2026

ILLINOIS POWER AGENCY

ELECTRICITY PROCUREMENT PLAN

2026 Draft Plan for Public Comment

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1 Executive Summary

This is the eighteenth electricity procurement plan (the "Plan," "Procurement Plan," "2026 Plan," or "2026 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 tenth time in the 2025 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 2026 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 2026-2027 Delivery Year[2] and lasts through the 2030-2031 Delivery Year.

The 2025 Procurement Plan, as approved by the Commission in Docket No. 24-0727, called for the energy requirements for Ameren Illinois, ComEd, and MidAmerican to be procured by the IPA through two block energy procurements (Spring 2025 and Fall 2025). In addition, the 2025 Plan included two capacity procurements for Ameren Illinois (Spring 2025 and Fall 2025), which expanded the capacity products being procured to include seasonal products and newly incorporated annual and financial swap contract option products.

This Plan proposes to continue the approach approved by the Commission in the 2025 Plan – previously updated in the 2024 Plan – which recognizes the offsetting price impacts for ComEd's eligible retail customers created as a result of the ComEd's Carbon Mitigation Credit ("CMC") contracts. The CMC contract will run through the end of the 2026-2027 Delivery Year and incorporates a specific modification for the non-summer period (the delivery months of October through May). As implemented, the IPA hedges 50% of ComEd's forecasted eligible retail customer load during the summer delivery months and 30% during the non-summer delivery months. The price volatility of the remaining load is offset by month-to-month changes in the CMC price.[3] With the 2026 Plan addressing the procurement of electricity through the 2028-2029 Delivery Year, it is summarily projected to include the conclusion of the CMC contracts and the loss of the cost offsetting feature of these contracts. For this reason, this Plan includes a ramping up of procurement volumes in anticipation of returning to hedging 100% of ComEd's forecasted eligible retail customer load starting in the 2027-2028 Delivery Year.

This 2026 Procurement Plan released for public comment proposes to maintain the energy and capacity procurement strategies adopted in the 2025 Procurement Plan; and subject to the Agency's review of stakeholder feedback received on this draft Plan, the Agency may modify those strategies in the Plan filed for Commission approval.

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[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 2026 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] See Section 6.8 of this Plan for more information.

1.1 Power Procurement Strategy

The 2026 Plan will continue implementing the risk management and procurement strategy that the IPA has historically utilized: hedging load by procuring on and off-peak blocks of forward energy in a three-year laddered approach. The IPA believes the continuation of its tested and proven risk management strategy is the most prudent and reasonable approach, and the approach most likely to meet its statutorily mandated objective to "[d]evelop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[4]

The IPA's energy hedging strategy for the 2026 Procurement Plan is largely consistent with the strategy used for the 2025 Plan as approved by the Commission in ICC Docket No. 24-0727.[5] That strategy involves the procurement of hedges in 2026 to meet a portion of anticipated eligible retail customer energy supply requirements for a three-year period and includes two block energy procurement events, the first in the Spring and the second in the Fall, with a partially open position for ComEd through the 2026-2027 delivery year in light of CMC contracts.

As explained in more detail in Section 5.2.2.1, MISO has implemented a seasonal resource adequacy construct starting with the 2023-2024 Delivery Year. Under the seasonal resource adequacy construct, capacity in the MISO Planning Resource Auction ("PRA")[6] and in the IPA's bilateral procurements is now procured for each of the four distinct seasons: summer, fall, winter, and spring.[7]

For the 2027-2028 and 2028-2029 Delivery Years, the IPA will continue the strategy of procuring a portion of Ameren Illinois' forecasted capacity requirements in bilateral transactions and the remaining balance through the MISO PRA. As also explained in more detail in Sections 5.2.2.7 and 7.2.1.2, the IPA will continue with its strategy of procuring up to 75% of its forecasted capacity requirements in its bilateral procurements. For the 2027-2028 Delivery Year, the IPA will procure up to 50% of its forecasted capacity requirements in bilateral transactions in Spring 2026 and up to 75% in Fall 2026, with the balance of the forecast capacity requirement to be procured in the 2027 MISO PRA. For the 2028-2029 Delivery Year, the IPA will procure up to 12.5% of its forecasted capacity requirements in bilateral transactions in Spring 2026 and up to 25% in Fall 2026, with the balance of the forecast capacity requirement to be determined in the 2027 Electricity Procurement Plan. The Agency will continue to include an additional option for a financial capacity swap contract product to the planned Ameren Illinois capacity procurements. **In addition to the proposed continuation of the 2025 capacity products, for this draft Plan the Agency is also interested in receiving stakeholder feedback on whether a multi-year capacity hedge should be added to the mix of products procured. See Section 5.2.3 for additional information.**

For ComEd, consistent with the strategy adopted in prior plans, capacity requirements will be secured by ComEd through the PJM Reliability Pricing Model ("RPM") process; however, **for this draft Plan the IPA is interested in receiving stakeholder feedback on whether the IPA should consider developing and implementing a capacity hedge for ComEd. See Section 5.2.1 for additional information.**

Following the approach taken in the 2025 Plan, the MidAmerican's forecasted capacity deficit will be secured by MidAmerican through the annual MISO PRA.[8]

In addition to the various approaches described above, ancillary services, load balancing services, and transmission services will be purchased by Ameren Illinois and MidAmerican from the MISO marketplace and by ComEd from the PJM markets.

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[4] 20 ILCS 3855/1-20(a)(1).

[5] See ICC Docket No. 24-0727, Final Order (Dec. 19, 2024).

[6] 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.

[7] Summer will cover the months of June to August, Fall will cover the months of September to November, Winter will cover the months of December to February, and Spring will cover the months of March to May.

[8] 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).

The following tables summarize the IPA's 2026 hedging strategy and planned procurements:

Table 1-1: Summary of Energy Hedging Strategy Targets for Ameren Illinois and MidAmerican[9]

Spring 2026 Procurement			Fall 2026 Procurement		
June 2026-2027 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2026-May 2027**	**Upcoming Delivery Year + 1**	**Upcoming Delivery Year + 2**
June 100% on-peak and off-peak July and Aug. 106% on-peak, 100% off-peak Sep. 100% on-peak and off-peak Oct. - May 75% on-peak and off-peak	37.5% all months, except June, July and August on-peak and off-peak, which should be 52.5%.	12.5% all months except June, July and August on-peak and off-peak which should be 15%.	100% all months.	50% all months, except June, July and August on-peak and off-peak, which should be 75%.	25% all months except June, July and August on-peak and off-peak which should be 30%.

Table 1-2: Summary of Energy Procurement Targets for ComEd[10]

Spring 2026 Procurement			Fall 202 Procurement		
June 2026-May 2027 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	October 2026-May 2027	Upcoming Delivery Year + 1	Upcoming Delivery Year + 2
June - Sep. 50% on-peak and off-peak, Oct. - May 22.5% on-peak and off-peak	37.5% all months, except June, July and August on-peak and off-peak, which should be 52.5%	12.5% all months, except June, July and August on-peak and off-peak, which should be 15%.	30% all months.	50% all months, except June, July and August on-peak and off-peak, which should be 75%.	25% all months, all months, except June, July and August on-peak and off-peak, which should be 30%.

[9] Table 1-1 shows the cumulative percentage of targeted load to be hedged by the conclusion of the indicated procurement events. Any shortfalls from prior procurement events would be added to the targets for each procurement event to meet the applicable cumulative percentage.

[10] Table 1-2 shows the cumulative percentage of targeted load to be hedged by the conclusion of the indicated procurement events. Any shortfalls from prior procurement events would be added to the targets for each procurement event to meet the applicable cumulative percentage.

Table 1-3: Summary of Capacity Procurement Targets for Ameren Illinois[11, 12]

June 2026-May 2027	June 2027-May 2028	June 2028-2029
12.5% in Spring 2024 25% in Fall 2024 50% in Spring 2025 75% in Fall 2025 100%, MISO PRA	12.5% in Spring 2025 25% in Fall 2025 50% in Spring 2025 75% in Fall 2026 100%, MISO PRA	12.5% in Spring 2026 25% in Fall 2026 Remainder to be determined in 2027 Plan.

Table 1-4: Summary of Capacity Procurement Targets for ComEd

June 2026-May 2027	June 2027-May 2028	June 2028-May 2029	June 2029-May 2030
100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions

Table 1-5: Summary of Capacity Procurement Targets for MidAmerican

June 2026-2027 (Upcoming Delivery Year)	June 2027-2028	June 2028-2029
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."[13] Thus, the procurement of renewable energy resources is included in the IPA's Long-Term Renewable Resources Procurement Plan ("Long-Term Plan") rather than this Plan. The IPA's Initial Long-Term Plan was approved by the Commission in April of 2018, and its First Revised Plan was approved in February of 2020. Consistent with the enactment of Public Act 102-0662, the Agency's 2022 Long-Term Plan was filed with the Commission on March 21, 2022, and approved with modification on July 14, 2022.[14] Subsequently, the Agency sought reopening of the 2022 Long-Term Plan to address the potential expansion of Equity Eligible Contractor category capacity in the Adjustable Block Program. That process culminated in the ICC issuing a Final Order modifying the 2022 Long-Term Plan on May 4, 2023, and the Agency released a Modified 2022 Long-Term Plan on May 9, 2023. The Agency released its Draft 2024 Long-Term Plan for public comment on August 15, 2023, and filed that plan with the Commission for approval on October 20, 2023. The 2024 Long-Term Plan was approved by the ICC on February 20, 2024, and a Final Plan reflecting the

[11] Table 1-3 shows the cumulative up-to percentage of capacity targeted to be procured by the conclusion of the indicated procurement event. Any shortfalls from prior procurement events would be added to the targets for each subsequent procurement event in an attempt to meet the applicable cumulative percentage.

[12] Procurement percentage targets for the 2026-2027 and 2027-2028 Delivery Years from procurements conducted in 2025 were approved under the 2025 Procurement Plan. Actual procurement volumes to date do not match percentage targets listed in Table 1-3. Furthermore, the table lists the hedging targets across all seasons, while to date actual procurement results by season have varied.

[13] 20 ILCS 3855/1-75(a).

[14] See ICC Docket No. 22-0231, Final Order (Jul. 14, 2022).

Commission's Final Order was published on April 19, 2024. Concurrent with the release of this draft 2026 Electricity Procurement Plan for public comment, the Agency is also releasing a draft 2026 Long-Term Plan for public comment.

1.3 Procurement Recommendations

Table 1-6 summarizes the IPA's recommendations as described in this Plan.

Table 1-6: Summary of Procurement Plan Recommendations Based on July 15, 2025 Utility Load Forecasts (Quantities to be Adjusted Based on the March and July 2026 Load Forecasts)

	Delivery Year	Energy	Capacity[15][16]	Transmission and Ancillary Services
Ameren Illinois	2026-2027	Up to 425 MW forecasted requirement (Spring Procurement) Up to 250 MW additional forecasted requirement (Fall Procurement)	Up to 12.5% in Spring 2024 Up to 25% in Fall 2024 Up to 50% in Spring 2025 Up to 75% in Fall 2025 Remaining balance from MISO PRA	Will be purchased from MISO
	2027-2028	Up to 225MW forecasted requirement (Spring Procurement) Up to 225 MW additional forecasted requirement (Fall Procurement)	Up to 12.5% in Spring 2025 Up to 25% in Fall 2025 Up to 50% in Spring 2026 Up to 75% in Fall 2026 Remaining Balance from MISO PRA	Will be purchased from MISO
	2028-2029	Up to 100 MW forecasted requirement (Spring Procurement) Up to 150MW additional forecasted requirement (Fall Procurement)	Up to 12.5% in Spring 2026 Up to 25% in Fall 2026[17] Remaining balance to be determined in 2026 Plan	Will be purchased from MISO
	2029-2030	No energy procurement required	No further action at this time	Will be purchased from MISO
	2030-2031	No energy procurement required	No further action at this time.	Will be purchased from MISO
ComEd	2026-2027	Up to 525 MW forecasted requirement (Spring Procurement) Up to 250 MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2027-2028	Up to 950 MW forecasted requirement (Spring Procurement) Up to 950 MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2028-2029	Up to 550 MW forecasted requirement (Spring Procurement) Up to 625 MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2029-2030	No energy procurement required	100% PJM RPM Auctions	Will be purchased from PJM
	2030-2031	No energy procurement required	No further action at this time	Will be purchased from PJM
MidAmerican	2026-2027	Up to 50 MW forecasted requirement (Spring Procurement) No additional energy procurement needed (Fall Procurement)	100% of deficit from MISO PRA	Will be purchased from MISO
	2027-2028	No energy procurement needed (Spring Procurement) No additional energy procurement needed (Fall Procurement)	100% of deficit from MISO PRA	Will be purchased from MISO
	2028-2029	No energy procurement required	100% of expected deficit from MISO PRA	Will be purchased from MISO
	2029-2030	No energy procurement required	No further action at this time	Will be purchased from MISO
	2030-2031	No energy procurement required	No further action at this time	Will be purchased from MISO

[15] Cumulative percentage of capacity targeted to be procured by the conclusion of the indicated procurement event.

[16] Procurement percentage targets for the 2026-2027 Delivery Year conducted in 2024 were approved under the 2024 Electricity Procurement Plan. Procurement percentage targets for the 2026-2027 and 2027-2028 Delivery Years conducted in 2025 were approved under the 2025 Electricity Procurement Plan. Actual procurement volumes may not match percentage targets.

[17] Additional Procurements for the 2028-2029 Delivery Year will be considered in the 2027 Procurement Plan.

1.4 The Action Plan

In this Plan, the IPA recommends the following items for ICC approval:

1. Approve the base case load forecasts of ComEd, Ameren Illinois, and MidAmerican as submitted in July 2025.
2. Approve two energy procurement events scheduled for Spring 2026 and Fall 2026. The energy amounts to be procured in the spring will be based on updated March 2026 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 2026 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. In the event of default on CMC contracts, the IPA may change the hedging percentages for ComEd to mirror those of Ameren Illinois and MidAmerican, with the consensus of the IPA, ICC Staff, and the Procurement Monitor.
3. Approve two capacity procurement events for Ameren Illinois scheduled for Spring 2026 and Fall 2026. These events will procure both Zonal Resource Credits and financial swap contracts. The capacity target for the Spring 2026 procurement will be based on the updated March 16, 2026 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 capacity target for the Fall 2026 procurement will be based on the July 15, 2026 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.
4. The March 16, 2026, and the July 15, 2026 load 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 forecast updates with the ICC. In the event 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 2025 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 2026 Procurement Plan for public comment and invites the affected utilities and any interested parties to public comments on the Plan to the Agency by September 15, 2025.

2 Legislative/Regulatory Requirements of the Plan

This Section of the 2026 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.

As explained above in Section 1.2, the 2026 Procurement Plan is focused only on the procurement of standard wholesale power products to meet the needs of the eligible retail customers of Ameren Illinois, ComEd, and MidAmerican.

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"),[18] benefit from retail and wholesale competition. The original objective of the IPA Act was to improve the process to procure electricity for those customers.[19] 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."[20] 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.[21] 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 ComEd and Ameren Illinois, as well as "small multi-jurisdictional utilities" should they request to participate.[22] 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"[23] and "Procurement Administrator."[24] The Commission is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[25]

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);[26] 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);[27] and the elimination of the statutory requirement that the Agency include cost-effective incremental energy efficiency programs in its annual power procurement plan.[28]

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[18] 220 ILCS 5/16-111.5(a).

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

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

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

[22] 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.")

[23] 20 ILCS 3855/1-75(a)(1).

[24] 20 ILCS 3855/1-75(a)(2).

[25] 220 ILCS 5/16-111.5(b), (c)(2).

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

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

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

Public Act 102-0662, effective September 15, 2021, contained significant additional changes to the IPA's renewable energy credit procurement obligations, and tasked the Agency with the development of a new procurement plan for the procurement of CMCs from at-risk nuclear facilities.[29] Additionally, changes to Section 16-111.5 of the PUA could alter procurement strategies and bid evaluation for the Agency's future energy procurement processes.[30]

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 2026 Procurement Plan began on July 15, 2025. 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 2026 Plan was made available for public review and comment on August 15, 2025. The Public Utilities Act provides for a 30-day comment period starting on the day the IPA releases its draft plan. The 2026 Plan comment period concludes on September 15, 2025.[31] As in prior years, during the 30-day comment period, the Agency plans to hold public hearings for the 2026 Plan virtually in lieu of the in-person meetings in each utility's service area.[32]

After the receipt of public comments, the IPA plans to revise the procurement plan as necessary based on the comments received, with that revised Plan required to be filed with the Commission within 14 days of the conclusion of that comment period, or by September 29, 2025.[33] Withing five days after the Plan is filed with the Commission, parties may file Objections.[34]

Under the PUA, the Commission approves the Procurement Plan, including the load forecasts contained within, 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."[35]

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.[36] In addition, the Procurement Plan must analyze the impact of demand side and renewable energy initiatives, including the

[29] For more information on the Agency's Carbon Mitigation Credit Procurement Plan, see https://ipa.illinois.gov/energy-procurement/prior-approved-plans.html.

[30] Specifically, through changes to Section 16-111.5(b)(3)(iv), the statutory definition of "standard wholesale products" now includes "other standardized energy or capacity products designed to provide eligible retail customer benefits from commercially deployed advanced technologies including but not limited to high voltage direct current converter stations, as such term is defined in Section 1-10 of the Illinois Power Agency Act, whether or not such product is currently available in wholesale markets." Likewise, the assessment required under Section 16-111.5(b)(3)(vi) now includes consideration of "mitigation in the form of additional retail customer and ratepayer price, reliability, and environmental benefits from standardized energy products delivered from commercially deployed advanced technologies, including, but not limited to, high voltage direct current converter stations, as such term is defined in Section 1-10 of the Illinois Power Agency Act, whether or not such product is currently available in wholesale markets."

[31] Because the 30th day is Sunday September 14, 2025, the comment period will close on Monday, September 15, 2025.

[32] The virtual public hearings on the Draft 2026 Plan will held using the Zoom platform at 9:30 a.m. (MidAmerican), 11 a.m. (Ameren Illinois), and 1 p.m. (ComEd) on September 11, 2025.

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

[34] 220 ILCS 5/16-111.5(d)(3); see also 5 ILCS 70/1.11.

[35] 220 ILCS 5/16-111.5(d)(4).

[36] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).

impact of demand response programs and energy efficiency programs, both current and projected.[37] 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,[38] 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.[39]
- 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.[40] 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.[41]
- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[42]
- 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.[43] Certain load forecasts for the 2023 Plan also take into account the estimated impact of the ongoing 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.
- 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. [44]
- Include demand-response products, as discussed below.
- Procurements of standard wholesale products may include energy from high voltage direct current ("HVDC") transmission lines with converter stations located in Illinois.[45] The Agency may consider how products supplied by HVDC transmission lines can be bid into the competitive procurements for wholesale energy products on a basis that treats this source of supply equally with other sources of supply in selecting for contract awards.

2.4 Standard Product Procurement

As noted in Section 2.3, the PUA provides examples of "standard wholesale products."[46] This listing has been understood by the Commission to be non-exhaustive and non-static.[47] Instead, as articulated by the Commission in approving the 2015 Plan, "[w]henever the Commission is confronted with a unique product, there must be an examination of the attributes of the product and whether those are consistent with other

[37] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).

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

[39] 220 ILCS 5/16-111.5(b)(i), (b)(iii).

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

[41] Id.

[42] 220 ILCS 5/16-111.5(b)(3)(v).

[43] 220 ILCS 5/16-111.5(b)(3)(vi).

[44] 220 ILCS 5/16-111.5(b)(4).

[45] Id.

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

[47] 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").

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."[48] Standard wholesale products are further discussed in Sections 6.3.1, 7.1, 7.2, and in Chapter 8.

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,[49] 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.[50] 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."[51]

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."[52] 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.[53] Specifically:

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;[54]
- 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;[55]
- The products must provide for customers' participation in the stream of benefits produced by the demand-response products;[56]
- 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;[57] 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.[58]

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

[48] Id.

[49] 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").

[50] 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).

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

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

[53] Id.

[54] 220 ILCS 5/16-111.5(b)(3)(ii)(A).

[55] 220 ILCS 5/16-111.5(b)(3)(ii)(B).

[56] 220 ILCS 5/16-111.5(b)(3)(ii)(C).

[57] 220 ILCS 5/16-111.5(b)(3)(ii)(D).

[58] 220 ILCS 5/16-111.5(b)(3)(ii)(E).

within 60 days after the Commission approved the utility's Advanced Metering Infrastructure ("AMI") Plan.[59] 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.[60] 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. Under the current provisions of Section 8-103, both Ameren and ComEd were required to file new energy efficiency plans with the Commission by February 28, 2025 to cover the 2026-2029 period.[61] As of the date of this draft 2026 Procurement Plan, both utilities' new energy efficiency plans are pending before the Commission.[62]

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.[63] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[64] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[65] Section 1-75(d) describes two special cases: the "initial clean coal facility"[66] 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").[67] 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.[68] 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.[69] The FutureGen Alliance's Board of Directors "approved a resolution, dated January 6, 2016, ceasing all FutureGen Project development efforts"[70] 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.[71]

2.7 Recent Legislative Proposals and Related Developments

Incremental energy efficiency programs and renewable energy resource procurement provided for the bulk of contested issues in past IPA Annual Electricity Plan approval proceedings prior to the enactment of Public Act 99-0906. 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

[59] 220 ILCS 5/16-108.6(g).

[60] 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.

[61] 220 ILCS 5/8-103B(f)(2).

[62] See Docket Nos. 25-0211 and 25-0213.

[63] 20 ILCS 3855/1-75(d).

[64] 20 ILCS 3855/1-75(d)(1).

[65] 20 ILCS 3855/1-10.

[66] Id.

[67] 20 ILCS 3855/1-75(d)(5).

[68] Commonwealth Edison Co. v. Ill. Commerce Comm'n, et al., 2014 IL App (1st) 130544, July 22, 2014.

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

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

[71] Commonwealth Edison Co. v. Ill. Commerce Comm'n, et al., 2016 IL 118129, May 19, 2016.

similar percentage-based requirements for all retail customer load, handled exclusively through a separate planning process.[72] The number of contested issues and intensity of arguments in attaining approval of the IPA's annual electricity procurement plan has reduced significantly in recent years: there were just two contested issues for the 2018 Plan, no contested issues for the 2019 Plan, one contested issue for the 2020 Plan, no contested issues for the 2021 and 2022 Plans, three contested issues for the 2023 Plan, one contested issue for the 2024 Plan, and one contested issue for the 2025 Plan.

The enactment of omnibus energy legislation, often referred to as the Climate and Equitable Jobs Act, through Public Act 102-0662 (effective September 15, 2021) significantly expanded the Agency's responsibilities. Many of these additional responsibilities, such as the CMC procurement and coal-to-solar procurements, were handled through separate processes from this Plan; nonetheless, changes of this magnitude can provide impacts on the development of the Agency's annual electricity procurement plans (as evidenced, for example, by comments received in the litigation surrounding the 2023 Electricity Plan advocating for the adjustment of electricity procurement hedging strategies for ComEd based on the presence of CMC delivery contracts).

As outlined above, the IPA is tasked with developing a separate Long-Term Renewable Resources Procurement Plan through which it proposes procurements and programs to meet Illinois RPS targets.[73] The Agency's initial Long-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 publication of the Draft 2022 Procurement Plan; however, due to changes to Section 1-75(c)(1)(A) of the IPA Act made pursuant to the enactment of Public Act 102-0662, the Draft Second Revised Long-Term Plan was withdrawn. The IPA released a draft 2022 Long-Term Plan on January 13, 2022. After the receipt of public comments on that draft Plan, the Agency updated the Plan and on March 21, 2022 filed the 2022 Long-Term Plan for approval by the Commission. On July 14, 2022 the Commission approved the 2022 Long-Term Plan in Docket No. 22-0231. On December 2, 2022, the Agency petitioned the ICC to reopen the proceeding that approved the 2022 Long-Term Plan to potential expansion of the Equity Eligible Contractor category in the Adjustable Block Program. That process culminated in the ICC issuing a Final Order modifying the 2022 Long-Term Plan on May 4, 2023, and the Agency released a Modified 2022 Long-Term Plan on May 9, 2023. On August 15, 2023, the Agency released its Draft 2024 Long-Term Plan for public comment. After the receipt of public comments on that draft Plan, the Agency updated the Plan and filed the 2024 Long-Term Plan for Commission approval on October 20, 2023. The 2024 Long-Term Plan was approved by the ICC on February 20, 2024, and the Final version of that Plan was published on April 19, 2024. Concurrent with the release of this draft of the 2026 Electricity Procurement Plan, the Agency is releasing a draft of the 2026 Long-Term Plan on August 15, 2025.

No new legislation was passed in the 103rd Illinois General Assembly that directly impacts this draft 2026 Plan; however, Public Act 103-1066, effective February 20, 2025, establishes ICC workshops on energy storage procurement, updates provisions related to REC contract payment obligations, requires annual revisions to low-income household eligibility criteria, allows for repowered wind projects to be considered in future Indexed REC procurements, and allows the IPA to propose alternative RPS percentages across different technologies. Many of these provisions support the advancement of renewable energy generation which indirectly will impact the future development of wholesale energy markets in Illinois – providing additional energy and capacity, and more broadly, supporting improved grid reliability.

New electricity and renewable resource procurement bills also failed to pass in the Spring 2025 Legislative Session. However, several bills were proposed during the 104th General Assembly that were largely consolidated in an energy omnibus bill, SB 40. The bill received significant input, revisions, and support late into the session; work continued throughout the summer of 2025 and will likely continue into Veto Session in October 2025. Among the many items included in the omnibus legislation, the bill would have implemented several new requirements to address resource adequacy. First, the IPA would have been directed to procure 3 GW of storage capacity to be online by 2030, with an additional 3 GW to be procured and online by 2035. Second, the bill incentivized an estimated 1.8 GW, or 5.5% of peak load, through the use of virtual power plants – energy storage, demand response, and other technologies – at homes and businesses. Third, SB 40 directed

[72] 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)).

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

the ICC to evaluate transmission technologies and designate state priority projects. Fourth, the ICC, IPA, and other agencies were directed to lead an integrated resource planning process which would provide targeted and broad-based solutions mitigate grid reliability risks, increase flexibility to existing clean and alternative energy targets and programs to ensure new resource generation is not delayed. That process could result in substantial changes to the content of the IPA's annual electricity procurement plans through empowering the Agency to include in its plan "the procurement of energy, capacity, environmental attributes, resource adequacy attributes, or some combination thereof intended to serve all retail customers" as a means to "to facilitate new and additive supply resources." Contract structures and cost allocation mechanisms would be determined through this planning process. Finally, the bill would have increased ComEd's and Ameren Illinois' energy efficiency programs that provide incentives for efficient appliances, insulating homes, and installing smart thermostats to reduce energy usage by 2% per year.

The energy omnibus bill also contained several provisions expanding clean energy initiatives including: – protecting and expanding renewables funding; adjusting the RPS budget for inflation; speeding up the interconnection process; setting up thermal energy network pilots; adjusting school solar initiatives; streamlining the tax assessment process; and expanding solar consumer protections. Further, the bill included equity and labor provisions including: applying minimum equity and labor standards to the new energy initiatives; allowing an advance of capital for Illinois Solar for All projects; allowing the IPA to create an income eligible storage program; and addressing Climate Work Hubs recruitment.

The IPA will continue to participate in and monitor progress on Illinois energy legislation and will make adjustments to its governing documents as required by law.

On a national level, litigation and federal policy decisions over the past decade have until quite recently continued to shape the United States Environmental Protection Agency's ("U.S. EPA") approach to limiting emissions from electric generating plants. In 2015, the U.S. EPA released 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. The Clean Power Plan was subsequently stayed by the U.S. Supreme Court on February 9, 2016, and has never gone into effect.[74] The U.S. EPA proposed the "Affordable Clean Energy" ("ACE") rule in 2018, which was intended to replace the Clean Power Plan, and finalized the rule in 2019.[75] The ACE rule established emissions guidelines for states to use for developing limits to CO_2 emissions from coal-fired power plants which identifies coal plant heat rate improvements as the best system of emission reduction (BSER).[76] A coalition of 23 states challenged the rule in court and on January 19, 2021, the D.C. Circuit vacated the ACE Rule and remanded it to the EPA for further proceedings. The EPA finalized the repeal of the ACE rule on July 8, 2024, simultaneously finalizing multiple other actions under Section 111 of the Clean Air Act. These additional rules finalized emission guidelines for both coal-fired and oil/gas-fired steam generating electric generating units and finalized revisions to the New Source Performance Standards for greenhouse gas emissions from new reconstructed fossil fuel-fired stationary combustion turbine electric generating units.[77]

The EPA announced the final standards for limiting carbon emissions from coal-fired and natural gas-fired power plants on April 25, 2024.[78] Following the announcement, several industry groups and states requested that the implementation of the rule by the EPA be blocked during litigation challenging the standards. In July of 2024, the U.S. Court of Appeals for the District of Columbia denied the request, and the U.S. Supreme Court denied an emergency petition to block implementation of the standards while litigation over the standards is

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

[75] 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.

[76] See: https://www.epa.gov/stationary-sources-air-pollution/affordable-clean-energy-rule.

[77] See: https://www.federalregister.gov/documents/2024/05/09/2024-09233/new-source-performance-standards-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed.

[78] Fact Sheet Carbon Pollution Standards for Fossil-Fuel-Fired Power Plants Final Rule Standards and Regulatory Impact. https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-standards-and-ria-2024.pdf.

pursued in federal courts in October 2024, leaving the standards in place.[79] Subsequently, however, changes in federal leadership have resulted in a shift in the policy of reducing emissions over the last seven months. After the new administration took office, the U.S. EPA notified the court that it would be revising the 2024 rule and requested that the litigation be held in abeyance pending the new rule, which the court approved. On June 17, 2025, the EPA published a proposed rule that rescinds all greenhouse gas emissions standards for fossil fuel-powered electric generation units, based on a revised finding that these emissions do not "contribute significantly to dangerous air pollution."[80] The public comment period for the proposed rule closed on August 7, 2025.[81] The Agency will continue to monitor this proposed rulemaking and its impact upon energy markets.

Similarly, the enactment of the Inflation Reduction Act ("IRA") in 2022 was (at the time of enactment) expected to result in substantial greenhouse gas reductions through providing extensive tax incentives supporting wind and solar energy projects, the development of nuclear power technology, geothermal energy, carbon capture and storage, and zero-carbon fuels, along with improved methane abatement in the oil and gas industries. Under the IRA, greenhouse gas reductions were expected to be reduced by a cumulative 6.3 billion metric tons through 2032.[82] The IRA was expected to impact electricity markets through increased section 45Q tax credits[83] providing incentives to install economically viable carbon capture and storage technologies at new and existing natural gas power plants and existing coal power plants. In an effort to increase the impact of the IRA in supporting new green energy developments, the U.S. Treasury Department and Internal Revenue Service released clarifying guidance in 2023 regarding the investment tax credit and production tax credit provisions of the IRA.[84] In July of 2025, however, new federal legislation was enacted which includes the rapid-phase out of the IRA's flagship tax credits. Additionally, an executive order issue on July 7, 2025, instructs the Secretary of the Treasury to "take all action as the Secretary of the Treasury deems necessary and appropriate to strictly enforce the termination of the clean electricity production and investment tax credits under sections 45Y and 48E of the Internal Revenue Code for wind and solar facilities. This includes issuing new and revised guidance as the Secretary of the Treasury deems appropriate…[.]"[85] The Agency understands that this guidance is required to be released on or by August 18, 2025 per the Executive Order.

Additionally, the Agency has observed a federal policy shift related to the planned retirements of certain fossil generating plants. On April 8, 2025, the White House issued Executive Order 14262, which directed the Secretary of Energy to establish a protocol to identify regions with what the Secretary deems as insufficient reserve margins.[86] The EO also directs the Secretary to create a mechanism to "ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource" and prevent any generation unit of at least 50 MW from closing or switch fuel sources, if such switch resulted in a decreased accredited capacity.[87] On May 23, 2025, the Secretary of Energy issued an emergency order pursuant to EO 14262 and claimed statutory authority under the Federal Power Act requiring the Midcontinent Independent System Operator and Consumers Energy to delay the planned shutdown of the Campbell coal-fired power plant in West Olive, MI on May 31, 2025. The order requires that the plant remain dispatchable through August 21, 2025.[88]

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[79] States' Emergency Application for an Immediate Stay of Administrative Action Pending Review in the D.C. Circuit, https://ago.wv.gov/Documents/Carbon%20Rule%20Stay%20Application.pdf.

[80] Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units, Federal Register, vol. 90, 25752. https://www.federalregister.gov/documents/2025/06/17/2025-10991/repeal-of-greenhouse-gas-emissions-standards-for-fossil-fuel-fired-electric-generating-units#h-20

[81] Id.

[82] Princeton University Zero-carbon Energy Systems Research and Optimization Laboratory, "Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022," August 2022.

[83] A "45Q tax credit" is a tax credit under Internal Revenue Code Section 45Q intended to incentivize investment in carbon capture and sequestration.

[84] See https://www.whitehouse.gov/cleanenergy/clean-energy-updates/2023/05/12/treasury-releases-new-guidance-strenthening-incentives-for-domestic-clean-energy-manufacturing/; https://home.treasury.gov/news/press-releases/jy1533.

[85] https://www.whitehouse.gov/presidential-actions/2025/07/ending-market-distorting-subsidies-for-unreliable-foreign%E2%80%91controlled-energy-sources/.

[86] Executive Order 14262, Strengthening the Reliability and Security of the United States Electric Grid (April 8, 2025).

[87] Id.

[88] Midcontinent Independent System Operator (MISO) 202(c) Order_1.pdf.

The Agency will continue monitoring federal actions and policy on these items and others, such as potential tariff changes and updated permitting rules impacting new build, all of which are expected to have impacts upon the electricity market.

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."[89] 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 electricity[90] for a portion of its load.[91] 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.[92]

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.*[93]

The forecasts are prepared by the utilities, but the Procurement Plan is ultimately the responsibility of the Agency. The Commission is required to review and 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, on July 15, 2025 Ameren Illinois Company ("Ameren" or "AIC") provided the IPA with the following documents for use in preparation of this Plan:

- Ameren Illinois Company Load Forecast for the period June 1, 2026 – May 31, 2031 (See Appendix B)
- Spreadsheets of the expected (base), high, and low load forecasts. (Summarized in Appendix E)
- A description of the AIC Forecasting Methodology. (See Appendix B)

[89] 220 ILCS 5/16-111.5(a).

[90] 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.

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

[92] 220 ILCS 5/16-111.5(b)(1).

[93] 220 ILCS 5/16-111.5(d)(1).

An additional forecast is offered for this Plan. It includes:

- A forecast of AIC Expected Energy October 2025 to May 2026. (See Appendix B)

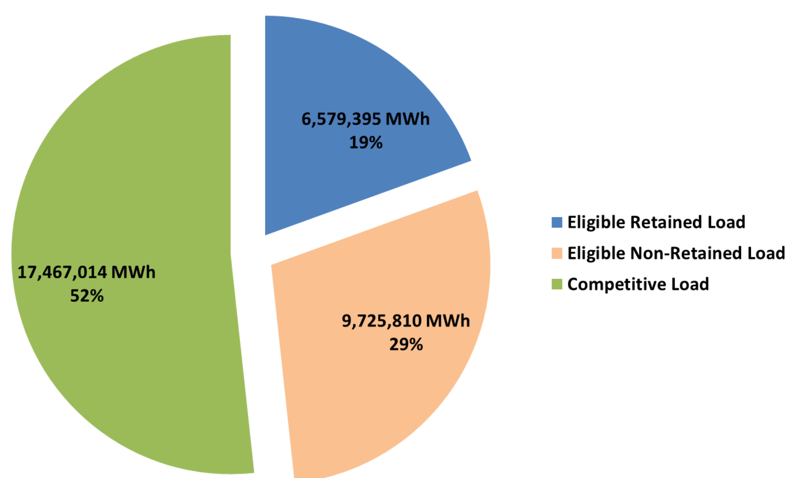
This additional forecast was provided in response to the previous 2025 Electricity Procurement Plan which required an updated forecast be provided to support the determination of the balance of the year energy procurement quantities during the September 2025 solicitation.

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. Forecasts account for switching behavior (customers leaving Ameren default supply) in favor of alternative retail energy suppliers, with adjustments made using recent data and qualitative judgement. They include energy use by customer class, monthly load shape, and eligible retail load after removing switched customers.

Figure 3-1 shows Ameren's retail load forecasted annual energy usage percentage.[94] In Figure 3-1 and similar Figures that follow, "Eligible Retained Load" represents those customers eligible to choose their power supplier (i.e., residential and small business customers) and whom choose default service supply; "Eligible Non-Retained Load" represents eligible customers that switched to an Alternative Retail Energy Supplier ("ARES") or took hourly pricing rather than default service supply; and, "Competitive Load" represents larger customers who are not eligible to receive default service supply.

Figure 3-1: Ameren Illinois' Forecast Retail Customer Load Breakdown, Delivery Year 2026-2027[95]

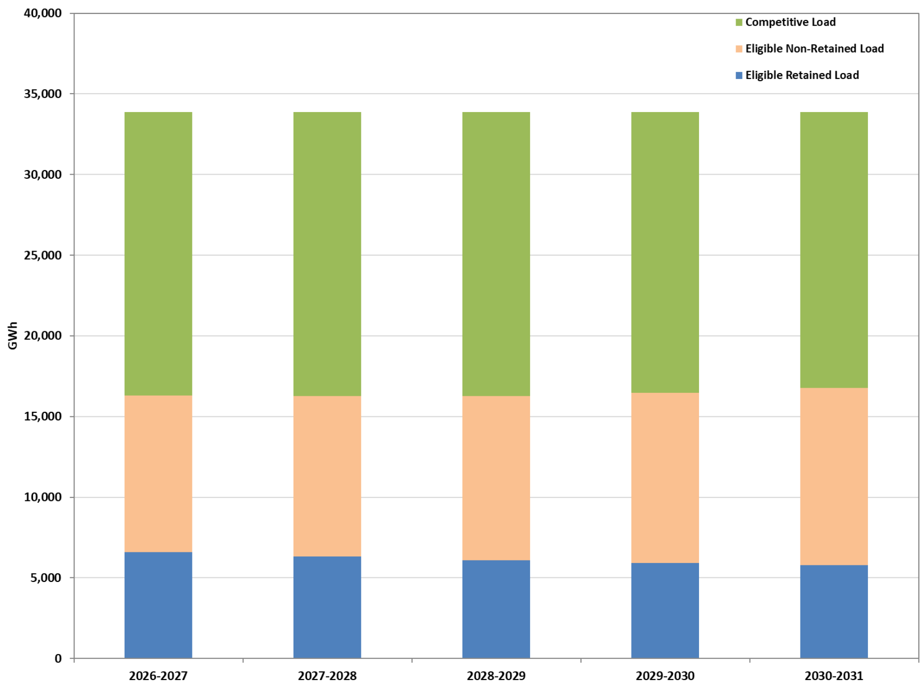


[94] Ameren Illinois assigns load profile classifications at the point of service level and only to points of service that are metered. The classifications are as follows: DS-1 – Residential, DS-2 – Non-Time of Use Commercial & Industrial with demands less than 150 kW, DS-3 – Time of Use Commercial & 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. DS-6 is temperature sensitive service.

[95] For the 2026-2027 Delivery Year, Ameren Illinois' projected total Retail Load is forecasted to be 33,873,550 MWh, where the Eligible Retained Load accounts for 6,579,395 MWh, the Eligible Non-Retained Load accounts for 9,725,810 MWh, and the Competitive Load

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. This Figure is very similar to the Figure in the 2025 Plan indicating that the relative share of customer load has not changed significantly in the past year.

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 ARES, including municipal aggregation.[96] Ameren Illinois establishes the current customer switching trend line utilizing actual switching data by customer class and then applies qualitative judgment 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.

Ameren's July 15, 2025, load forecast emphasizes that municipal aggregation continues to create considerable uncertainty into the forecasting process, similar to previous years, and this uncertainty will continue through this planning horizon. For example, the majority of municipal aggregation contracts that are set to expire in this planning cycle occur in December 2025. AIC has no definitive information to suggest these municipalities will come back to Ameren Illinois, and their research and analysis suggests that these communities will likely remain with the ARES. AIC believes the forecasts they have provided represent reasonable estimates. However, AIC also notes that municipal aggregation, community solar and ever-changing market dynamics has created considerable complexities to the forecasting process and cautions that actual results could vary considerably.

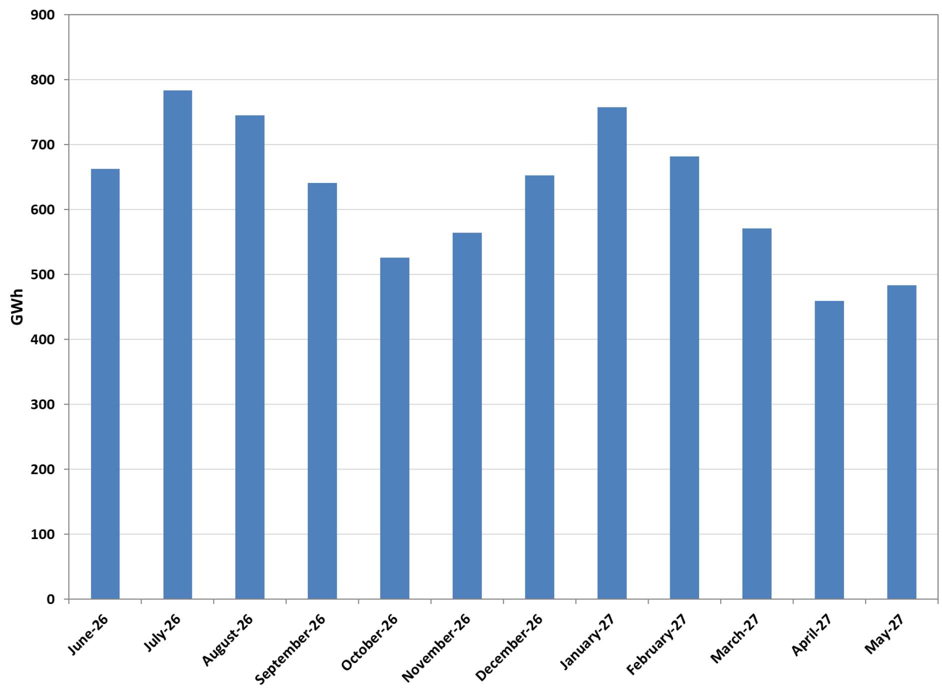
accounts for 17,568,344 MWh. The amount for the projected total Retail Load was provided by Ameren in their July 2024 response to the IPA Data Request for the 2025 Long-Term Plan.

[96] 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. This form of aggregation allows communities to opt groups of residents and small businesses into a power supply source, rather than individual residents making the choice themselves. Residents may opt out of the aggregation, which otherwise becomes the default choice for them.

Accordingly, the AIC expected (base) forecasts assume little change in municipal aggregation going forward. Conversely, their low-range and high-range forecasts assume increases and decreases in municipal aggregation and other switching, respectively.

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

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



*Total load, prior to netting QF supply.

Ameren Illinois provides a base case and two complete alternate 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, not remodeled assumptions. For the residential electric customer class, Ameren Illinois currently projects a 5-year compound annual growth rate of -0.6%. This is an increase from the -1.2% growth rate provided for the 2025 Plan. For commercial customers, the growth rate for Ameren Illinois is projected to be -1.5%, a decrease from last year's -1.2%. While for industrial customers, the growth rate for Ameren Illinois is projected to be 14.1%, a significant increase relative to last year's 1.0%, due to projected data center load growth. See Section 3.5.1 for a discussion of how this load forecast compares to national trends in electricity load growth.

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 nonfully 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	0.93	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. Weather effects are captured using the same multipliers used for macroeconomic uncertainty. The high and low scenarios only account for an average impact of weather, and macroeconomic effects, which are 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 variations Ameren Illinois attributes to macroeconomic effects, not 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, 2025, customer switching has resulted in approximately 48% of residential load choosing an ARES, a 6% *decrease* from the previous year, and 67% of small commercial load, a 1% *decrease* from the previous year, taking service from ARES rather than from Ameren's default service supply. Ameren Illinois expects that the amount of load supplied by ARES will remain flat across the planning horizon. They are kept flat "because AIC has no compelling information at this time that can indicate one direction or another."[97] The majority of municipal aggregation contracts expiring in this planning cycle occurred in June 2025 or will occur in December 2025. Most communities with contracts set to expire in June 2025 have already renewed with an ARES, now being contracted through June 2026. Ameren provided multiple load forecasts representing different switching scenarios.[98] Additionally, as shown in Table 3-2 presented in Section 3.5.4, ARES pricing offerings to individual customers, in general, are about half a cent per kWh 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 47% and 60%, respectively, in May 2025, 39% and 53%, respectively, in May 2026, and 11% and 24%, 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 60% and 73%,

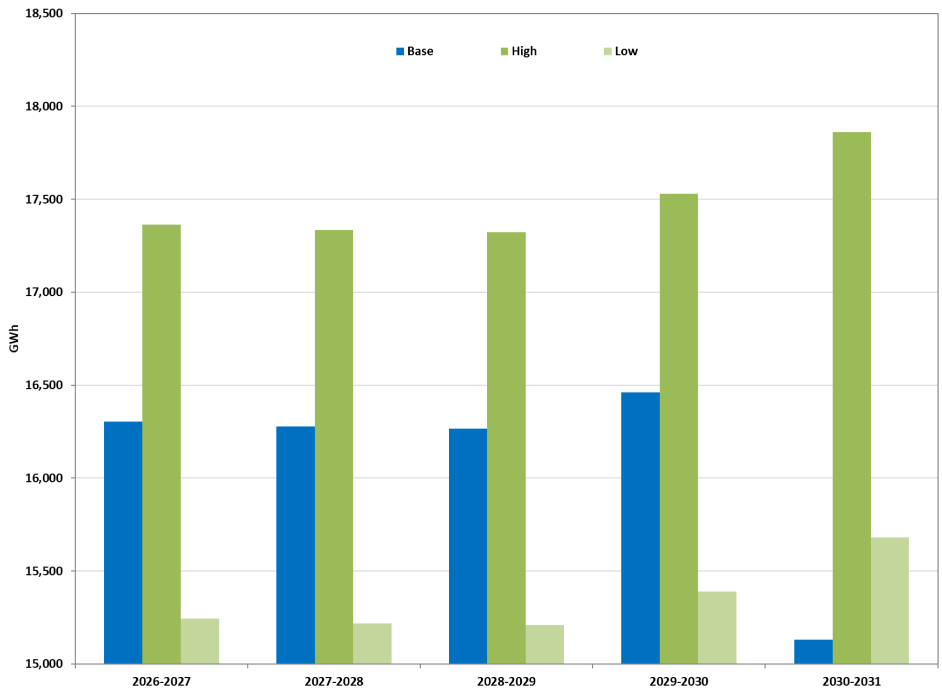
[97] See Ameren Load Forecast Submittal, Appendix B at https://ipa.illinois.gov/electricity-procurement/electricity-procurement-plan/2026-appendices.html.

[98] 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 2025 load forecasts and procurement volumes adjusted accordingly.

respectively, in May 2025, 55% and 75%, respectively, in May 2026, and 78% and 97%, 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 to serve eligible retail customers in each case. The Base Case assumes the expected switching, the High Load assumes low switching, and the Low Load assumes high switching.

Figure 3-4: Supply Obligation in Ameren Illinois' Forecast Scenarios



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. In Figure 3-5 for summer days, there is little difference between the profiles of the high, low, and base cases. However, in Figure 3-6 for spring days, there is significant difference in the load profiles of the high, low, and base cases during the daylight hours.

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

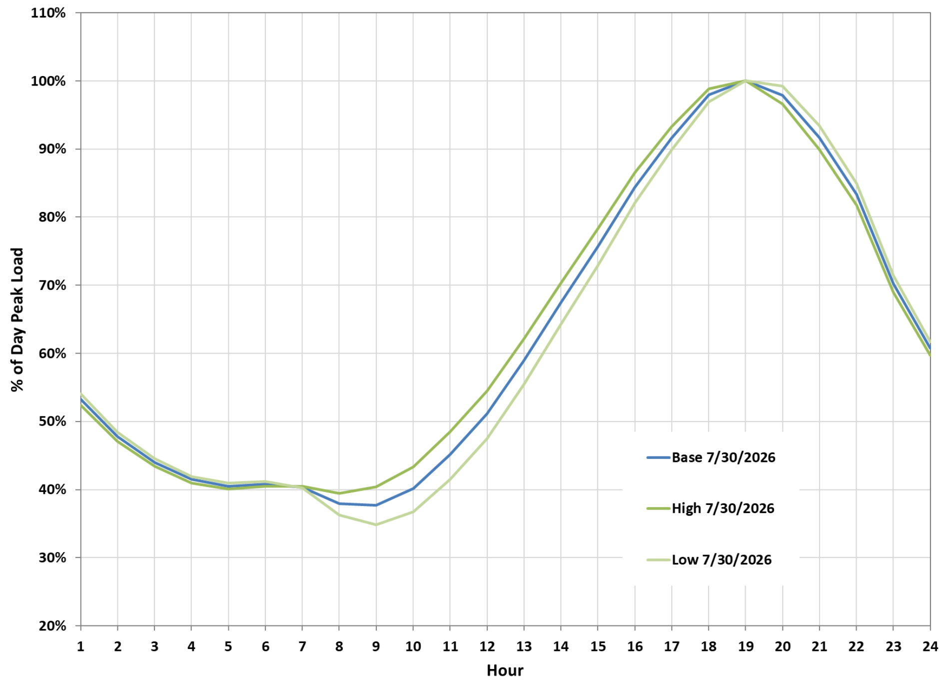
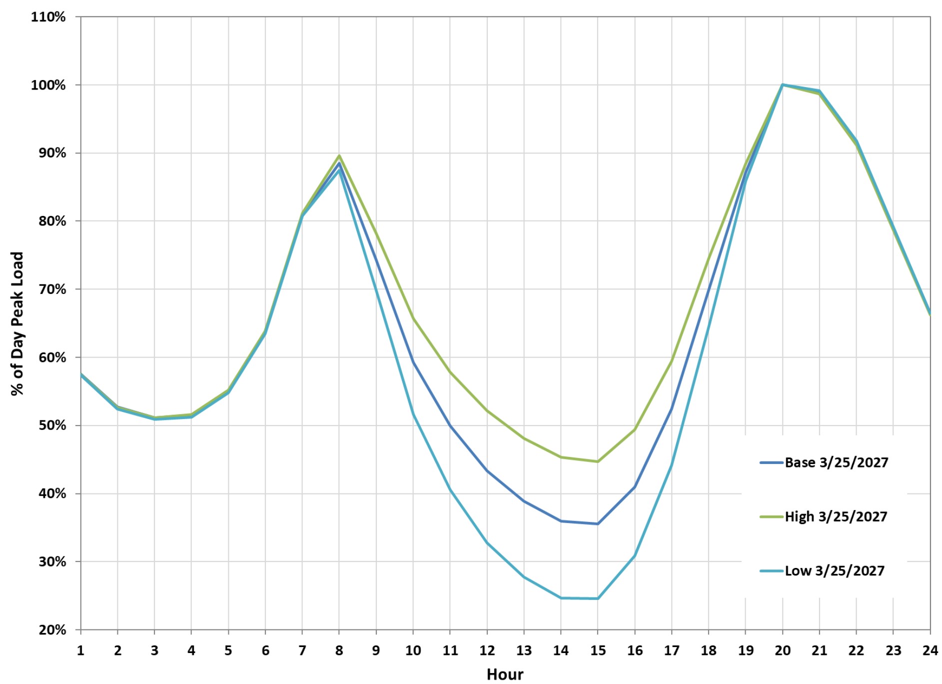


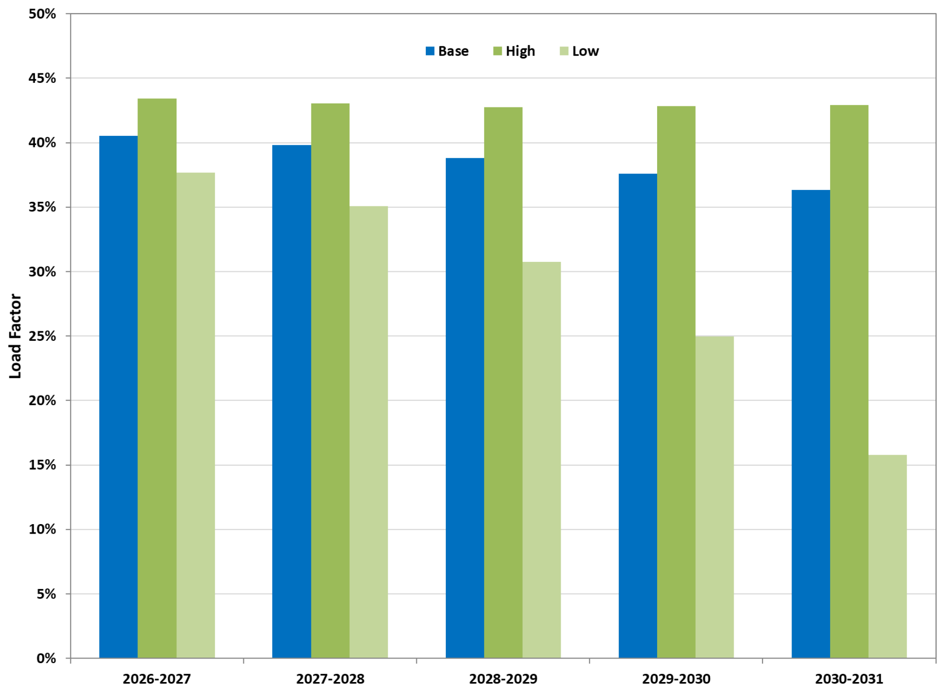
Figure 3-6: Sample Daily Load Shape, Spring Day in Ameren Illinois' Forecasts



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 or otherwise flat. 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' Forecast Scenarios



3.3 Summary of Information Provided by ComEd

In compliance with Section 16-111.5(d)(1) of the Public Utilities Act, on July 15, 2025 ComEd provided the IPA the following documents for use in preparation of this Plan:

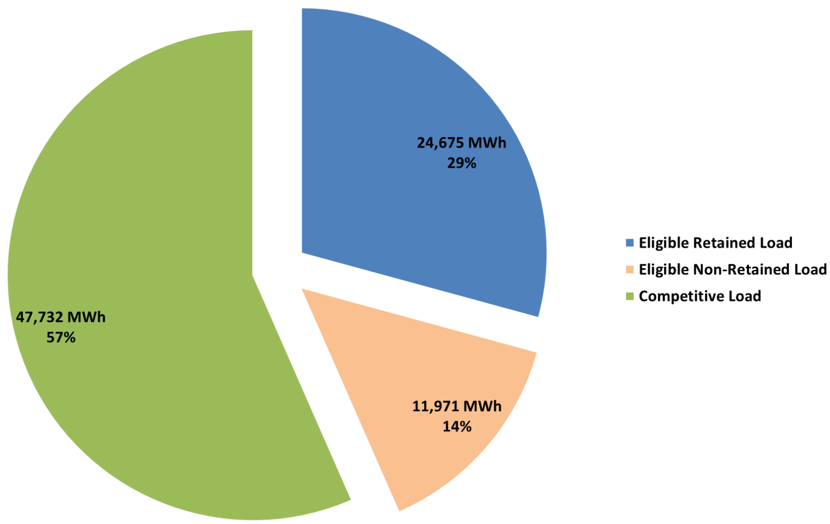
- *Load Forecast for Five-Year Planning Period June 2025 – May 2030.* (See Appendix C) This document also contained several appendices.
- Information supporting the load forecasts including spreadsheets of load profiles, hourly load strips, model inputs, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix F) [99]

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 are not eligible retail customers. Figure 3-8 shows ComEd's retail load forecasted annual energy usage percentage. These percentages have changed very little from the 2025 Plan.

[99] In its July 15, 2025 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 2026-2027[100]



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 to account 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. The Figure shows little change in Eligible Retained Load and Non-Retained Load compared to the last Plan. But significant increases in Competitive Load.

[100] For the 2025-2026 Delivery Year, ComEd's projected total Retail Load is 84,260 GWh, where the Eligible Retained Load accounts for 23,870 GWh, the Eligible Non-Retained Load accounts for 13,054 GWh, and the Competitive Load accounts for 47,337 GWh. The amount for the projected total Retail Load was provided by ComEd in their July 2024 response to the IPA Data Request for the 2025 Long-Term Plan.

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

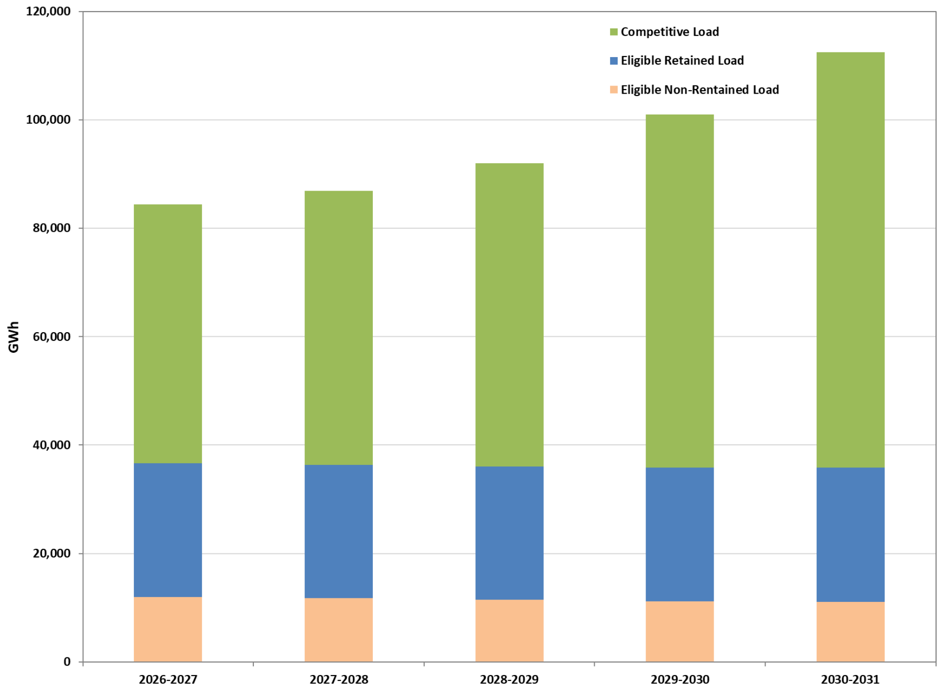
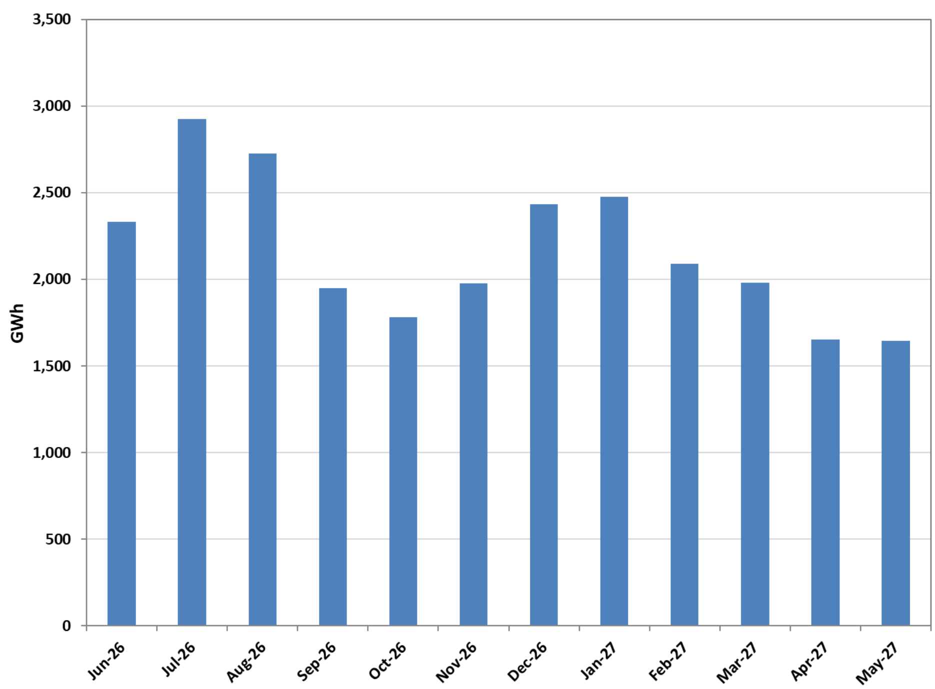


Figure 3-10 provides a monthly breakdown of the base-case forecast of ComEd's eligible retail customer load, that is, the load of customers who are forecasted to take bundled supply under this Plan. This Figure shows little change as compared to the 2025 Plan.

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). ComEd provided a June 2026 – May 2031 monthly expected load forecast that included a calculated annual growth rate of approximately 0.06%. This is an increase compared to the June 2025 – May 2030 monthly expected load forecast which reflected a decline of -0.38%, provided in July 2024. There is a slight negative growth rate in the first two years of the forecast; however, the growth rates turn positive in the final two years. See Section 3.5.1 for a discussion of how this load forecast compares to national trends in electricity load growth.

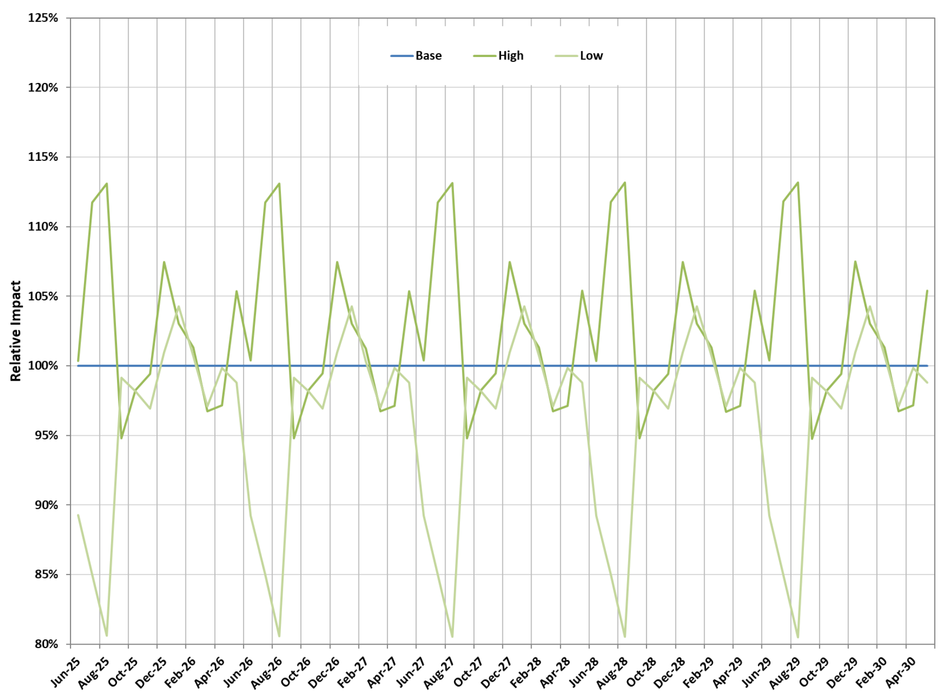
3.3.2 Weather

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 percentage adjustments not remodeling) 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

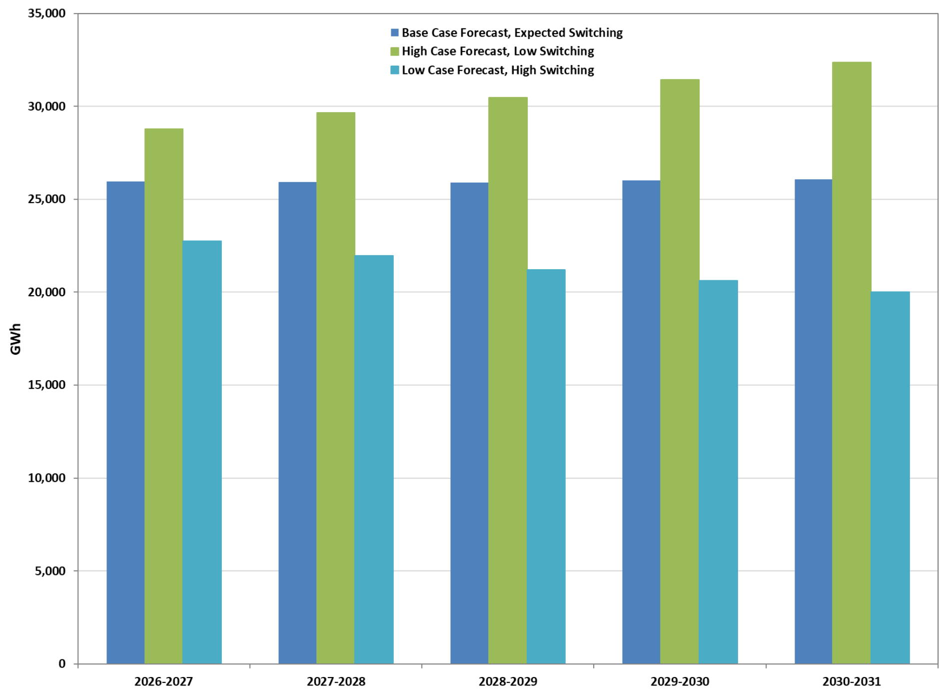


3.3.3 Switching

The high switching (low load) case assumes residential, watt-hour, and 0 to 100 kW blended service[101] usage will be reduced by a total of 4% by December 2025 and 6% by December 2026 as the communities that are opting out from ComEd service renew their municipal aggregation programs. Municipal aggregation has historically been a major factor in the rapid expansion of residential ARES supply. In total, there are 358 governmental entities (i.e., municipalities, townships, or counties) within the ComEd service territory that had approved aggregation as of May 2025, with 175 of those communities actively being served through municipal aggregation (a decrease from 200 in June 2024). The percentage of potentially eligible retail customers taking blended service in this switching scenario is 60% (based on usage) as of December 2026 compared to 66% in the expected load forecast.

The low switching (high load) case assumes additional communities opt out of municipal aggregation such that residential usage increases by a total of 4% by December 2025 and 6% by December 2026. The percentage of potentially eligible retail customers taking blended service in this switching scenario is 72% (based on usage) as of December 2026 as compared to 66% 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.

Figure 3-12: Supply Obligation in ComEd's Forecast Scenarios



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 solar daylight hours, with the peak shifted to later in the day. During the sample spring day, the base case, high case, and low case peaks are very similar.

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

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

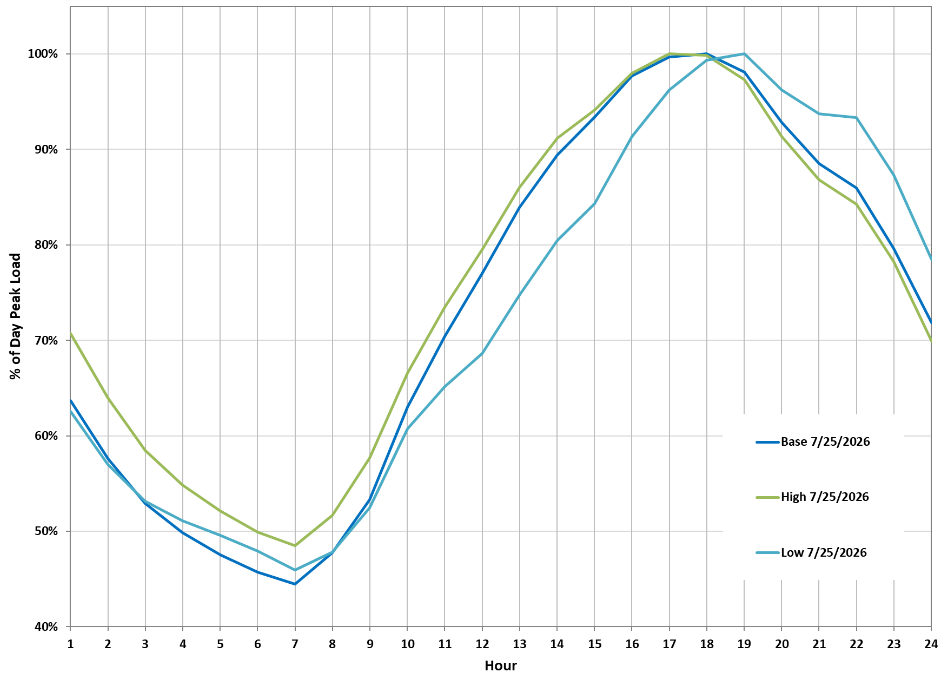
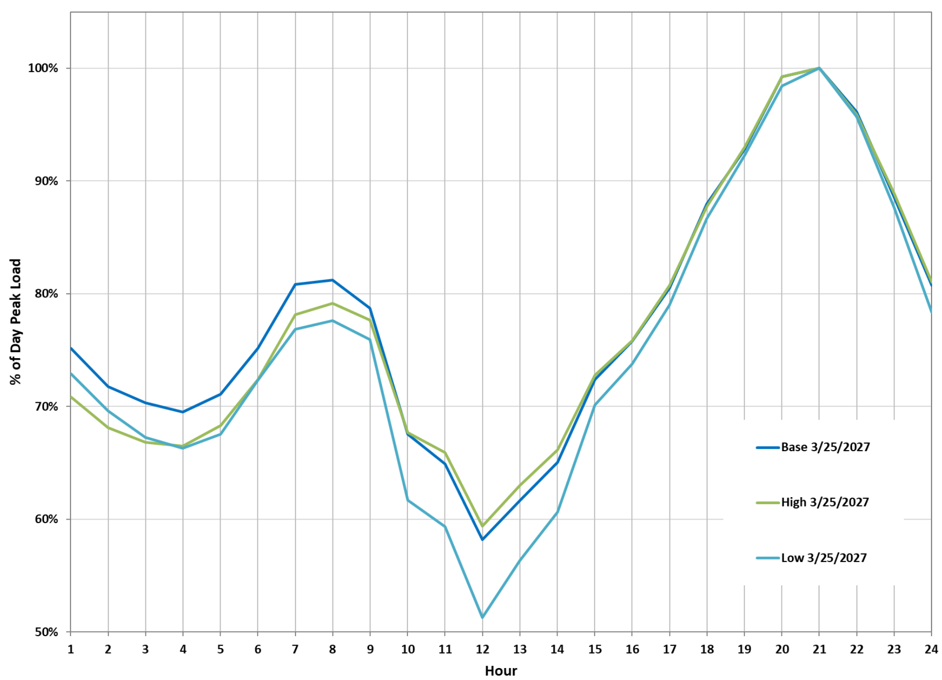
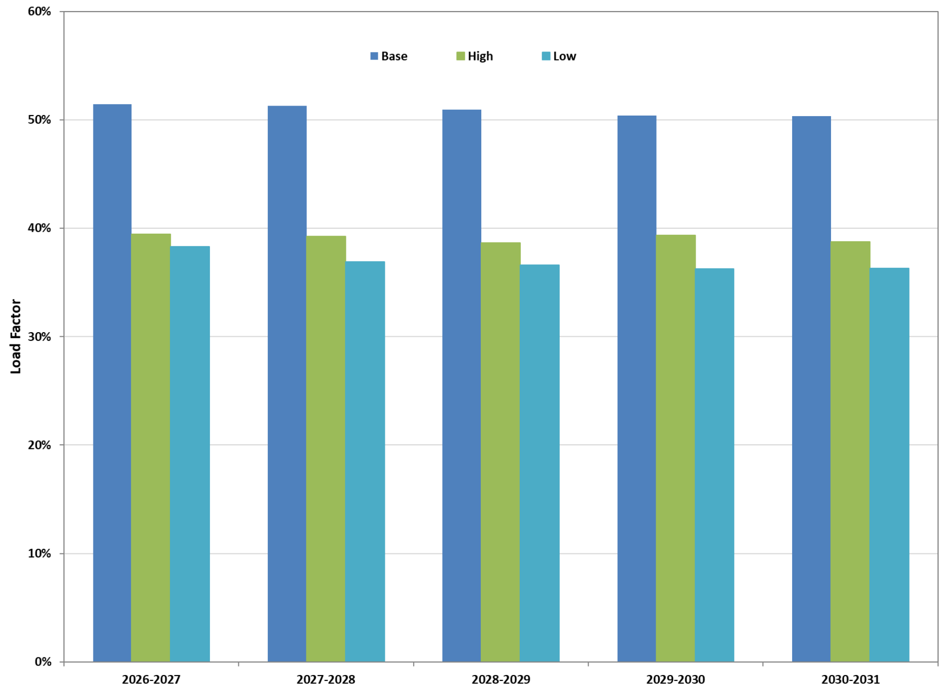


Figure 3-14: Sample Daily Load Shape, Spring Day in ComEd's Forecasts



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). This information is essentially unchanged from the previous Plan.

Figure 3-15: Load Factor in ComEd's Forecasts Scenarios



3.4 Summary of Information Provided by MidAmerican

In compliance with Section 16-111.5(d)(1) of the Public Utilities Act, similar to Ameren and ComEd MidAmerican provided the IPA the following documents on July 15, 2025 for use in preparation of this plan:

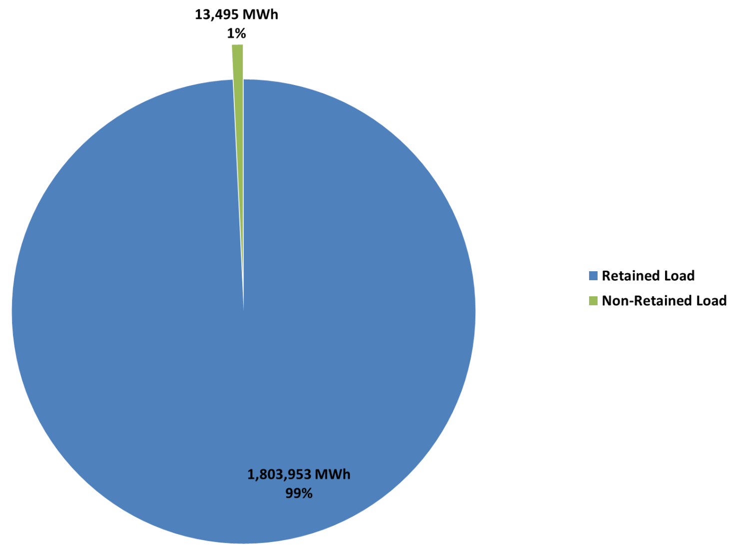
- *Methodology for the 2026 Plan Illinois Electric Customers and Sales Forecasts.* This document contained a discussion of load forecast methodology for all MidAmerican scenarios and supporting data for the base scenario forecast. This provides data similar to that provided in previous plans. The load 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)
- The load and capability data uses the planning reserve margin target provided by MISO and does not contain an additional reserve margin adjustment to forecast the impact of MISO's reliability-based demand curve that was recently approved by the Federal Regulatory Commission.

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 MidAmerican'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 2026-2027 [102]



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. The data shows constant levels of retained load over time, and relatively little switching activity.

[102] For the 2025-2026 Delivery Year, MidAmerican's projected total Retail Load is 1,926,118 MWh, where the Eligible Retained Load accounts for 1,863,101 MWh and the Eligible Non-retained Load accounts for 63,017 MWh. The amount for the projected total Retail Load was provided by MidAmerican in their July 2024 response to the IPA Data Request for the 2025 Long-Term Plan.

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

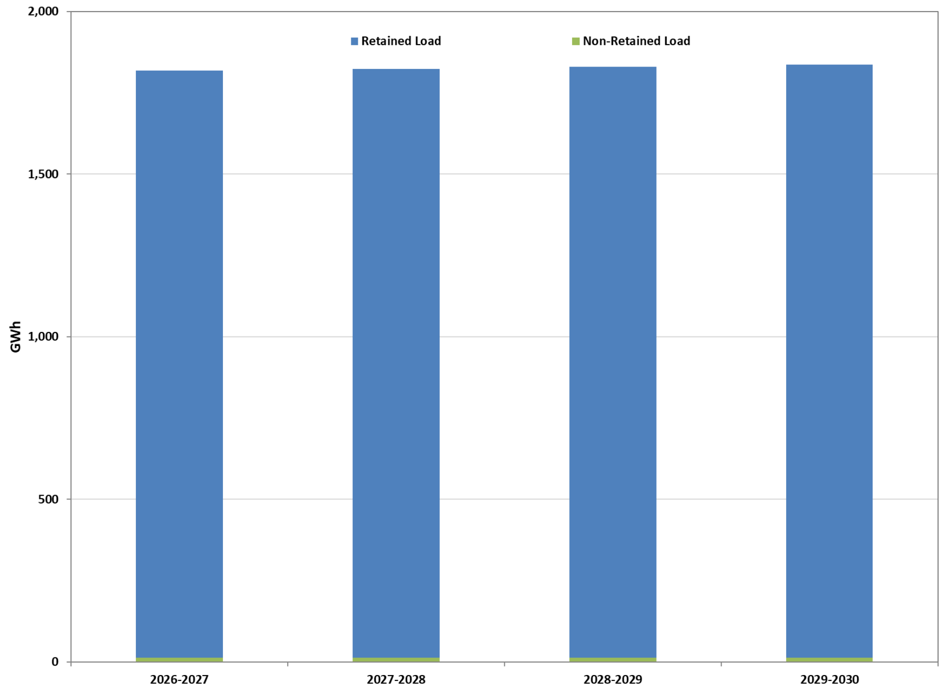
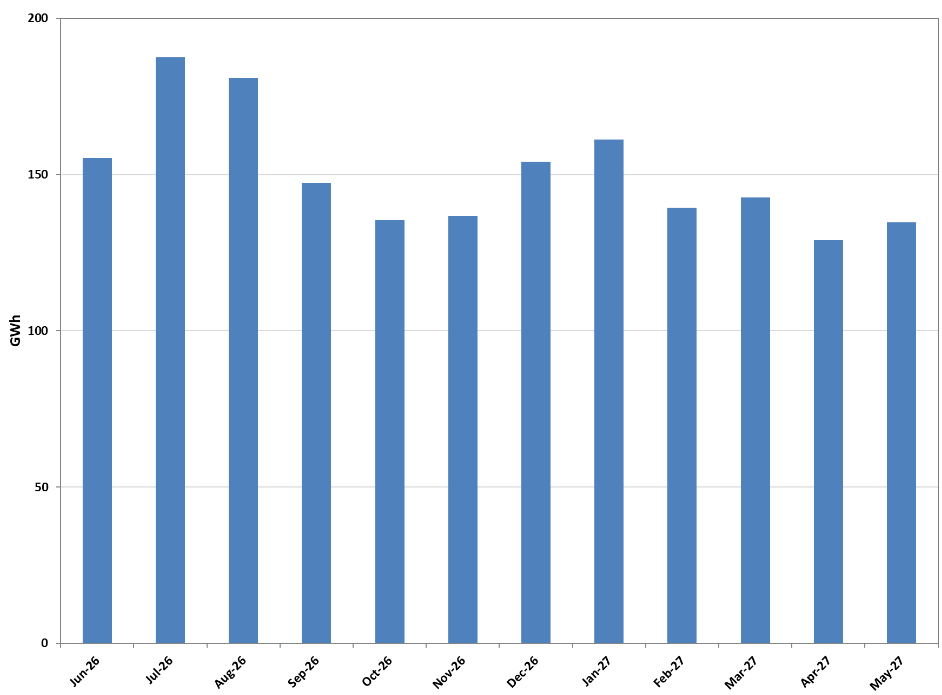


Figure 3-18 provides a monthly breakdown of the base case forecast of MidAmerican retained eligible retail customer load, that is, the load of customers on bundled supply to be considered under this Procurement Plan.

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 assumed to remain constant.

MidAmerican provided a June 2025 – May 2031 monthly expected load forecast which included a calculated annual growth rate of approximately -1.2%. While this growth rate is declining, on a relative basis the value is increasing as compared to the June 2024 – May 2030 monthly expected load forecast, provided in July 2024, which was -1.9%. MidAmerican has provided an additional notation that they are projecting a load reduction to their Illinois operations stemming from an expected change in operations of a manufacturer – 3M is expected to conclude operation of an energy-intensive product line beginning in 2025. See Section 3.5.1 for a discussion of how this load forecast compares to national trends in electricity load growth.

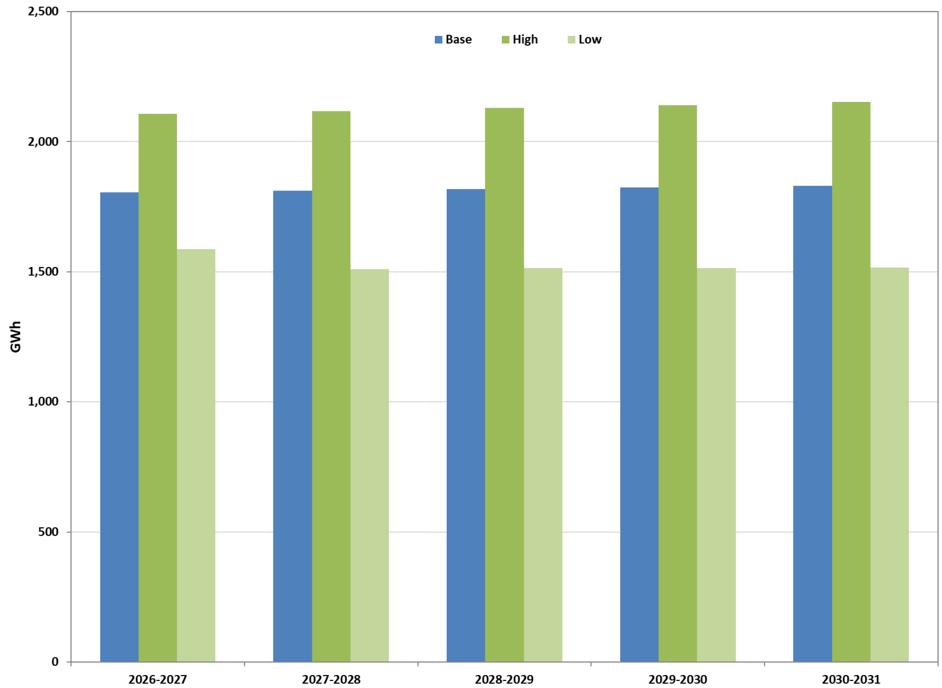
3.4.2 Weather

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 Forecast Scenarios



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 in the afternoon, and the low case is peakier than the base case at night.

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

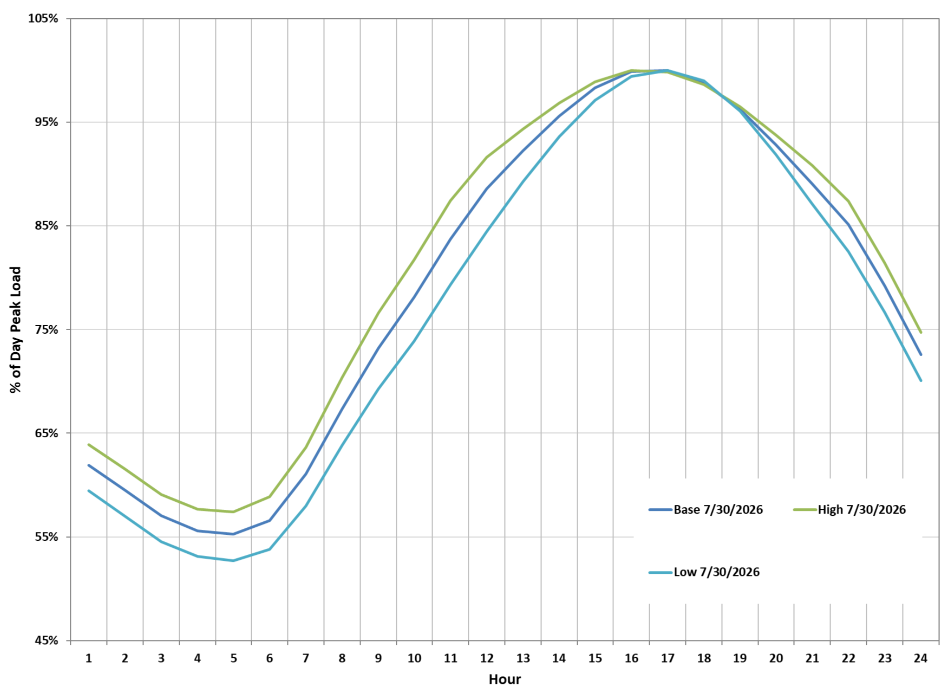
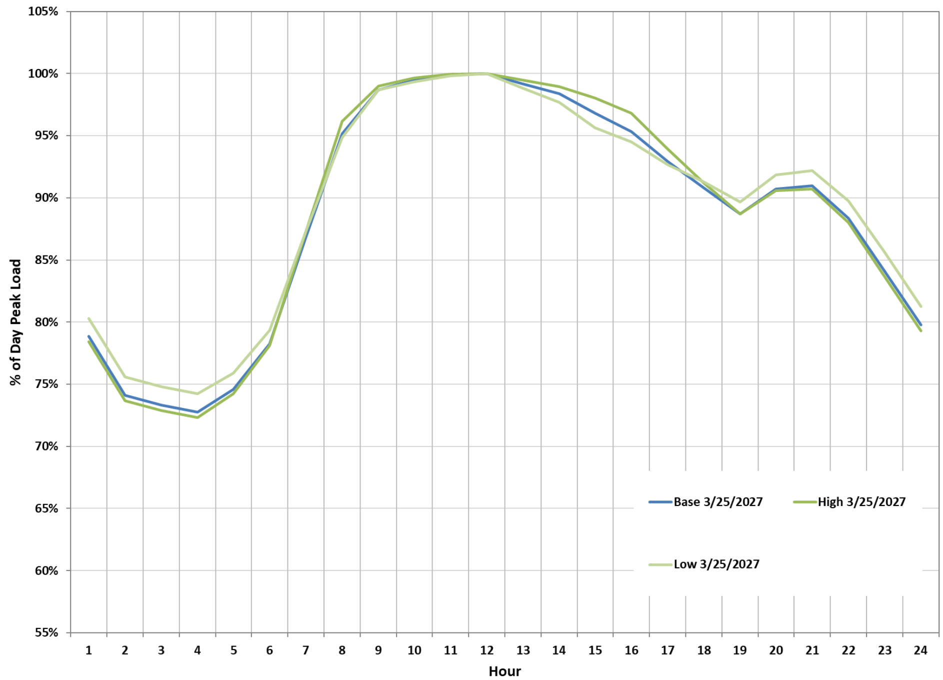
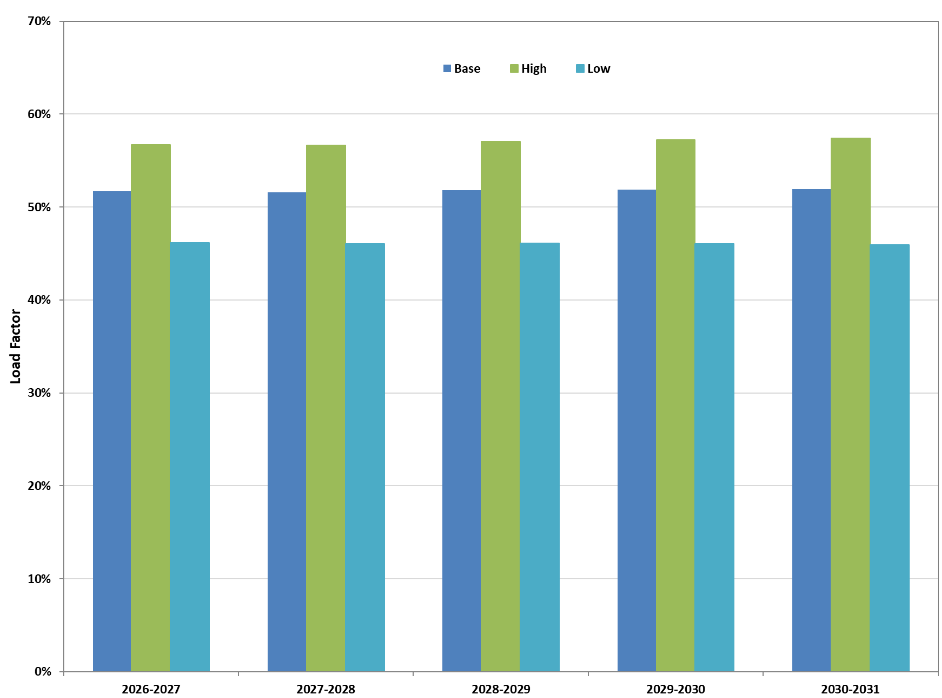


Figure 3-21: Sample Daily Load Shape, Spring Day in MidAmerican's Forecasts



The annual load factors are shown in Figure 3-22. As expected, the base, the high, and the low case load factors are consistent over time, being within the 46-57% range.

Figure 3-22: Load Factor in MidAmerican's Forecast Scenarios



3.5 Sources of Uncertainty in the Load Forecasts

In the past, the Agency has procured power for all three 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 was extremely advantageous, the Agency does not purchase its entire forecast that far ahead because the forecast is itself uncertain due to load growth, weather, switching, and hourly variability. 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

The demand for electricity across the U.S., as well as in the Midwest and Illinois specifically, has been largely flat to declining through the 2010's through early 2020's. Recent trends show an increase in electricity demand driven by current and projected data center growth, increased vehicle electrification, and economic growth, such as growth in domestic manufacturing activity. The Chicago area has been identified as a primary U.S. data center market which will impact Illinois' growing load. In 2024, U.S. electricity sales to retail customers increased by 2.3%. In the August 2025 Short-Term Energy Outlook, the U.S. EIA forecasts U.S. electricity sales to retail customers increased by 2.2% in 2025 and 2.4% in 2026.[103] By comparison, total electricity end use as reported by the EIA was essentially flat during the five-year period ending in 2023.[104]

While data centers are driving major increases in forecasted electricity demand, they are typically large commercial customers[105] and therefore will not impact the Agency's eligible retail load, which consists of residential and small commercial customers. The base case utility load forecasts consider specific factors impacting load growth for eligible retail load. Other drivers such as vehicle electrification and economic growth are being realized throughout all customer segments, including eligible retail load. Beyond the identified load growth factors, according to Ameren, the greatest driver of uncertainty for eligible retail load forecasts is municipal aggregation and customer switching.

For the residential electric customer class, Ameren Illinois currently projects a 5-year compound annual growth rate decline of -0.6%. This is a relative increase from the -1.2% growth rate provided for the 2024 Plan. For commercial customers, the growth rate for Ameren Illinois is projected to be a decline of –1.5%. For industrial customers, the growth rate for Ameren Illinois is projected to be 14.1%, a substantive increase from the preceding year's 1.0% growth rate, primarily driven by the projected increase in data center load growth. ComEd provided a June 2026 – May 2031 monthly expected load forecast, with a calculated annual growth rate of approximately 0.06%. This is an increase as compared to the June 2025 – May 2030 monthly expected load forecast, which was -0.38%, provided in July 2024. Of note, the ComEd forecast includes a slight negative growth rate in the first two years; however, the growth rates turn positive in the final two years. MidAmerican provided a June 2025 – May 2031 monthly expected load forecast, with a calculated annual growth rate decline of approximately -1.2%. This statistic has increased on a relative bases when compared to the June 2024 – May 2030 monthly expected load forecast provided in July 2024, which was -1.9%. MidAmerican has noted in their forecast documentation that they have projected a load reduction to occur in their Illinois operations stemming from the expected reduction in a manufacturer's operations – that of 3M who is expecting to conclude operations around an energy-intensive product line starting in 2025.

[103] U.S EIA Short-Term Energy Outlook (August 2025). https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf.

[104] U.S. EIA Total Energy Monthly Energy Review Table 7.6 Electricity End Use and Electric Vehicle Use. Total End Use. https://www.eia.gov/totalenergy/data/brows.

[105] See https://www.datacenterknowledge.com/energy-power-supply/data-center-power-fueling-the-digital-revolution for examples of the power consumption of typical data centers.

The IPA will continue to monitor national load growth trends and the utilities' updated forecasts to determine if these trends are likely to impact eligible customer retail load growth in Illinois which could subsequently be addressed in future procurement plans.

Ameren Illinois and ComEd construct their load forecasts by projecting load for their entire delivery service area, then completing subsequent load forecasting for each customer class or rate class within the service territory, and finally 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 ±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 ±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

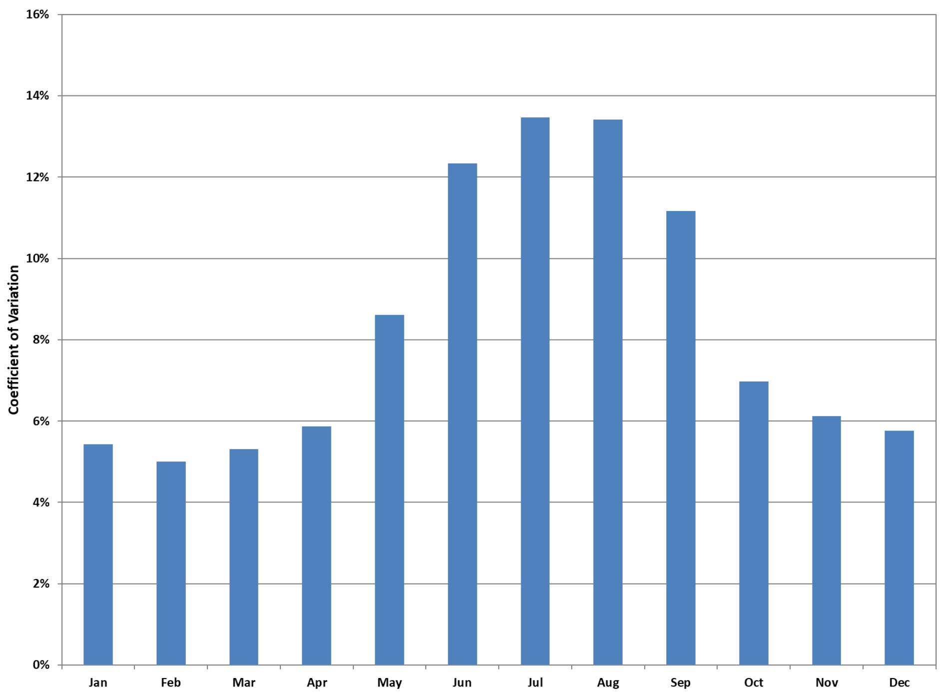
On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The discussion of high and low scenarios in Sections 3.2.2, 3.3.2, and 3.4.2 notes the way that Ameren Illinois, ComEd, and MidAmerican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

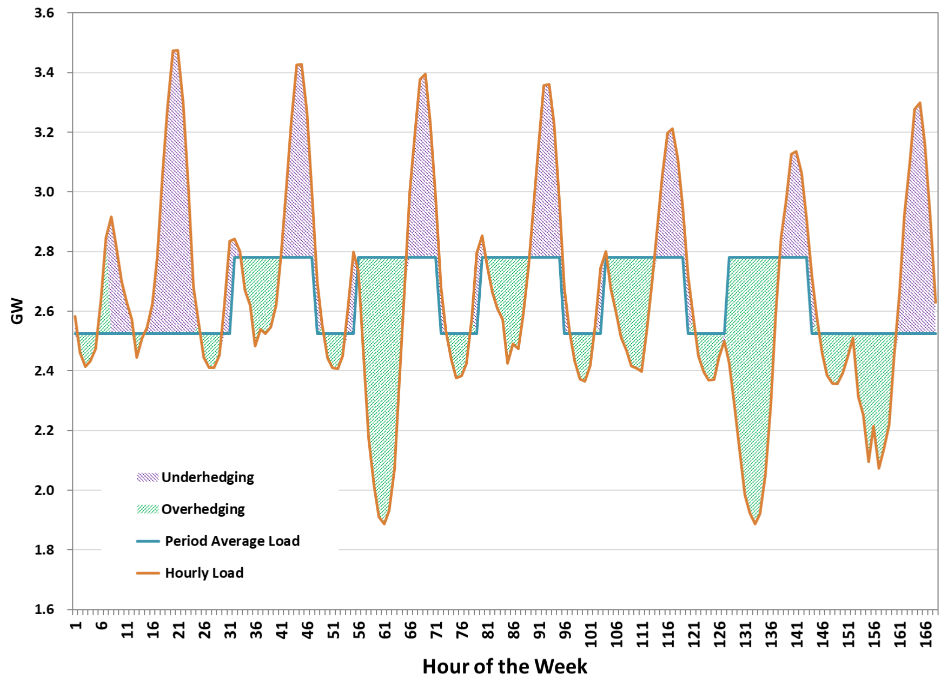
Figure 3-23 illustrates this disconnect by showing, for each month, the average historical "daily coefficient of variation" for peak period loads. This figure is based on historical ComEd loads from 2009 through 2023, normalized to the monthly base case forecasts in the first Delivery Year. To calculate 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

Municipal aggregation is a significant source of uncertainty in utility load forecasts. In its base case, Ameren Illinois projected that approximately 48% of potentially eligible retail customer load[106] switched away from Ameren Illinois default fixed price tariff service by the end of the 2024-2025 Delivery Year. This is lower than the 54% switching statistics in the July 2024 forecast. Ameren expects that the communities will renew their agreements with the ARES, and AIC will see a similar rate of individual opt-out within these communities.[107] Ameren Illinois' current default service price is lower than comparable ARES prices for individual customers (as shown in Table 3-2 below), which may result in some individual customers opting to return to utility service.

For ComEd, approximately 10% of Municipal Aggregation Communities by usage opted to suspend their programs and return customers back to ComEd in 2024. ComEd assumes a 5% suspension rate for the rest of 2025 as reflective of recent activity. 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.[108] Individual customers who choose one of these other rate structures presumably have made an affirmative choice to take on those alternative services.

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

[107] In March 2025 AIC developed three energy forecasts that assume that these communities will renew their agreements with the ARES, and AIC will see a similar rate of individual opt-out within these communities. As such, the forecasts do not contain a switching scenario where load leaves or returns to AIC's fixed price supply due to the expiration of municipal aggregation agreements.

[108] For more information on choices offered by ARES, see the July 2024 Annual Report of the ICC Office of Retail Market Development at https://icc.illinois.gov/api/web-management/documents/downloads/public/icc-reports/2024%20ORMD%20Section%2020-110%20Report.pdf .

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.[109] 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 to individual residential customers.[110] The variability of PTC values between summer and non-summer months for Ameren, seen especially in summer of 2025, was largely driven by Ameren's basing the capacity component for summer months on summer capacity prices. Capacity prices for the Summer 2025 MISO PRA cleared at $666.50/MW-day, over 20 times higher than the Summer 2024 MISO PRA, which cleared at $30/MW-day. Following this summer period, Ameren's PTC is projected to drop down a bit in the non-summer period. It is reasonable to assume that switching behavior by individual customers (other than those who chose an ARES rate that is not an "apples-to-apples" comparison to the utility rate, or one that offers additional perceived value) will not be a significant factor in the load forecast, except for transition to municipal aggregation, opt-out from municipal aggregation, and return from municipal aggregation. The ARES offer currently applicable to MidAmerican's service territory is a variable rate which is not comparable to the utility's price.

Table 3-2: Representative ARES Fixed Price Offers and Utility Price to Compare[111]

Utility Territory	Utility Price to Compare (¢/kWh)	Representative ARES Price (¢/kWh)
Ameren Illinois (Rate Zone I)	12.18	12.79
Ameren Illinois (Rate Zone II)	12.18	12.65
Ameren Illinois (Rate Zone III)	12.18	12.79
ComEd	10.03	10.25

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,[112] 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

[109] 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.

[110] 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 July2025 would pay approximately 5% more than if they were to take default supply service from the utility. ComEd retail customers would pay approximately 2% less.

[111] The values in the table are as of July 31, 2025. Offers without an explicit premium renewable component. Monthly service fees and early termination fees are not included in rates.

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

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 2024, there were 67 operational utility scale battery-based storage systems with a total capacity of 415 MW operating in PJM and 35 systems totaling 84.7 MW operating in MISO. Illinois was listed as having 13 utility scale projects with 117.6 MW in operation and 6 utility scale projects with 220.0 MW proposed and under construction.[113] The overwhelming majority of these projects are based on Li-ion chemistry.

While utility scale energy storage technology continues to be developed and deployed, solar PV integrated with storage offers significant potential to enhance the benefits and spur the development of solar generation at utility scale. 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 2008 to 2022[114] and are now expected to fall by an average of 11% per year from 2023 to 2030.[115] 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 encouraged the development of distributed solar PV, there were clear provisions in Illinois law to encourage the adoption of integrated storage technologies prior to the enactment of Public Act 102-0662 on September 15, 2021. Public Act 102-0662 includes several provisions encouraging the development of integrated energy storage in Illinois, including storage co-located at shuttered coal plant sites alongside new utility-scale solar projects,[116] rebates for energy storage systems,[117] and mandating a study of policies and programs that could support energy storage systems.[118] Multiple proposals in the Spring 2024 session of the 103rd General Assembly sought for the IPA to develop an energy storage procurement plan and procure energy storage credits to support the development of new energy storage projects, although no such bills passed. On January 7, 2025, HB 587 passed the General Assembly; assuming that the legislation is enacted, the Commission will initiate a workshop process for the purpose of facilitating the development of a storage procurement process in consultation with the Agency. The Agency will continue to monitor the development of the energy storage market in the coming years and monitor developments on additional energy storage legislation in the Illinois General Assembly.

[113] The summary values were calculated by reviewing the following two databases: 1) U.S. Department of Energy 2023 Form EIA-860 Data - Schedule 3, 'Energy Storage Data', https://www.eia.gov/electricity/data/eia860/, release date 6/12/2024 and 2) https://sandia.gov/ess-ssl/gesdb/public/, queried in July 2023. Duplicate projects identified across the two databases were removed from the totals.

[114] Electric Vehicle Battery Pack Costs in 2022 Are Nearly 90% Lower than in 2008, according to DOE Estimates, January 9, 2023

https://www.energy.gov/eere/vehicles/articles/fotw-1272-january-9-2023-electric-vehicle-battery-pack-costs-2022-are-nearly#:~:text=The%20Department%20of%20Energy's%20(DOE's,least%20100%2C000%20units%20per%20year.

[115] https://www.goldmansachs.com/intelligence/pages/electric-vehicle-battery-prices-falling.html.

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

[117] See 220 ILCS 5/16-107.6(b-5) and (c).

[118] See: 220 ILCS 5/16-135.

3.6 Recommended Load Forecasts

3.6.1 Base Cases

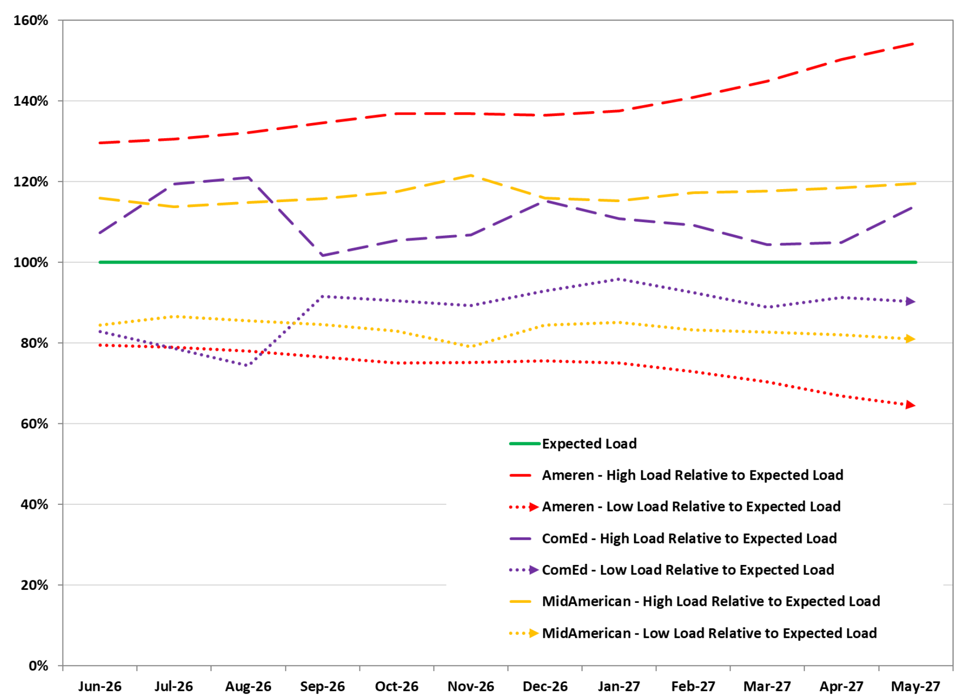
The IPA recommends adoption of the Ameren Illinois, ComEd, and MidAmerican base case load forecasts.[119] The Ameren Illinois and ComEd forecasts include already approved energy efficiency programs, and MidAmerican's forecast includes verified energy efficiency program impacts as well.

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 74% and 139% of the base case forecast, respectively, during the 2026-2027 Delivery Year. Comparatively, for the same period, ComEd's low and high load forecasts are on average equal to 88% and 110% of the base forecast, respectively. This reflects the differences in switching assumptions used by the two utilities. MidAmerican's low and high load forecast deviations from the base case are flat and symmetrical being equal to 83% and 117%, respectively. The reference case forecasts for retail switching were not changed in Mid American's high and low load forecasts. This information is similar to the previous Plan, with Ameren's data showing a wider range high and low over time.

Figure 3-25: Comparison of Ameren Illinois, ComEd, and MidAmerican High and Low Load Forecasts for Delivery Year 2026-2027



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

[119] As discussed in Footnote 107, the Agency also adopts Ameren Illinois' mid scenario of switching related to municipal aggregation contained within the base case load forecast.

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.[120] 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.[121]

The 2025 Procurement Plan targeted 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 2026 Procurement Plan will continue to target the procurement of energy supply to meet the needs of eligible retail customers 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 wholesale market. 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 2024 Procurement Plan's energy procurement strategy involved procurement of hedges to meet a portion of the hedging requirements over a three-year period and included two procurement events in which the July and August peak requirements were targeted to be hedged at 106% for Ameren Illinois and MidAmerican, while the remaining peak and off-peak requirements were targeted to be hedged at 100% for Ameren Illinois and MidAmerican. The Commission's Final Order approving the 2025 Plan included hedging targets of 50% in June through September and 30% in remaining months for the upcoming delivery year.

In response to FERC's decision on August 31, 2022, approving revisions to the Midcontinent Independent System Operator, Inc. ("MISO") Open Access Transmission, Energy and Operating Reserve Markets Tariff, MISO established a seasonal resource adequacy construct. Following MISO's implementation of this seasonal capacity construct in the 2023-2024 Delivery Year, the Agency held its third and fourth capacity events to procure seasonal Zonal Resource Credits ("ZRCs") in the Fall 2023 Capacity Procurement and the Spring 2024 Capacity Procurement, respectively.

For Ameren Illinois and MidAmerican, this Plan maintains the 106% hedging target for July and August on-peak to mitigate the impact of shaping risk, which due to the correlation between load and price, results in load-weighted prices during peak hours being greater than time-weighted prices. In the risk analysis conducted for the 2014 Plan, the IPA determined that load shape and its correlation with prices adds approximately 6% to the average cost of energy supply. For Ameren Illinois and MidAmerican, the IPA will continue its current energy procurement strategy for July and August which involves procurement of on-peak hedges at 106% and off-peak at 100%. Based on the Commission's Order approving the 2025 Plan, the IPA will maintain the hedging targets for ComEd of 50% for June through September and 30% for October through May of the 2026-2027 Delivery Year to recognize the value that CMCs can provide to eligible retail customers in offsetting energy price fluctuations. Because CMC contracts end after the 2026-2027 Delivery Year, procurement targets for ComEd for the third year of procurement (the 2027-2028 Delivery Year) will return to a level designed to hedge to 100% (and 106% on-peak for July and August) at the conclusion of the three-year cycle of procurements.

Additionally, the IPA will continue its current energy procurement strategy to meet the hedging requirements over a three-year period and includes two procurement events each year, one in the spring and the second in

[120] See 2014 IPA Procurement Plan at 93.

[121] https://ipa.illinois.gov/energy-procurement/prior-approved-plans.html.

the fall. Percentage and quantity targets for each procurement event in 2026 are specified in Section 7.1 of this Plan.

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 "LTPPAs"), starting in June 2012, made by Ameren Illinois and ComEd in December 2010 pursuant to the Final Order in Docket No. 09-0373.[122]
- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017.[123]

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 2026 through May 2031, planning period, using the base case on-peak forecast described in Chapter 3.

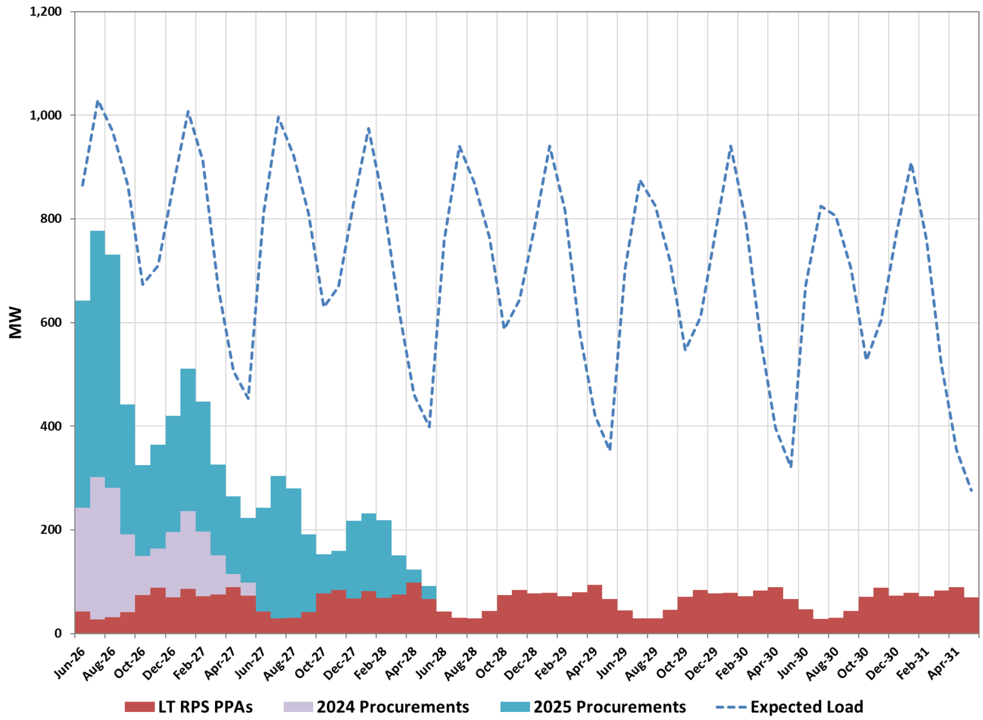
Ameren Illinois' existing supply portfolio, including long-term renewable energy resource contracts, is not sufficient to cover the projected load for the 2026-2027 Delivery Year. Additional energy supply will be required for the entire 5-year planning period. As of April 2023, Ameren Illinois was serving approximately 57% of its eligible load. However, in response to recent volatile pricing and market conditions, the utility is forecasting a switching percentage of approximately 45% in its residential load forecast which is discussed in Chapter 3. The Ameren Illinois switching assumptions are summarized in Section 3.2.3.

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

[122] MidAmerican is not a counterparty to the LTPPAs. Additionally, through the passage of P.A. 103-1066, to ensure payment certainty for Sellers, utilities are now obligated to make payments and continue collections for projects under contract even in the event of the Illinois RPS Budget being exceeded.

[123] 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.

Figure 4-1: Ameren Illinois' On-Peak Supply Gap - June 2026-May 2031 Period - Base Case Load Forecast

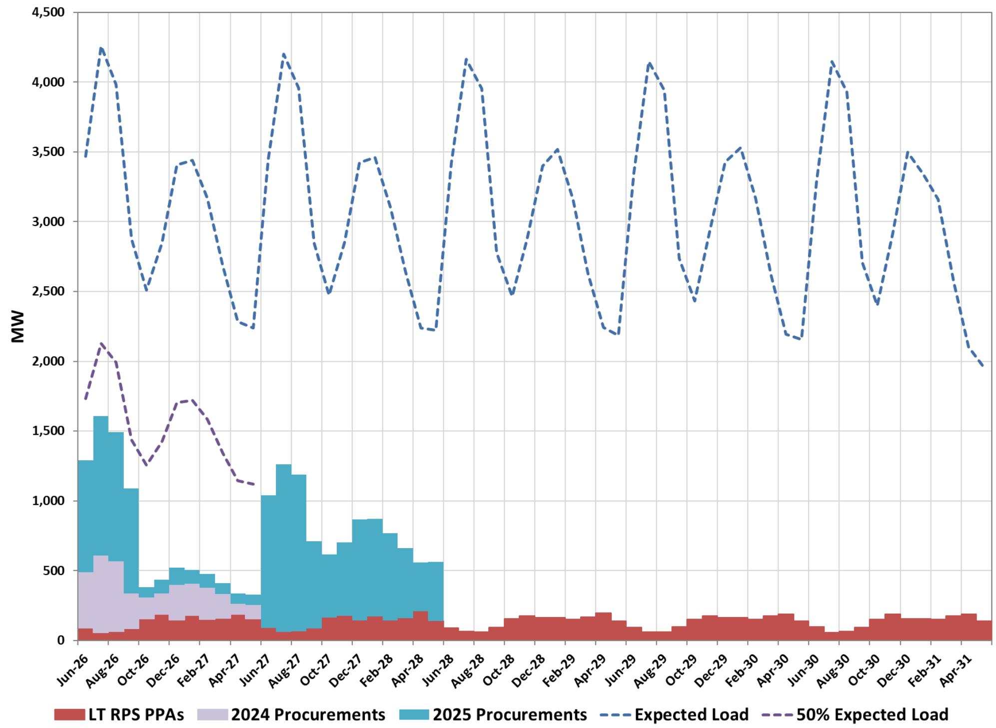


Under the base case load forecast scenario, the average supply gap for peak hours of the 2026-2027 Delivery Year is estimated to be 337 MW, the peak period average supply gap for the 2027-2028 Delivery Year is estimated to be 549 MW, and the average peak period supply gap for the 2028-2029 Delivery Year is estimated to be 641 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 2026-May 2031 planning period, using the base case load on-peak forecast described in Chapter 3. Note that through May 2027, this Plan seeks to hedge 50% of ComEd Expected Load during June through September and 30% during October through May due to the offsetting value created by CMC Contracts (See Section 6.9). As of May 2025, approximately 20% of total residential ComEd customers were taking retail electric supply and 59% of the 0 to 100 kW non-residential delivery customers were served by retail electric suppliers or hourly supply.

Figure 4-2: ComEd's On-Peak Supply Gap - June 2026-May 2031 period - Base Case Load Forecast



As with Ameren Illinois, ComEd's current energy resources will not cover eligible retail customer load starting in June 2026. The average supply gap during peak hours for the 2026-2027 Delivery Year under the base case load forecast is estimated to be 2,358 MW. The average supply gap during peak hours for the 2027-2028 and 2028-2029 Delivery Years is estimated to be 2,255 MW and 2,930 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.[124]

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, 2021, 2022, 2023, 2024, and 2025 Plans. The IPA, for the 2026 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.
- Nuclear Resources: Quad Cities Nuclear Power Station.

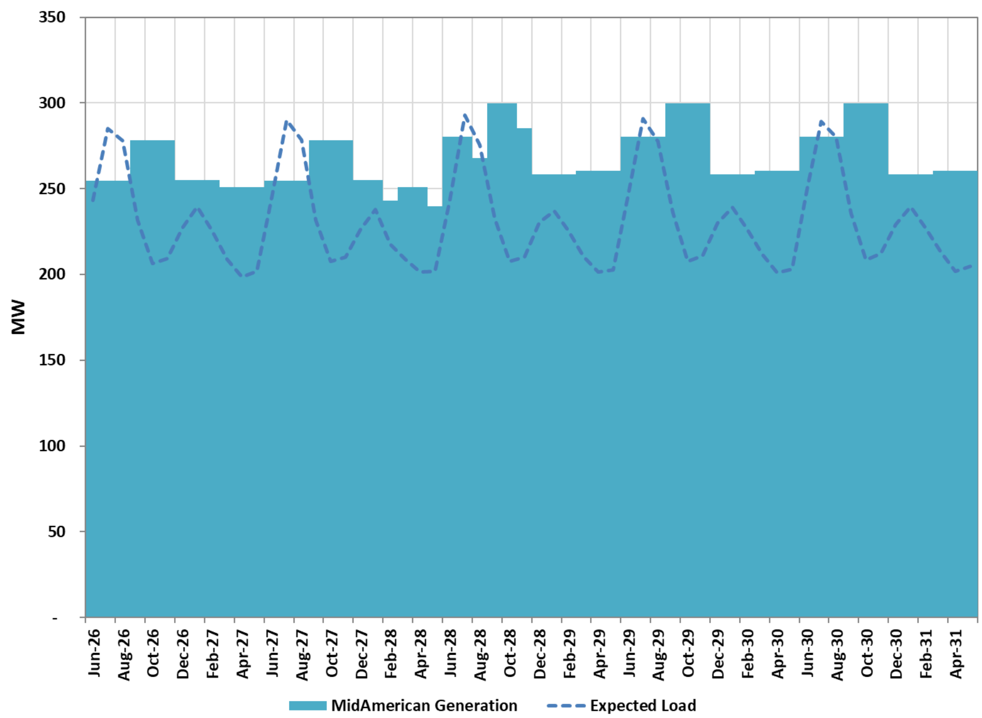
124 MidAmerican allocates 10.86% of the UCAP ratings of its baseload units for Illinois Historical Generation.

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 2025 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 2026-2027 Delivery Year under the base case load forecast is estimated to be 38 MW. The average supply surplus during peak hours for the 2027-2028 Delivery Year is 28 MW and for the 2028-2029 Delivery Year the supply surplus is 41 MW.

Figure 4-3: MidAmerican's On-Peak Supply Gap - June 2026-May 2031 period - Base Case Load Forecast



5 PJM and MISO Resource Adequacy Outlook and Uncertainty

Resource adequacy means ensuring electricity supply is available to meet demand in all hours at an acceptable level of certainty (probability). Customers in the state of Illinois are served by two integrated regional markets (MISO and PJM). The reliability of the electricity system in Illinois is dependent on the resource adequacy of these larger markets. Retail service providers in Illinois are responsible for contributing their share of MISO and PJM's resource adequacy needs according to the requirements of each market. MISO and PJM enforce resource adequacy requirements through capacity market auctions, which set prices payable by all load serving entities (according to their share of peak load) to eligible generation resources. Load-serving entities can hedge their exposure to the capacity market price by i) owning generation assets with capacity values, ii) signing contracts for capacity from eligible resources, or iii) signing financial hedge contracts with counterparties. If a load serving entity does not own or contract enough capacity to meet its obligations, the load serving entity must pay the capacity auction price to the market for any missing capacity. Generation resources in turn receive the capacity market price for their reliability contributions (MW) under the market rules. The capacity market price is designed to be a price incentive to both loads and generators—if the market needs new capacity, high market prices create a revenue stream for new generation resources and an incentive price for load serving entities to contract with new resources as an alternative to the market price. Capacity markets only function properly to bring new generation online if the incentive price is high enough to encourage new capacity resource development. This Chapter reviews the likely load and resource outcomes over the planning horizon to determine if the current system in each market 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 have been made 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 the ComEd service territory.
- Midcontinent Independent System Operator ("MISO"), which operates the transmission grid in most of central and southern Illinois, serving Ameren Illinois and MidAmerican service territories.

The 2024 NERC Long-Term Reliability Assessment ("2024 NERC LTRA") provides a region-wide annual forecast of resource adequacy for a period of ten years. NERC is comprised of multiple regional entities, overlapping with PJM and MISO RTO balancing authority regions. As noted in previous procurement plans, the findings of the annual forecast are based on the resource assumptions available at the time the report is published. Most importantly, for MISO, the forecast is published five months before the release of the actual results of the MISO PRA for the most recent delivery year, which may result in a disconnect between the forecast and the actual results.[125] The most recent NERC forecast projected resource shortfalls for MISO starting in the 2028-2029 Delivery Year, with a potential shortfall occurring earlier if resource retirement assumptions hold and project delays persist. For the current assessment of the 2025-2026 Delivery Year, there was agreement between the 2024 NERC LTRA and the MISO PRA in that resource adequacy requirements were met but new capacity additions are not keeping pace with retirements. The results of the PRA showed sufficient capacity at the regional, sub-regional, and zonal levels, including MISO Zone 4 (which includes Illinois). The NERC forecast showed that PJM will maintain adequate resources to meet the collective needs of customers in the PJM region.

5.1 Resource Adequacy Projections

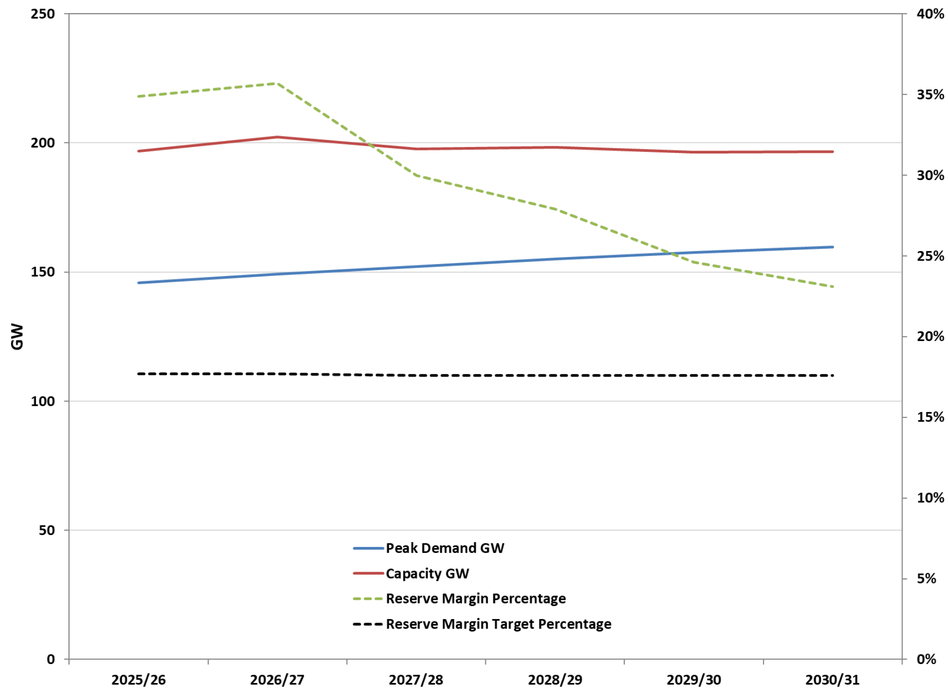
5.1.1 PJM RTO

As shown in Figure 5-1, based on the 2024 NERC LTRA, PJM is projected to have sufficient resources to meet load plus required reserve margins for Delivery Years 2025-2026 through 2030-2031, with projected reserve margins above the 17.7% target reserve margin for Delivery Years 2025-2026 and 2026-2027, and the 17.6%

[125] The reliability assessment by NERC was published in December 2024, five months before the results of the 2025-2026 MISO PRA were published. 2025-2026 is the most recent Delivery Year for the MISO PRA.

target reserve margin for Delivery Years 2027-2028 through 2030-2031. For the 2026-2027 Delivery Year, the reserve margin is 18.0% above the target reserve margin and is 5.5% above the target reserve margin for the 2030-2031 Delivery Year.

Figure 5-1: NERC Projection of Supply and Demand for Delivery Years 2025-2026 to 2030-2031

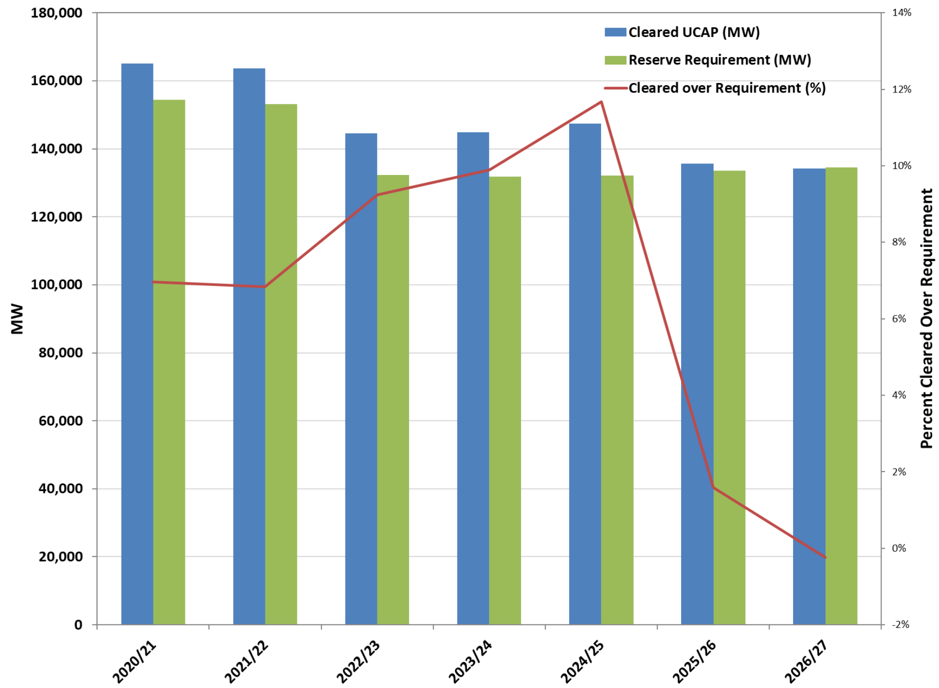


Source: 2024 NERC LTRA

The cleared UCAP, capacity requirement (expressed in MW), and percentage cleared over the requirement in previous PJM Base Reserve Auctions ("BRA") are displayed in Figure 5-2[126]. The reserve margin represents the percentage of installed capacity ("ICAP") cleared in the auction and committed by fixed resource requirement ("FRR") entities in excess of the RTO load. From the 2020 auction through the most recent 2026 BRA, both cleared capacity and the accompanying reserve margin have been in general decline.

[126] PJM 2026-2027 BRA Report

Figure 5-2: PJM Historical BRA Cleared UCAP and Reserve Margins



PJM Interconnection is rolling out several key updates to its capacity auction process aimed at boosting grid reliability, accelerating resource integration, and protecting ratepayers from price volatility. The following include a list of key changes:[127,128]

- Market Rule Enhancements
  - Price Cap and Floor Introduced: PJM implemented a FERC-approved cap of $329.17/MW-day and a floor of $177.24/MW-day for the 2026/2027 and 2027/2028 auctions.
  - Expanded Must-Offer Requirements: All resource types—including solar, wind, batteries, and hybrids—must now offer into the auction, increasing the number of actively participating resources, and enhancing competition and transparency.
  - Retirement of Energy Efficiency Product: PJM removed this category as an eligible resource.

- Interconnection Reforms
  - Accelerated Queue Processing: PJM has cleared over 60% of its transition backlog and has communicated it plans to review another 63,000 MW of capacity during the 2025–2026 term.
  - AI-Powered Efficiency: Partnering with Google, PJM is using artificial intelligence to reduce interconnection study times and improve throughput.
  - New Cycle Launch: A fresh interconnection cycle is set to begin in spring 2026, aiming to bring more resources online faster.

- Reliability Resource Initiative
  - PJM attracted 11,000+ MW of planned new projects through this initiative, signaling strong investor interest in long-term grid reliability.
  - These projects include upgrades to existing generation resources and new capacity additions that could ease future supply constraints.

- Resource Accreditation Updates

127 "Latest PJM power compacity auction clears maximum price in all zones", Renewable Energy World, July 22, 2025, https://www.renewableenergyworld.com/power-grid/latest-pjm-power-capacity-auction-clears-maximum-price-in-all-zones/.

128 "PJM Auction Procures 134,311 MW of Generation Resources, Supply Responds to Price Signals", MENAFN Newswire, July 22, 2025, https://menafn.com/1109834123/PJM-Auction-Procures-134311-MW-Of-Generation-Resources-Supply-Responds-To-Price-Signal.

- PJM is refining Effective Load Carrying Capability ("ELCC") ratings for resource reliability contributions. For example, the demand response ELCC is expected to rise from 69% to 92% in the 2027-2028 delivery year auction.
- This ELCC refinement will be paired with a shift to 24/7 availability requirement for demand response resources, aligning with other markets and improving grid flexibility.

5.1.2 MISO RTO

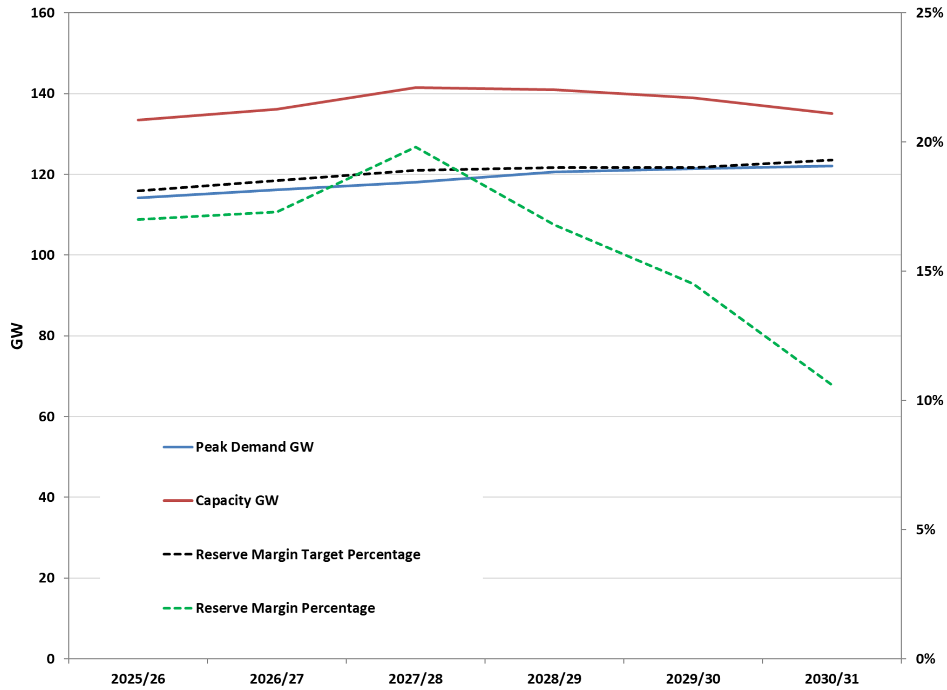
The 2024 NERC LTRA projects that MISO will have insufficient resources on a region-wide basis to meet load plus a target reserve margin starting with the 2025-2026 Delivery Year. The projections are shown in Figure 5-2. For the 2025-2026 Delivery Year, the reserve margin is approximately 1.1% below the target reserve margin, increasing to 0.9% above the target reserve margin for the 2027-2028 Delivery Year, falling to 2.2% below the target reserve margin for the 2028-2029 Delivery Year, and further dropping to 8.7% below the target reserve margin for the 2030-2031 Delivery Year.

For the 2025-2026 Delivery Year, there was slight disagreement between the 2024 NERC LTRA and the PRA, as the results of the PRA showed sufficient capacity at the regional, sub-regional, and zonal levels; whereas, the 2024 NERC LTRA anticipated a slight capacity shortfall. There was, however, agreement between the two reports regarding reduced capacity surplus across the region.

The results of the 2025 survey jointly conducted by MISO and the Organization of MISO States ("2025 MISO-OMS Survey") indicate a potential surplus of 1.4 GW to a 6.1 GW of capacity for the summer of the 2026-2027 Delivery Year, depending on critical yet uncertain drivers, such as the pace and quantity of new resource additions.[129] An additional 3.1 GW of capacity on top of committed capacity is needed to meet the projected planning reserve margin forecast. An assumption of 8.6 GW/year of potential new capacity results in a surplus of 6.1 GW of capacity in the summer of the 2026-2027 Delivery Year. On the other hand, a more conservative assumption of 4.7 GW/year of potential new capacity results in a surplus of 1.4 GW of capacity in the 2026-2027 Delivery Year.

[129] https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf

Figure 5-3: NERC Projection of Supply and Demand for the Delivery Years 2025-2026 to 2030-2031[130]



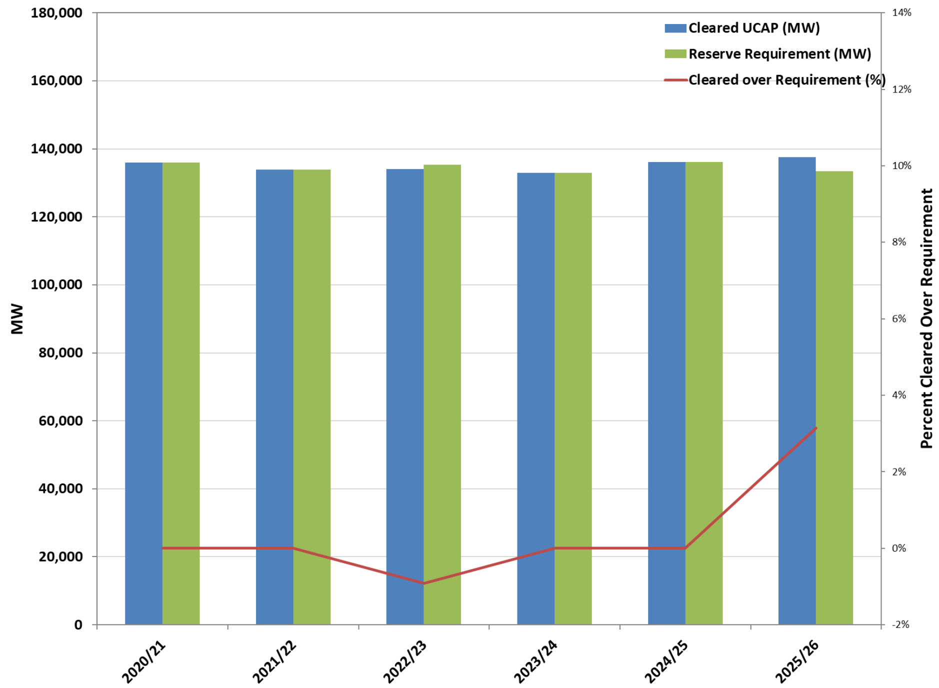
While the IPA acknowledges the findings of the 2024 NERC LTRA's region-wide long-term assessment, the IPA also notes that the results of these findings are based on the resource assumptions available at the time the report was published. The IPA will continue to review and analyze the various studies and assessments to estimate the accuracy of future resource adequacy projections.

The cleared capacity and associated planning reserve margins (PRM) in historical PRAs for MISO are illustrated in Figure 5-4.[131] The UCAP PRM is the UCAP (MW) requirement in excess of MISO forecast peak load for a given season. The figure uses summer PRMs for the PRAs in which seasons are differentiated. Cleared capacity has stayed relatively flat from the 2020-2021 through 2025-2026 planning years. The PRM has stayed mostly within a 7% to 9% range, although the most recent 2025-2026 PRA cleared at 9.8%, above the target 7.9% PRM.

[130] 2024 NERC LTRA.

[131] MISO 2025-2026 PRA Report.

Figure 5-4: MISO Historical PRA Cleared UCAP and Reserve Margin



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 RPM, which was approved by FERC in December 2006. In 2015, PJM implemented changes to the RPM construct, which established a Capacity Performance product.[132] The RPM is a forward capacity auction through which generators offer capacity to serve the obligations of load-serving entities ("LSEs"). 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.[133] In addition to the BRAs, up to three incremental auctions are held, at intervals of 20 months, 10 months, 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.[134] A Conditional Incremental Auction may be conducted, if and when necessary, to secure commitments of

[132] 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, 2021-2022, 2022-2023, 2023-2024, and 2024-2025 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.

[133] 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.

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

additional capacity to address reliability criteria violations arising from the delay of a backbone transmission upgrade modeled in the BRA.

The Final Zonal Net Load Price, which is the price paid by LSEs for capacity procured as part of the RPM, is calculated just prior to the beginning of each Delivery Year. 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 5-5. However, while Figure 5-5 shows little variation in the ComEd zone between the BRA clearing price and the Final Zonal Net Load Price for the Delivery Years through 2015-2016, Delivery Years 2016-2017 and 2017-2018 show a significant variation between the prices. This is because the Final Zonal Net Load Price for 2016-2017 and 2017-2018 includes the incremental costs of each year's transitional Capacity Performance Incremental Auction ("CPIA").[135]

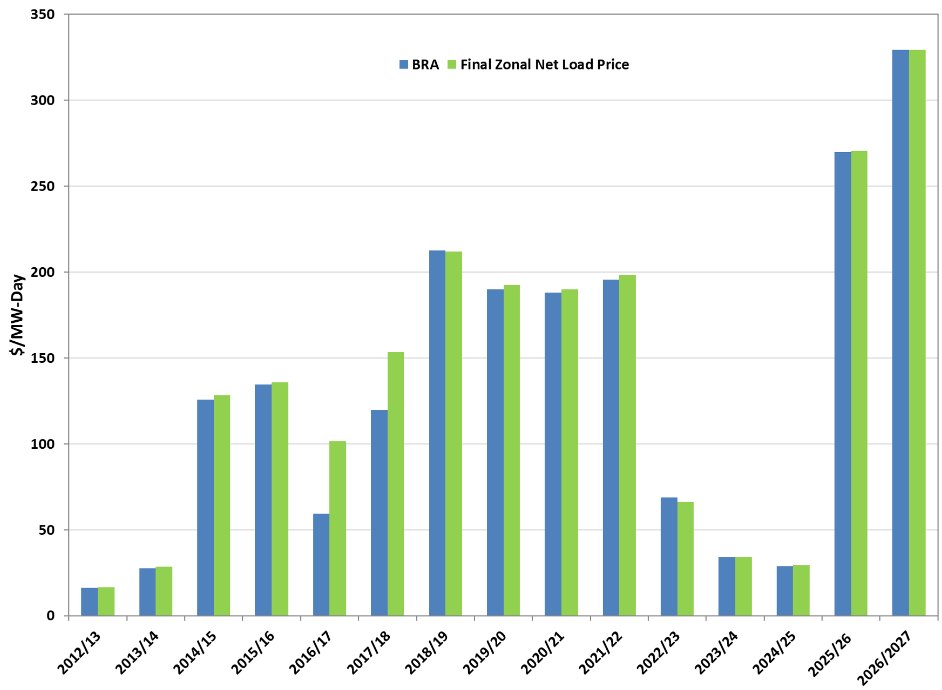
Figure 5-5 shows higher BRA prices in the ComEd zone for Delivery Years 2018-2019 through 2021-2022 relative to 2017-2018, which are attributable to the transition to full implementation of the Capacity Performance product (i.e., Capacity Performance Resources bidding in the BRA) as well as transmission constraints in the ComEd LDA. There was also a notable drop in price in Delivery Years 2022-2023, 2023-2024, and 2024-2025.[136] However, the results for the 2025-2026 and 2026-2027 Delivery Years show a very dramatic increase in the capacity price.[137] The clearing price for the 2026-2027 BRA hit the established cap of $329.17/MW-day, highlighting tight supply from revised capacity accreditations for all resources and increased demand from load growth.

[135] 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.

[136] In 2017-2018, 2018-2019, 2019-2020, 2020-2021, 2021-2022, 2022-2023, 2023-2024, and 2024-2025 the ComEd Zone was modeled as a separate Locational Deliverability Area ("LDA"), and in all years starting with 2018-2019, with the exception of 2023-2024 and 2024-2025, the results showed that the zone was a constrained LDA. Binding constraints therefore also contributed to the higher clearing price although 2022-2023, 2023-2024, and 2024-2025 cleared at a significantly lower price than the previous years. For 2022-2023 the lower price was due to a lower load forecast and reserve requirement, and overall lower prices from resources participating in the BRA. For 2023-2024 potential factors contributing to the lower clearing price include, but are not limited to, (i) the first application of the less restrictive minimum offer price rule, (a revised lower unit-specific market seller offer cap, (ii) less lead time to the delivery year (one year instead of three), and (iii) expected higher energy prices leading to lower offers in the capacity market. For 2024-2025 the lower price was due to overall lower prices of resources participating in the BRA.

[137] See: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf .

Figure 5-5: PJM (ComEd Zone) Capacity Price for Delivery Years 2012-2013 to 2026-2027[138]



For additional historical context on the PJM capacity auction, please reference the 2025 Plan Section 5.2.1.

As shown in Figure 5-5, PJM capacity prices for the 2025-2026 Delivery Year increased from $28.92 to $269.92 per MW-day. While capacity prices were expected to increase,[139] this increase was significantly higher than those expectations and may indicate a new era of capacity pricing and volatility for PJM and for the purpose of consideration in this plan, the ComEd zone. According to PJM, auction prices were significantly higher across the RTO due to decreased electricity supply offers in the auction caused primarily by a large number of generator retirements, increased projected peak load, and implementation of FERC-approved market reforms including improved reliability risk modeling for extreme weather and accreditation that more accurately values each resource's contribution to reliability.[140] PJM's President and CEO Manu Asthana has said, "significantly higher prices in this auction confirm our concerns that the supply/demand balance is tightening across the RTO. The market is sending a price signal that should incent investment in resources."[141]

The recent spikes in PJM's capacity prices raised concerns over costs to consumers. In response to a complaint filed with FERC by Pennsylvania Governor Josh Shapiro in December 2024, PJM filed a request to FERC in February 2025 to establish a price cap and floor for the next two capacity auctions (2026/2027 and 2027/2028 delivery years).[142] FERC approved a price cap of $325/MW-day and a price floor of $175/MW-day in April 2025.[143] The 2026/2027 base residual auction cleared at the price cap (equal to $329.17/MW-day when adjusted between UCAP and ICAP values in PJM's auction methodology), and PJM reports that the auction would have cleared higher at $388.57/MW-day if the cap had not been in place.[144]

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[138] 2024-2025 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.

[139] See for example, "Almost 20% of Americans face prospect of higher electric bills," Crains Chicago Business, July 29, 2024, https://www.chicagobusiness.com/utilities/electric-bills-set-rise-demand-spikes-pjm-grid.

[140] See https://insidelines.pjm.com/pjm-capacity-auction-procures-sufficient-resources-to-meet-rto-reliability-requirement/.

[141] Id.

[142] See: https://www.utilitydive.com/news/ferc-pjm-interconnection-capacity-auction-price-cap-collar/745979/

[143] See: https://www.utilitydive.com/news/ferc-pjm-interconnection-capacity-auction-price-cap-collar/745979/

[144] "2026/2027 Base Residual Auction Report," PJM, July 22, 2025, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf. Page 16.

For the 2025-2026 and 2026-2027 delivery years, the impact of higher capacity prices will be blunted for eligible retail customers in Illinois as the price of CMCs factors in the price of capacity; thus, an increase in the price of capacity will result in a decrease in the price of CMCs (see Section 6.9 for further discussion of this mechanism), but that offset only covers about 60% of load which means that about 40% of the impact of the capacity price spike will be felt by eligible retail customers. After the 2026-2027 delivery year, this benefit will go away with the expiration of CMC contracts, leaving customers fully exposed to capacity price volatility.

For this draft Plan, the Agency is interested in stakeholder feedback on the advantages and disadvantages of the Agency beginning to procure capacity for ComEd eligible retail customers in light of ongoing price volatility. In particular, the Agency is interested in responses to the following questions:

1. **Should the agency consider procuring capacity for ComEd eligible retail customers?**
2. **If the Agency were to begin procuring capacity for ComEd eligible retail customers, how should the Agency structure the capacity product? In particular, are there any recommendations on what portion (in % terms) of ComEd eligible retail customer capacity obligations should be hedged, what portion (in % terms) should be procured through the BRA, for what forward capacity periods, and utilizing what contract term(s) (i.e., 1-year contract covering one BRA period and/or utilization of a multi-year product covering multiple BRA periods)?**

The Agency asked a similar set of questions in the draft 2025 Plan and based on the stakeholder feedback received at that time,[145] the Agency did not propose any capacity hedging for ComEd eligible retail customers in the 2025 Plan. Given the impact on customers of rising capacity prices and likelihood that capacity prices will remain elevated for the foreseeable future, the Agency remains interested in the input of stakeholders on potential solutions that could benefit eligible retail customers.

5.2.2 MISO Planning Resource Auction

The MISO Resource Adequacy Construct, specified in Module E-1 of its Tariff,[146] 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")[147] for the Delivery Year. An LSE's total resource adequacy obligation is referred to as the Planning Reserve Margin Requirement ("PRMR").

MISO has made several significant changes to its capacity auction process over the past two years, reflecting a shift toward more granular reliability planning and market transparency. Key changes include:

- **Shift to Seasonal Capacity Products.** Prior to 2023, MISO held a Planning Resource Auction for capacity spanning a one-year period (similar to PJM). Starting with the 2023 PRA, MISO transitioned to procuring capacity for four seasons in a single auction (Summer, Fall, Winter, Spring) to better reflect year-round reliability risks. This change was prompted because of increasing grid emergencies outside of summer peaks and to better isolate and define costs on a more granular basis, addressing reliability concerns by season instead of aggregated across a year.
- **Introduction of the Reliability-Based Demand Curve ("RBDC").** Implemented in 2025, the RBDC replaced the previous vertical demand curve with a sloped curve that better reflects the value of capacity as reserve margins tighten. This reform is intended to aid in price stabilization, reduce excessive year-over-year price volatility, and provide clearer price signals to market participants to incent investment. Importantly, the RBDC also provides greater pricing nuance, with prices reflecting constraints; which can also result in higher prices not previously experienced in the preceding method until an extreme constraint was realized.

[145] See https://ipa.illinois.gov/energy-procurement/plans-under-development/stakeholder-feedback-on-draft-2025-electricity-procurement-plan.html.

[146] 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.

[147] 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.

- **Enhanced Resource Accreditation.** MISO refined how it accredits capacity from different resource types. The new capacity accreditation framework resulted in material changes to solar and wind capacity values by season, while thermal resources were less impacted overall.
- **Improved Outage Modeling & Forecasting.** MISO adopted more flexible outage scheduling and seasonal planning reserve margin targets to better align with real-world conditions. MISO also began incorporating extreme weather assumptions and load growth from electrification and data centers into its forecasts.

As described in more detail in Section 5.2.2.1, beginning with the 2023-2024 Delivery Year, MISO has implemented a seasonal resource adequacy construct.

5.2.2.1 Seasonal Resource Adequacy Construct

Effective with the 2023-2024 Delivery Year, MISO has implemented a seasonal resource adequacy construct. As explained in the IPA's 2023 Electricity Procurement Plan, MISO has transitioned from the previous Summer-based, annual construct to four distinct Seasons: June to August for Summer, September to November for Fall, December to February for Winter, and March to May for Spring.[148] Under the new construct, MISO establishes PRMRs for all market participants representing load serving entities on a seasonal basis. MISO also develops seasonal local reliability requirements, seasonal LCRs, seasonal capacity import limits, and seasonal capacity export limits. MISO then conducts the PRA and establishes an Auction Clearing Price for each Local Resource Zone ("LRZ") for each season. The PRA is conducted once each year, in the spring before the applicable Delivery Year, but clears the requirements for each season.

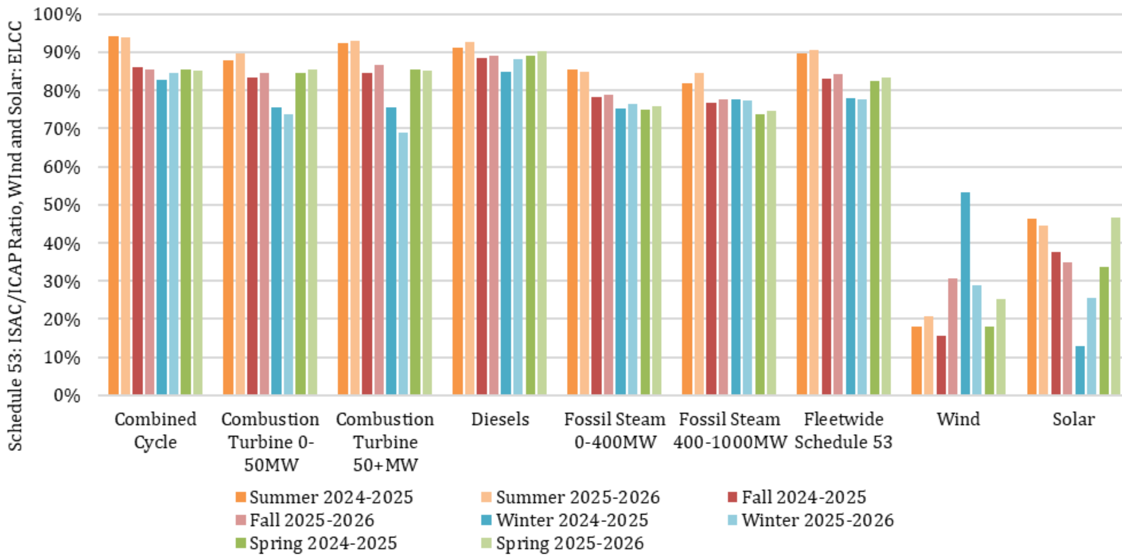
Under the Seasonal Resource Adequacy Construct, MISO also determines seasonal accredited capacities for certain classes of resources. The affected resources are Demand Response Resources and Capacity Resources that are Generation Resources (collectively "Schedule 53 Resources"). These Schedule 53 Resources are subject to the availability-based accreditation methodology established in a new Schedule 53 of the MISO Tariff. Resources that are not subject to Schedule 53 (Dispatchable Intermittent Resources, Intermittent Generation, Electric Storage Resources, External Resources or Use Limited Resources) continue to have their accreditation determined generally as before, with appropriate adjustments made to convert their accreditation to a seasonal basis.[149] Figure 5-6 below, compares the 2024/2025 results to the 2025/2026 results.

The seasonal ELCCs for wind and solar for the previous three PRAs are also shown in the figure below. MISO calculates ELCCs in its Loss of Load Expectation ("LOLE") Study process for both wind and solar. The ELCCs for solar, however, are not used in accreditation and are only used in calculating the UCAP for solar in the PRM. New solar resources receive a 50% ELCC for all seasons except winter, for which they receive 50%. Existing solar resources receive an ELCC based on historical performance. The figure demonstrates the inverse seasonal contributions of wind and solar resources.

[148] See IPA's 2023 Electricity Procurement Plan, Section 5.2.2.1.

[149] This accreditation process, which for thermal resources is based on UCAP, is determined using resource performance between September 1 and August 31 of the three years prior to the Planning Year. This data is used to determine Equivalent Forced Outage Rate Demand ("XEFORd"), excluding events outside of management control, which is then used as a component in the calculation of UCAP. The UCAP is calculated by taking Installed Capacity ('ICAP") and multiplying it by (1- XEFORd).

Figure 5-6: Schedule 53 Seasonal Resource ISAC/ICAP; Wind and Solar ELCCs[150]

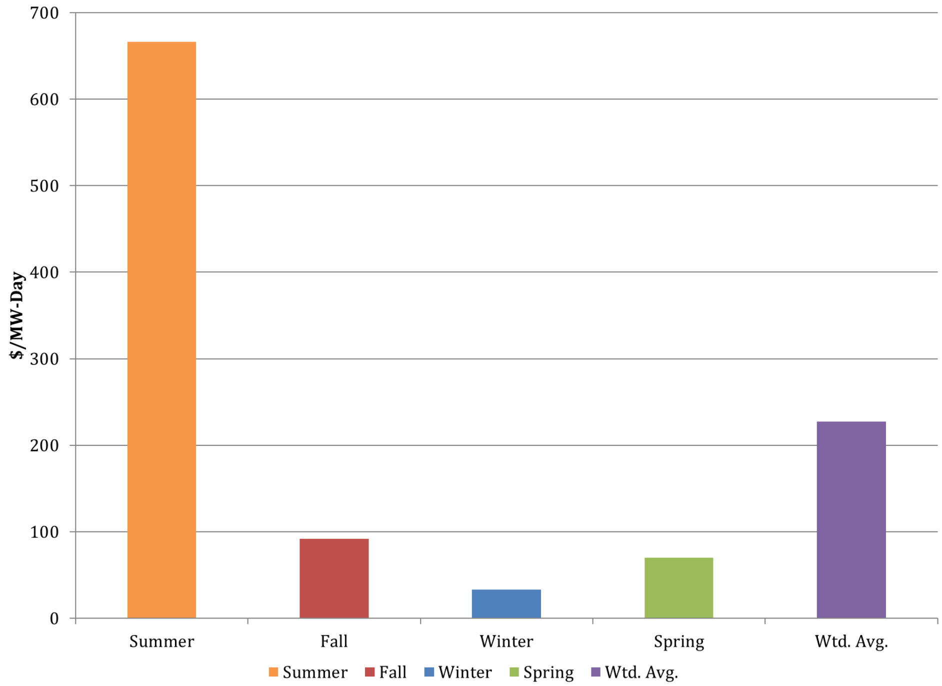


The results of the second seasonal PRA were finalized on May 29, 2025.[151] Figure 5-7 shows the seasonal PRA results for Zone 4 (which includes Illinois) for Delivery Year 2025-2026. An explanation of the results is provided in Section 5.2.2.5..

[150] Note that in 2024/2025 Combustion Turbines were disaggregated into 0-20MW and 20-50MW. The two values were averaged into one category of 0-50MW to match the 2025/2026 reporting. Similarly, in 2024/2025 Fossil Steam was disaggregated into 0-100MW and 200-400MW. The values were averaged into one 0-400MW category to match the 2025/2026 reporting. Depending on the number of units within each of the subcategories, averaging the categories may not accurately represent the ISAC/ICAP value of the combined category. Schedule 53 Results can be found at: https://cdn.misoenergy.org/PY%202024-2025%20Schedule%2053%20Class%20Average631181.pdf and https://cdn.misoenergy.org/PY%202025-2026%20%20Schedule%2053%20Class%20Average%20-%20Final667331.pdf

[151] The PRA results can be found at:
https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

Figure 5-7: 2025-2026 Delivery Year Seasonal PRA Results for MISO Zone 4



The IPA notes that in line with the MISO Tariff and the move to a Seasonal Resource Adequacy Construct, changes have been made to the IPA's bilateral procurement approach. The IPA has stopped procuring annual ZRCs and is now conducting bilateral procurements for each of the four seasons and procuring seasonal ZRCs. The results of the seasonal procurements conducted by the IPA to date can be found on the IPA's website.[152]

For a given Delivery Year, MISO procures all seasonal capacity products in one auction (rather than separately timed auctions for each season). The IPA is also conducting procurements of seasonal ZRCs for all four seasons simultaneously; however, consistent with the IPA's general approach of laddered hedging, the procurement of seasonal ZRCs for a given Delivery Year is conducted over multiple procurement events in the two years prior to the given Delivery Year. The target quantities of seasonal ZRCs used for each procurement event are based on updated capacity forecasts that are provided by Ameren Illinois.

5.2.2.2 MISO's Filing to Reform Resource Accreditation Requirements

MISO's filing to reform resource accreditation requirements[153] notes that MISO is at an inflection point in its portfolio evolution. Sizable segments of dispatchable thermal generation are aging into retirement and being replaced with increasing amounts of highly weather-dependent intermittent wind and solar resources. These retirements, combined with the significant penetration of intermittent resources and increased frequency of extreme weather events, are shifting the nature of system risk and creating challenges to maintaining reliable system operations. These events are highlighting the fact that MISO's existing resource accreditation methods are no longer sufficiently robust to capture those risks and send the proper signals to state regulators and LSEs participating in integrated resource planning processes for the investment and retirement of resources needed to maintain reliability into the future.

MISO notes that in response to these challenges and the continued need for diversity in the resource mix, MISO proposes to transition to a direct loss of load-based methodology (DLOL-based methodology). The proposed method measures a resource's availability when reliability risk is the greatest. The proposal builds upon the current seasonal accreditation methodology. The DLOL-based methodology first measures a resource's expected marginal contribution to reliability using the resource's performance during a loss of load expectation

[152] See procurement results on https://ipa.illinois.gov/energy-procurement/current-approved-plan.html and https://ipa.illinois.gov/energy-procurement/prior-approved-plans.html

[153] Filing to Reform MISO's Resource Accreditation Requirements, FERC Docket No. ER24-1638-000, March 28, 2024.

("LOLE") analysis. The second step in the DLOL-based methodology uses historical resource-level performance (deterministic-approach) in the hours that are currently employed under MISO's Tariff to accredit individual resources within their respective resource class. The DLOL-based methodology is meant to address a range of reliability risks in the planning and operations horizons by incorporating a forward-looking probabilistic analysis and measuring a resource's performance during recent periods of high system risk. Under the proposal, MISO defines the periods of highest system risk identified in the probabilistic analysis as "Critical Hours." Critical Hours include all loss of load hours and may also include low margin hours comprised of those hours where available generation in excess of load is less than or equal to 3% of load in that hour (*i.e.*, low generation reserve margin).

MISO is proposing a change in how all capacity resources, except external resources (referred to as "Schedule 53A Resources"), receive capacity credit at the resource class-level, as well as how the resource class-level UCAP megawatts are allocated amongst the individual resources. In addition, MISO is proposing to use the same methodology to calculate the PRMR that it uses to accredit resource classes. The proposal thus preserves the deterministic element of resource accreditation established in Schedule 53 by accrediting all Schedule 53A resources based upon their actual performance during resource adequacy hours. The DLOL-based accreditation proposal also enhances the Schedule 53 methodology by adding a probabilistic element to perform resource class-level UCAP calculations to align the class-level accreditation of all Schedule 53A resources with the determination of PRMR.

On October 25, 2024, FERC issued an order approving MISO's proposal to establish a DLOL-based accreditation methodology. The DLOL-based methodology will be fully implemented in the 2028-29 PRA, after a three-year transition period.[154]

5.2.2.3 MISO's Filing to Implement a Reliability Based Demand Curve

In its 2023 filing to implement a reliability-based demand curve,[155] MISO notes that its historical application of a vertical demand curve in the PRA has contributed to low auction clearing prices as a result of setting the Auction Clearing Price close to zero when the market has even a small surplus of capacity and inversely setting an artificially high Auction Clearing Price at or near the Cost of New Entry if there is any shortfall of capacity. Vertical curves therefore tend to produce high levels of price volatility, more frequent pricing at the auction price cap, and more frequent capacity shortfalls. MISO further notes that the prolonged prevalence of low prices throughout much of the PRA's history disregarded the significance of incremental capacity, failed to incentivize new investments, and has played an adverse role in the premature retirement of both merchant and utility resources.

In order to fix the problems caused by the vertical demand curve, MISO proposed to implement a downward sloping RBDC, commonly known as a sloped demand curve. MISO noted that the RBDC would mitigate price volatility, modestly increase the total volume of capacity maintained in the market and reduce the frequency and severity of shortfalls. MISO proposed to implement the downward sloping, RBDC in the PRA beginning with the 2025-2026 Delivery Year.

On June 27, 2024 FERC issued an Order accepting MISO's filing.[156] In its Order FERC noted: "We find that MISO's downward-sloping demand curve will reduce volatility in Auction Clearing Prices, increase the stability of the capacity revenue stream over time, and render capacity investments less risky, thereby encouraging greater investment and at a lower financing cost. Additionally, we find that using the proposed sloped demand curve will result in capacity price signals that reflect the marginal reliability impact of incremental capacity additions, provide better incentives for efficient resource entry and exit, and as a result, improve resource adequacy and economic efficiency across the MISO footprint."[157] FERC accepted MISO's proposed Tariff revisions, effective June 3, 2024 (the beginning of the 2025-2026 Delivery Year), as requested by MISO.

[154] Order Accepting Proposed Tariff Revisions, FERC Docket Nos. ER24-1638-000/ER24-1638-001

[155] Reliability Based Demand Curve, FERC Docket No. ER23-2977-000, September 29, 2023.

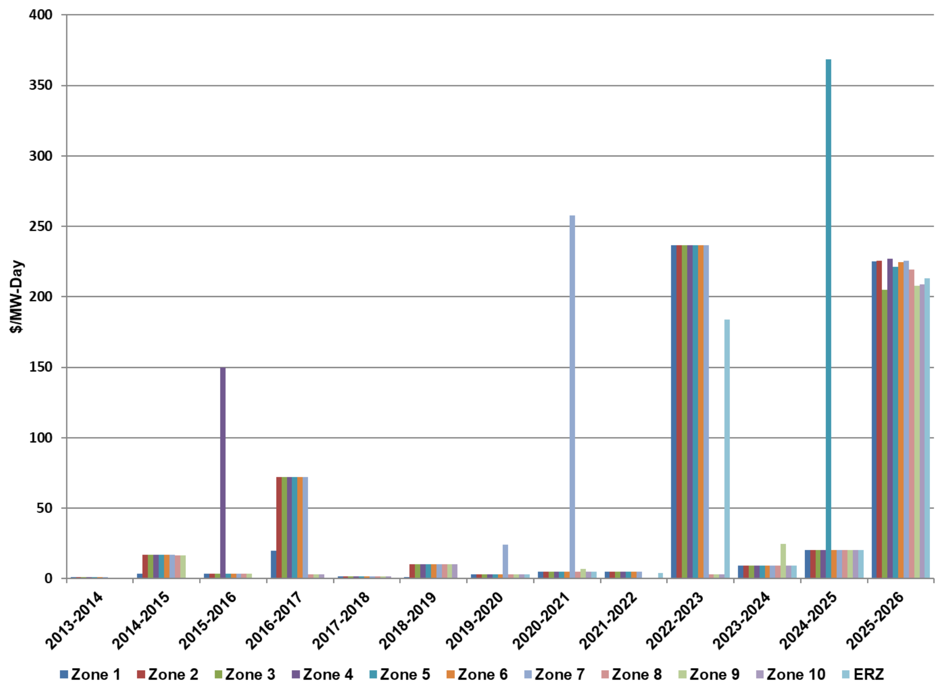
[156] Order Accepting Tariff Revisions, FERC Docket No. ER23-2977-000, June 27, 2024.

[157] Id. at page 36.

5.2.2.4 Overview of Results of the MISO PRA

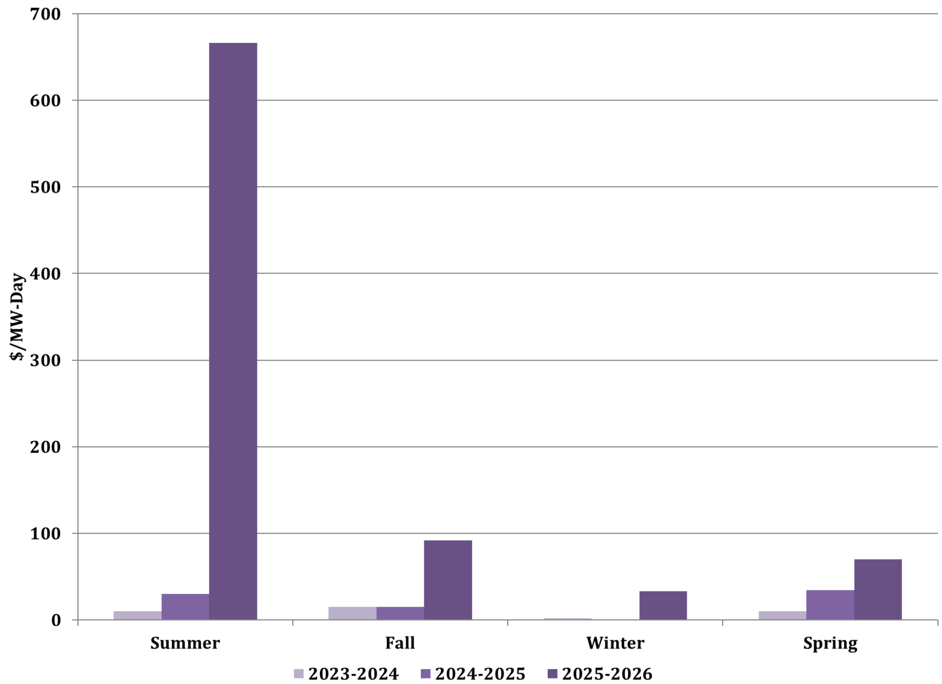
Figure 5-8 below shows the results of the MISO PRA since its inception. The results for the 2023-2024, 2024-2025, and 2025-2026 Delivery Years are a weighted average of the seasonal results.[158] Figure 59 illustrates the seasonal PRA results for Zone 4 for the past three auctions. Seasonal prices are increasing year over year, with summer showing the greatest increase from 2024 to 2025.

Figure 5-8: MISO PRA Results for Delivery Years 2013-2014 to 2025-2026



[158] The weighting of the results is based on the hours in each season.

Figure 5-9: Historical MISO Zone 4 Seasonal PRA Results



As shown in Figure 5-5, and explained in detail in previous procurement plans, 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 $236.66/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 IPA's 2016 Electricity Procurement Plan.[159] For the 2021-2022 PRA, Zones 1 through 7 cleared at $5/MW-Day, and Zones 8-10 cleared at $0.01/MW-Day. For the 2022-2023 PRA, Zones 1-7 cleared at $236.66/MW-Day, and Zones 8-10 cleared at $2.88/MW-Day. A detailed explanation of the results for the 2022-2023 are presented in the 2023 Electricity Procurement Plan.[160] For the 2023-2024 PRA, with the exception of the Fall and Winter prices for Zone 9 (Louisiana and parts of Texas), all zones cleared at the same seasonal prices: $10.00/MW-Day (Summer), $15.00/MW-Day (Fall), $2.00/MW-Day (Winter), and $10.00/MW-Day (Spring). The Fall and Winter prices for Zone 9 were $59.21/MW-Day and $18.88/MW-Day respectively. In the Fall and Winter, Zone 9 required higher priced supply within the zone to meet its LCRs. For the 2024-2025 Delivery Year, with the exception of the Fall and Winter prices for Zone 5 (Missouri), all zones cleared at the same seasonal prices: $30.00/MW-Day (Summer), $15.00/MW-Day (Fall), $0.75/MW-Day (Winter), and $34.10/MW-Day (Spring). The Fall and Winter prices for Zone 5 were $719.81/MW-Day, which is the seasonal CONE. In the Fall and Winter, Zone 5 cleared at the seasonal CONE due to inadequate capacity to meet its LCRs, driven by resource retirements and seasonal outages.

The results of the 2025-2026 PRA are explained in the Section 5.2.2.5 below.

5.2.2.5 Results of the 2025-2026 PRA

The 2025-2026 PRA was the first PRA to use the RBDC methodology. For the 2025-2026 Delivery Year, with the exception of the Fall prices for Zones 8, 9, 10, and External Resource Zones ("ERZ"), all zones cleared at the same seasonal prices: 666.50/MW-Day (Summer), $91.60/MW-Day (Fall), $33.20/MW-Day (Winter), and $69.88/MW-Day (Spring). The Fall prices for Zones 8, 9, and 10 were $74.09/MW-Day, and for ERZ the range

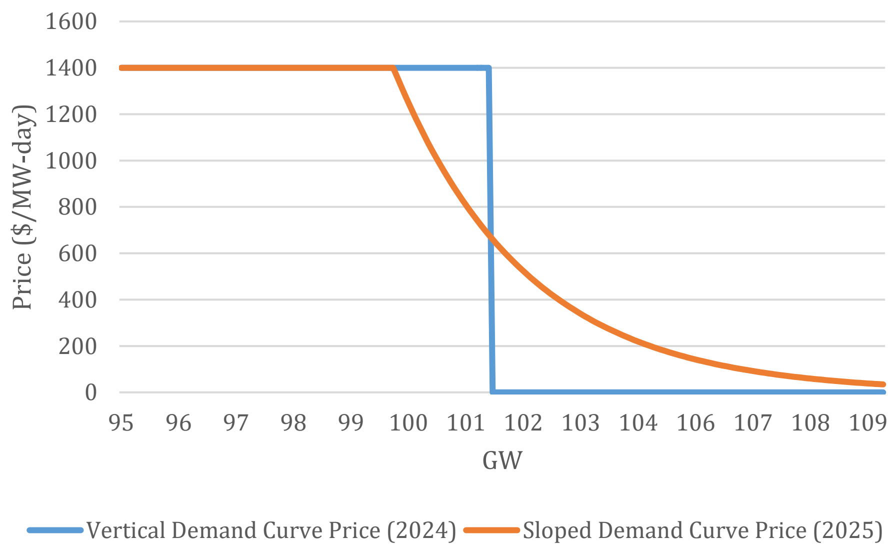
[159] See IPA's Final 2016 Electricity Procurement Plan, Section 5.2, pages 58-62.

[160] See IPA's Final 2023 Electricity Procurement Plan, Section 5.2.2.2.3, pages 60-62.

was $83.24/MW-Day to $91.60/MW-Day. The Fall prices for the South subregions—Zones 8, 9, and 10—diverge due to import and export constraints.

Figure 5-9 below shows the new sloped demand curve used in MISO's 2025 PRA for the North/Central region.[161] Compared to the vertical demand curve used in prior years, this design allows prices to reflect the degree of tightness in supply. The clearing point of $666.50/MW-day at 101.8 GW — highlights a tight capacity situation across the MISO North region and a significant price response. This stands in contrast to 2024–2025 results, where the same region cleared at $30/MW-day under the older vertical curve structure.[162]

Figure 5-10: Comparison of Vertical vs Sloped Demand Curves for MISO PRA (Zone 4 2024 / North Central 2025)



In the 2025-26 PRA, capacity supply cleared at 1.9%[163] above the capacity requirement, indicating sufficient supply, but with a very narrow surplus. Under the previous vertical demand curve, this surplus (even while small) would have resulted in a very low auction price when intersecting with the sloped supply curve. Consistent with the intention of the RBDC reform, the RBDC instead resulted in a much higher price signal for this narrow surplus that is roughly midway towards the price ceiling of $1400/MW-Day—thereby sending a stronger price signal to reflect tighter market conditions.

Figure 5-4 presents the seasonal PRA results for Zone 4. The weighted average seasonal results for all the zones are presented in Figure 5-5.

5.2.2.6 Previous Request for Stakeholder Feedback: Capacity Hedging for Ameren Illinois Eligible Retail Customers

In June 2024, the Agency issued a Request for Stakeholder Comments in which stakeholders were asked for feedback related to the capacity procurements the Agency conducts on behalf of the eligible retail customers of Ameren Illinois.[164] The Agency summarized stakeholder feedback in Section 5.2.1.1 of the 2025 Plan.[165]

The Agency views swap contracts bid in capacity procurements as products designed to provide benefits to eligible retail customers because adding this new financial product in IPA-administered capacity procurements will increase bidder participation and liquidity resulting in lower costs and stable prices over time. Accordingly, the Agency will continue to include the procurement of financial capacity products structured as a fixed-for-float swap ("Financial ZRC") in addition to taking bids for the delivery of ZRCs. While a swap product would not

[161] See: https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

[162] See: https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf

[163] See: https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

[164] See: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240610-2025-electricity-procurement-plan-request-for-stakeholder-feedback-capacity-hedging.pdf.

[165] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20250124-2025-electricity-procurement-plan.pdf

actually be a contract for ZRCs, the settlement prices of the swap contracts would be based on the prices of ZRCs from the MISO PRA. For example, if the swap contract price for a given season was $10 and the MISO PRA for that season was $5, the seller would be paid $5. If the MISO PRA for the season was $15, then the seller would pay Ameren Illinois $5. No transfer of ZRCs between the seller and Ameren Illinois would occur.

As stated in the stakeholder support through the 2025 Electricity Procurement Plan concerning the inclusion of financial products in the IPA-administered procurement events, enabling bidders to bid in financial products could increase options for prospective bidders to bid in swap contracts, which could result in higher bidder participation in the IPA's capacity procurement events which previously saw low bidder participation and resulted in a lack of cleared ZRCs in Ameren Illinois.

As first authorized in the 2025 Plan, the IPA will continue to include the financial capacity product in both of its customary Spring and Fall capacity procurement events scheduled for 2027. The IPA, through its Procurement Administrator, will simultaneously analyze bids received for the traditional physical capacity product (ZRCs) and bids received for the financial capacity product (Financial ZRC) and select the least cost alternative, up to the procurement target for each of the delivery years being procured.

5.2.3 Request for Stakeholder Feedback: Capacity Hedging Through Multi-Year, All-Season Capacity Contracts

Considering the previous input from stakeholders described above, and in light of the tightening capacity markets in MISO (and corresponding increases in recent capacity auction prices as described above), the IPA is considering as part of this 2026 Plan additional options for hedging capacity prices on behalf of eligible retail customers starting in 2026 for the 2027-28 delivery year and beyond. Principally, the IPA is considering solicitations for multi-year, all-season capacity contracts. Details and a potential framework for this proposal are below.

Why procure multi-year, all-season contracts?

Capacity prices are highly volatile, and even though fundamental dynamics point to continued tightening of the supply-demand balance in the MISO capacity market in the future, MISO PRA price outcomes could still vary widely. Generation owners value revenue certainty, which decreases revenue risk and thereby improves risk-adjusted returns on capital investments. Capacity contracts for all seasons across multiple years could offer significant revenue stability and certainty, reducing risk and incentivizing generators to offer more favorable contract prices in exchange. These multi-year, all-season contracts would also provide a more consistent price for eligible retail customers between period rate changes (e.g., from summer PTCs to non-summer PTCs as provided in section 3.5.4). These contracts could be used to cover a portion of the capacity position for eligible retail customers in combination with existing and future contracts for seasonal capacity as well to balance the capacity portfolio across seasons.

What are the risks or challenges associated with multi-year, all-season contracts?

- Lock-in pricing means more exposure to long-term changes in prices and economics, reducing flexibility that *could* lower costs as the market evolves.
- Reduced inter-year flexibility may also limit the speed with which IPA, through its annual procurement plan development process, can respond to changes in peak demand timing or factors, as prior year procurements may lock in under- or over- procurement in a given future year.
- Risk of customer load decreases via municipal aggregation or other customer switching leading to an over-procurement of capacity product hedging.
- Managing regulatory compliance in the event of any future policy / rule-changes.

These risks / challenges could be mitigated to a meaningful degree by making the multi-year, all-season contract an option and not an obligation, meaning these longer-term contracts would be part of the hedging portfolio and not 100% of the portfolio. Other alternatives to mitigate the risk could include incorporating a smaller share of multi-year product contracts (e.g., 10%), thus reducing the exposure to some risk elements such as over-procurement. Doing so also mitigates the potential benefits of the approach as well, thus requiring careful consideration to balance both risk and benefit.

Questions for stakeholder feedback:

1. Should a multi-year, all-season capacity contract be added to the existing seasonal and annual contract options in future capacity solicitations?
2. If pursued, what portion (percent) of capacity procurement should be procured through multi-year, all-season capacity contracts?
3. In addition to purchase of ZRCs, should a multi-year financial hedge be offered?
4. What should the duration (total length) and start date (current year, subsequent year, or two years in the future) options be for bidders to consider?
5. Should multi-year, all-season capacity contracts be procured twice per year with the seasonal and annual contract options, or only once per year?
6. How should multi-year, all-season capacity contracts be evaluated and compared to seasonal and annual contract options?
7. Are there other impacts to customer rates that should be considered in pursuing multi-year, all-season capacity contracts?

IPA requests stakeholder feedback on this proposal for multi-year, all-season capacity contracts to be included as options in future capacity solicitations.

5.2.3.1 Capacity Hedging Strategy for Ameren Illinois

In the IPA's 2023 Electricity Procurement Plan, the Agency made an adjustment to its capacity hedging strategy for the 2024-2025 and 2025-2026 Delivery Years by adopting a hedging strategy of procuring up to 75% in the IPA's bilateral procurements and the balance in the PRA.[166] The 75% would be equally applied to all four seasons in the IPA's procurements. In adopting the adjusted hedging strategy, the IPA noted that a 75%/25% procurement strategy would mostly hedge Zone 4 eligible retail customers in the event of another price shock in the PRA; however, it would also allow the customers to benefit if the PRA clears at a price that is lower than the price in the IPA's bilateral procurements. The IPA decided not to propose any changes to the 75%/25% procurement strategy in its 2024 Electricity Procurement Plan after reviewing the results of the 2023-2024 PRA.

For the 2025 Electricity Procurement Plan the Agency conducted a stakeholder feedback process. After reviewing the stakeholder response, for the draft Plan the IPA decided to maintain the current hedging strategy. The IPA therefore continued with the 75%/25% procurement strategy for the 2026-2027, 2027-2028, and 2028-2029 Delivery Years, and proposed to continue with those hedging levels for the 2026 Plan.

More details on the hedging strategy are provided in Section 7.2. For the 2025 Plan, the Agency will use a consistent hedging level across all four seasons. As future results of MISO seasonal capacity auctions become available, the Agency will analyze the results of those auctions and may propose changes in seasonal hedging levels in future Plans.

[166] See discussion in the IPA's 2023 Electricity Procurement Plan in Section 5.2.2.2.4.

6 Managing Supply Risks

The Illinois Power Agency Act lists the priorities applicable to the IPA's portfolio design, which are "to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." [167]

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.* [168]

Public Act 102-0662 adjusted the Procurement Plan priorities of the IPA by adding:

> *…mitigation in the form of additional retail customer and ratepayer prices, reliability, and environmental benefits from standardized energy products delivered from commercially deployed advanced technologies, including, but not limited to, high voltage direct current converter stations, as such term is defined in Section 1-10 of the Illinois Power Agency Act, whether or not such product is currently available in wholesale markets…*

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. The IPA's review of HVDC transmission and the assessment of the applicability of HVDC products as part of the Agency's procurement and hedging approach are also discussed in Section 6.3. 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.[169] 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 as well as the hedging considerations going forward. Section 6.7 describes the number and timing of the IPA's procurement events. Section 6.8 addresses the role of demand response programs in risk management. Finally, Section 6.9 provides a discussion of the use of CMCs to offset the reduction of the IPA's energy hedging targets including a review of the relative cost of the offsetting benefits provided by CMC contracts.

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 entirely 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.

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[167] 20 ILCS 3855/1-20(a)(1).

[168] 220 ILCS 5/16-111.5(b)(3)(vi).

[169] 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).

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 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 toward non-utility retail contracts that ran through the 2014-2015 procurement year. In recent years, prior to the 2022-2023 Delivery Year, the number of residential customers taking ARES or municipal aggregation supply declined. Starting in December 2021 and continuing into early 2024, volatile market conditions and high electricity prices resulted in uncertainty with regard to the level of customer switching experienced by the utilities. Many customers taking service from alternative suppliers during this period also experienced volatile electricity supply prices ranging from well below to significantly above their default electric service cost, generating unprecedented uncertainty for attempts to forecast customer switching levels. During the first half of 2024, the number of residential customers taking fixed price supply service from ComEd and Ameren decreased. More recently, from June 30, 2024 through January 31, 2025, the number of residential customers taking fixed price supply service from the utilities increased 8.5% for ComEd and increased 11.6% for Ameren Illinois.[170] The primary uncertainty surrounding customer switching going forward is related to how the recent switching patterns will settle and the potential for additional retail load migration back to or away from the utilities. The key switching assumptions for customer switching affecting the utilities' load forecasts are described in detail in Chapter 3 of this Plan. 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 over a three-year procurement horizon. 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 volumes and prices across a fixed number of hours while hourly prices as well as load vary across the day and within each of the on-peak and off-peak periods. Because of this variation, even if the average on-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.

[170] See: Illinois Commerce Commission, Office of Retail Market Development, Industry Reports, Electric Switching Statistics.

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 forecasted to be met by the Illinois-allocated MidAmerican resources. Following the approach started for the 2016 Plan, and continued under subsequent Plans through the 2024 Plan, for the 2025 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). Prior to the 2023 Plan, the Ameren Illinois capacity needs had been 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. Starting with the 2023 Procurement Plan, and continuing with the 2024 Plan, the IPA proposed to procure up to 75% of these needs through the IPA procurements, with the balance to be procured through the PRA. This 75% capacity procurement target for Ameren Illinois has been retained for the 2025 Plan.

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.[171]

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

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.[172] 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.[173] 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.[174] 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 helps 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

[171] 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.

[172] 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 success of its procurement approach in producing competitive supply rates for Ameren Illinois, MidAmerican, and ComEd eligible retail customers.

[173] 220 ILCS 5/16-111.5(b), (e), (f).

[174] 220 ILCS 5/16-111.5(f)

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. 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 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.

Section 16-111.5(b)(3)(iv) of the Public Utilities Act provides that procurements of standard wholesale products may include energy from HVDC transmission lines that would have converter stations located in Illinois. To the extent such products qualify to participate in the IPA's procurement events, HVDC products are to be treated on a comparable basis with other sources of supply utilized in the IPA's hedging strategy and procurement process.

For this 2026 Plan, the IPA reviewed the development status of potential HVDC projects to assess the HVDC products that could be used by the Agency as a suitable risk management tool. The IPA's review identified several issues and uncertainties that would have to be addressed prior to incorporating HVDC products into the IPA's risk management strategy and an IPA Procurement Plan, including:

The SOO Green HVDC link is a proposed 350-mile long, 525 kV, bidirectional underground transmission line capable of transmitting 2,100 MW from a point near Mason City, Iowa in MISO to a point on the ComEd transmission system near Plano, Illinois in PJM. The commercial operation date for this project has been delayed several times. The uncertainty regarding the project's commercial operation date raises the issue of timing as to when the IPA would be able to consider products from the HVDC project for inclusion in the procurement process.

If the SOO Green HVDC transmission link is constructed, it would offer a path for the transmission of wholesale energy, but the project will seek to also be compensated for the value of its capacity. Since the proposed terminus of the line would be in PJM, the IPA would only be procuring energy for ComEd's eligible customers that would be delivered through the HVDC line not capacity. This raises additional uncertainties regarding how this product could be incorporated in the IPA procurement process and still provide sufficient revenues to help make the project economically viable. In its recent Policy Study,[175] the IPA's analysis of a policy to establish a procurement for RECs from a high voltage direct current transmission line included a review of the potential costs to ratepayers, the impact on grid reliability and impact on resource adequacy in Illinois of the proposed SOO Green HVDC line.

[175] See https://ipa.illinois.gov/ipa-policy-study.html

Another proposed HVDC line, the Grain Belt Express, is proposed as a nominally 600 kV line with a capacity of 5,000 MW that would run from Ford County, Kansas to an interconnection in MISO in Missouri in the project's first phase. The second phase of the project would involve 2,500 MW of the line's capacity to be delivered to a converter station in Clark County, Illinois with further deliveries along a 345 kV AC transmission line to a termination point in Sullivan County, Indiana.[176] In July 2025, the Department of Energy terminated its loan guarantee for the first phase of the project.[177] The current schedules for construction and operation of the first and second phases are uncertain. Merchant HVDC projects, such as the projects referenced above, typically require long-term transmission contracts with terms of 15 to 20 years to be signed ahead of financing and construction. Since the IPA's procurement horizon is focused on three years, such long-term contracts do not fit into the IPA's statutorily defined procurement process.

Questions related to these issues were posed in the draft 2023 Procurement Plan, but no parties offered comment in response. As a consequence, the 2023 Plan did not offer resolution on these issues and uncertainties. While these issues remained unresolved through the 2024 Plan and through the 2025 Plan, the uncertainty around the in-service dates of the two HVDC projects products pushes the delivery of HVDC electricity products beyond the planning horizon for this Plan.

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 at a specified strike price.

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 ensure 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.

[176] See Illinois Commerce Commission March 8, 2023 Order in Docket No. 22-0499.

[177] U.S. Department of Energy: https://www.energy.gov/articles/department-energy-terminates-taxpayer-funded-financial-assistance-grain-belt-express (July 23, 2025)

The use of options is subject to regulations under the federal Dodd-Frank Act of 2010 (specifically Title VII).[178] 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 five years after the termination of trade (either through exercise or expiration) and must be made available within five business days of request. This would add to either the purchase cost or the ownership cost of options.

6.4 Tools for Managing Surpluses and Portfolio Rebalancing

The Illinois Power Agency Act specifies that the Procurement Plan "shall include … the criteria for portfolio re-balancing in the event of significant shifts in load."[179] 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.[180]
- 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.[181]
- 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 ensure 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

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

[179] 220 ILCS 5/16-111.5(b)(4).

[180] As the state's renewable portfolio standard has transitioned 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)).

[181] 125 FERC ¶ 61,064, Oct. 16, 2008.

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.

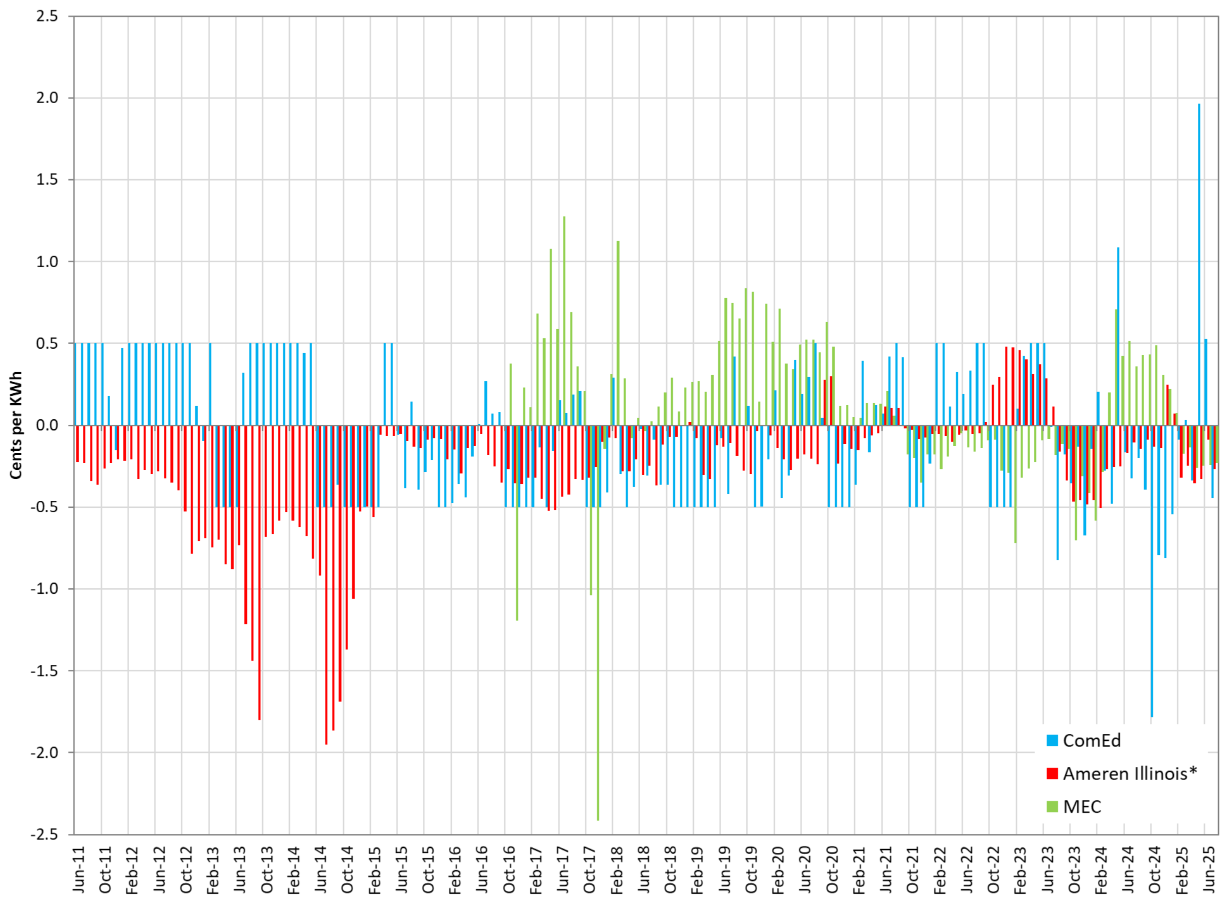
The PEA provides some guidance as to the amount by which the complete set of risk factors caused the cost of energy supply to differ from utility estimates. Figure 6-1 shows how the PEAs for Ameren Illinois and ComEd have changed over the last 13 years. The figure also shows the applicable MidAmerican PEAs starting with October 2016. Ameren Illinois' PEAs have been generally "negative" (i.e., operating as a credit to customers) since the early part of this period with a few positive months until turning positive from September 2022 through July 2023. The Ameren PEA was a negative value from August 2023 through June 2024. Similarly, for all months from July 2024 through July 2025, except December and January, PEAs were negative. ComEd's have been "negative" as well as "positive" (i.e., operating as charge to customers). For the second half of 2024 and through February 2025, PEAs were negative. From then through July 2025, PEAs have fluctuated between negative and positive values. ComEd has voluntarily limited its PEA to move between +0.5 cents/ kWh and -0.5 cents/kWh throughout this period, and the figure shows that ComEd's PEA has oscillated between those limits. Although based on a relatively short period, the MidAmerican PEA exhibited significant volatility from 2016 to 2018, 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. Since then, MidAmerican's PEA has exhibited somewhat less volatility and was consistently positive from July 2018 through August 2021, then turned negative from September 2021 through February 2024, and turned positive again from March 2024 through June 2024. MidAmerican's PEAs continued to be positive through January 2025, after which PEAS have negative through July 2025.

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. Since May 2015, the ComEd PEA has reflected both credits and charges. Through February 2023, ComEd voluntarily limited its PEA to move between +0.5 cents/ kWh and -0.5 cents/kWh. The change to the hedging strategy for ComEd that was implemented by the IPA in 2023, to only procure 50% of expected customers load, means that the ComEd PEA could have larger swings to reflect the cost of electricity purchased from the spot electricity market for the remaining 50% of load. However, that change was made in conjunction with a change to Rider CRFA "(Carbon-Free Resource Adjustment") which is the Rider that reflects the price of CMCs on customer bills. As discussed in Section 6.9, changes to the PEA are offset by changes to Rider CFRA.

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 resulted in 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 mostly 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 (a credit to customers) throughout this period with a few shorter periods of positive values (a charge to customers). 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 with a period of negative values from September 2021 through February 2024.

Figure 6-1: Purchased Electricity Adjustments in Cents/kWh, June 2011 – July 2025

*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 on-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 on-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 on-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 through 2024 Procurement Plans, the IPA continued the use of two annual procurement events for standard energy blocks, one held in the spring with a subsequent event scheduled for each fall. Under the 2025 Procurement Plan, the IPA will continue the use of two procurement events to be held in the spring and fall, as described below and in Section 7.1.

Coming into the Spring 2022 energy procurement event, slightly less than 50% of the hedging requirements for the 2022 summer months had been procured, leaving the balance to be procured in the Spring 2022 events. The IPA's Spring 2022 energy procurements were exposed to unprecedented market volatility and unexpected high prices resulting in higher costs for eligible retail customers than would have been incurred if the balance to be procured in the Spring event had been less. In response, for the 2023 Plan, the IPA increased the percentage of summer load to be hedged in early procurement events in such a way that the summer procurement volumes to be hedged in the spring prior to delivery are reduced by about half. This approach seeks to limit the exposure to the adverse price risks during the volatile summer months by reducing the hedging percent target for the prompt summer months in the Spring procurement events. This approach was continued for the 2024 Plan and the 2025 Plan.

The tables below illustrate the cumulative targets for July and August on-peak by procurement event and reflect a phase-in of the procurement for Delivery Years 2026, 2027, 2028, 2029, and 2030. Targets to be used in the Spring and Fall 2026 procurement events are specified in Section 7.1.1 of this Plan.

Table 6-1: Proposed Cumulative Procurement Targets for Ameren Illinois and MidAmerican

Procurement Event	July and August On-Peak for Calendar Year					
	2026	2027	2028	2029	2030	2031
Fall 2025*	50%	25%				
Spring 2026	106%	52.5%	15%			
Fall 2026		75%	30%			
Spring 2027		106%	52.5%	15%		
Fall 2027			75%	30%		
Spring 2028			106%	52.5%	15%	
Fall 2028				75%	30%	
Spring 2029				106%	52.5%	15%

** Approved targets in the 2025 Plan.*

Table 6-2: Proposed Cumulative Procurement Targets for ComEd

Procurement Event	July and August On-Peak for Calendar Year					
	2026	2027	2028	2029	2030	2031
Fall 2025*	37.5%	30%				
Spring 2026	50%	52.5%	15%			
Fall 2026		75%	30%			
Spring 2027		106%	52.5%	15%		
Fall 2027			75%	30%		
Spring 2028			106%	52.5%	15%	
Fall 2028				75%	30%	
Spring 2029				106%	52.5%	15%

** Approved targets in the 2025 Plan.*

The targets in Table 6-2 reflect the scheduled end of CMC contracts and their associated offsetting value at the end of the 2026-2027 Delivery Year. For 2027 and subsequent years, the cumulative targets for ComEd would match the schedule for Ameren Illinois and MidAmerican. As discussed in Section 6.9.1, the Agency has adjusted ComEd hedging levels to reflect ComEd's feedback on the draft Plan to reduce the amount of eligible retail customer load hedged by IPA procured contracts to 30% for the October through May delivery months.

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

The IPA's procurement and hedging strategy has been challenged by volatile market conditions which had a major impact on the prices and availability of the wholesale energy blocks procured during the Spring 2022 procurement events. 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 utilities' supply portfolios. 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 eligible ratepayers for 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 random level of forward prices experienced on the specific days in which components of the portfolio are procured.

The IPA conducted an analysis for the 2021 Plan related to procurement scheduling and volatility. That analysis was updated for the 2023 Plan and was reviewed for the 2024 Plan and this 2025 Plan. The updated analysis examined the degree to which varying the number of scheduled annual procurement events and moving procurements closer to their delivery months affect volatility price risk for individual delivery months in the portfolio. Shortening the time interval between the Agency's procurement event and the initial delivery month, along with using multiple annual procurement events, can result in an improved portfolio with lower price volatility.

The results of the updated analysis indicate that the closer the procurement events are held to the product delivery date, the greater the price volatility on the hedges 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 reduce 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 reduce price volatility. Other overriding factors, such as the risk of load switching associated with Municipal Aggregation programs, also impact the scheduling of procurement events relative to delivery timing and 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 have produced the lowest volatility of portfolio price.

6.6.3 Review of Proposed Changes to Hedge Volumes to be Procured in the Last Procurement Event Ahead of the upcoming June, July, and August

In previous Plans, the Agency reviewed proposed changes to hedging volumes to be procured in the last procurement event prior to the upcoming June, July, and August months.[182] The previous data did not provide strong support for increasing the number of annual procurements events beyond the current Spring and Fall schedule.

The conclusions from previous analyses remain relevant for this Plan. Taking into consideration the changes proposed for the summer month procurement targets, the IPA will continue to use the energy procurement schedule and implement a modification to the hedging approach utilized in the prior Plan. Following the Commission's Order approving the 2023 Electricity Procurement Plan, the Agency's hedging approach for the ComEd energy procurements includes consideration of the offsetting cost impact that CMCs can provide to eligible retail customers by leaving 50% of load unhedged through IPA procurements. The Agency continued this approach for the 2025 Plan and 2026 Plan, with the modification of hedging to only 30% non-summer period (e.g., leaving 70% of the load unhedged). CMC contracts expire at the end of the 2026-2027 Delivery Year. Following the end of those contracts, the IPA plans that its hedging strategy and procurement targets will cover all of the energy supply requirements of ComEd's eligible retail customers, and that is reflected in the targets for the 2027-2028 Delivery Year.

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 act as supply risk management tools 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

[182] Section 6.7.1: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20250124-2025-electricity-procurement-plan.pdf

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 can 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.[183] 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.[184] On February 19, 2019, FERC approved revisions to MISO's tariff which allow MISO to more effectively access the capabilities 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.[185] 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.[186] Chapter 7 of this Plan provides details and additional discussion regarding demand response resources.

6.8 Impact of Carbon Mitigation Credits on the Hedging Strategy for ComEd Eligible Retail Load

Carbon Mitigation Credits can help offset the impact of higher wholesale prices on retail customers in the ComEd service territory, including eligible retail customers, due to the indexing of the CMC price to the PJM busbar price. A key consideration for the determination of CMC payments is the legislated baseline CMC costs set at $30.30/MWh for the 2022-2023 Delivery Year, $32.50/MWh for the 2023-2024 Delivery Year, $33.43/MWh for the 2024-2025 Delivery Year, $33.50/MWh for the 2025-2026 delivery year, and $34.50/MWh for the 2026-2027 Delivery Year. The baseline costs set the limit for CMC price bids. All of the accepted CMC bids were priced at the baseline costs. The day-ahead market price for the relevant month and the value of capacity stated on a $/MWh basis are subtracted from the CMC bid price to determine the amount to be used in calculating the CMC payment. If the monthly CMC price calculation results in a net negative value, such as is likely to be the case during periods of high wholesale electricity prices, the CMC supplier makes payments that benefit all of ComEd's retail customers. As a result, payments from the CMC supplier would help offset the impact of higher wholesale prices on retail customers.

In the Commission proceeding approving the 2023 Plan, ComEd argued that the volume of CMCs purchased by ComEd could serve to provide offsetting price benefits for 60% to 65% of the eligible customer energy requirements in each month going forward. Under this approach, the IPA's block energy procurements would be implemented to hedge less than half of ComEd's eligible customer load, with the portion of the energy requirements not covered to be settled through purchases in the spot day-head market in the relevant delivery month (which would eventually be offset by ComEd's CMC purchases).

[183] 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.

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

[185] See Midcontinent Independent System Operator, Inc., 166 FERC ¶ 61,116 (2019).

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

In its Final Order approving the 2023 Plan, the Commission conditionally accepted ComEd's proposal to reduce the hedging target in the ComEd service territory to 50%.[187] The Commission found that ComEd's hedging strategy would be a reasonable approach if revisions to Rider Carbon-Free Resource Adjustment "CFRA" (the CMC tariff) were first made allowing for more frequent adjustments "to reconcile any over- or under-collections under the CMC tariff on the same four-month lag that the PEA follows to reconcile purchased energy." The Commission explained that approval of such tariff revisions "would trigger the associated reduction in the hedging level to 50% if those revisions are approved by March 31, 2023."[188] ComEd accordingly filed the necessary tariff changes on December 21, 2022, the Commission voted not to suspend the filing on January 19, 2023, and the tariff changes became effective on February 4, 2023.[189] The updated reconciliation process was fully implemented by the October 2023 monthly billing period.

The Agency updated the 2023 Plan hedging target in the ComEd territory for all months to 50%. The hedging targets for ComEd updated in the previous Plan will be continued for this Plan through the 2026-2027 Delivery Year, with the additional adjustment started in the 2025 Plan of hedging non-summer months to 30%. The Commission explicitly noted in its Final Order that "[i]n the event of default on CMC contracts, the IPA may change the hedging percentages for ComEd to mirror those of Ameren and MidAmerican, with the consensus of the IPA, Staff, and the Procurement Monitor."[190]

In comments received on the draft 2025 Plan, ComEd proposed that "to maximize the CMC hedge during the non-summer months of October to May, when ComEd deliveries are the lowest, the percentage of open load should increase from 50% in the IPA's current 2025 Draft Plan to 70%."[191] This proposal was based on ComEd's previous recommendations and ComEd's analysis below. Taking this adjustment into account yields a lower net cost when compared to the previous methodology of a 50% year-round hedge. The Agency considered ComEd's proposal and included it in the 2025 Plan and will continue that approach in the 2026 Plan.

6.8.1 Results of CMC Benefits Analysis: Relative Cost Impact

The CMC price is calculated by taking the CMC Bid Price for the delivery year and subtracting, (1) the weighted monthly average busbar price for the participating nuclear units, and (2) the price of capacity for the delivery year.[192] The resulting price can be either positive or negative depending on wholesale electricity prices. ComEd's eligible retail customers thus benefit when negative prices result in payments made by the CMC suppliers, while when prices are positive the CMC suppliers receive payments.

The price of CMCs from June 2022 through June 2025 varied significantly. CMC prices were initially negative due to the price spike that occurred in 2022. This variance reflects falling energy prices after the summer of 2022 and relative price stability since the extreme price volatility seen through much of calendar year 2022. Negative CMC prices were also observed in January and February of 2025 due to high electricity prices and starting in June of 2025 CMC prices have been negative due to the substantial increase in PJM capacity prices and higher summer electricity prices. The CMC prices are shown in Table 6-3.

[187] See ICC Docket No. 22-0590, Final Order at 23.

[188] Id.

[189] See: https://www.icc.illinois.gov/meetings/meeting/commission-meeting/21512.

[190] See ICC Docket No. 22-0590, Final Order at 24.

[191] See ComEd comments at: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240917-comed-comments.pdf .

[192] CMC prices will also be adjusted to account for the value of any Federal subsidies. As of the release of this draft 2025 Electricity Procurement Plan, the IRS has not finalized the guidelines for a nuclear production tax credit. See Section 4.2 of the CMC Procurement Plan for more information of the process that would be utilized to introduce such an adjustment.

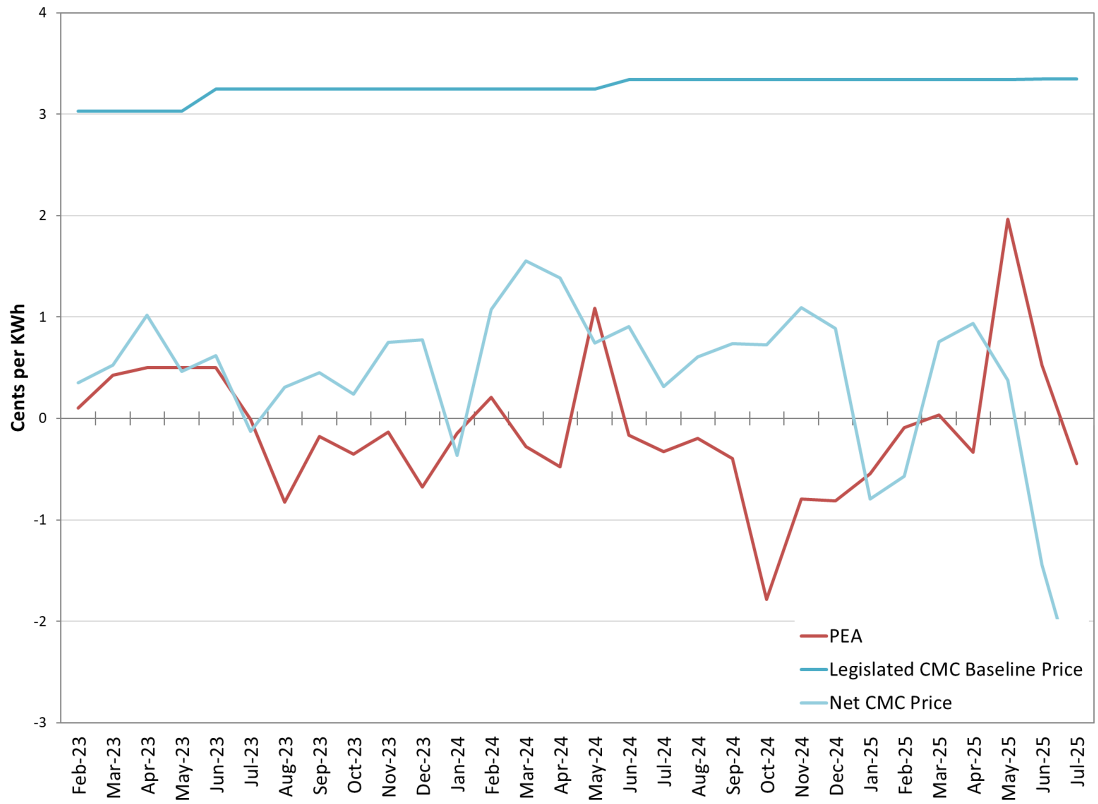
Table 6-3: Carbon Mitigation Credit Prices, June 2022 through July 2025

Month	CMC Price ($ / MWh)
Jun-22	-$52.30
Jul-22	-$52.79
Aug-22	-$60.11
Sep-22	-$42.21
Oct-22	-$18.35
Nov-22	-$16.05
Dec-22	-$33.36
Jan-23	-$4.24
Feb-23	$3.49
Mar-23	$5.28
Apr-23	$10.17
May-23	$4.62
Jun-23	$6.21
Jul-23	-$1.25
Aug-23	$3.09
Sep-23	$4.51
Oct-23	$2.39
Nov-23	$7.50
Dec-23	$7.76
Jan-24	-$3.63
Feb-24	$10.73
Mar-24	$15.54
Apr-24	$13.85
May-24	$7.43
Jun-25	$9.03
Jul-25	$3.17
Aug-25	$6.05
Sep-25	$7.39
Oct-25	$7.28
Nov-25	$10.94
Dec-25	$8.85
Jan-25	-$7.94
Feb-25	-$5.73
Mar-25	$7.54
Apr-25	$9.37
May-25	$3.76
June-25	-$14.40
July-25	-$26.41

Figure 6-2 below presents a monthly comparison of the Purchased Electricity Monthly Factors versus both the Legislated CMC Baseline Price and the Net CMC Price. The Net CMC Prices are calculated by adjusting the CMC Baseline Costs for monthly energy and capacity credits. Prior to February, 2023, CMC prices seen by customers did not change on a monthly basis, rather they were set based on an energy price forecast conducted by ComEd in the spring of 2022. Following a revision to Rider CFRA by ComEd, the CMC price seen by customers adjusts on a monthly basis. Initially those adjustments included recalibrating the mismatch between the energy price forecast and actual market prices that reflected how energy prices fell in the second half of 2022. As shown in

Figure 6-2, since the summer of 2023, the CMC price and the PEA have generally moved in opposite directions, as was expected through this change.

Figure 6-2: Monthly Purchased Electricity Adjustment Factors vs. CMC Baseline and CMC Net Prices



The 2025 Plan included a detailed CMC Benefits Analysis in Section 6.9.[193] The results provided an indication of the relative benefits that ComEd's eligible retail customers could expect to receive when 50% of their load is left uncovered by (e.g., not covered by hedges procured by the IPA) in order to take advantage of the CMC contracts.[194] The net cost analysis took into consideration the cost of CMCs, the cost of the IPA's procured hedges, and the day ahead market price of electricity during a specific month to identify the relative value of leaving 50% of the customer supply uncovered by IPA procured hedges to take advantage of the off-setting benefits of CMCs which are paid for by ComEd's eligible customers in either case. The costs associated with IPA's forward contracts and CMCs are balanced against the credit for the market value of the forward contracts, with the net cost compared for each procurement/hedging approach. The lower net cost reflects the benefit to eligible retail customers.

In the 2025 Plan, the IPA, in agreement with ComEd (see comments submitted by ComEd on the Draft 2025 Plan in September 2024), left 70% of the procurement requirements for ComEd's eligible retail customers in October to May uncovered to maximize the value of CMCs.[195]

In future Electricity Procurement Plans, the IPA will continue to monitor the impacts of recent Federal legislation on the existing nuclear fleet. Treasury Department guidance on tax credits had not been issued at the time of this Draft Plan. Initial review of recent Federal legislation indicates that Section 45U tax credits for existing nuclear power plants remain in effect through 2032. Beginning in 2028, plants will be ineligible for the tax credits if they procure fuel from certain nations.[196]

[193] IPA 2025 Plan, https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20250124-2025-electricity-procurement-plan.pdf.

[194] Please see 2025 Plan Appendix H for additional information on this analysis.

[195] See ComEd Comments at: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240917-comed-comments.pdf.

[196] United States Congress, *Public Law 119-21*. 119th Congress, 2025, p. 181.

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's energy hedging strategy for the 2026 Procurement Plan is consistent with the strategy used for the 2025 Plan.

- Procure hedges consisting of standard 25 MW energy blocks.
- Hedges will be calculated on the expected monthly average on-peak and off-peak load.
- Conduct two procurement events in 2026: one in the Spring, and one in the Fall.

This Plan continues the approach adopted in the 2023 Plan which recognizes the offsetting price impacts for ComEd's eligible retail customers created by ComEd's CMC contracts through the end of the 2026-2027 Delivery Year. Under this approach, as refined in the 2025 Plan, the IPA only hedges 50% of ComEd's forecast eligible retail customer load in summer months and 30% of ComEd's forecast eligible retail customer load during non-summer months, with the price volatility of the remaining load offset by month to month changes in the CMC price.[197] As this Plan calls for the procurement of electricity through the 2028-2029 Delivery Year, this Plan includes a ramping up of procurement volumes in anticipation of returning to hedging 100% of ComEd's forecast eligible retail customer load starting in the 2027-2028 Delivery Year.

For Ameren Illinois and MidAmerican, 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 2026-2027 Delivery Year, the target cumulative hedges should be approximately 100% of each monthly average on-peak and off-peak load, except for July and August on-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 on-peak and off-peak average load.
- For the 2027-2028 Delivery Year the target cumulative hedges in the portfolio should be approximately 37.5% of each monthly on-peak and off-peak average load, except for June, July and August on-peak and off-peak, which should be approximately 52.5%.
- For the 2028-2029 Delivery Year the target cumulative hedges in the portfolio should be approximately 12.5% of each monthly on-peak and off-peak average load, except for June, July and August on-peak and off-peak, which should be approximately 15%.

For Ameren Illinois and MidAmerican, 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 2026-2027 Delivery Year the target cumulative hedges in the portfolio should be approximately 100% of the average monthly on-peak and off-peak load, except for July and August peak, which should have been hedged at 106% in the Spring procurement.
- For the 2027-2028 Delivery Year the target cumulative hedges in the portfolio should be approximately 50% of the average monthly on-peak and off-peak load, except for June, July and August on-peak and off-peak, which should be approximately 75%.
- For the 2028-2029 Delivery Year the target cumulative hedges in the portfolio should be approximately 25% of the average monthly on-peak and off-peak load, except for June, July and August on-peak and off-peak, which should be approximately 30%.

For ComEd, 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 2026-2027 Delivery Year, the target cumulative hedges should be approximately 50% of each monthly average on-peak and off-peak load. For the

[197] See Section 6.9 of this Plan for more information.

period of October through May of the prompt Delivery Year, the target cumulative hedges in the portfolio should be approximately 22.5% of each monthly on-peak and off-peak average load.
- For the 2027-2028 Delivery Year the target cumulative hedges in the portfolio should be approximately 37.5% of each monthly on-peak and off-peak average load, except for June, July, August, and September on-peak and off-peak, which should be approximately 52.5%.
- For the 2028-2029 Delivery Year the target cumulative hedges in the portfolio should be approximately 12.5% of each monthly on-peak and off-peak average load, except for June, July and August on-peak and off-peak, which should be approximately 15%.

For ComEd 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 2026-2027 Delivery Year the target cumulative hedges in the portfolio should be approximately 30% of the average monthly on-peak and off-peak load.
- For the 2027-2028 Delivery Year the target cumulative hedges in the portfolio should be approximately 50% of the average monthly on-peak and off-peak load, except for June, July, August , and September on-peak and off-peak, which should be approximately 75%.
- For the 2028-2029 Delivery Year the target cumulative hedges in the portfolio should be approximately 25% of the average monthly on-peak and off-peak load, except for June, July and August on-peak and off-peak, which should be approximately 30%.

The strategy is summarized in Tables 7-1 and 7-2.

Table 7-1: Summary of Energy Procurement Strategy for Ameren Illinois and MidAmerican[198]

Spring 2026 Procurement			Fall 2026 Procurement		
June 2026-May 2027 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2026-May 2027**	**Upcoming Delivery Year + 1**	**Upcoming Delivery Year + 2**
June 100% on-peak and off-peak July and Aug. 106% on-peak, 100% off-peak Sep. 100% on-peak and off-peak Oct. – May 75% on-peak and off-peak	37.5% all months, except June, July and August on-peak and off-peak, which should be 52.5%.	12.5% all months, except June, July and August on-peak and off-peak, which should be 15%.	100% all months	50% all months, except June, July and August on-peak and off-peak, which should be 75%.	25% all months, all months, except June, July and August on-peak and off-peak, which should be 30%.

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

Table 7-2: Summary of Energy Procurement for ComEd[199]

Spring 2026 Procurement			Fall 2026 Procurement		
June 2026-May 2027 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2026-May 2027**	**Upcoming Delivery Year + 1**	**Upcoming Delivery Year + 2**
June - Sep. 50% on-peak and off-peak, Oct. - May 22.5% on-peak and off-peak	37.5% all months, except June, July and August on-peak and off-peak, which should be 52.5%.	12.5% all months, except June, July and August on-peak and off-peak, which should be 15%.	30% all months	50% all months, except June, July and August on-peak and off-peak, which should be 75%.	25% all months, all months, except June, July and August on-peak and off-peak, which should be 30%.

7.1.2 Energy Procurement Implementation

The following tables and figures were constructed using each utility's July 2025 base load forecasts to provide indicative procurement values for the 2026-2027 Delivery Year.[200] The actual target procurement volumes used for the Spring and Fall 2026 procurements will be calculated using the March 2026 and the July 2026 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 2029-2030 and 2030-2031) in this Procurement Plan. Therefore, the tables and figures that follow only cover Delivery Years 2026-2027, 2027-2028, and 2028-2029.

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

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

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

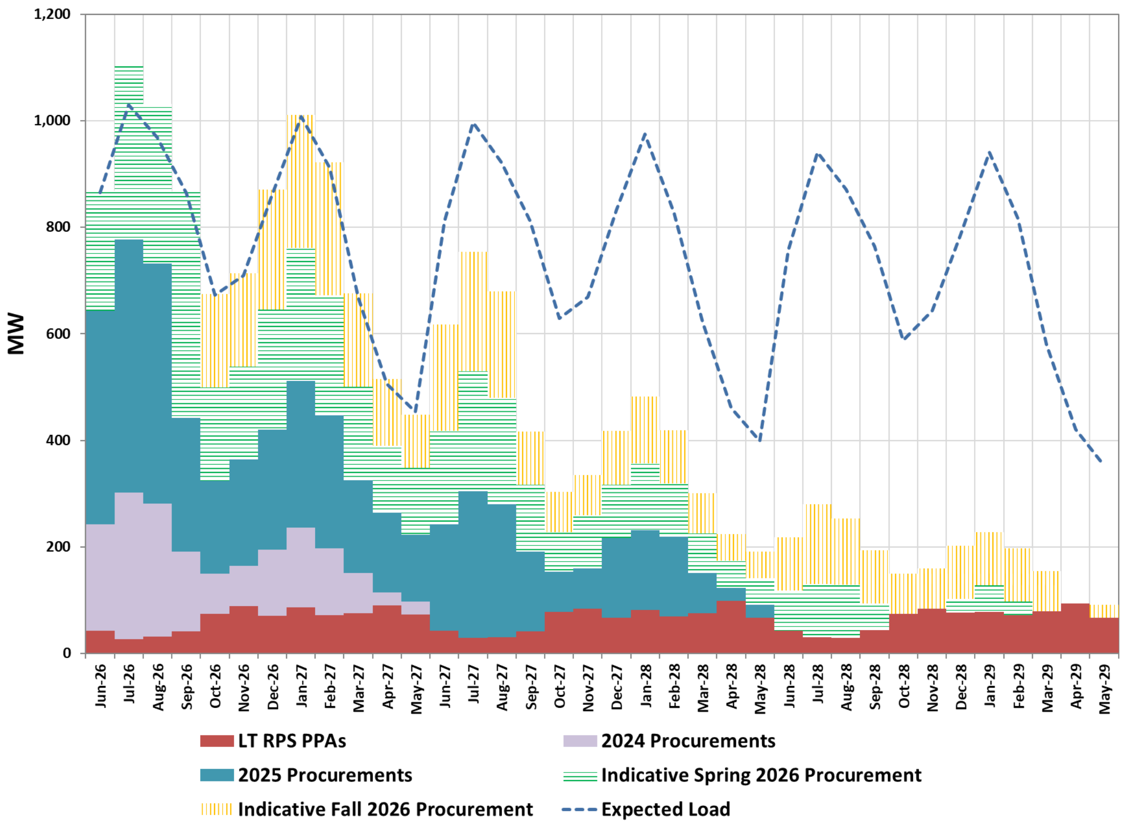


Figure 7-2: Ameren Illinois Off-Peak Energy Supply Portfolio and Load

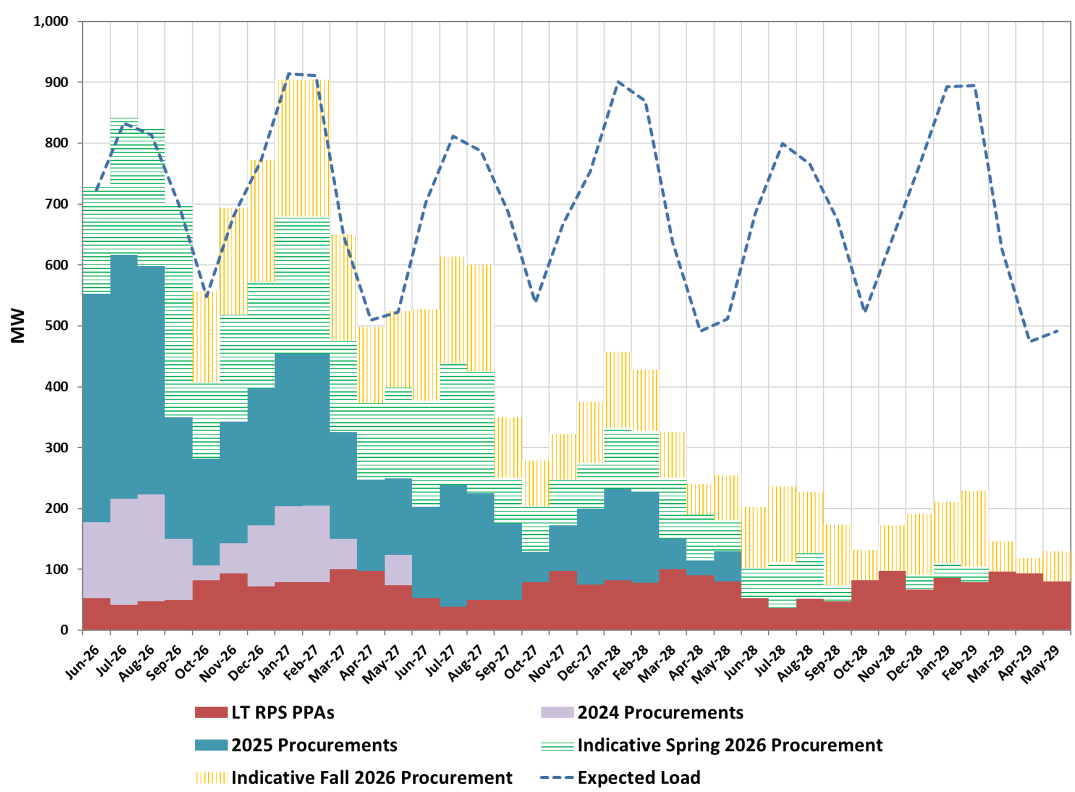


Table 7-3: Ameren Illinois 2026 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2026 Purchases (MW)		Anticipated Fall 2026 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2026-2027				
Jun-26	225	175	0	0
Jul-26	325	225	0	0
Aug-26	300	225	0	0
Sep-26	425	350	0	0
Oct-26	175	125	175	150
Nov-26	175	175	175	175
Dec-26	225	175	225	200
Jan-27	250	225	250	225
Feb-27	225	225	250	225
Mar-27	175	150	175	175
Apr-27	125	125	125	125
May-27	125	150	100	125
Delivery Year 2027-2028				
Jun-27	175	175	200	150
Jul-27	225	200	225	175
Aug-27	200	200	200	175
Sep-27	125	75	100	100
Oct-27	75	75	75	75
Nov-27	100	75	75	75
Dec-27	100	75	100	100
Jan-28	125	100	125	125
Feb-28	100	100	100	100
Mar-28	75	100	75	75
Apr-28	50	75	50	50
May-28	50	50	50	75
Delivery Year 2028-2029				
Jun-28	75	50	100	100
Jul-28	100	75	150	125
Aug-28	100	75	125	100
Sep-28	50	25	100	100
Oct-28	0	0	75	50
Nov-28	0	0	75	75
Dec-28	25	25	100	100
Jan-29	50	25	100	100
Feb-29	25	25	100	125
Mar-29	0	0	75	50
Apr-29	0	0	0	25
May-29	0	0	25	50

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

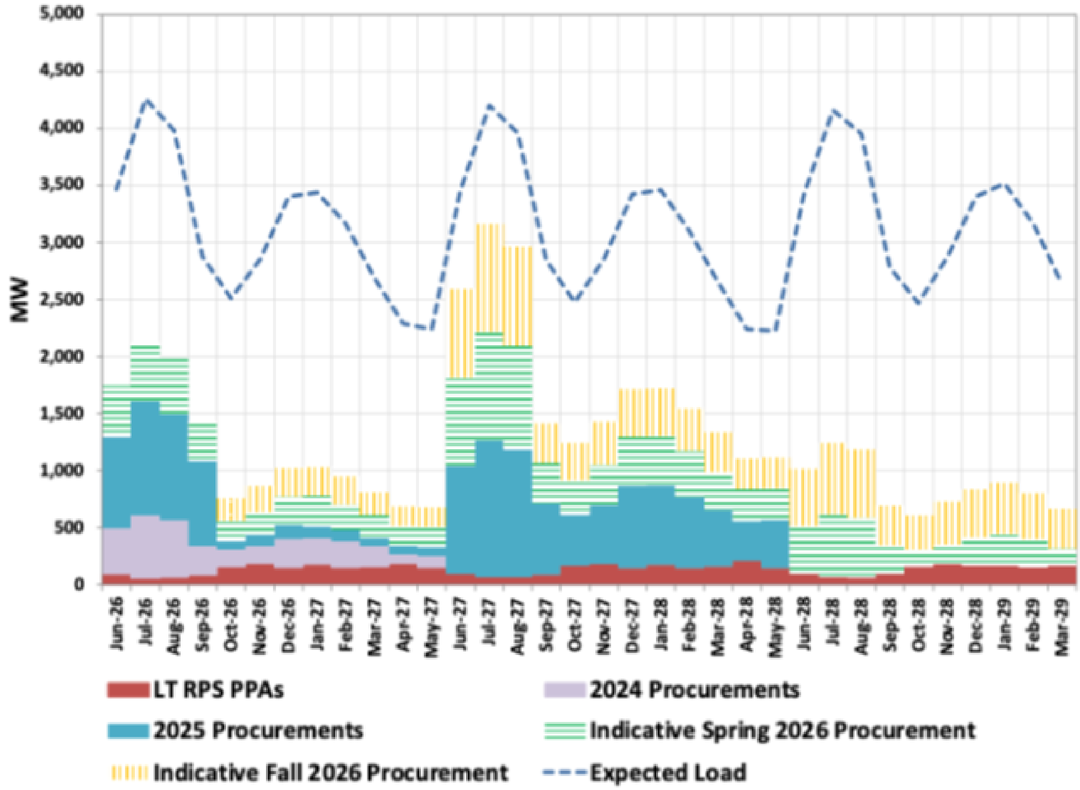


Figure 7-4: ComEd Off-Peak Energy Supply Portfolio and Load

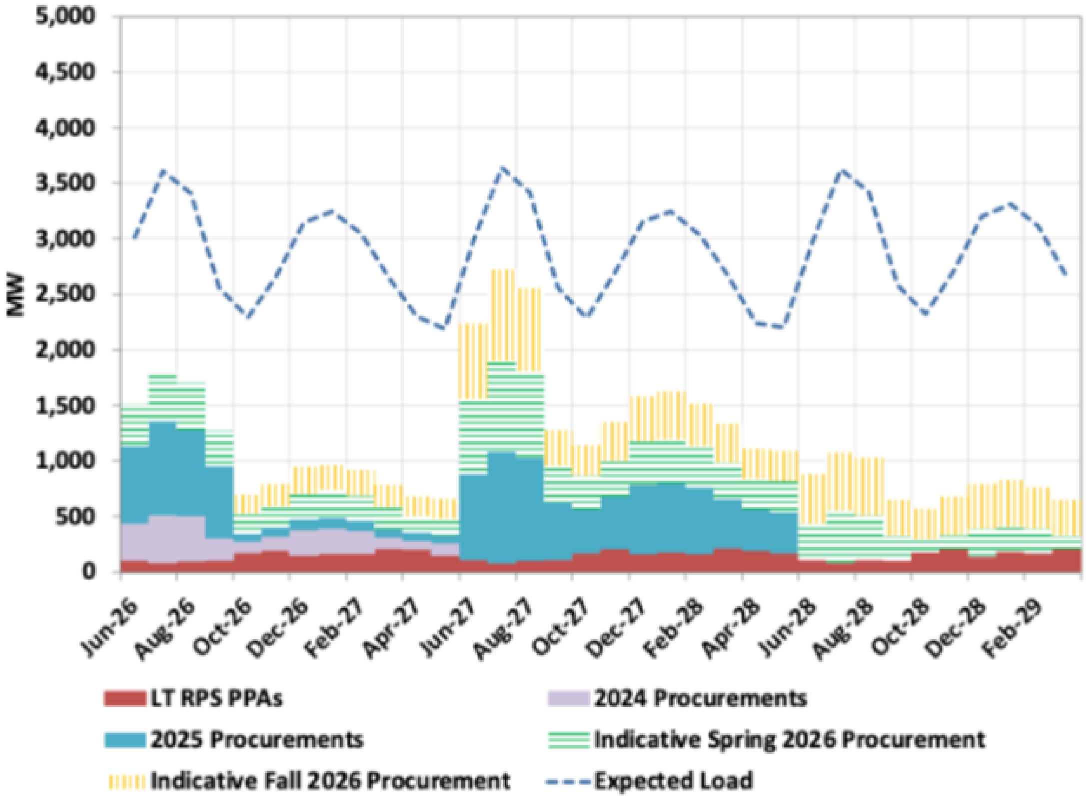


Table 7-4: ComEd 2026 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2026 Purchases (MW)		Anticipated Fall 2026 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2026-2027				
Jun-26	450	375	0	0
Jul-26	525	450	0	0
Aug-26	500	425	0	0
Sep-26	350	325	0	0
Oct-26	175	175	200	175
Nov-26	200	200	225	200
Dec-26	250	225	250	250
Jan-27	275	250	250	225
Feb-27	225	225	250	225
Mar-27	200	200	200	200
Apr-27	175	150	175	175
May-27	175	150	175	175
Delivery Year 2027-2028				
Jun-27	775	675	775	675
Jul-27	950	825	950	825
Aug-27	900	775	875	750
Sep-27	350	325	350	325
Oct-27	300	300	325	275
Nov-27	350	325	375	350
Dec-27	425	400	425	400
Jan-28	425	400	425	425
Feb-28	400	375	375	375
Mar-28	325	325	350	350
Apr-28	275	275	275	275
May-28	275	275	275	275
Delivery Year 2028-2029				
Jun-28	425	325	500	450
Jul-28	550	475	625	525
Aug-28	525	400	600	525
Sep-28	250	225	350	325
Oct-28	150	125	300	275
Nov-28	175	125	375	350
Dec-28	250	250	425	400
Jan-29	275	225	450	425
Feb-29	250	225	400	375
Mar-29	150	125	350	325
Apr-29	75	75	300	300
May-29	125	100	275	275

Figure 7-5: MidAmerican Peak Energy Supply Portfolio and Load[201]

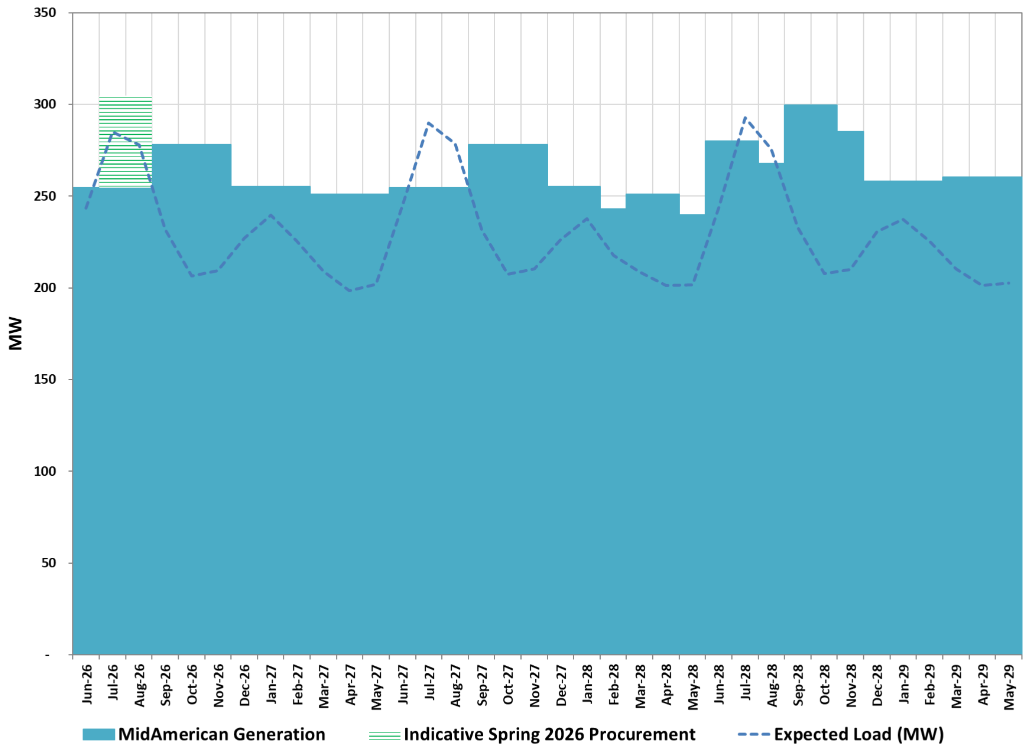
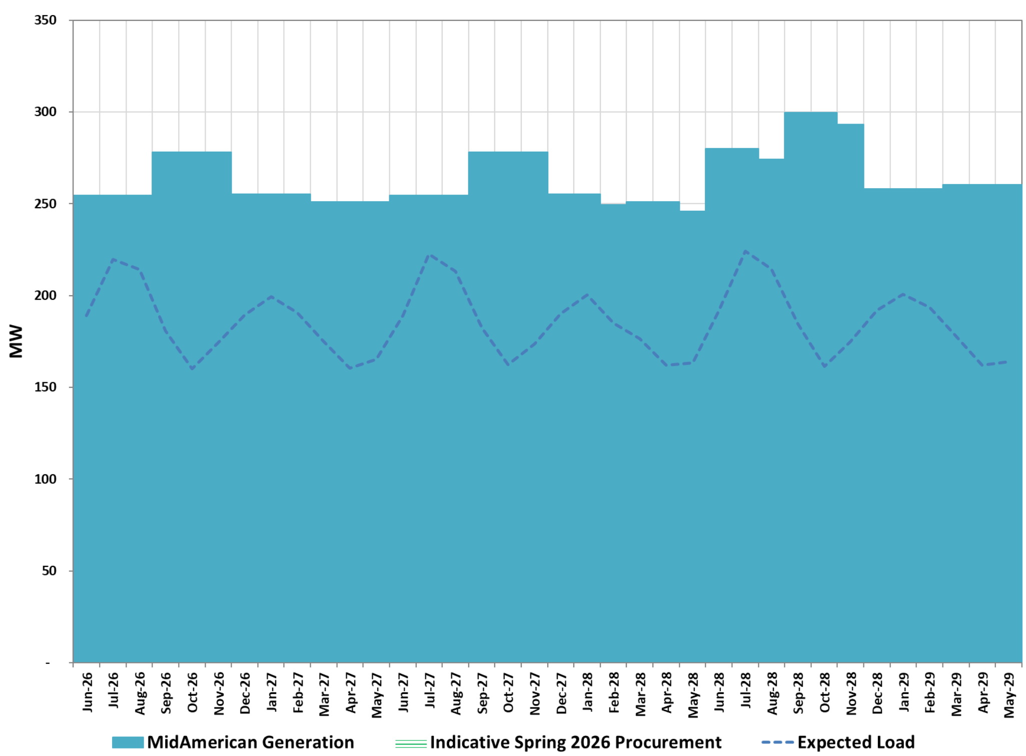


Figure 7-6: MidAmerican Off-Peak Energy Supply Portfolio and Load



201 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 7-5: MidAmerican 2026 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2026 Purchases (MW)		Anticipated Fall 2026 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2026-2027				
Jun-26	0	0	0	0
Jul-26	50	0	0	0
Aug-26	50	0	0	0
Sep-26	0	0	0	0
Oct-26	0	0	0	0
Nov-26	0	0	0	0
Dec-26	0	0	0	0
Jan-27	0	0	0	0
Feb-27	0	0	0	0
Mar-27	0	0	0	0
Apr-27	0	0	0	0
May-27	0	0	0	0
Delivery Year 2027-2028				
Jun-27	0	0	0	0
Jul-27	0	0	0	0
Aug-27	0	0	0	0
Sep-27	0	0	0	0
Oct-27	0	0	0	0
Nov-27	0	0	0	0
Dec-27	0	0	0	0
Jan-28	0	0	0	0
Feb-28	0	0	0	0
Mar-28	0	0	0	0
Apr-28	0	0	0	0
May-28	0	0	0	0
Delivery Year 2028-2029				
Jun-28	0	0	0	0
Jul-28	0	0	0	0
Aug-28	0	0	0	0
Sep-28	0	0	0	0
Oct-28	0	0	0	0
Nov-28	0	0	0	0
Dec-28	0	0	0	0
Jan-29	0	0	0	0
Feb-29	0	0	0	0
Mar-29	0	0	0	0
Apr-29	0	0	0	0
May-29	0	0	0	0

7.2 Capacity

7.2.1 Capacity Procurement Strategy

7.2.2 ComEd

Prior procurement plans, including the 2025 Procurement Plan, have recommended that ComEd obtain its capacity needs through the PJM-administered capacity market and sought stakeholder feedback on if the Agency should consider a change to this approach. For this 2026 Plan, ComEd will continue to obtain its capacity needs from the PJM-administered capacity market. Table 7-8 summarizes the proposed capacity procurement for ComEd. As discussed in Section 5.2.1, the Agency is interested in stakeholder feedback on if the Agency should consider a change to this approach.

7.2.3 Ameren Illinois

For Ameren Illinois, the 2025 Procurement Plan recommended a procurement of a portion of the Ameren Illinois capacity needs for the 2025-2026, 2026-2027, and 2027-2028 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 will continue this capacity procurement strategy which involves the procurement of 75% of the capacity requirements (in the form of ZRCs and financial capacity swaps (Financial ZRCs) in the near-term forward markets through IPA administered RFPs in a laddered fashion, and the remaining balance through the MISO PRA. Additionally, as discussed in Section 5.2.2.1 and elsewhere in this Plan, in line with the MISO Tariff and the move to a Seasonal Resource Adequacy Construct, the IPA has adjusted its bilateral procurement approach. The IPA no longer procures annual ZRCs and instead conducts bilateral procurements for each of the four seasons and procuring seasonal ZRCs. For this 2026 Plan, the Agency will use a consistent hedging level across all four seasons. Also, for this Plan, in addition to seasonal capacity, the IPA will include the procurement of annual planning year capacity products, both physical ZRCs and financial capacity swaps (Financial ZRCs). As future year results of MISO seasonal capacity auctions become available, the Agency will analyze the results of those auctions and may propose changes in seasonal hedging levels in future plans.

As also discussed in Section 5.2.2.6, the 2026 Plan does not change the 75%/25% procurement strategy which was approved in the 2025 Plan. The strategy uses the same level of hedging for each of the four seasons (i.e., the 75% is equally applied to all four seasons in the IPA's procurements).

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

- Conduct two procurement events in 2026, one in Spring, and one in Fall.
- Provide option for bidders to bid on an annual combination product (e.g., a bid for a quantity of ZRCs for all four seasons that would be accepted in totality, rather than separate bids for each season) in addition to bidding on each season individually.
    - As discussed in Section 5.2.3, the Agency is interested in stakeholder feedback on if the Agency should consider adding a multiyear capacity product.
- Provide an option for taking bids on a financial swap product (Financial ZRCs). As described in Section 5.2.2.6, this product would not require the actual delivery of ZRCs to Ameren, rather the product would be a financially settled product where the price paid under the contract is settled against the resulting applicable seasonal MISO PRA price.
- Bids for ZRCs and the Financial ZRCs will be evaluated together, including both seasonal and annual bids. The Procurement Administrator will determine the least cost package of bids that are below the applicable benchmark and within the procurement target for approval by the Commission.
- For the 2026-2027 Delivery Year, no change to the procurement target from what was approved in the 2025 Procurement Plan. That is, to procure up to 75% of the forecasted capacity requirements through an RFP administered by the IPA in Fall 2025 and procure the remaining balance through the MISO PRA scheduled for April of 2026.
- For the 2027-2028 and 2028-2029 Delivery Years, the IPA will procure capacity requirements through its two 2026 capacity procurement events, resulting in hedging at the following levels:
    - At the conclusion of the Spring 2026 procurement event, the target cumulative capacity hedges in Ameren Illinois portfolio of ZRCs or Financial ZRCs should be as follows:

        - For the 2027-2028 Delivery Year, the target cumulative hedges should be no more than 50% of the capacity requirements.
        - For the 2028-2029 Delivery Year, the target cumulative hedges should be no more than 12.5% of the capacity requirements.
    - At the conclusion of the Fall 2026 procurement event, the target cumulative capacity hedges in Ameren Illinois portfolio of ZRCs or Financial ZRCs should be as follows:
        - For the 2027-2028 Delivery Year, the target cumulative hedges should be no more than 75% of the capacity requirements.
        - For the 2028-2029 Delivery Year, the target cumulative hedges should be no more than 25% of the capacity requirements.
- Procure the remaining balance of the 2027-2028 Delivery Year capacity requirements through the MISO PRA scheduled for April of 2027. No additional procurements of capacity for the 2025-2026 Delivery Year will be needed.
- Procure the remaining balance of the 2028-2029 Delivery Year capacity requirements in the MISO PRA and/or additional procurement events to be determined in the 2027 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 2028-2029 Delivery Year in this Procurement Plan.

7.2.4 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 7-6 which presents MidAmerican's load and capability. Consistent with the discussion regarding the procurement strategy for ComEd, MidAmerican will procure 100% of its forecasted capacity deficit through its RTO's capacity market, the MISO PRA.

Table 7-6: Summary of MidAmerican Load and Capability

Summer						
Delivery Year	**Non-Coincident Peak Load**	**Coincident Peak Load**	**Reserves**	**Coincident Peak Load with Reserves**	**Total Net Capability**	**Deficit to be Procured in MISO PRA**
2025-2026	430.6	417.1	40.9	458.0	342.7	115.3
2026-2027	406.5	393.8	31.1	424.9	342.8	82.1
2027-2028	407.6	394.8	31.2	426.0	342.8	83.2
2028-2029	408.4	408.4	11.8	420.2	363.6	56.6
2029-2030	409.5	409.5	11.9	421.4	363.6	57.8
2030-2031	410.4	410.4	11.9	422.3	363.6	58.7
Fall						
Delivery Year	**Non-Coincident Peak Load**	**Coincident Peak Load**	**Reserves**	**Coincident Peak Load with Reserves**	**Total Net Capability**	**Deficit to be Procured in MISO PRA**
2025-2026	368.7	348.7	61.0	409.7	370.9	38.8
2026-2027	347.4	328.5	48.9	377.5	370.9	6.6
2027-2028	348.3	329.4	49.1	378.4	370.9	7.5
2028-2029	349.0	349.0	14.3	363.3	389.4	-26.1
2029-2030	349.9	349.9	14.3	364.3	389.4	-25.1
2030-2031	350.7	350.7	14.4	365.1	389.4	-24.3
Winter						
Delivery Year	**Non-Coincident Peak Load**	**Coincident Peak Load**	**Reserves**	**Coincident Peak Load with Reserves**	**Total Net Capability**	**Deficit to be Procured in MISO PRA**
2025-2026	297.9	287.8	70.5	358.3	342.1	16.2
2026-2027	289.0	279.2	51.4	330.6	342.1	-11.5
2027-2028	289.8	280.0	51.5	331.5	342.1	-10.6
2028-2029	290.8	290.8	18.0	308.8	340.3	-31.5
2029-2030	291.6	291.6	18.1	309.7	340.3	-30.6
2030-2031	292.5	292.5	18.1	310.6	340.3	-29.7
Spring						
Delivery Year	**Non-Coincident Peak Load**	**Coincident Peak Load**	**Reserves**	**Coincident Peak Load with Reserves**	**Total Net Capability**	**Deficit to be Procured in MISO PRA**
2025-2026	287.5	272.5	73.0	345.6	349.5	-3.9
2026-2027	288.3	273.3	69.1	342.4	349.5	-7.1
2027-2028	289.0	273.9	69.3	343.2	349.5	-6.3
2028-2029	289.8	289.8	6.1	295.9	341.2	-45.3
2029-2030	290.5	290.5	6.1	296.6	341.2	-44.6
2030-2031	291.2	291.2	6.1	297.4	341.2	-43.8

7.2.5 Capacity Procurement Implementation

7.2.6 Ameren Illinois

For Ameren Illinois, the IPA concludes that it does not need to include any extraordinary measures in the 2026 Procurement Plan to assure reliability over the planning horizon. For the 2026-20267Delivery Year, the IPA will not implement changes from the previously approved strategy. For the 2027-2028 and 2028-2029 Delivery Years, the IPA will continue the strategy of procuring Ameren Illinois capacity requirements through IPA-administered procurements and through the MISO PRA, as shown below in Table 7-7.[202]

[202] In Table 7-7, references to ZRCs include consideration of financial capacity swap product volumes.

Table 7-7: Summary of Capacity Procurement for Ameren Illinois

Delivery Year	Season	Requirement	Spring 2024 RFP	Fall 2024 RFP	Spring 2025 RFP	Fall 2025 RFP	April 2026 PRA
June 2026 - May 2027	Summer	2,005	0 ZRCs Procured	293 ZRCs Procured	350 ZRCs Procured	861 ZRCs Targeted for Procurement	Balance of Requirements 501 ZRCs Estimated
	Fall	2,102	0 ZRCs Procured	32 ZRCs Procured	536 ZRCs Procured	1,008 ZRCs Targeted for Procurement	Balance of Requirements 526 ZRCs Estimated
	Winter	1,921	0 ZRCs Procured	0 ZRCs procured	421 ZRCs Procured	1,020 ZRCs Targeted for Procurement	Balance of Requirements 480 ZRCs Estimated
	Spring	1,616	0 ZRCs Procured	3 ZRCs Procured	552 ZRCs Procured	657 ZRCs Targeted for Procurement	Balance of Requirements 404 ZRCs Estimated
Delivery Year	**Season**	**Requirement**	**Spring 2025 RFP**	**Fall 2025 RFP**	**Spring 2026 RFP**	**Fall 2026 RFP**	**April 2027 PRA**
June 2027 - May 2028	Summer	1,957	236 ZRCs Procured	253 ZRCs Targeted for Procurement	Balance of Requirements 489 ZRCs Estimated	Balance of Requirements 489 ZRCs Estimated	Balance of Requirements 489 ZRCs Estimated
	Fall	2,071	64 ZRCs Procured	454 ZRCs Targeted for Procurement	Balance of Requirements 518 ZRCs Estimated	Balance of Requirements 518 ZRCs Estimated	Balance of Requirements 518 ZRCs Estimated
	Winter	1,916	30 ZRCs procured	449 ZRCs Targeted for Procurement	Balance of Requirements 479 ZRCs Estimated	Balance of Requirements 479 ZRCs Estimated	Balance of Requirements 479 ZRCs Estimated
	Spring	1,560	62 ZRCs Procured	328 ZRCs Targeted for Procurement	Balance of Requirements 390 ZRCs Estimated	Balance of Requirements 390 ZRCs Estimated	Balance of Requirements 390 ZRCs Estimated
Delivery Year	**Season**	**Requirement**	**Spring 2026 RFP**	**Fall 2026 RFP**	**Additional Procurements**		
June 2028 - May 2029	Summer	1,935	Balance of Requirements 242 ZRCs Estimated	Balance of Requirements 242 ZRCs Estimated	To be determined in 2026 Plan		
	Fall	1,969	Balance of Requirements 246 ZRCs Estimated	Balance of Requirements 246 ZRCs Estimated			
	Winter	1,923	Balance of Requirements 240 ZRCs Estimated	Balance of Requirements 240 ZRCs Estimated			
	Spring	1,584	Balance of Requirements 198 ZRCs Estimated	Balance of Requirements 198 ZRCs Estimated			

7.2.7 ComEd

For ComEd, the IPA concludes that it does not need to include any extraordinary measures in the 2026 Procurement Plan to assure reliability over the planning horizon. ComEd will 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 7-8: Summary of Capacity Procurement for ComEd

June 2026-May 2027	June 2027-May 2028	June 2028-May 2029	June 2029-2May 030
100% PJM RPM Auctions*	100% PJM RPM Auctions**	100% PJM RPM Auctions***	100% PJM RPM Auctions****

* The 2026-2027 auction was held in July 2025 with the 3rd incremental auction scheduled for February 2026.

** The 2027-2028 auction is scheduled for December 2025 with the 3rd incremental auction scheduled for February 2027.

*** The 2028-2029 auction is scheduled for June 2026 with the 3rd incremental auction scheduled for February 2028.

****The 2029-2030 auction is scheduled for December 2026 with the 3rd incremental auction scheduled for February 2029.

7.2.8 MidAmerican

For MidAmerican, the IPA concludes that it does not need to include any extraordinary measures in the 2026 Procurement Plan to assure reliability over the planning horizon. MidAmerican will continue to procure 100% of its capacity deficit for the 2026-2027, 2027-2028, and 2028-2029 Delivery Years through the MISO PRAs as indicated below.

Table 7-9: Summary of Capacity Procurement for MidAmerican

June 2026-May 2027 (Upcoming Delivery Year)	June 2027-May 2028	June 2028-May 2029
100% of capacity deficit through MISO PRA*	100% of capacity deficit through MISO PRA**	100% of capacity deficit through MISO PRA***

*MISO Auction for 2026-2027 is expected to clear in April 2026.
** MISO Auction for 2027-2028 is expected to clear in April 2027.
** MISO Auction for 2028-2029 is expected to clear in April 2028.

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.*[203]

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

[203] 220 ILCS 5/8-103(c).

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."[204] This updated requirement now "continues until December 31, 2026."[205]

ComEd provided information[206] regarding its existing demand response programs for 2025-2026 which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 61,800 customers and an estimated load reduction potential of 61.8 MW.
- Voluntary Load Reduction ("VLR") Program: VLR is an energy-based demand response program that provides fixed compensation amounts to customers for the energy (kWh) they reduce during curtailment events. This program provides for transmission and distribution ("T&D") compensation based on the local conditions of the T&D network. The portfolio has an estimated 1,237 MW of potential load reduction (ComEd Rider VLR).
- Hourly Pricing (formerly known as Residential Real-Time Pricing (RRTP) Program): ComEd residential supply customers have the option to elect hourly pricing, which gives customers access to hourly electricity prices based on their PJM zone. The program has 54,266 customers but based on previous findings, day-ahead alerts do not have a statistically significant impact on participants' load reduction.
- Peak Time Savings (PTS) Program: This program offered pursuant to 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 currently has 36,505 customers enrolled, enabling ComEd to clear 88.9 MW of summer only capacity from the program into the PJM capacity auction for the 2025-2026 Delivery Year. The capacity sold for the 2026-2027 Delivery year has yet to be determined.

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 127,000 customers and Ameren Illinois sold 13.5 MW of related capacity in the MISO PRA for the 2025-2026 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 will not procure any demand response from eligible retail customers in the 2026-2027 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)

[204] 220 ILCS 5/8-103B(g)(4.5).

[205] Id.

[206] See Appendix C.

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.[207] As a part of the goal, the IPA's Procurement Plans are to also include electricity generated from clean coal facilities.[208] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[209] Section 1-75(d) describes two special cases: the "initial clean coal facility"[210] 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"[211] ("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"[212] (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."[213] 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

[207] 20 ILCS 3855/1-75(d).

[208] 20 ILCS 3855/1-75(d)(1).

[209] 20 ILCS 3855/1-10.

[210] Id.

[211] 20 ILCS 3855/1-75(d)(5).

[212] See Comments on the Draft 2019 Procurement Plan from Mattoon Power Enterprises LLC and Coles Together, available at https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2019procurementplan/mpe-procurement-comment.pdf and https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2019procurementplan/coles-together-comments-to-ipa-on-2019-draft-procurement-plan.pdf.

[213] Docket No. 14-0588, Final Order dated December 17. 2014 at 315.

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 including 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. To date, the Agency has not identified any carbon capture and sequestration projects, proposed or in development, that would qualify as "clean coal" facilities to be located in Illinois.

8 Procurement Process Design

The procedural requirements for the procurement process are detailed in Section 16-111.5 of the Illinois PUA.[214] The IPA retains a Procurement Administrator that conducts competitive procurement events on behalf of the IPA. The costs of the Procurement Administrator that the IPA incurs are recovered from the bidders and suppliers that participate in the Agency's 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. The IPA and the Procurement Administrator review the procurement process each year to operate in the best interests of consumers and identify potential improvements, as required by the PUA.[215] 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.

Under requirements enacted through P.A. 102-0662, starting with the IPA's 2022 procurements, bidders must comply with the Displaced Energy Workers Bill of Rights, as defined in the Energy Community Reinvestment Act. Section 10-25(b) of the Energy Community Reinvestment Act outlines the responsibilities that Illinois power plant operators, involved in the deactivation or closure of fossil fuel or nuclear power plants, have for the workers displaced by the deactivation or closure of these plants. The Agency will not procure any wholesale energy products from bidders that fail to comply with these requirements.

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 its annual Electricity Procurement Plan. The procurement of renewable energy credits ("RECs") is instead covered by the Agency's Long-Term Renewable Resources Procurement Plan.[216] The IPA's procurement process going forward will continue to procure standard wholesale products for the utilities' eligible retail customers through the annual procurement plans.

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

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

> *The procurement administrator shall disseminate information to potential bidders to promote a procurement event, notify potential bidders that the procurement administrator may enter into a post-bid price negotiation with bidders that meet the applicable benchmarks,[217] 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*

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

[215] In 2020 in response to changes in workplace procedures due to the ongoing COVID-19 pandemic, 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.

[216] The IPA's Initial Long-Term Plan was approved by the Commission on April 3, 2018 through Docket No. 17-0838. A Revised Long-Term Plan was approved by the Commission in Docket No. 19-0995 on February 18, 2020, and subsequently modified upon reopening as approved by the Commission on May 27, 2021. While a Draft Second Revised Long-Term Plan was published concurrent with the Draft 2022 Procurement Plan, it was subsequently withdrawn in accordance with the enactment of P.A. 102-0662. A revised Long-Term Plan was released for public comment on January 13, 2022, in accordance with the recently enacted changes to Section 1-75(c)(1)(A) of the IPA Act. The Long-Term Plan was then filed with the ICC for approval on March 21, 2022, and approved by the ICC on July 14, 2022. The 2022 Long-Term Plan covered planned procurements and program activity for the 2022-23 and 2023-24 program years. A draft of the 2024 Long-Term Plan, which covers the 2024-25 and 2025-26 program years, was released for public comment on August 15, 2023. Following the public comment period, the revised 2024 Long-Term Plan was filed with the Commission for approval on October 20, 2023. The Commission approved the 2024 Long-Term Plan with the Final Order issued in Docket No. 23-0714 on February 20, 2024 and the final 2024 Long-Term Plan was published on April 19, 2024. The Agency is releasing a draft 2026 Long-Term Plan concurrent with the release of this draft 2026 Electricity Procurement Plan.

[217] 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.

developed pursuant to paragraph (2) of this subsection (e). The procurement administrator shall then identify and register bidders to participate in the procurement event.

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

The procurement administrator, in consultation with the utilities, the Commission, and other interested parties and subject to Commission oversight, shall develop and provide standard contract forms for the supplier contracts that meet generally accepted industry practices. Standard credit terms and instruments that meet generally accepted industry practices shall be similarly developed. The procurement administrator shall make available to the Commission all written comments it receives on the contract forms, credit terms, or instruments. If the procurement administrator cannot reach agreement with the applicable electric utility as to the contract terms and conditions, the procurement administrator must notify the Commission of any disputed terms and the Commission shall resolve the dispute. The terms of the contracts shall not be subject to negotiation by winning bidders, and the bidders must agree to the terms of the contract in advance so that winning bids are selected solely on the basis of price.

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

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

(4) Request for proposals competitive procurement process.

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

(5) A plan for implementing contingencies

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

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 2025, the process to receive comments from potential bidders can be restricted to substantial changes to the forms (including contract forms, credit terms and instruments, and RFP documents), 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. Procurement events conducted under the 2026 Procurement Plan will be the twentieth iteration of IPA-run procurement events. 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 2025, 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 2021 capacity procurement and remained in the agreement for the subsequent capacity procurements to accommodate the changes to the MISO resource adequacy construct that would result in changes to the MISO capacity products to be procured for

Ameren's eligible customers. As a result of FERC approval of MISO's Seasonal Capacity and Accreditation Requirements filling, (as discussed in Chapter 5) an update to the current Ameren Capacity Agreement was necessary prior to the Early 2023 Capacity Procurement event as discussed in Chapter 7. In addition, the Capacity Agreement was further updated in 2025 to incorporate the financially settled ZRC product used for Ameren's seasonal 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.

Since electricity markets are dynamic, periodic review of contract terms is necessary to ensure proper protection for the utilities, utility customers, and suppliers. Therefore, the IPA recommends that the most recently used forms, namely the energy contracts used in the 2025 procurement events, are 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.

In the ICC docket that litigated the IPA's 2023 Electricity Procurement Plan, several arguments were raised by ComEd related to the consideration of bids based upon fuel mix, as well as the disclosure of the fuel mix at the time a bid is made and the publication of the fuel mix of winning bids. The Commission found that the law prohibits the consideration of fuel mix in bid evaluation, and confidentiality provisions found in Section 16-111.5(h) of the Public Utilities Act prohibit the publication of the fuel mix of winning bids. Nonetheless, the Commission accepted a proposal to have bidders disclose the fuel source of their bids.[218] Aggregated expected fuel mix data were reported for the winning bidders in the Spring 2023 energy procurement, the Fall 2023 energy procurement, the Spring 2024 energy procurement, and the Spring 2025 energy procurement.[219]

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.

[218] See Docket No. 22-0590, Final Order dated December 15, 2022, at 12.

[219] See: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/42023/public-notice-of-sprint-2023-standard-energy-products-procurement-results-2023-04-23.pdf; https://www.ipa-energyrfp.com/wp-content/uploads/2023/09/Public-Notice-of-Fall-2023-Standard-Energy-Products-Procurement-Results-2023-09-14.pdf; https://www.ipa-energyrfp.com/wp-content/uploads/2024/04/Public-Notice-of-Spring-2024-Standard-Energy-Products-Procurement-Results-2024-04-18.pdf;

[220] 20 ILCS 3855/1-75(h).

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

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 be 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 belongs to the IPA and not the applicable utility. 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 Supplier Fees are not paid by a certain date (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 continued through the 2025 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 Two Procurement Events

Procurement events under the 2026 Electricity Procurement Plan will continue to be held in the spring and fall for the procurement of energy blocks and a portion of the necessary Ameren Illinois capacity products (Zonal Resource Credits and financial swap products).

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 5, 2025, the ICC Staff posted a public notice[222] for the informal hearing to receive comments regarding the procurement process for the procurement events that were held from Summer 2024 through Spring 2025. The Fall 2024 energy procurements included the procurement of standard wholesale energy blocks for ComEd,

[222] Public Notice of Informal Hearing (Request for Comments) Concerning Electric Procurement Events Which Were Held from Summer 2024 through Spring 2025, Issued May 5, 2025, https://www.icc.illinois.gov/programs/Electricity-Procurement-Process-for-Plan-Years-Beginning-June-2025.

Ameren Illinois, and MidAmerican, covering portions of their forecasted needs from October 2024 through May 2027. The Fall 2024 capacity procurement involved Ameren's solicitation of MISO Zonal Resource Credits for the 2025–2026 and 2026–2027 Planning Years. The Spring 2025 energy procurement events, held in April 2025, included procurements of energy blocks for Ameren, ComEd, and MidAmerican across three delivery years from June 2025 to May 2028. The Spring 2025 capacity procurement, also held on behalf of Ameren, sought additional ZRCs for seasonal delivery in the 2025–2026 Planning Year. These procurements were authorized by Commission Orders in Docket Nos. 23-0665 and 24-0727, as well as the procurement of seasonal MISO Zonal Resource Credits for Ameren Illinois for Spring 2026 delivery.

In response to the Commission's request for comments for the informal hearing, on May 16, 2025, Bates White Economic Consulting ("Bates White"), the ICC's Procurement Monitor, submitted comments offering their perspective on the seven procurement events held from Summer 2024 through Spring 2025. [223] In their comments, Bates White reiterated that the IPA's procurements and hedging process continue to effectively leverage competition for the benefit of Illinois ratepayers. They reaffirmed support for the IPA's use of competitive solicitations with confidential price benchmarks as best practices.

Bates White also reviewed ComEd's energy procurements following the reduction in block targets designed to reflect the hedging value of CMCs. They found no evidence of adverse effects on competition or pricing resulting from the adjusted procurement volumes. Specifically, they noted that ComEd consistently procured 100% of its target blocks since 2023, the number of winning suppliers has remained healthy, and prices have remained competitive and highly correlated with Ameren's results. Bates White concluded there were no "red flags or strong evidence of material impacts" to ComEd's procurement outcomes due to the CMC-driven adjustments.

[223] Bates White Economic Consulting Initial Comments on the Summer 2024 through Spring 2025 Electric Procurement Events, May 16, 2025.

Appendices (Overview)

Appendices are available separately at:
https://ipa.illinois.gov/electricity-procurement/electricity-procurement-plan/2026-appendices.html

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

A. Statutory Compliance Index

B. Ameren Illinois Submittal

- Ameren Illinois Letter Transmitting Final Data
- Ameren Illinois Forecasting Methodology - July 15, 2025

C. ComEd Submittal

- ComEd Load Forecast for Five-Year Planning Period June 2026 – May 2031 and Appendices - July 15, 2025

D. MidAmerican Submittal

- IPA Letter Transmitting Final Data and Methodology – July 15, 2025
- Methodology for the 2026 Plan Illinois Electric Customers and Sales Forecasts

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