand curve coupled with new restrictions on capacity imports by PJM Interconnection, LLC (PJM) and increased sub-regional transfer capability between MISO South and MISO Midwest."¹⁷¹

¹⁶² <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210708-board-letter-communicating-critical-issue-fast-path-minimum-offer-price-rule-decision.ashx>.

¹⁶³ Revisions to Application of Minimum Offer Price Rule, FERC Docket No. ER21-2582-000, July 30, 2021.

¹⁶⁴ Buyer-Side Market Power is the ability of a market participant with a load interest to suppress market-clearing prices for the overall benefit of the participant's portfolio.

¹⁶⁵ Conditioned State Support is defined as out-of-market payments provided by states to generation capacity resources in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any PJM capacity market. Conditioned State Support refers to any directives the state may provide as to the price level at which a generation capacity resource must be offered in the PJM RPM auction or directives that the generation capacity resource is required to clear in any PJM RPM auction.

¹⁶⁶ 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.

¹⁶⁷ The PRM (or target reserve margin) is determined by MISO, based on a Loss of Load Expectation ("LOLE") of one day in ten years, or state-specific standards. If a state regulatory body establishes a minimum PRM for the LSEs under its jurisdiction, then that state-set PRM would be adopted by MISO for jurisdictional LSEs in that state.

¹⁶⁸ Refiling of MISO's Resource Adequacy Construct, FERC Docket No. ER18-462-000, December 15, 2017.

¹⁶⁹ Order Accepting Tariff Filing, 162 FERC ¶ 61,176, FERC Docket No. ER18-462-000, February 28, 2018.

¹⁷⁰ Id. at 6.

¹⁷¹ Id. at 6.

On March 26, 2018, MISO filed changes to the MISO Tariff to enhance the locational aspect of their Resource Adequacy Construct with FERC by (i) creating External Resource Zones (“ERZs”), (ii) allocating excess auction revenues through Historic Unit Considerations (“HUCs”), and (iii) aligning parameters used to calculate auction inputs such as Capacity Import Limits (“CIL”), Capacity Export Limits (“CEL”) and Local Clearing Requirements (“LCR”) with the use of these limits in the PRA.¹⁷² FERC’s Staff issued a Deficiency Letter¹⁷³ to MISO on May 15, 2018, to which MISO responded on June 5, 2018.¹⁷⁴ FERC issued an Order on August 2, 2018 rejecting MISO’s proposed tariff revisions but providing some guidance for a revised proposal.¹⁷⁵ On August 31, 2018 MISO submitted a revised proposal.¹⁷⁶ On October 31, 2018, FERC issued an order accepting MISO’s filing.¹⁷⁷

In the spring of 2013, MISO administered its first PRA which covered the 2013-2014 Delivery Year. Since then, in the spring of each year MISO has conducted its annual PRA; the spring 2021 MISO PRA was the ninth auction administered by MISO.

5.2.2.1 Proposed Changes to MISO’s Resource Adequacy Construct

Stakeholders in MISO are discussing a proposal by MISO for a sub-annual resource adequacy construct. MISO said the proposal would address the following flaws with the current construct: (i) under the current construct the resource adequacy analysis does not sufficiently capture reliability risks across the year; (ii) the current approach to setting resource adequacy requirements does not sufficiently contribute to mitigating risks across the year; and (iii) the current approach to resource accreditation does not adequately reflect operational availability of resources during times of need.

MISO’s proposal has the following features:¹⁷⁸

- Resource adequacy requirements will be calculated on a seasonal basis using four seasonal PRMs/LCRs.
- Resource accreditation will be based on four seasonal values.
- Four independent seasonal PRAs will be conducted at one time. There will be a minimum capacity requirement which sets a 50% procurement cap in the PRA.
- For the day ahead market there will be seasonal must offer requirements for cleared seasons.

The minimum capacity requirement is based on the following:

- All load will be expected to have a minimum amount of resources under contract prior to participating in the PRA.
- The capacity auction is designed to balance the market, not be a primary source of capacity while sending new build signals.
- There will be no in-zone requirement to meet the minimum capacity requirement, which is a change from the original proposal which had an in-zone requirement.

¹⁷² MISO filing to “Enhance Locational Aspect of Resource Adequacy Construct”, FERC Docket No. ER18-1173-000, March 26, 2018.

¹⁷³ See <https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14920258>.

¹⁷⁴ See <https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14938877>.

¹⁷⁵ Order on Tariff Filing, 164 FERC ¶ 61,081, FERC Docket No. ER18-1173-000 et al., August 2, 2018.

¹⁷⁶ Refiling of Resource Adequacy Construct Locational Enhancements, FERC Docket No. ER18-2363-000, August 31, 2018.

¹⁷⁷ Order Accepting Tariff Filing, 165 FERC ¶ 61,067, FERC Docket No. ER18-2363-000, October 31, 2018.

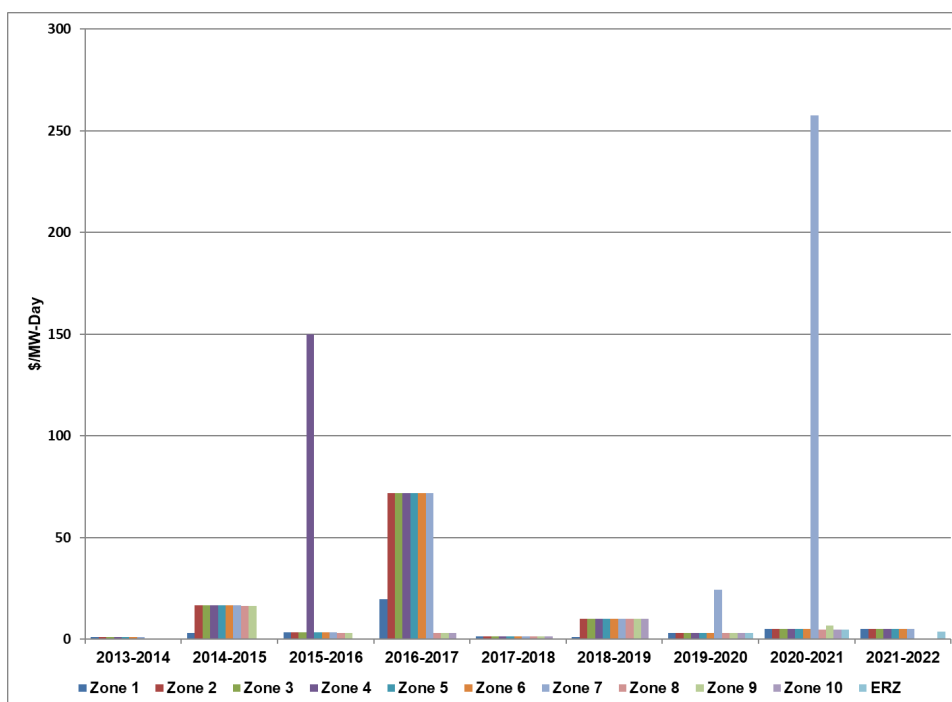
¹⁷⁸ <https://cdn.misoenergy.org/20210512%20RASC%20Item%2004a%20Sub-Annual%20Construct%20Presentation548774.pdf>
<https://cdn.misoenergy.org/20210521%20RAN%20Workshop%20Sub-Annual%20Construct%20Presentation552959.pdf>

Discussion of MISO's proposal continues in the stakeholder process. The current schedule is for the final design to be completed in August 2021, and the final tariff language to be reviewed in September 2021.

5.2.2.2 Results of the MISO PRA

Figure 5-11 below shows the results of the MISO PRA since its inception.

Figure 5-11: MISO PRA Results



As shown in Figure 5-11, and explained in detail in the 2019 Electricity Procurement Plan,¹⁷⁹ capacity prices in the MISO PRA have been volatile, ranging from a low of \$1.00/MW-Day to a high of \$257.53/MW-Day (For Zone 4 the range has been \$1.05/MW-Day to \$150/MW-Day). For the 2020-2021 PRA, most of the MISO zones cleared between \$4.75/MW-Day and \$6.88/MW-Day. Zone 7 (Michigan) cleared at \$257.53/MW-Day, the Cost of New Entry (CONE). Zone 7 cleared at the CONE due to insufficient capacity to meet the LCR. The IPA notes that for the 2015-2016 PRA, in order to meet the LCR in Zone 4, a higher priced bid was selected, resulting in the zone clearing at \$150/MW-Day, a price which was 9 times greater than the price for the previous Delivery Year. A detailed explanation of the results of the 2015-2016 PRA, including an analysis of the Zone 4 price, is provided in the 2016 Electricity Procurement Plan.¹⁸⁰ For the 2021-2022 PRA, Zones 1 through 7 cleared at \$5/MW-Day, and Zones 8-10 cleared at \$0.01/MW-Day. MISO notes that compared with the previous years the lower prices in Zones 7-10 are a result of lower peak demand or additional supply.

As reaffirmed by FERC's February 28, 2018 order mentioned above, the PRA remains as the only market-based capacity auction for all load in MISO.¹⁸¹ Also, in their protest to MISO's refiling of MISO's Resource Adequacy Construct, the MISO IMM stated that "given the nature of capacity market supply, any capacity market with a vertical demand curve and a small amount of surplus capacity would clear close to zero, which is consistent

¹⁷⁹ See IPA's Final 2019 Electricity Procurement Plan, Section 5.2.2, pages 54-55.

¹⁸⁰ See IPA's Final 2016 Electricity Procurement Plan, Section 5.2, pages 58-62.

¹⁸¹ The IPA, however, notes that in MISO the majority of capacity is procured either bilaterally or through Fixed Resource Adequacy Plans.

with the recent auction results in MISO”.¹⁸² By the same token, the IPA notes that the nature of the vertical demand curve is such that even small deficits in supply can lead to a significantly higher price. While there has been significant price volatility in the results of the MISO PRA over recent years, the clearing price for Zone 4 in the last four auctions (2018-2019, 2019-2020, 2020-2021, and 2021-2022 Delivery Years) is significantly lower than in the 2015-2016 and 2016-2017 Delivery Years. However, the PRA results for Zone 7, which mirror the results of Zone 4 in the 2015-2016 PRA, in that they were both caused by a need to meet the LCR, provide market signals for the risk management decision not to rely on the MISO PRA as the only option for meeting capacity requirements for Zone 4. Also, based on the analysis of Available UCAP to meet LCR in section 5.1.3 the IPA remains concerned that planned coal plant retirements will continue to put pressure on the LCR Margin. Also, MISO’s rationale for the minimum capacity requirement (setting a 50% procurement cap for the PRA) as discussed in section 5.2.2.1, suggests that MISO may not have confidence that the PRA is adequate to meet all the capacity requirements for the LSEs. The proposed changes to the rules at MISO, ongoing changes to rules at FERC, and other potential legislative and regulatory changes represent significant uncertainty in the capacity market that could result in additional PRA price volatility. Based on the analysis in section 5.1.3, as the LCR Margin continues to tighten due to the pressure from retirements, it is conceivable, considering what took place in Zone 7, that a similar occurrence could take place in Zone 4 in the future. In light of this, the IPA’s procurement strategy will continue to balance anticipated low capacity clearing prices coupled with high price volatility in the MISO PRA with relatively higher capacity prices observed in the IPA’s capacity procurements. Accordingly, as outlined in Section 7.2, the IPA recommends a continuation of the capacity procurement strategy for Ameren Illinois eligible retail customer load for the 2023-2024 and 2024-2025 Delivery Years.

¹⁸² Refiling of MISO’s Resource Adequacy Construct, FERC Docket No. ER18-462-000, December 15, 2017, at 9.

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."¹⁸³

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.*¹⁸⁴

This Chapter discusses and assesses risk in the supply portfolio, as well as tools and strategies for mitigating the relevant risks. Developing a risk management strategy requires knowledge of the risk factors associated with energy procurement and delivery, and of the tools available to manage those risks. Section 6.1 describes the relevant risk factors. Sections 6.2 and 6.3 describe the tools for managing supply risk and the types of contracts and hedges that can be used to manage supply risk. Those products provide the basis for building the 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 must do so by selling previously purchased hedges. Section 6.5 provides a historical summary of the Ameren Illinois, ComEd, and MidAmerican Purchased Electricity Adjustment ("PEA") rates as a guide to the historical impact of risk factors.¹⁸⁵ This section also addresses the changes in MidAmerican pricing that reflect the costs of participating in the IPA procurements. Section 6.6 discusses the IPA's historical approach to risk and portfolio management. Finally, Section 6.7 addresses the role of demand response programs in risk management.

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

6.1 Risks

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

6.1.1 Volume Uncertainty and Price Risk

The accuracy of load forecasts directly impacts volume uncertainty. Accurate customer consumption profiles, load growth projections, and weather forecasts impact both the total energy requirement and the shape of the load curve. Chapter 3 describes the load forecasting processes utilized by Ameren Illinois, ComEd and

¹⁸³ 20 ILCS 3855/1-20(a)(1).

¹⁸⁴ 220 ILCS 5/16-111.5(b)(3)(vi).

¹⁸⁵ See 220 ILCS 5/16-111.5(l). This policy is manifest through riders filed by each utility – ComEd's Rider PE (Purchased Electricity), and Ameren Illinois' Rider PER (Purchased Electricity Recovery).

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. For Ameren Illinois and ComEd, the switched load percentage is expected to remain essentially flat over the 5-year forecasting horizon. MidAmerican's switched load is projected to grow slightly before leveling off but will remain a much smaller part of its total Illinois load (less than 5%).

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 a three-year approach. In a period of rising prices, those forward purchases are likely to be priced below market. Therefore, the blended price of utility supply may be less than the current price of an ARES offer, even an offer through municipal aggregation. This price difference can result in increased customer migration back to the utility. The reverse can occur as well; higher utility supply costs relative to alternatives through ARES suppliers or municipal aggregation can result in eligible retail customers migrating away from the utilities.

6.1.2 Residual Supply Risk

Hedging imperfection can contribute to supply risks through mismatches in procurement supply shape, supply delivery points and customer load locations. The standard on-peak and off-peak block energy products procured by the IPA do not reflect the variation in hourly loads. These products provide constant volume and prices across a fixed number of hours while hourly prices as well as load vary across the day and within each of the peak and off-peak periods. Because of this variation, even 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.

6.1.3 Basis Differential Risk

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

6.2 Tools for Managing Supply Risk

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

Following the enactment of the Electric Service Customer Choice and Rate Relief Law (Public Act 90-0561) in 1997, ComEd and Ameren Illinois divested their generating plants to unregulated affiliates or third parties. ComEd and Ameren Illinois have no contracts for unit-specific physical delivery, other than certain Qualifying Facilities (as designated under the federal Public Utilities Regulatory Policies Act) contracts. The utilities' supply positions, other than RTO spot energy purchases, are exclusively price hedges. MidAmerican has retained the resources that serve its Illinois customers; most of these resources are located outside of Illinois. MidAmerican allocates a portion of the capacity and energy from specified resources under its control for its Illinois eligible retail customers. Prior to the 2016 Plan procurements, the allocated capacity and energy from MidAmerican owned resources were sufficient to meet the needs of MidAmerican's Illinois eligible retail

customers. Current and planned retirements among these resources are reducing the capacity available for allocation to MidAmerican's Illinois customers. As a result, MidAmerican requested that the IPA procure the portion of energy and capacity that is not forecast to be met by the Illinois-allocated MidAmerican resources. Following the approach started for the 2016 Plan and continued under the 2017, 2018, 2019, 2020, and 2021 Plans, for the 2022 Plan, the IPA will procure the net energy requirements between MidAmerican's eligible retail customer load and the MidAmerican controlled generation allocated to its Illinois customers. The portion of MidAmerican's capacity requirements for eligible retail customers in Illinois not covered by MidAmerican's owned resources will be procured through the MISO PRA.

ComEd's capacity requirements will continue to be obtained through the PJM-Administered capacity market (absent any legislative changes). The Ameren Illinois capacity needs will be procured through a combination of IPA procurements for 50% of its needs in the near-term forward market with the remaining balance obtained through the MISO PRA.

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

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

6.3 Types of Supply Hedges

The 2014 Procurement Plan contained a detailed description of a number of different types of supply hedges, which are listed below. One point made in that Plan is that hedges available in the market are not perfect; the risks listed in Section 6.1 cannot all be hedged away except perhaps through a specially tailored "full requirements" hedge contract, whose price premium may not be acceptable in return for that degree of risk mitigation.¹⁸⁶

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

Unit-Specific Hedges

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

- As-available
- Baseload
- Dispatchable

¹⁸⁶ Even a full requirements hedge does not truly eliminate all risk. For example, if a supplier of a full requirements tranche were to default, additional procurement costs to make up the shortfall could be passed along to eligible retail customers.

Unit-Independent Hedges

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

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

6.3.1 Suitability of Supply Hedges

Not all of the types of hedges listed in Section 6.3 are suitable for use in this Procurement Plan, and not all may be readily available in electricity markets.¹⁸⁷ 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.¹⁸⁸ 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.¹⁸⁹ The level of bidding competitiveness can be gauged by the breadth of participation by bidders in the procurement.

Hedges most suitable for use by the Agency are those standardized products that are well-understood, and preferably widely-traded. If a product has liquid trading markets, or is similar to other products with liquid markets, a bidder can manage its risk exposure. The availability of information on current prices and the price history of similar products helps 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 energy hedges in 50 MW increments. The IPA began using 25 MW increments and a second, fall energy procurement with the 2014 Plan. The Agency’s recommended plans have been stated in terms of monthly contracts, although procurement events have met some of these needs with multi-month contracts.

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

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

¹⁸⁷ There had been substantial debate in the approval of certain past Procurement Plans related to whether a full requirements approach is a more suitable approach for eligible retail customers. In approving the 2015 Plan and rejecting the Illinois Competitive Energy Association’s full requirements procurement proposal as “not supported by the record,” the Commission stated that it “wishe[d] to make clear that it is not inclined to consider future years’ full requirements procurement proposals absent new arguments supported by an analysis quantifying benefits to eligible retail customers.” Docket No. 14-0588, Final Order dated December 17, 2014 at 114. Since that decision, the IPA is not 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 supply rates for Ameren Illinois, MidAmerican, and ComEd eligible retail customers.

¹⁸⁸ 220 ILCS 5/16-111.5(b), (e), (f).

¹⁸⁹ 220 ILCS 5/16-111.5(f).

markets for near term contracts, however. The Agency would need to obtain competitive pricing on such contracts if it were to incorporate them in its supply portfolio. However, it would be difficult or impossible to conduct the statutory RFP process for exchange-traded futures contracts: setting a price through an RFP process structured per legislative mandates is incompatible with price-setting in an open outcry auction, through electronic trading 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 for the commodity.

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

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

- A large part of the volume of options on the market is traded on exchanges. They have a particular advantage in that the trading exchange bears the counterparty default risk. However, the Agency's structured procurement process prevents the Agency from buying options on the exchanges.
- Option contracts can be relatively illiquid, making it more difficult to assure fair pricing. If options purchased through the IPA procurement process required an affirmative exercise decision, which most likely they would, the utilities would seek regulatory comfort on their exercise decision-making before agreeing to use options. For example, if an exercise decision were dependent on the utility's load forecast or view of municipal aggregation, the utility would want to be able to show it had acted prudently. If the utility exercised a put option, to sell the underlying hedge, it would want to be sure that decision did not make it a wholesale market participant for purposes of FERC Order 717. If the option exercise were 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 federal Dodd-Frank Act of 2010 (specifically Title VII).¹⁹⁰ Under the Dodd-Frank 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.

¹⁹⁰ Pub. Law 111-203, July 21, 2010 (modifying, *inter alia*, the Commodity Exchange Act at 7 U.S.C. § 2).

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 rebalancing in the event of significant shifts in load.”¹⁹¹ It is therefore appropriate to consider what tools are available to conduct such rebalancing, keeping in mind that the utilities, not the Agency, are the owners of the forward hedges and that selling of excess supply in the forward markets may have unintended cost and accounting consequences.

- To date, the only rebalancing of hedge portfolios prior to the delivery date has been the curtailment of long-term renewable contracts due to budget restrictions. Spending on these contracts was subject to a limit related to a statutorily-mandated rate impact cap calculated based on eligible retail customer load, making the budget available for payment under those contracts subject to fluctuation due to load migration away from (and back to) utility supply.¹⁹²
- Sales of excess supply by the utilities via a reverse RFP to rebalance their supply portfolio may create a de facto “wholesale marketing function” within the utilities. The employees involved in wholesale marketing activities would be subject to the separation of functions in accordance with FERC Order 717.¹⁹³
- To date, the utilities have scheduled excess supply in their portfolios, or made-up supply deficits in the RTOs’ day-ahead markets with residual balancing occurring in the RTOs’ real-time markets. This has been the dominant mode of portfolio rebalancing.
- As an alternative form of rebalancing, the Agency could conduct “reverse RFP” procurement events, in which the bids are to buy rather than sell forward hedges. The Agency does not believe that it has the authority to sell excess supply via its authority to “conduct competitive procurement processes” under 20 ILCS 3855/1-20(a)(2).
- The Agency could conceivably issue an RFP to purchase derivative products, such as put options on forward hedges, which would have a similar risk reduction effect to selling forwards. This may avoid legal and contractual difficulties associated with selling forward hedge contracts. This approach would also require the utilities to ensure they had regulatory approval to exercise the options after purchasing them, and the employees who exercise the option could become classified as part of a “marketing function.” The Agency does not envision entering into derivative contracts for rebalancing purposes.
- The Agency could conduct multiple procurement events in a year if the rebalancing required is to increase the supply under contract. Since 2014, the IPA has conducted two energy procurements each year, one in the spring and the other in the fall. Starting with the 2018 Procurement Plan, the IPA began conducting two capacity procurements to cover a portion of Ameren’s capacity requirements, one in the spring and one in the fall. Conducting multiple procurements each year provides for a more precise portfolio balance, which is the direct result of using more current load forecasts.

6.5 Purchased Electricity Adjustment Overview

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

¹⁹¹ 220 ILCS 5/16-111.5(b)(4).

¹⁹² As the state’s renewable portfolio standard has transitioned as to being funded through a charge assessed to all utility retail customers, and as the IPA Act expressly prioritizes “renewable energy credits under existing contractual obligations” in prioritizing limited funding, future curtailment of these agreements is no longer a meaningful risk. (See 20 ILCS 3855/1-75(c)(1)(E), (F)).

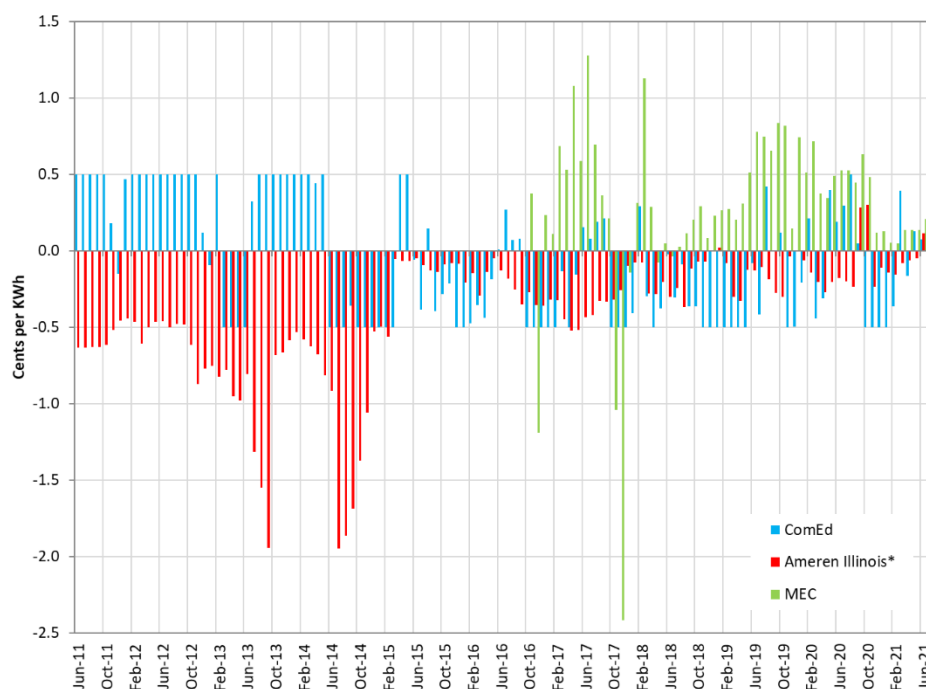
¹⁹³ 125 FERC ¶ 61,064, Oct. 16, 2008.

The PEA provides some guidance as to the amount by which the complete set of risk factors caused the cost of energy supply to differ from utility estimates. Figure 6-1 shows how the PEAs for Ameren Illinois and ComEd have changed over the last ten years. The figure also shows the applicable MidAmerican PEAs starting with October 2016. While Ameren Illinois' PEAs have been generally "negative" (i.e., operating as a credit to customers) over this period, ComEd's have been "negative" as well as "positive" (i.e., operating as charge to customers). ComEd has voluntarily limited its PEA to move between +0.5 cents/ kWh and -0.5 cents/kWh, and the figure shows that ComEd's PEA has oscillated between those limits. Although based on a relatively short period, the MidAmerican PEA has shown significantly more volatility, ranging from a negative 2.415 cents/kWh in November 2017 to a positive 1.277 cents/kWh in June 2017 and a positive 1.127 cents/kWh in February 2018. MidAmerican's PEA has been consistently positive since June 2018.

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 April and May of 2015 (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, June through September 2016, June through September 2017, in February 2018, in August 2019, in October 2019, February 2020, in May through September 2020, in March 2021, and in May through July 2021. The ComEd PEA reflected credits for most of the other months from October 2016 through July 2019, as well as September 2019, November 2019 through January 2020, March 2020, April 2020, October 2020 through February 2021, and April 2021.

In the early months of the historical period, notably July 2013 through September 2013 and July 2014 through November 2014, the magnitude of the Ameren Illinois negative PEAs increased significantly. The IPA understands that this change was largely the result of the long position in the supply portfolio of Ameren Illinois resulting from the increase in municipal aggregation switching, and that long position was subsequently settled favorably to customers within the MISO balancing markets. This drove an over-collection from eligible retail customers during the previous winters and the large negative PEA values represent the return of those proceeds to the remaining eligible retail customers. Since December 2014, the negative values of the Ameren Illinois PEAs have been much smaller as portfolio volumes have become better matched with actual load. Ameren Illinois' PEA values have been primarily negative through May 2021 ranging from -0.005 cents/ kWh to -0.561 cents /kWh with small positive values in December 2018 and January 2019. September 2020 and October 2020 had positive PEA values of 0.280 cents/kWh and 0.301 cents/kWh respectively, while the June 2021 PEA was a positive 0.115 cents/kWh and a positive 0.108 cents/kWh in July 2021.

Prior to April of 2018, MidAmerican had been including in the PEA factor the entire adjustment amount in a single month, creating significant volatility in the PEA factor. In April of 2018, MidAmerican began amortizing the monthly adjustment amount over multiple months when needed. MidAmerican is using a "soft cap" of +\$100,000 to determine if the monthly adjustment amount should be amortized. During the time that the amortization has been used in the calculation, MidAmerican has seen a reduction in volatility with the PEA mostly positive, ranging from a negative 0.076 cents/kWh in April 2018 to a positive 0.836 cents/kWh in September 2019. MidAmerican and the IPA will continue to monitor this situation over the next year to assess whether further adjustments to the forecast process are warranted.

Figure 6-1: Purchased Electricity Adjustments in Cents/kWh, June 2011 – July 2021

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

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

6.6.1 Historical 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 the immediately following June-October. These months would be close to the

procurement date and no benefit was seen in deferring 25% of the procurement to the spot market. On the other hand, because of the correlation between load and price and because prices in the hours of high usage are more than 100% of the time-weighted average price, a \$1/MWh movement in the monthly average price translates into an increase of more than \$1/MWh in the average portfolio cost (the load-weighted average price) – in fact, approximately \$1.06/MWh. The Agency continued to recommend hedging up to only 75% of the expected load for November-May of the prompt Delivery Year in the April procurement, but also recommended a second procurement in September to bring the hedged volume for those months to 100%.

In the 2015 Procurement Plan, the IPA adopted some minor changes from the 2014 Plan. The hedge ratios for the April procurement event were adjusted to 100% of the expected load for off-peak hours for June through October delivery in the prompt delivery year and for on-peak hours for June, September, and October delivery in the prompt delivery 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 37.5% for all months (June-May) of the following delivery year for the April procurement event, 50% for all months of the following delivery year for the September event, 12.5% for all months of the second delivery year out for the April event, and 25% for all months of the second delivery year out for the September 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 target cumulative hedge ratios for various delivery months, effective at the next to last scheduled event prior to delivery.

For the 2017, 2018, 2019, 2020, and 2021 Procurement Plans, the IPA continued the use of two procurement events for standard energy blocks, which were held in the spring with a subsequent event scheduled for each fall.

Under the 2022 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 2021 Plan.

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

To address the risks associated with volatility in forward energy prices, the IPA has periodically reviewed its approach to hedging and investigated the merits of alternative procurement strategies. The primary goal of these reviews has been to evaluate the potential for further minimizing the volatility and cost of the portfolios of supply contracts procured for each delivery month. An objective of the procurement strategy is to maximize stability of the resulting rates for service to eligible retail customers, while minimizing cost.

The cost to ratepayers for qualified service in a given month is driven by the average price paid for energy procured under an IPA 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 level of forward prices on the days in which components of the portfolio are procured.

The IPA conducted an analysis in the 2020 Plan related to procurement scheduling and volatility. This analysis addressed the degree to which varying the number of scheduled annual procurement events and moving procurements closer to their delivery months might affect volatility risk for individual delivery months in the portfolio. Moving the procurements is designed to reduce the time interval between the Agency's procurement event and the initial delivery month, which in conjunction with using multiple annual procurement events, can result in an improved mix of portfolio hedging and volatility.

The results of the analysis for the 2021 Plan indicate that the closer the procurement events are held to the product delivery date, the greater the price volatility on the products procured. Also, a review of monthly forward market volatilities does not support a preference for any periods of the year as ideal or to be avoided for conducting procurement events. However, to avoid excessive uncertainty in procurement costs, the shape of the volatility-to-term curves indicate that procurements should be made several months in advance of the contract delivery dates to avoid higher price volatility. Other factors also impact the scheduling of procurement events relative to delivery timing and may result in reasonable decisions to hold procurement events close to product delivery dates. The IPA's current hedging approach using a forward hedging strategy involving procurements over parts of three delivery years with two annual energy procurement events provides a means for reasonably mitigating price and volume risks associated with the procurement of energy supply blocks. The purchases of quantities up to three years prior to delivery, produces the lowest volatility of portfolio price.

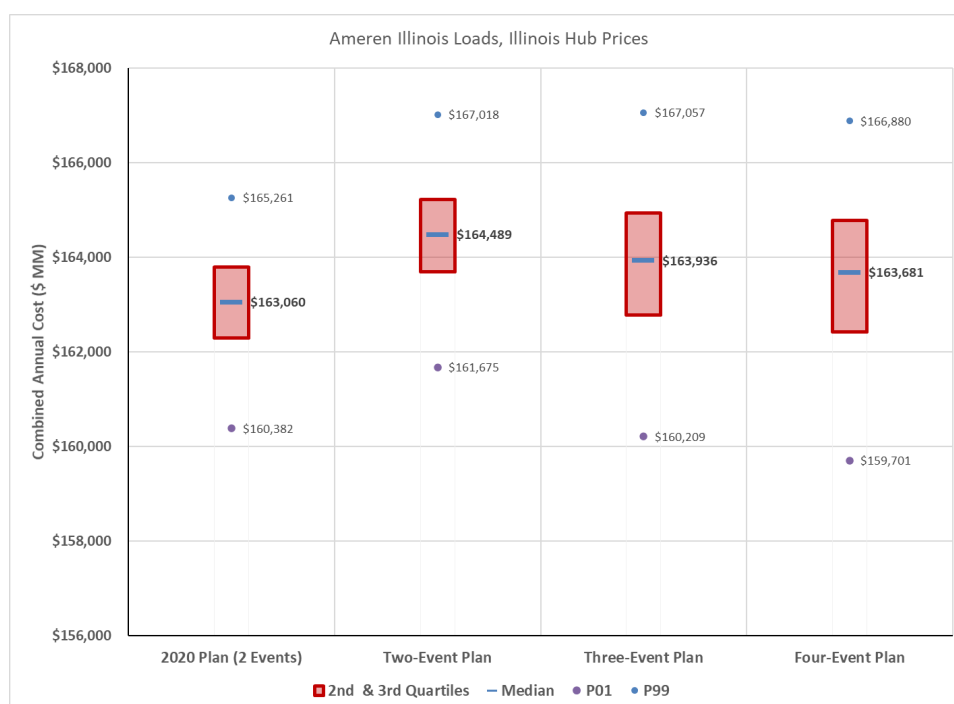
As indicated above, the stability of the average prices paid for blocks of on-peak and off-peak energy is a function of the long-term trends (both predictable and random) in forward prices over the procurement period and the more random level of forward prices on the days in which components of the portfolio are procured. The IPA performed a "backcast" analysis to study the portfolio cost volatility effects of different procurement schedules. For this study, the IPA analyzed the on-peak energy component of the monthly portfolios for the one-year period of September 2019 through August 2020, using the PJM Northern Illinois Hub monthly forward contract price data and comparable prices for the MISO Illinois Hub.

Four alternative procurement schedules were considered.¹⁹⁴ The first schedule represents a backcast of the 2020 procurement plan schedule with procurements in April and September from 2017 through 2019 and in April of 2020. The second schedule considered also has two annual procurement events, occurring in March or April and in September or October. The cumulative procurement targets are adjusted somewhat so that 25% of the requirement for each delivery month would be procured in each of four events over 18 months. The third procurement schedule considered incorporates a third annual event in May or June, in addition to the Spring and Fall procurement events and allocates the targeted procurements for each delivery month evenly over five events and roughly 14 to 18 months. The fourth procurement schedule considered includes an additional procurement event in November or December. Targets are set so that the portfolio for each delivery month is acquired in five equal parts over 13 months.

For the purpose of demonstrating how timing of procurement events and allocating purchases among events might have affected the level and volatility of ratepayer costs for a 12-month delivery period, each of the four procurement schedules described above was modeled using Monte Carlo simulation, which was conducted with 10,000 iterations. The total on-peak and off-peak energy requirements for monthly delivery in the simulation period were derived for each utility from the 2020 Plan. In each iteration, the weighted average portfolio cost (\$/MWh) of procuring on-peak and off-peak forward energy to hedge load for a delivery month was calculated under each of the four procurement schedules. This produced a probability distribution for the weighted-average portfolio cost, from which summary statistics such as mean, median, standard deviation, and quartiles were determined.

The distributions for the September 2019 through August 2020 delivery months for the four hypothesized procurement schedules were developed for Commonwealth Edison (Figure 6-2 below) and Ameren Illinois (Figure 6-3 below). For these months, the 2020 Plan appears to offer relatively low volatility, as measured by the range of the two middle quartiles and the spread between the 1% and 99% confidence values. The Four-Event Plan appears to have the highest volatility for each month.

¹⁹⁴ These four procurement schedules were selected for analysis to provide a comparison with the procurement schedule in the 2020 Plan by adjusting the percent of the procurement target distributed over a schedule with 2 annual procurement events, adding a summer procurement event to test the implications of 3 annual procurements, and adding a winter procurement to test a schedule with 4 annual procurement events. While other procurement schedules could have been analyzed, the schedules tested in this analysis reflect the most likely alternatives to the current procurement schedule.

Figure 6-2: Commonwealth Edison Total Annual Cost Distributions**Figure 6-3: Ameren Illinois Total Annual Cost Distributions**

In order not to have particular recent trends or events drive the conclusions, a statistical analysis focused on a model-based decomposition of the sources of seasonal and stochastic fluctuations was also conducted. This second approach grounded in financial economic theory and quantitative methods, was used to assess key aspects of electric energy forward prices that are important considerations for price hedging. MISO Illinois hub and PJM Northern Illinois hub peak and off-peak forwards prices were analyzed with a general model for use

with forwards that have seasonally-varying prices.¹⁹⁵ This modeling approach has three basic steps for characterizing price volatility of a particular forward product. The data sample analyzed spans monthly forwards from September 2015 through August 2020 and trade dates from August 3, 2015 through August 31, 2018.

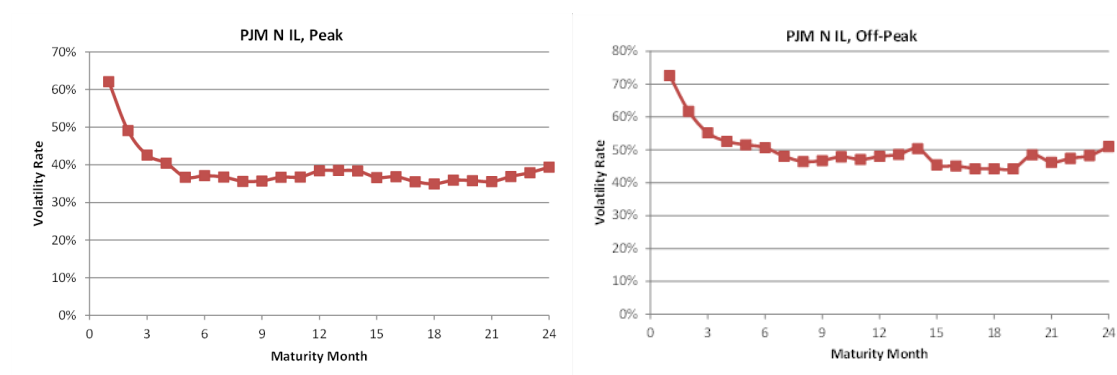
First, for each trading date, the deseasonalized average of prices for the forward curve over 24 months is calculated for each trade date, starting with the prompt month. (Using data for 24 months ensures that the impact of seasonality is removed.) The daily fluctuations in 24-month average prices reflect market conditions apart from the predictable expected seasonal component of forward prices. In the model, logarithms of prices are used because commodity prices have uncertainty distributions that resemble the lognormal distribution more than the normal distribution. The deseasonalized log price series is modeled as a stochastic, or uncertain, variable that represents the historical trajectory of 24-month average forward prices over time.

Second, the seasonal premia by calendar month, expressed as percent of the deseasonalized prices, were calculated as the average difference between the daily prices for a product that expires (or physically delivers) in the specific calendar month and the daily deseasonalized prices.

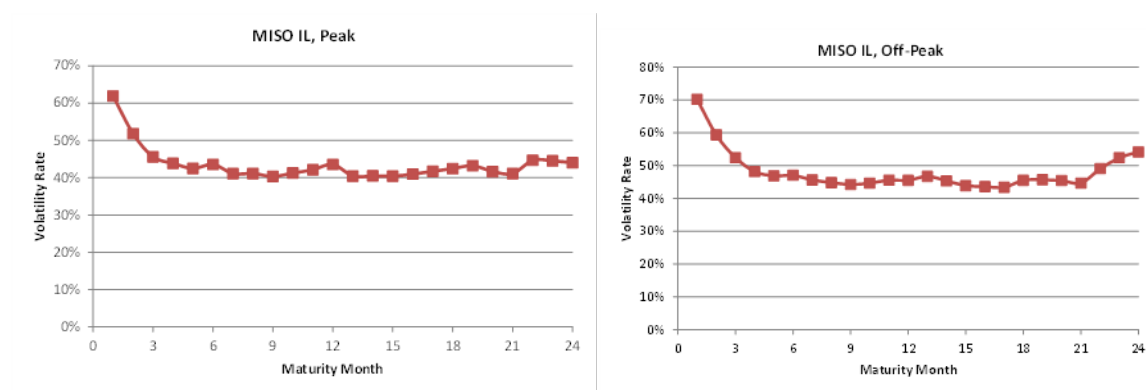
The third and final factor in the decomposition of forward prices is what is known as the “convenience yield.” The convenience yield is the residual of the forward price minus the deseasonalized forward price and the seasonal premium. The convenience yield is modeled as a second stochastic factor, which varies by time to maturity, accounting for the dynamics of supply-demand imbalances. The convenience yield volatility curves have smooth and rapidly decaying convenience yield volatility rates at more distant maturities. This shape is expected because more information about impending spot market conditions becomes known in the final months and days before the forward product’s delivery period begins than is known many months in advance of delivery. The convenience yield volatilities of the off-peak product are slightly higher than the on-peak product at each hub, with the difference most pronounced in the prompt month.

Combining the deseasonalized forward price volatility factor and the convenience yield factor produces a term structure of average volatility. The curves for the PJM Northern Illinois and MISO Illinois hubs decline for the first several months due to the relatively high convenience yield, and then stay roughly constant, consistent with the assumption that forward prices do not exhibit mean-reversion, which would be indicated by continued decline in volatility at more distant maturities. For all of the deseasonalized forward volatility curves, the volatility rate becomes roughly constant after month five to eight. Figure 6-4, and Figure 6-5 depict the calculated term structure of average volatility applicable to ComEd and Ameren Illinois wholesale markets.

Figure 6-4: PJM Northern Illinois, Volatility Term Structure



¹⁹⁵ S. Borovkova and H. Geman, “Seasonal and stochastic effects in commodity forward curves,” *Review of Derivatives Research* (2006) pp. 167-186.

Figure 6-5: MISO Illinois, Volatility Term Structure

The fairly stable volatility of average forward 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.

In conclusion, based on the analysis conducted for the 2021 Plan and the Agency's recent procurement experience, the IPA proposes to continue the energy procurement schedule and hedging approach that was initiated with the 2015 Plan, which has been utilized for intervening Plans, for the Agency's 2022 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. To participate fully as a source of supply, the demand response resource must, either by itself or, if seasonal, by being coupled with another eligible seasonal resource, be able to meet the annual availability requirements imposed on resources by PJM's adoption of Capacity Performance requirements.

In the case of Ameren Illinois and MidAmerican, MISO provides the ability for demand response measures to reduce supply risk. On March 14, 2014, FERC approved MISO's modification to its Module E-1 tariff to treat demand response and energy efficiency resources in a manner similar to other capacity providing resources for operational planning purposes. MISO distinguishes between capacity resources that clear the capacity auction and load modifying resources ("LMR") that have no capacity supply obligation. LMR have different obligations than capacity resources but do count toward planning resources. By qualifying as an LMR, the demand resource is able to help meet resource adequacy requirements obligations and receives compensation for providing planning resource capability. Also, by qualifying as an LMR, the demand resource is obligated to curtail during emergencies and may be penalized for failure to do so.¹⁹⁶ On February 2, 2017, FERC approved proposed changes to MISO's tariff to establish measurement and verification criteria for the LMR for the purpose of determining whether these resources are meeting their performance obligations.¹⁹⁷ On February 19, 2019, FERC approved revisions to MISO's tariff which allow MISO to more effectively access the capabilities

¹⁹⁶ A service that can include LMRs in MISO is Emergency Demand Response (EDR). EDR resources are required to respond during an emergency. EDR resources may qualify as LMR but are not required to do so. The EDR has flexibility with respect to offering emergency energy but is not counted as capacity towards resource adequacy requirements.

¹⁹⁷ See Midcontinent Independent System Operator, Inc., 158 FERC ¶ 61,119 (2017).

of LMRs by requiring an LMR to offer its capability based on availability in all seasons and be deployed based on the shortest notification requirement that it can meet.¹⁹⁸ These rules will improve transparency around LMR capability by providing firmer and more clearly documented commitments regarding availability prior to participating in MISO's capacity market.

FERC Order No. 745 requires Independent System Operators and RTOs to compensate demand response resources participating in wholesale markets at the market price. In January 2016, the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals ruling and upheld FERC's jurisdiction over demand response competing in wholesale markets, holding that the Federal Power Act provides FERC with the authority to regulate wholesale market operators' compensation of demand response bids and affirming the validity of the methodology used by FERC to provide compensation.¹⁹⁹ Chapter 7 of this Plan provides details and additional discussion regarding demand response resources.

¹⁹⁸ See *Midcontinent Independent System Operator, Inc.*, 166 FERC ¶ 61,116 (2019).

¹⁹⁹ See *FERC v. Electric Power Supply Ass'n*, 2016 WL 280888, 136 S. Ct. 760 (2016).

7 Resource Choices

This Chapter of the Procurement Plan sets out recommendations for the resources to be procured for the forecast horizon covered by this Plan. These include: (1) energy; (2) capacity; (3) transmission and ancillary services; (4) demand response; and (5) clean coal.

7.1 Energy

7.1.1 Energy Procurement Strategy

The IPA recommends maintaining the energy procurement strategy utilized for the 2021 Procurement Plan as explained below.

The IPA's proposed energy hedging strategy for the 2022 Procurement Plan is entirely consistent with the strategy used for the 2021 Plan:

- Procure hedges consisting of standard 25 MW energy blocks.
- Hedges will be calculated on the expected monthly average peak and off-peak load.
- Conduct two procurement events in 2022, one in the Spring and one in the Fall.

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

- For the period of June through September of the prompt Delivery Year (2022-2023), the target cumulative hedges should be approximately 100% of each monthly average peak and off-peak load, except for July and August peak, which should be 106%. For the period of October through May of the prompt Delivery Year, the target cumulative hedges in the portfolio should be approximately 75% of each monthly peak and off peak average load.
- For the second Delivery Year (2023-2024) the target cumulative hedges in the portfolio should be approximately 37.5% of each monthly peak and off peak average load.
- For the third Delivery Year (2024-2025) the target cumulative hedges in the portfolio should be approximately 12.5% of each monthly peak and off-peak average load.

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

- For the prompt Delivery Year (2022-2023) the target cumulative hedges in the portfolio should be approximately 100% of the average monthly peak and off-peak load, except for July and August peak, which should have been hedged at 106% in the Spring procurement.
- For the second Delivery Year (2023-2024) the target cumulative hedges in the portfolio should be approximately 50% of the average monthly peak and off-peak load.
- For the third Delivery Year (2024-2025) the target cumulative hedges in the portfolio should be approximately 25% of the average monthly peak and off-peak load.

The strategy is summarized in Table 7-1.

Table 7-1: Summary of Energy Procurement Strategy for all Utilities²⁰⁰

Spring 2022 Procurement			Fall 2022 Procurement		
June 2022-May 2023 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	October 2022-May 2023	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%

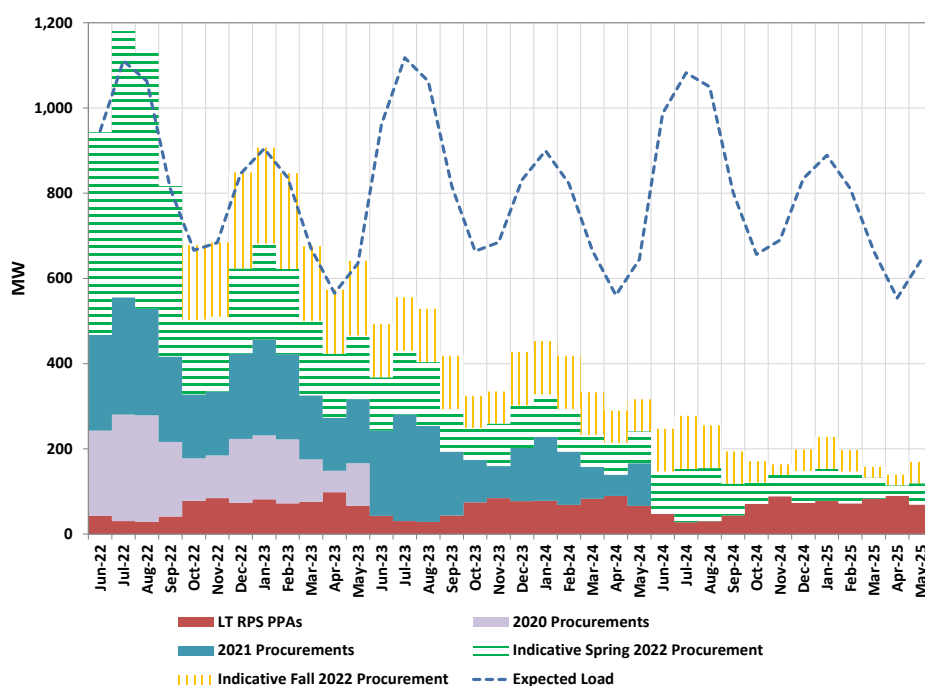
²⁰⁰ Table shows the cumulative percentage of load targeted to be hedged by the conclusion of the indicated procurement events.

7.1.2 Energy Procurement Implementation

The following tables and figures were constructed using each utility's July 2021 base load forecasts to provide indicative procurement values for the 2022-2023 Delivery Year.²⁰¹ The actual target procurement volumes used for the Spring and Fall 2022 procurements will be calculated using the March 2022 and the July 2022 updated load forecasts respectively. The IPA recommends that each utility submit forecast updates that reflect the most accurate and up-to-date information and modeling available at the time. In updating the load forecasts, the utilities may incorporate refinements to their forecasts including but not limited to changes to variables' values (such as switching) and reasonable enhancements to econometric models, provided that any such refinements are properly disclosed and subject to the review and consensus of the IPA, ICC Staff, the Procurement Monitor, and the applicable utility.

While the utilities provided five years of load forecasts, given the absence of visible and liquid block energy markets four and five years out, it is not recommended that any block energy purchases be made to secure supply for those years (Delivery Years 2025-2026 and 2026-2027) in this Procurement Plan. Therefore, the tables and figures that follow only cover Delivery Years 2022-2023, 2023-2024, and 2024-2025.

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



²⁰¹ The anticipated procurement volumes are rounded up or down to the nearest 25 MW block. For additional information on expected load and supply already under contract, see Appendices E (Ameren Illinois), F (ComEd), and G (MidAmerican).

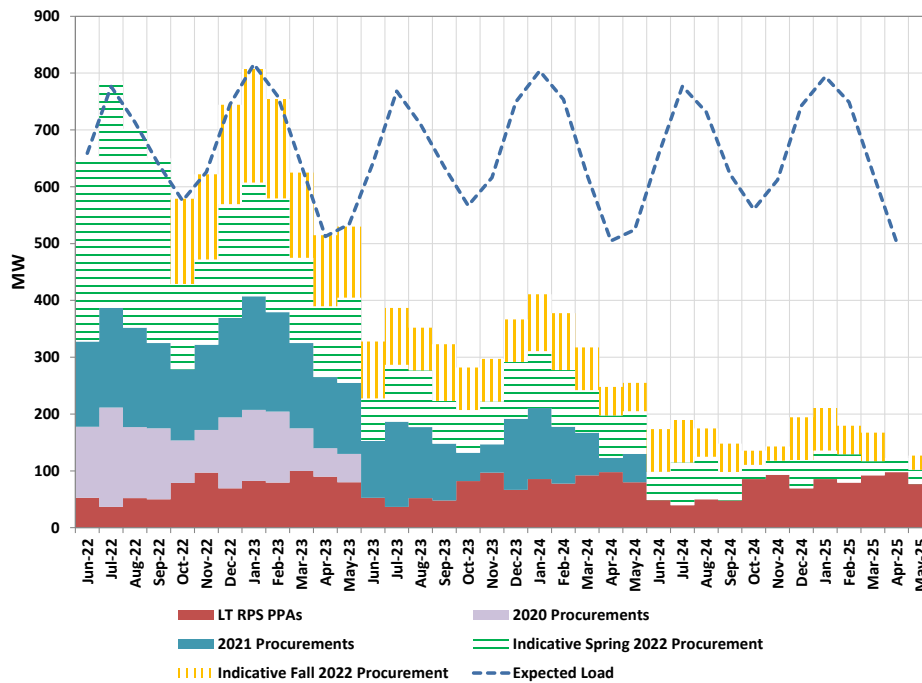
Figure 7-2: Ameren Illinois Off-Peak Energy Supply Portfolio and Load

Table 7-2: Ameren Illinois 2022 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2022 Purchases (MW)		Anticipated Fall 2022 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2022-2023				
Jun-22	475	325	0	0
Jul-22	625	400	0	0
Aug-22	600	350	0	0
Sep-22	400	325	0	0
Oct-22	175	150	175	150
Nov-22	175	150	175	150
Dec-22	200	200	225	175
Jan-23	225	200	225	200
Feb-23	200	200	225	175
Mar-23	175	150	175	150
Apr-23	150	125	150	125
May-23	150	150	175	125
Delivery Year 2023-2024				
Jun-23	125	75	125	100
Jul-23	150	100	125	100
Aug-23	150	100	125	75
Sep-23	100	75	125	100
Oct-23	75	75	75	75
Nov-23	100	75	75	75
Dec-23	100	100	125	75
Jan-24	100	100	125	100
Feb-24	100	100	125	100
Mar-24	75	75	100	75
Apr-24	75	75	75	50
May-24	75	75	75	50
Delivery Year 2024-2025				
Jun-24	100	50	100	75
Jul-24	125	75	125	75
Aug-24	125	75	100	50
Sep-24	75	50	75	50
Oct-24	50	25	50	25
Nov-24	50	25	25	25
Dec-24	75	50	50	75
Jan-25	75	50	75	75
Feb-25	75	50	50	50
Mar-25	50	25	25	50
Apr-25	25	25	25	0
May-25	50	25	50	25

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

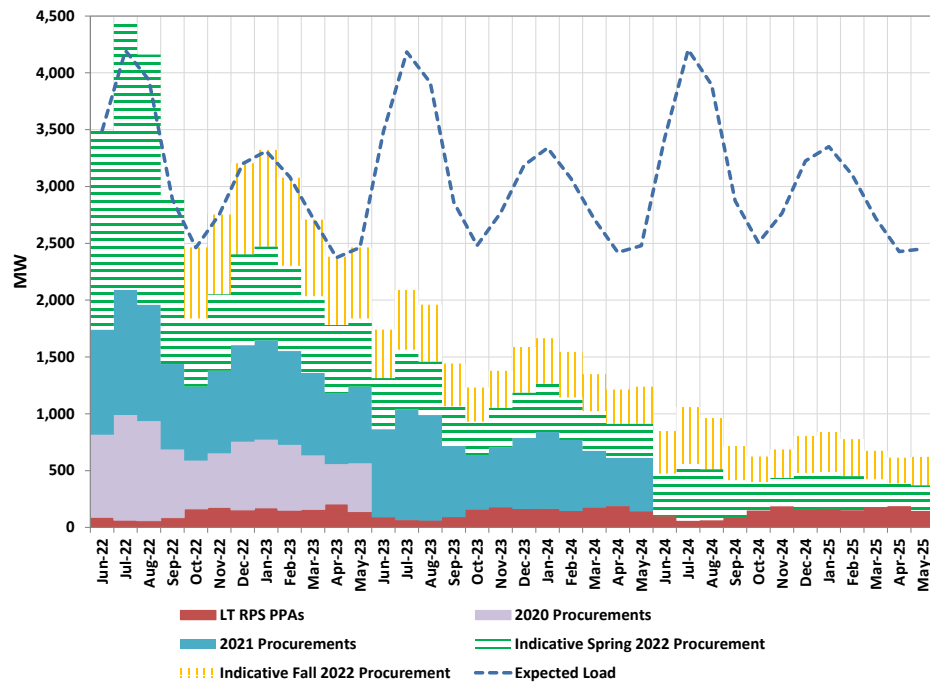


Figure 7-4: ComEd Off-Peak Energy Supply Portfolio and Load

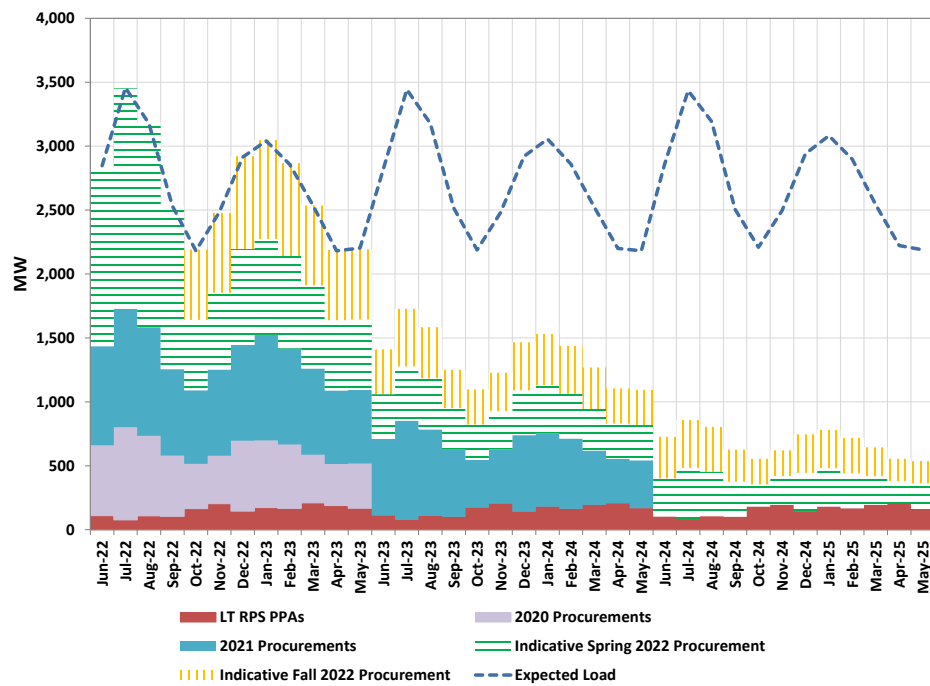
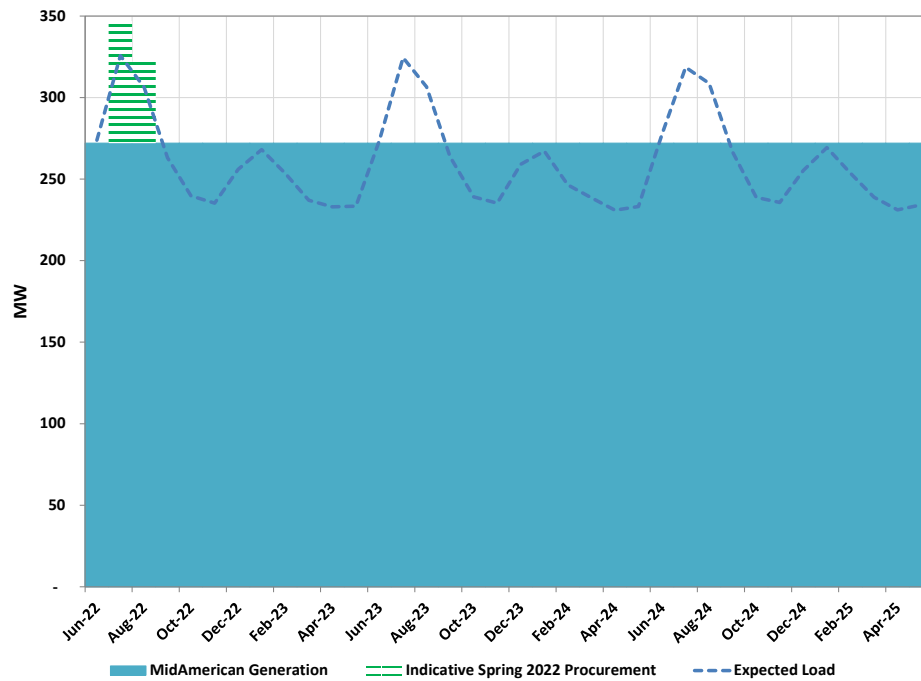
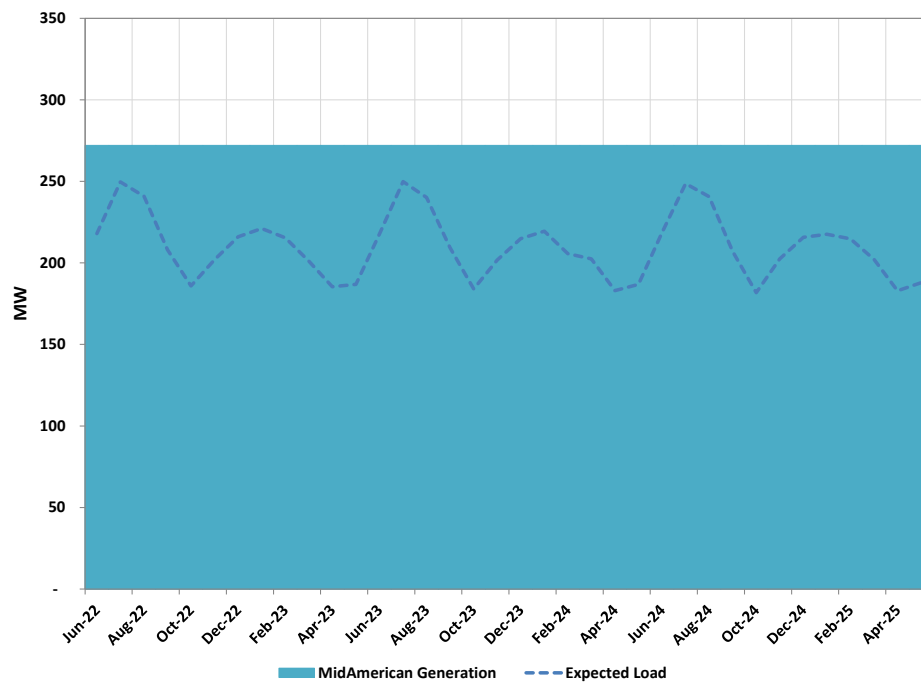


Table 7-3: ComEd 2022 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2022 Purchases (MW)		Anticipated Fall 2022 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2022-2023				
Jun-22	1,750	1,400	0	0
Jul-22	2,350	1,725	0	0
Aug-22	2,200	1,600	0	0
Sep-22	1,450	1,275	0	0
Oct-22	600	550	625	550
Nov-22	675	600	700	625
Dec-22	800	750	800	725
Jan-23	825	750	850	775
Feb-23	750	725	775	725
Mar-23	675	650	675	625
Apr-23	600	550	600	550
May-23	600	550	625	550
Delivery Year 2023-2024				
Jun-23	450	350	425	350
Jul-23	525	425	525	450
Aug-23	475	400	500	400
Sep-23	350	325	375	300
Oct-23	300	275	300	275
Nov-23	350	300	325	300
Dec-23	400	350	400	375
Jan-24	425	375	400	400
Feb-24	375	350	400	375
Mar-24	350	325	325	325
Apr-24	300	275	300	275
May-24	300	275	325	275
Delivery Year 2024-2025				
Jun-24	375	300	375	325
Jul-24	500	400	500	375
Aug-24	450	350	450	350
Sep-24	325	275	300	250
Oct-24	250	175	225	200
Nov-24	250	225	250	200
Dec-24	325	300	325	300
Jan-25	325	300	350	300
Feb-25	300	275	325	275
Mar-25	250	225	250	225
Apr-25	200	175	225	175
May-25	225	200	250	175

Figure 7-5: MidAmerican Peak Energy Supply Portfolio and Load²⁰²**Figure 7-6: MidAmerican Off-Peak Energy Supply Portfolio and Load**

²⁰² While it may appear that the volume of hedges to be procured for MidAmerican is relatively small, it is important to recognize that the incremental cost of acquiring these hedges is also relatively small and that the hedges cover a period of significant price volatility in the electric power markets - peak summer.

Table 7-4: MidAmerican 2022 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2022 Purchases (MW)		Anticipated Fall 2022 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2022-2023				
Jun-22	0	0	0	0
Jul-22	75	0	0	0
Aug-22	50	0	0	0
Sep-22	0	0	0	0
Oct-22	0	0	0	0
Nov-22	0	0	0	0
Dec-22	0	0	0	0
Jan-23	0	0	0	0
Feb-23	0	0	0	0
Mar-23	0	0	0	0
Apr-23	0	0	0	0
May-23	0	0	0	0
Delivery Year 2023-2024				
Jun-23	0	0	0	0
Jul-23	0	0	0	0
Aug-23	0	0	0	0
Sep-23	0	0	0	0
Oct-23	0	0	0	0
Nov-23	0	0	0	0
Dec-23	0	0	0	0
Jan-24	0	0	0	0
Feb-24	0	0	0	0
Mar-24	0	0	0	0
Apr-24	0	0	0	0
May-24	0	0	0	0
Delivery Year 2024-2025				
Jun-24	0	0	0	0
Jul-24	0	0	0	0
Aug-24	0	0	0	0
Sep-24	0	0	0	0
Oct-24	0	0	0	0
Nov-24	0	0	0	0
Dec-24	0	0	0	0
Jan-25	0	0	0	0
Feb-25	0	0	0	0
Mar-25	0	0	0	0
Apr-25	0	0	0	0
May-25	0	0	0	0

7.2 Capacity

7.2.1 Capacity Procurement Strategy

7.2.1.1 ComEd

Prior procurement plans, including the 2021 Procurement Plan, have recommended that ComEd obtain its capacity needs through the PJM-administered capacity market. For the 2022 Plan, the IPA recommends that ComEd continue to obtain its capacity needs from the PJM-administered capacity market. Table 7-7 summarizes the proposed capacity procurement for ComEd.

7.2.1.2 Ameren Illinois

For Ameren Illinois, the 2021 Procurement Plan recommended a procurement of a portion of the Ameren Illinois capacity needs for the 2021-2022, 2022-2023, and 2023-2024 Delivery Years through bilateral capacity purchases obtained through the IPA competitive procurement process, with the remainder of its capacity needs procured through the MISO PRA. The IPA recommends a continuation of this capacity procurement strategy, which is to target the procurement of 50% of the capacity requirements in the near-term forward markets through IPA administered RFPs in a laddered fashion, and the remaining balance through the MISO PRA.

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

- Conduct two procurement events in 2022, one in the Spring and one in the Fall.
- For the 2022-2023 Delivery Year, no change to what was approved in the 2021 Procurement Plan. That is, to procure up to 50% of the forecasted capacity requirements through an RFP administered by the IPA in Fall, 2021, and procure the remaining balance through the MISO PRA scheduled for April of 2022. No additional procurements of capacity for the 2022-2023 Delivery Year will be needed.
- For the 2023-2024 Delivery Year, up to 25% of the forecasted capacity requirements will be procured through an RFP administered by the IPA in Fall, 2021, as outlined in the 2021 Procurement Plan.
- For the 2023-2024 and 2024-2025 Delivery Years, the IPA proposes to procure capacity requirements through its two 2022 capacity procurement events, resulting in hedging at the following levels:
 - At the conclusion of the Spring 2022 procurement event, the target cumulative capacity hedges in Ameren Illinois portfolio of Zonal Resource Credits (“ZRCs”) should be as follows:
 - For the 2023-2024 Delivery Year, the target cumulative hedges should be no more than 37.5% of the capacity requirements.
 - For the 2024-2025 Delivery Year, the target cumulative hedges should be no more than 12.5% of the capacity requirements.
 - At the conclusion of the Fall 2022 procurement event, the target cumulative capacity hedges in Ameren Illinois portfolio of Zonal Resource Credits (“ZRCs”) should be as follows:
 - For the 2023-2024 Delivery Year, the target cumulative hedges should be no more than 50% of the capacity requirements.
 - For the 2024-2025 Delivery Year, the target cumulative hedges should be no more than 25% of the capacity requirements.
- Procure the remaining balance of the 2023-2024 Delivery Year capacity requirements through the MISO PRA scheduled for April of 2023. No additional procurements of capacity for the 2023-2024 Delivery Year will be needed.
- Procure the remaining balance of the 2024-2025 Delivery Year capacity requirements in the MISO PRA and/or additional procurement events to be determined in the 2023 Procurement Plan.

While Ameren Illinois provided a five-year capacity requirement forecast, given the absence of visible and liquid capacity markets in MISO, it is not recommended that any capacity hedges be procured for years beyond the 2024-2025 Delivery Year in this Procurement Plan.

7.2.1.3 MidAmerican

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

Table 7-5: Summary of MidAmerican Load and Capability

	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
Coincident Peak Load	425	425	425	426	426
Reserves	40	40	40	40	40
Coincident Peak Load with Reserves	465	465	465	466	466
Total Net Capability	385	385	385	385	385
Deficit to Be Procured in MISO PRA	80	80	80	81	81

7.2.2 Capacity Procurement Implementation

7.2.2.1 Ameren Illinois

For Ameren Illinois, the IPA concludes that it does not need to include any extraordinary measures in the 2022 Procurement Plan to assure reliability over the planning horizon. For the 2022-2023 Delivery Year, the IPA recommends no changes from the previously approved strategy. For the 2023-2024 and 2024-2025 Delivery Years, the IPA recommends a continuation of the strategy of procuring Ameren Illinois capacity requirements through IPA-administered RFPs and through the MISO PRA, as shown below in Table 7-6.

The figures in this table were constructed using Ameren Illinois July 2021 base load forecasts to provide indicative procurement values for the 2023-2024 and 2024-2025 Delivery Years. The target Zonal Resource Credits (“ZRCs”) procurement volumes to be used for the Spring and Fall 2022 procurements will be calculated using the March 2022 and the July 2022 updated load forecasts respectively. For the 2024-2025 Delivery Year, any additional procurements to be conducted in 2023 will be determined in the 2023 Procurement Plan. Consistent with the recommendation in Section 7.1.2, the IPA recommends that Ameren Illinois submit forecast updates inclusive of capacity requirements that reflect the most accurate and up-to-date information and modeling available at the time.

Table 7-6: Summary of Capacity Procurement for Ameren Illinois²⁰³

Delivery Year	Requirement	Spring 2020 RFP	Fall 2020 RFP	Spring 2021 RFP	Fall 2021 RFP	April 2022 PRA	Additional Procurements
June 2022 - May 2023	1,722 ZRCs	203 ZRCs Procured	252 ZRCs Procured	Quantity not disclosed ²⁰⁴	356 ZRCs Targeted for Procurement	Balance of Requirements, 861 ZRCs estimated	0 ZRCs
Delivery Year	Requirement	Spring 2021 RFP	Fall 2021 RFP	Spring 2022 RFP	Fall 2022 RFP	April 2023 PRA	Additional Procurements
June 2023 - May 2024	1,715 ZRCs	Quantity not disclosed	409 ZRCs Targeted for Procurement	214 ZRCs Targeted for Procurement	214 ZRCs Targeted for Procurement	Balance of Requirements, 857 ZRCs estimated	0 ZRCs
June 2024 - May 2025	1,709 ZRCs	0 ZRCs	0 ZRCs	214 ZRCs Targeted for Procurement	214 ZRCs Targeted for Procurement	Not Available	To be determined in 2023 Plan

7.2.2.2 ComEd

For ComEd, the IPA concludes that it does not need to include any extraordinary measures in the 2022 Procurement Plan to assure reliability over the planning horizon. The IPA, as indicated below, recommends that ComEd continue to meet all of its capacity obligations through the PJM-administered capacity market in which capacity is purchased in a three-year ahead forward market through mandatory capacity rules.

Table 7-7: Summary of Capacity Procurement for ComEd

June 2022-May 2023 (Upcoming Delivery Year)	June 2023-May 2024	June 2024-May 2025	June 2025-May 2026
100% PJM RPM Auctions*	100% PJM RPM Auctions*	100% PJM RPM Auctions***	100% PJM RPM Auctions****

* PJM RPM Base Residual Auction for 2022-2023 has already cleared.

**The 2023-2024 auction has been delayed to December 1, 2021.

*** The 2024-2025 auction has been delayed to June 15, 2022.

*** The 2025-2026 auction has been delayed to January 4, 2023.

7.2.2.3 MidAmerican

For MidAmerican, the IPA concludes that it does not need to include any extraordinary measures in the 2022 Procurement Plan to assure reliability over the planning horizon. The IPA recommends that MidAmerican continue to procure 100% of its capacity deficit for the 2022-2023, 2023-2024, and 2024-2025 Delivery Years through the MISO PRAs as indicated below.

²⁰³ Procurements results for the scheduled Fall 2021 procurement events and April 2022 PRA volume are estimates.

²⁰⁴ In accordance with previous Commission orders, quantity information not released when the number of successful bidders is fewer than three.

Table 7-8: Summary of Capacity Procurement for MidAmerican

June 2022-May 2023 (Upcoming Delivery Year)	June 2023-May 2024	June 2024-May 2025
100% of capacity deficit through MISO PRA*	100% of capacity deficit through MISO PRA**	100% of capacity deficit through MISO PRA***

* MISO Auction for 2021-2022 is expected to clear in April 2022.

** MISO Auction for 2022-2023 is expected to clear in April 2023.

***MISO Auction for 2023-2024 is expected to clear in April 2024.

7.3 Transmission and Ancillary Services

Ameren Illinois, MidAmerican, and ComEd purchase their transmission and ancillary services (which included energy balancing) from their respective RTOs, Ameren Illinois and MidAmerican from MISO and ComEd from PJM. The utilities also manage their Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR) processes in their respective RTOs, consistent with ICC orders in prior Plans. The IPA is not aware of any justification or reason to alter these practices and therefore recommends they remain unchanged.

7.4 Demand Response Products

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

*Electric utilities shall implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Section 16-111.5 of this Act, and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive. This requirement commences June 1, 2008 and continues for 10 years.*²⁰⁵

Section 8-103B(g)(4.5) of the PUA contains a similar requirement, requiring that Ameren Illinois and ComEd, “in submitting proposed plans and funding levels” to meet the state’s new energy efficiency portfolio standard targets adopted through Public Act 99-0906, “implement cost-effective demand-response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Section 16-111.5 of this Act, and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive.”²⁰⁶ This updated requirement now “continues until December 31, 2026.”²⁰⁷

ComEd provided information²⁰⁸ regarding its existing demand response programs for 2021-2022 which include:

- Direct Load Control (“DLC”): ComEd’s residential central air conditioning cycling program is a DLC program with 67,000 customers with a load reduction potential of 67 MW.
- Voluntary Load Reduction (“VLR”) Program: VLR is an energy-based demand response program, providing compensation based on the value of energy as determined by the real-time hourly market run by PJM. This program also provides for transmission and distribution (“T&D”) compensation based on the local conditions of the T&D network. This portion of the portfolio has 856 MW of potential load reduction.
- Hourly Pricing (formerly known as Residential Real-Time Pricing (RRTP) Program): All of ComEd’s residential customers have an option to elect an hourly, wholesale market-based rate. The program uses ComEd’s Rate BESH to determine the monthly electricity bills for each RRTP participant. This program has 37,500 customers and a load reduction potential of 15 MW.

²⁰⁵ 220 ILCS 5/8-103(c).

²⁰⁶ 220 ILCS 5/8-103B(g)(4.5).

²⁰⁷ Id.

²⁰⁸ See Appendix C.

- **Peak Time Savings (PTS) Program:** This program is required by Section 16-108.6(g) of the PUA and was approved by the ICC in Docket No. 12-0484. The PTS program is an opt-in, market-based demand response program for customers with smart meters. Under the program, customers receive bill credits for kWh usage reduction during curtailment periods. The program commenced in 2015 with 56,000 customers and has grown to more than 312,000 customers in 2021. ComEd sold 80 MW of capacity from the program into the PJM capacity auction 80 MW in the 2021-2022 Delivery Year, and 135 MW in the 2022-2023 Delivery Year.

Ameren Illinois has implemented a Voltage Optimization Program (including, for example, Conservation Voltage Reduction (“CVR”) Program). Ameren Illinois also offers a Real Time Pricing (“RTP”) option and the additional associated Power Smart Pricing (“PSP”) program for smaller customers. Pursuant to the Commission’s Interim Order in Docket No. 13-0105, Ameren Illinois offers a Peak Time Rewards program (Rider PTR). According to Ameren Illinois, the program currently has approximately 130,000 customers and Ameren Illinois sold 15.9 MW of related capacity in the MISO PRA for the 2021-2022 Delivery Year, which provides the pool of funds used for customer rebates. This tariff pertains to an optional program available to DS-1 customers as of June 1, 2016, whereby a customer would receive a billing credit if they curtail electric energy use during specific peak usage periods.

MidAmerican administers a program called “SummerSaver Program,” a residential Direct Load Control (DLC) program. At the time of gross system peak, the SummerSaver program was not in effect. In addition, there is a potential for load displacement due to curtailment of customers on an interruptible rate. There was no curtailment event in effect at the time of gross system peak.

The IPA does not propose any procurement of demand response programs from eligible retail customers in the 2022-2023 Delivery Year. Under current market and regulatory conditions, the IPA believes that a new demand response procurement by the IPA could not meet the standards set forth in Section 16-111.5(b)(3) of the Public Utilities Act. Reasons for this include, for example, the statutory requirement that demand response under this provision must come from “eligible retail customers,” and as the IPA is not aware of any simple, straightforward way of definitively determining whether a non-competitive class customers take supply from the utility or an alternative retail electric supplier for purposes of any demand response aggregation, there may simply be no feasible way to ensure that only eligible retail customers participate. This challenge significantly reduces the likelihood that any demand response procurement would be “cost-effective.” Further, there could be challenges in “satisfy[ing] the demand-response requirements of the regional transmission organization market in which the utility’s service territory is located,” and “provid[ing] for customers’ participation in the stream of benefits produced by the demand-response products.” Fortunately for customers (including both eligible retail customers and those who have switched suppliers or take hourly priced service), the Peak Time Rewards (or Savings) programs as offered by Ameren Illinois and ComEd create value through reduction in capacity charges and the technologies utilized for capacity reductions also have the potential to provide longer term demand response capability that could operate over more peak hours than those used for calculations of capacity obligations.

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

7.5 Clean Coal

The IPA Act contains an aspirational goal that cost-effective clean coal resources will account for 25% of the electricity used in Illinois by January 1, 2025.²⁰⁹ As a part of the goal, the Plan must also include electricity generated from clean coal facilities.²¹⁰ While there is a broader definition of “clean coal facility” contained in

²⁰⁹ 20 ILCS 3855/1-75(d).

²¹⁰ 20 ILCS 3855/1-75(d)(1).

the definition section of the IPA Act,²¹¹ Section 1-75(d) describes two special cases: the “initial clean coal facility”²¹² 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”²¹³ (“retrofit clean coal facility”). Each of these special cases includes specific processes through which sourcing agreements for the power from the facilities would be entered into by both utilities and ARES. Currently, the IPA is unaware of any facility meeting the definition of either an “initial clean coal facility” or a “retrofit clean coal facility” that has announced plans to begin operations within the next five years.

In comments on the Draft 2019 Plan, the Agency received a proposal by two commenters seeking for the Plan to include a competitive procurement for sourcing agreements from a “clean coal facility”²¹⁴ (i.e., a facility that meets the definition of a “clean coal facility” under Section 1-10 of the IPA Act, but not the definition of “initial clean coal facility” or a “retrofit clean coal facility”). As the Agency understands it, these commenters were seeking a procurement to support the development of a small “clean coal” plant in Mattoon at the location of the original FutureGen project.

As a threshold matter, it is unclear what authority was granted to the Agency to procure sourcing agreements from a “clean coal facility” that does not meet either of the above-referenced special definitions. A similar proposal to procure sourcing agreements from a “clean coal facility” not meeting these special definitions through a competitive procurement process was made in connection with the IPA’s 2015 Plan; after reviewing the arguments of all parties, the Commission articulated serious concerns with whether such a procurement was consistent with the IPA Act, concluding that it was “not convinced” that a proposal of this type “was contemplated by the Illinois General Assembly or is in the public interest.”²¹⁵ Given the scant guidance and authority offered by the IPA Act for such a procurement process, that conclusion appears well-justified.

Other statutory and budgeting barriers also apply to the procurement of sourcing agreements from a “clean coal facility” that do not apply to the special cases mentioned above. Given the absence of any mechanism in the IPA Act to require ARES to purchase or pay for the output of such a facility, the facility’s additional costs would only be borne by eligible retail customers. At present, eligible retail customer load is less than 25% of the total retail customer load in Illinois (and could vary significantly in future years with customer switching), thus leading to limited (and volatile) funding under the rate impact cap contained in Section 1-75(d)(2). Given cost estimates typically presented for proposed “clean coal” plants, it appears highly unlikely that a clean coal facility could be developed within statutory funding limitations.

The IPA is concerned that should it propose a “competitive” procurement event for clean coal facilities, all reasonable market information indicates that there would be very few or no viable bidders. As the competitive procurement model relies on robust participation that captures the value created by competition, such a process would have difficulty yielding least-cost results.

For these reasons, the Agency is not proposing a dedicated clean coal procurement in this Plan. To be clear, nothing in this analysis is intended to prohibit any “clean coal” facility from participating in the IPA’s proposed block energy or capacity procurements described elsewhere in this Chapter; it is merely concluding that special treatment through a dedicated procurement event for long-term, source-specific “clean coal facility” sourcing agreements is not presently warranted by Section 1-75(d) of the Act. Currently, as far as the Agency can determine, development activities for the Mattoon “clean coal” plant have ceased. The Agency will continue to monitor developments in federal carbon capture and sequestration legislation and policies in the event that these developments would have an impact on the development of clean coal projects in Illinois.

²¹¹ 20 ILCS 3855/1-10.

²¹² *Id.*

²¹³ 20 ILCS 3855/1-75(d)(5).

²¹⁴ See Comments on the Draft 2019 Procurement Plan from Mattoon Power Enterprises LLC and Coles Together, available at <https://www2.illinois.gov/sites/ipa/Documents/2019ProcurementPlan/MPE%20procurement%20comment.pdf> and <https://www2.illinois.gov/sites/ipa/Documents/2019ProcurementPlan/Coles%20Together%20Comments%20to%20IPA%20on%202019%20Draft%20Procurement%20Plan.pdf>.

²¹⁵ Docket No. 14-0588, Final Order dated December 17, 2014 at 315.

8 Procurement Process Design

The procedural requirements for the procurement process are detailed in the Illinois Public Utilities Act at Section 16-111.5.²¹⁶ The Procurement Administrator, retained by the IPA in accordance with Section 1-75(a)(2) of the IPA Act, conducts the competitive procurement events on behalf of the IPA. The costs of the Procurement Administrator incurred by the IPA are recovered from the bidders and suppliers that participate in the competitive solicitations, through both IPA-assessed Bid Participation Fees and Supplier Fees. The “eligible retail customers” for each of the participating utilities ultimately incur these costs as it is assumed that suppliers’ bid prices reflect a recovery of these fees. As required by the PUA and in order to operate in the best interests of consumers, the IPA and the Procurement Administrator review the procurement process each year in order to identify potential improvements.²¹⁷ The Agency implemented changes to the procurement process in response to the COVID-19 pandemic involving remote submission of bid documentation that have proven successful and reflect good practice; those will be continued going forward.

Consistent with changes to the IPA’s procurement process resulting from Public Act 99-0906, the IPA no longer includes the procurement of renewable energy resources as part of the annual procurement plan. The procurement of REC’s is instead covered by the Long-Term Renewable Resources Procurement Plan.²¹⁸ The IPA’s procurement process going forward will continue to procure standard wholesale products for the utilities’ eligible retail customers through the annual procurement plans.

Section 16-111.5(e) of the Public Utilities Act specifies that the procurement process must include the following components:

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

The procurement administrator shall disseminate information to potential bidders to promote a procurement event, notify potential bidders that the procurement administrator may enter into a post-bid price negotiation with bidders that meet the applicable benchmarks²¹⁹, provide supply requirements, and otherwise explain the competitive procurement process. In addition to such other publication as the procurement administrator determines is appropriate, this information shall be posted on the Illinois Power Agency’s and the Commission’s websites. The procurement administrator shall also administer the prequalification process, including evaluation of credit worthiness, compliance with procurement rules, and agreement to the standard form contract developed pursuant to paragraph (2) of this subsection (e). The procurement administrator shall then identify and register bidders to participate in the procurement event.

(2) Standard contract forms and credit terms and instruments.

The procurement administrator, in consultation with the utilities, the Commission, and other interested parties and subject to Commission oversight, shall develop and provide standard contract forms for the supplier contracts that meet generally accepted industry practices. Standard credit terms and instruments that meet generally accepted industry practices shall be similarly developed. The procurement administrator shall make available to the Commission all written comments it receives on the contract forms, credit terms, or instruments. If the procurement administrator cannot reach agreement with the applicable electric utility as to the contract terms and conditions, the procurement administrator must notify the Commission

²¹⁶ See generally 220 ILCS 5/16-111.5.

²¹⁷ Due to the COVID-19 emergency measures, the Procurement Administrator implemented changes to the proposal submission process to accept digitally signed inserts to the Part 1 Form certifications instead of the previously required notarized signatures.

²¹⁸ The IPA’s Long-Term Renewable Resources Procurement Plan (“LTRRPP”) was approved by the Commission on April 3, 2018 through Docket No. 17-0838. A Revised LTRRPP was approved by the Commission in Docket No. 19-0995 on February 18, 2020. A draft Second Revised LTRRPP was published concurrent with the publishing of this 2022 Procurement Plan.

²¹⁹ The IPA Act requires the procurement administrator to notify bidders that the procurement administrator may, in its discretion, enter into post-bid price negotiations with bidders. In order to encourage best and final bids from the bidders and taking into consideration the mandated use of confidential benchmarks, the procurement administrators in previous procurements have decided not to engage in post-bid negotiations.

of any disputed terms and the Commission shall resolve the dispute. The terms of the contracts shall not be subject to negotiation by winning bidders, and the bidders must agree to the terms of the contract in advance so that winning bids are selected solely on the basis of price.

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

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

(4) Request for proposals competitive procurement process.

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

(5) A plan for implementing contingencies

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

8.1 Contract Forms

The IPA believes that the standard wholesale energy product contract forms used in its procurements have now become largely standardized and should remain acceptable to future potential bidders. As was the case with the procurement events held from 2014 through 2021, the process to receive comments from potential bidders can be restricted to changes to the forms, thus reducing Procurement Administrator time and billable hours, while shortening the critical path time needed to conduct a procurement event. This is because, prior to the 2014 procurement events, the forms, terms and instruments had become relatively stable, with fewer comments being received from potential bidders requesting revision or optional terms for each succeeding procurement event. Any procurement event to be conducted under the auspices of the 2022 Procurement Plan would be the sixteenth iteration of IPA-run procurement events, when including the Spring and Fall 2021 procurement events for the procurement of capacity for Ameren Illinois and the procurement of standard energy products for Ameren, ComEd and MidAmerican. In each iteration prior to 2014, potential bidders had an opportunity to comment on documents and those comments have been, where appropriate, incorporated into the documents or provided as acceptable alternative language. For the procurement events held from 2014 through 2021, potential bidders submitted only limited comments on the proposed changes to the forms.

An amendment to the Ameren Capacity Agreement was included for the spring capacity procurement to accommodate the possibility that proposed changes to the MISO resource adequacy construct would result in changes to the MISO capacity products to be procured for Ameren's eligible customers. The IPA anticipates that this amendment will remain in place for the 2022 Plan capacity procurements.

In the procurement events conducted for energy blocks since 2012, comments have been few, with virtually no new modifications being accepted or made (in part because some comments made by new participants have been handled in prior procurement events). The documents used for the 2012 IPA-run procurement events illustrate both the breadth and depth of bidder input to the current state of the documents and the maturity of the documents themselves. The contract documents utilized for the MidAmerican energy blocks procurement events were, and continue to be, similar to the Ameren Illinois contract documents.

On the opposite side of this discussion, the IPA also understands that markets are dynamic and periodic review of contract terms is necessary to ensure proper protection for the utilities, utility customers and suppliers. The IPA therefore recommends that the most recently used forms, namely the energy contracts used in the 2020 procurement events, be the starting point for the contracts used in the energy procurements associated with this Plan. The IPA also recommends that the IPA, Commission Staff, Procurement Administrator, Procurement Monitor, and utilities undertake a joint review of such contracts in order to identify what terms, if any, need to be modified.

8.2 IPA Recovery of Procurement Expenses

Section 1-75(h) of the IPA Act states that “[t]he Agency shall assess fees to each bidder to recover the costs incurred in connection with a competitive procurement process.”²²⁰ Additionally, in April 2014, the IPA adopted administrative rules related to fee assessments that codify past practices including defining “bidders” and “suppliers” in procurement events as well as the process for determining those fees.²²¹

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

- A “Bid Participation Fee”, which is a flat fee paid by all bidders as a condition of qualification; and
- “Supplier Fees”, which are paid only by the winning bidders as a fee per block won at the conclusion of the procurement event.

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

1. If not all the blocks are procured (and no additional procurement event is held), the IPA will not recover the full cost of the procurement through the combination of the Bid Participation Fees and the Supplier Fees. The Supplier Fees are collected from the “winning bidders” based on the recommended blocks approved by the Commission; the Supplier Fees associated with the blocks that are not procured are not collected.
2. Suppliers may not necessarily pay the Supplier Fees on time (or pay them at all). Suppliers that have bids that are approved by the Commission proceed to the contract execution process with the utility and will get paid under that contract whether or not they have paid the Supplier Fees. When the structure of fees was first introduced, non-payment of the Supplier Fees was an event of default under the contract with the utility. Suppliers had a very strong incentive to pay the Supplier Fees as failure to do so meant that they would not be able to get compensated under the contract from winning the bid. As procurement events came to be IPA-run, this structure was abandoned as the responsibility for assessing fees to bidders is the IPA’s and not the utility’s. The incentives for suppliers to pay the Supplier Fees were reduced as a result.

In developing its procurement approach, the IPA has considered a number of approaches for addressing these risks, involving two broad categories of solutions:

- a. Maintain the current fee structure and use the pre-bid letter of credit provided by bidders as bid assurance collateral to ensure compliance with the payment obligation of the Supplier Fees.
- b. Change the current fee structure to have the cost of the procurement largely paid upfront and bar suppliers that fail to pay all fees due from participation in IPA-run events for a period of time.

Until the 2014 procurement events, the pre-bid letter of credit had been strictly a credit instrument held for the benefit of the utility and its customers. The utility was able to draw upon the pre-bid letter of credit if the supplier failed to complete the contract execution process. At that point, the utility that had filed its rates based on the winning bids would have to buy replacement supply, for which it could use funds under the pre-bid letter of credit to mitigate any impact of the default by a supplier on rates. Starting with the 2014 procurement events, the function of the pre-bid letter of credit was expanded to ensure payment of the Supplier Fees by adding a condition to the utility pre-bid letter of credit allowing the utility to draw on the letter of credit if the

²²⁰ 20 ILCS 3855/1-75(h).

²²¹ 83 Ill. Admin. Code. §§ 1200.110, 1200.220.

Supplier Fees are not paid by a date certain (and having an agreement between the IPA and the utility on how funds would flow back to the IPA for payment of the Supplier Fees). This is the approach that was used starting with the 2014 procurement events and continuing through the 2021 procurement events.

The IPA has previously received comments on these possible approaches and how the IPA could ensure that in conducting procurement events it complies with Section 1-75(h) of the IPA Act and Section 1200.220 of Title 83 of the Illinois Administrative Code. Based on those comments and subsequent review of the alternatives, the IPA recommends that the approach used in the procurement events since 2014 be continued to support the procurement events recommended in this Plan. That approach is for the energy contracts to maintain the condition in the utility pre-bid letter of credit allowing the utility to draw if the Supplier Fees are not paid by a date certain. Likewise, as used in the recent procurement events, there will also be an agreement between the IPA and each utility on how funds would flow back to the IPA for payment of the Supplier Fees under this circumstance.

8.3 Second Procurement Event

The IPA recommends that procurement events continue to be held in the spring and fall of 2022 for the purchase of energy blocks and a portion of the necessary Ameren Illinois capacity products (Zonal Resource Credits) under the 2022 Procurement Plan. The components of the procurement process detailed above would be conducted in the spring events. For the fall procurement events, for energy blocks under the Procurement Plan, certain activities would not occur as the fall procurement event could rely on the documents or processes established for the spring procurement event, as follows:

- The procurement administrator will rely on the contract and credit forms established in the Spring 2022 procurement event, and suppliers would not comment anew on these documents;
- The procurement administrator will rely on the RFP design and updated benchmarks using the benchmark methodology established in the Spring 2022 procurement event; and
- The procurement administrator, in consultation with each utility, IPA, ICC Staff and Procurement Monitor, will not be prohibited from making minor changes to the contract and credit terms or minor changes to the RFP documents, including but not limited to clarifications or corrections.
- Suppliers that participate in the Spring 2022 procurement event will have access to an abbreviated qualification and registration process if they also participate in the Fall 2022 procurement event;

The IPA recommends that the Fall 2022 procurement event includes the procurement of standard energy products for Ameren Illinois, ComEd, and MidAmerican (if needed), as well as Zonal Resource Credits for Ameren Illinois.

8.4 Informal Hearing

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

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

On May 4, 2021, the ICC Staff posted a public notice²²² for the informal hearing for the purpose of receiving comments regarding the procurement process for the procurement events that were held during the fall of 2020 and the spring of 2021. The Fall 2020 procurements involved the procurement of standard energy products to meet a portion of the requirements of ComEd's and Ameren Illinois' eligible retail customers for October 2020 through May 2023 and MISO Zonal Resource Credits capacity products for Ameren Illinois for the Delivery Years 2021-2022 and 2022 - 2023. The Spring 2021 procurement events included the purchase of a portion of the three utilities' energy requirements²²³ to meet eligible retail customers' needs for the 2021-

²²² <https://www.icc.illinois.gov/downloads/public/Public-Notice-of-Informal-Hearing-Electric-Events-Issued-May-4-2021.pdf>.
<https://www.icc.illinois.gov/downloads/public/Public-Notice-of-Informal-Hearing-Electric-Events-Issued-May-4-2021.pdf>.

²²³ MidAmerican energy blocks were procured for July and August 2021 on-peak only.

2022, 2022-2023 and 2023-2024 Delivery Years, as well as the purchase of MISO Zonal Resource Credits for Ameren Illinois for the 2022-2023 and 2023-2024 Delivery Years.

Initial comments for the informal hearing were due to the Commission by May 24, 2020 and Reply Comments were due by May 31, 2021. Initial Comments were received from Bates White Economic Consulting (“Bates White”), the ICC’s Procurement Monitor, on May 24, 2021. Overall, Bates White noted that the IPA’s procurements continued to be successful in leveraging the power of competition for the benefit of the utilities’ ratepayers and the procurement process has proven able to successfully adapt to changing market and regulatory conditions. Bates White specifically commented on the ability of the IPA procurement process to successfully adapt to changes in wholesale market conditions such as the changes to the capacity market that could result from MISO’s proposed resource adequacy construct modifications which would address seasonal reliability issues. Flexibility in the procurement process based on the Agency’s changes to bidding rules and contract forms for the Spring 2021 Ameren capacity procurement allowed bidders to deal with the uncertainties posed by the potential changes to the MISO capacity market. Comments received in the informal hearing process are available on the Commission’s website.²²⁴

²²⁴ See <https://www.icc.illinois.gov/workshops/Electricity-Procurement-Process-for-Plan-Years-Beginning-June-2021>.

Appendices (Overview)

Appendices are available separately at:

<https://www2.illinois.gov/sites/ipa/Pages/2022-Appendices.aspx> Note, the term “Expected Case” used in these appendices is synonymous with “Base Case” used in the main body of the Plan.

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