

2. Planning Environment

Highlights

- *Data center expansion has become the primary driver of load growth.*
- *Long-term natural gas price assumptions have been updated.*
- *Changes in environmental regulations, increasing renewable generation, and additional load will alter operational profiles of thermal generation, and may result in the deferral of coal-fired generation retirements across the U.S.*
- *Ameren Missouri has developed and modeled 15 scenarios, comprising ranges of values for key variables that drive wholesale power prices, for use in evaluating its alternative resource plans.*

In evaluating our customers' future energy needs and the various options to meet them, it is necessary to consider current and future conditions under which we must meet those needs. Ameren Missouri continuously monitors the conditions and circumstances that can drive or influence our decisions. Collectively, we refer to these conditions and circumstances as the "Planning Environment." This Chapter describes the basis for the assumptions used in our analysis of resource options and the performance of the alternative resource plans described in Chapter 9.

2.1 General Economic Conditions

Over the past six years, the US economy has weathered an exceptional sequence of disruptions: the COVID-19 pandemic, the rise in inflation and interest rates, and multiple rounds of tariff adjustments. Despite these headwinds, the economy continues to grow at a solid pace, even though momentum has recently slowed. Ameren Missouri's expectations continue to reflect relatively stable longer term economic growth, but at a slower pace than has been observed historically, in the 1.7 - 2.1% range annually for the real gross domestic product (GDP). Generally, demographic factors present the single largest long-term challenge to long-term growth. A key component affecting future long-term economic growth is the labor force, as the Baby Boomer generation continues to enter retirement while immigration slows. Also, the federal budget picture in the U.S. poses risks to the country's long-term economic health. That said, our base expectation is for economic growth at the national level to continue throughout the planning horizon of the IRP at a steady but modest pace by historical standards, subject to normal business cycle variability.

Ameren Missouri's outlook for the local economy in its service territory is less optimistic than the national outlook. Expectations are for area GDP to continue to grow at a slow

but steady 1.1%, well below the national average.¹ While the St. Louis area's unemployment rate is slightly lower than the nation as a whole, job growth stands at just over half than the national average. The St. Louis Metropolitan Area and surrounding parts of eastern Missouri have seen negative net migration continue along with declining birth rates. This has caused the population to grow more slowly than many other major cities and the country as a whole. Because the majority of economic activity is local in nature, population growth that is slower than the national average generally goes hand-in-hand with slower economic growth. Based in part on these long-term demographic trends, we expect the Ameren Missouri service territory to grow at around half the pace of the U.S. economy. We also expect long-term general inflation to be in the range of 2% - 2.3%.

The development of regulations that can impact a utility's resource planning have continued to evolve in recent years. These regulations include current and proposed EPA regulations regarding emissions primarily affecting our fossil fueled power plants. A complete assessment of current and future environmental regulations and mitigation is presented in Chapter 5.

2.2 Financial Markets²

For this IRP, long-range interest rate assumptions are based on the December 2025, semi-annual Blue Chip Financial Forecast. This forecast is a consensus survey of 44 economists from numerous firms including banks, investment firms, universities, and economic advisors. Table 2.1 shows the analyst expectations for the yield on 30-year Treasuries annually for 2027-2031 and a five-year average estimate for 2032-2036.

Table 2.1 Forecast Yield 30-year Treasury

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Long-term allowed return on equity (ROE) expectations for Ameren Missouri were developed using the projected long-term risk-free interest rate identified for 2032-2036 in Table 2.1. Ameren Missouri's forward equity risk premium was calculated by applying a linear fit relationship between historical electrical authorized ROEs and 30-year Treasury rates. This relationship provides an implied risk premium that can be determined based

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¹ See Chapter 3 – Load Analysis and Forecasting for discussion of economic growth assumptions underlying Ameren Missouri's load forecast assumptions.

² 20 CSR 4240-22.060(2)(B); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(5)(B)

on an expected Treasury rate. Using this approach, the resulting expected value of allowed ROE is ** % as shown in Table 2.2.

Table 2.2 Projected Allowed ROE

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The long-term borrowing rate for Ameren Missouri was calculated from an average of Blue Chip Financial Long-Range forecasts for Corporate Aaa and Corporate Baa bond yields for the 2032-2036 time frame. The base Consensus forecast is used as the base interest rate, while top 10 average and bottom 10 average rates are used as high and low interest rates, respectively.

Table 2.3 Corporate Bond Interest Rates

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Because planning decisions are made in the present, Ameren Missouri uses its current weighted average cost of capital as the discount rate for evaluating present value revenue requirements and cash flows. Based on Ameren Missouri’s most recently completed general rate review, our assumed discount rate is 6.96%. This is based on a capital structure that is 48.03% debt, 51.97% equity, and an allowed ROE of 9.5%.

2.3 Load Growth³

Load growth can be categorized as data center driven and non-data center driven. Load growth is a key driver of the market price of wholesale electric energy. The largest factor likely to affect non-data center load growth is the expected range of economic conditions that drive growth for the national economy and the energy intensity of that future economic growth. Historical trends in the energy intensity of the U.S. economy were studied to establish baseline trends. These studies revealed that the U.S. economy has exhibited long-term trends toward decreasing energy intensity (i.e., less energy input required per unit of economic output), however, with the addition of large loads from data centers, this trend may not hold true. Table 2.4 displays MW peak load growth projections from data centers under Regional Transmission Operators MISO and PJM, developed in 2024 by

³ 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(A); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

Charles River Associates and reviewed and confirmed by Ameren Missouri subject matter experts.

Table 2.4 MISO and PJM Load Growth, Data Center Peak Load Assumptions (MW)

PJM	Low Case	Mid Case	High Case	MISO	Low Case	Mid Case	High Case	PJM+MISO	Low Case	Mid Case	High Case
2026	167,250	168,665	171,914	2026	123,000	123,900	124,950	2026	290,250	292,565	296,864
2030	173,843	185,000	197,500	2030	128,306	135,000	142,500	2030	302,148	320,000	340,000
2035	180,804	204,750	226,582	2035	132,482	146,850	159,949	2035	313,286	351,600	386,531
2040	185,000	210,000	235,000	2040	135,000	150,000	165,000	2040	320,000	360,000	400,000
2045	187,657	213,925	242,972	2045	136,594	152,355	169,783	2045	324,030	366,060	412,219

To assess the potential magnitude of future declines in energy intensity, the key factors that drive energy intensity are considered independently. Those factors include expectations for trends in manufacturing, as manufacturing economic output is generally about three times as energy intensive as non-manufacturing activity.

Additionally, trends in energy efficiency, both efficiency induced by utility programs and that realized through building codes, appliance standards, and “naturally occurring,” or economically induced efficiency, were assessed. Many states have established Energy Efficiency Resource Standards that will serve to promote adoption of end use technologies that use less energy to perform the same function as previous technologies. The goal of increasing the energy efficiency of end use appliances and equipment is also furthered by federal standards that require improving performance from many electrical applications.

Customer-owned distributed generation, which appears as a reduction in demand for energy from utilities, was also analyzed for its impact over the planning horizon. Following the end of the Ameren Missouri Solar Rebate Program in December 2023 and the expiration of the federal residential solar Investment Tax Credit in 2026, a decline in customer-owned solar adoption was anticipated. Application data through July 2026 indicate that customer interest is trending below levels observed in recent years. Ameren Missouri received 372 solar interconnection applications through July 2026, compared to 741 applications through July 2025 and 752 applications through July 2024 over the same period. While it is too early to determine the long-term impact of the federal tax credit expiration, early 2026 application volumes suggest a reduction in customer adoption relative to the higher levels experienced in recent years.

Finally, trends in electrification are expected to continue due in part to customer preferences, economics, and policy. This includes not only the transportation sector, but also building efficiency, residential heating and cooling, and other uses of fossil fuels for which electric alternatives exist.

The updated planning case projects Ameren Missouri's retail sales, excluding large loads, to grow by 1.2% over the 20-year planning period, with retail peak demand to grow by 0.6% over that same period. This planning case expectation represents a slight increase

from our last IRP and reflects an updated view on economic conditions, energy efficiency programs and penetration of customer owned renewable generation. One of the most significant changes that affects this forecast is an increase in expected adoption of efficient electrification, such as electric vehicle adoption. Chapter 3 provides additional detail.

To reflect the uncertainty for a higher growth case, which may result from factors such as a more robust energy intense GDP driven by an increase in manufacturing and a reduced adoption of customer owned generation, an annual average growth rate of 2.2% was assumed.

Finally, to reflect a low-growth case in which a combination of accelerating adoption of distributed generation and robust energy efficiency programs could easily provide an expectation for a -0.1% average growth rate across the planning horizon. While there is no historical precedent for a period with economic growth and negative load growth, an acceleration of aggressive efficiency standards and programs coupled with rapid deployment of distributed energy technologies could offset the energy consumption driven by economic forces and efficient electrification for a considerable period of time under the right circumstances.

The Company's Large Load Tariff class (data centers), a new rate class that defines customers above 75 MW of monthly peak demand, supports significantly higher load growth for Ameren Missouri 2026 IRP forecast. The base case Large Load Tariff sales are forecast at a compound annual growth rate of 20.5% from 2027 to 2046. The low and high cases growth rates are forecast at 18.0% and 23.1%, respectively. For the peaks, Large Load Tariff demand is forecast at a growth rate of 14.0% for the base case during the planning horizon. From 2027 to 2046, the low growth scenario is forecast to be 11.6% and the high growth scenario is forecast to be 16.4%.

2.4 Reliability Requirements

Ameren Missouri is a member of the Midcontinent Independent System Operator (MISO) and participates in its capacity, energy and ancillary services markets. MISO has established a process to promote resource adequacy through Module E of its Federal Energy Regulatory Commission (FERC) tariff. Module E establishes an annual resource adequacy construct which requires load-serving entities to demonstrate adequate resource capacity to satisfy expected load and reserve margins. MISO establishes its planning reserve margin (PRM) requirements annually through its loss of load expectation (LOLE) study process. MISO's last LOLE study report,⁴ published in late 2025, includes seasonal requirements for the Planning Resource Auction (PRA) and sets system-wide

⁴ [MISO PY 2025-2026 Loss of Load Expectation Study Report](#)

PRM Unforced Capacity (UCAP) requirements by season. Table 2.5 shows the PRM UCAP seasonal values for year 2027.

Table 2.5 MISO System PRM UCAP 2027

Summer	Fall	Winter	Spring
7.9%	14.9%	18.4%	25.3%

In addition to establishing the PRM requirements, MISO also establishes a capacity credit for generation resources by season. The capacity credit is applied to the net output capability (in MW) of a resource to determine the amount of capacity that can be counted toward the planning reserve margin requirement (PRMR) for resource adequacy. The MISO capacity credit values by season for wind (Table 2.6), solar (Table 2.7), and battery energy storage (Table 2.8) are based on materials shared in MISO's 2025 Resource Adequacy Assumptions Futures Workshop.⁵

Table 2.6 Wind Capacity Credit by Season

Year	Winter	Spring	Summer	Fall
2026	22.0%	14.0%	8.0%	15.0%
2027	19.5%	13.4%	8.9%	14.3%
2028	17.0%	12.7%	9.8%	13.6%
2029	14.5%	12.1%	10.6%	12.9%
2030	12.0%	11.4%	11.5%	12.2%
2031	13.4%	11.1%	11.2%	13.0%
2032	14.9%	10.7%	10.9%	13.9%
2033	16.3%	10.4%	10.6%	14.7%
2034	15.8%	10.4%	10.4%	14.1%
2035	15.3%	10.4%	10.3%	13.5%
2036	14.8%	10.5%	10.1%	12.9%
2037	14.3%	10.5%	9.9%	12.3%
2038	13.8%	10.5%	9.8%	11.7%
2039	13.2%	10.5%	9.6%	11.0%
2040	12.7%	10.5%	9.4%	10.4%
2041	12.2%	10.6%	9.2%	9.8%
2042	11.7%	10.6%	9.1%	9.2%
2043	11.2%	10.6%	8.9%	8.6%

⁵ [MISO 2025 Resource Adequacy Assumptions](#)

Table 2.7 Solar Capacity Credit by Season

Year	Winter	Spring	Summer	Fall
2026	24.0%	32.0%	38.0%	21.0%
2027	18.2%	24.6%	29.5%	16.3%
2028	12.3%	17.2%	21.1%	11.6%
2029	6.5%	9.8%	12.6%	6.9%
2030	0.6%	2.4%	4.1%	2.2%
2031	0.5%	2.4%	4.1%	2.6%
2032	0.5%	2.3%	4.1%	2.9%
2033	0.4%	2.3%	4.1%	3.3%
2034	0.4%	2.2%	3.9%	3.1%
2035	0.4%	2.1%	3.6%	2.8%
2036	0.4%	1.9%	3.4%	2.6%
2037	0.4%	1.8%	3.2%	2.4%
2038	0.4%	1.7%	3.0%	2.2%
2039	0.4%	1.6%	2.7%	1.9%
2040	0.4%	1.5%	2.5%	1.7%
2041	0.4%	1.3%	2.3%	1.5%
2042	0.4%	1.2%	2.0%	1.2%
2043	0.4%	1.1%	1.8%	1.0%

Table 2.8 Battery Capacity Credit by Season

Year	Winter	Spring	Summer	Fall
2026	85.1%	89.8%	61.0%	88.5%
2027	84.7%	92.1%	70.1%	91.4%
2028	84.3%	94.4%	79.2%	94.3%
2029	83.9%	96.6%	88.3%	97.1%
2030	83.5%	98.9%	97.4%	100.0%
2031	81.4%	94.5%	97.3%	99.2%
2032	79.4%	90.1%	97.1%	98.4%
2033	77.3%	85.7%	97.0%	97.6%
2034	77.3%	85.7%	97.0%	97.6%
2035	77.3%	85.7%	97.0%	97.6%
2036	77.3%	85.7%	97.0%	97.6%
2037	77.3%	85.7%	97.0%	97.6%
2038	77.3%	85.7%	97.0%	97.6%
2039	77.3%	85.7%	97.0%	97.6%
2040	77.3%	85.7%	97.0%	97.6%
2041	77.3%	85.7%	97.0%	97.6%
2042	77.3%	85.7%	97.0%	97.6%
2043	77.3%	85.7%	97.0%	97.6%

The capacity PRM is the primary measure for resource adequacy in MISO, including consideration of seasonal capacity needs. This is reflected in capacity positions for alternative plans shown in Chapter 9, which show expected accredited resource capacity compared to capacity needs, which include expected demand and the associated PRM requirement. Our capacity positions also account for the need for resources to meet customer demand during periods of extreme weather. Analysis of the impacts of extreme weather are included in Chapter 3 (Section 3.3.7). That analysis indicates that load and reserve requirements increase due to extreme weather by approximately 750 MW in winter under the 10th percentile winter peak temperature scenario and approximately 500 MW in summer under the 90th percentile summer peak temperature scenario.⁶ The integration and risk analysis in Chapter 9 reflects the inclusion of these amounts in the estimation of the build thresholds for new resources, which are then used in the development of alternative resource plans and capacity positions. The capacity position, however, does not by itself indicate or ensure a portfolio is capable of reliably serving customer's energy needs across a range of conditions throughout the year.

The planning environment has seen a major shift in recent years, moving from one that is characterized by capacity surpluses and the predominance of dispatchable resources to one that is characterized by tight capacity supplies and increasing reliance on intermittent renewable energy resources. In this new environment, it is critical to have a planning framework that solves for both capacity and energy in an optimal manner.

The North American Electric Reliability Corporation's (NERC) most recent Long-Term Reliability Assessment (LTRA), published in January 2026, summarized the overall resource adequacy outlook for the North American bulk power system as "worsening." Aging, dispatchable fossil generation with on-site fuel storage is scheduled to retire, while new generation additions are led by inverter-based and weather-dependent solar and battery storage. These changes in the generation resource mix, coupled with significant increases in demand, are increasing reliability risks. For MISO in particular, NERC's assessment shows resource additions are not keeping pace with announced generation retirements and demand forecasts, resulting in risk levels progressing from normal to elevated to high over the 5-year horizon. Seasonal risks are also expected to develop and evolve. Increased solar penetration shifts summer risk to evening hours, as generation is dispatched to match the steep solar ramp-down. On September 2, 2026, MISO power prices reached their \$10,000/MWh cap during 5pm-7pm Central Daylight Time. During this period, solar generation peaked at approximately 18,350 MW and

⁶ For summer, this was calculated as the difference in load at the 90th percentile of summer peak temperatures and normal load (7,652 MW – 7,172 MW) plus the summer PRM of 7.9%, or 518 MW, which was rounded to 500 MW. For winter, this was calculated as the difference in load at the 10th percentile of winter peak temperatures and normal load (6,912 MW – 6,268 MW) plus the winter PRM of 18.4%, or 762 MW, which was rounded to 750 MW.

collapsed to 137 MW.⁷ The NERC assessment also shows winter reliability risks increasing, due to low solar contribution during the morning and evening load peaks, and elevated thermal forced outages and fuel availability issues induced by extreme cold weather.

NERC's LTRA recognizes a need for additional consideration of specific issues affecting reliability. Some priority actions specifically recommended by NERC include:

- Expedite new resources to meet growing demand and carefully manage generator deactivations
- Understand and manage reliability risks accompanying large-load growth and leverage potential capabilities in new types of loads to provide flexibility to operators during times of grid stress
- Continue to ensure that Essential Reliability Services are maintained, and that new resources are capable of supporting voltage, frequency, ramping, and dispatchability

Consistent with the broader market, Ameren Missouri's generation portfolio continues to shift. Prior to 2024, Ameren Missouri had been a net seller of energy into the MISO market, sometimes in excess of 10 million MWh annually, resulting in additional margins of tens of millions of dollars which directly offset a portion of costs to customers. With the retirements of the Meramec Energy Center (2022) and the Rush Island Energy Center (2024), Ameren Missouri has entered a period of tighter supply relative to demand in terms of both capacity and energy. This shift from a surplus to a deficit position has prompted Ameren Missouri to increase focus on market reliance risk.

In June 2025, MISO and the Organization of MISO States (OMS) presented survey results for a five-year planning horizon that outlines risks and potential impacts to resource adequacy, citing increasing load forecasts, tightening reserve margins, and increasing winter reliability risks, consistent with the NERC LTRA. More recently, MISO's 2026-2027 Planning Resource Auction, results of which were published in April 2026, shows reduced capacity prices in comparison to the previous planning year in each season except Winter. The overall improvement over the previous year's auction was attributed to new capacity and more imports outweighing lower accreditation and retirements/suspensions. MISO's PRA results also noted that faster resource additions are still needed to support large load growth and ensure resource adequacy.

Ameren Missouri remains committed to developing a generation plan that reliably meets its customers' needs, and includes the following actions and considerations in its resource planning process:

⁷ Enverus, "MISO Hits Price Cap of \$10,000," accessed September 14, 2026, <https://www.enverus.com/blog/miso-hits-price-cap-10000/>.

- Consideration of extreme weather in accordance with the Missouri Public Service Commission's IRP rules
- Performing granular reliability analysis with the assistance of PowerGEM Consulting and its SERVVM model to examine hourly and sub-hourly resource needs that are not considered in a traditional capacity-focused assessment of resource needs
- Assessing a range of potential for customer-owned DER and the potential impacts of FERC Order 2222 and including multiple levels of DER adoption in the range of load forecasts generated for IRP analysis
- Inclusion of a range of potential electrification impacts in the range of IRP load forecasts.

Ameren Missouri continues to utilize detailed hourly modeling to assess reliability and support generation resource planning. This has largely been performed by PowerGEM consulting with its SERVVM model, which is also relied upon by various RTOs, including MISO. In short, the SERVVM model examines reliability with robust consideration of uncertainty and volatility, including variations in weather, generator outages, and load forecast variability. See Chapter 10 for analysis and discussion of SERVVM modeling and results.

2.5 Energy Markets

Energy market conditions that may affect utility resource planning decisions include prices for natural gas, coal, nuclear fuel, electric energy, and capacity. Natural gas prices in particular continue to have a strong influence on energy prices as on-peak wholesale prices are often set by gas-fired generators. Ameren Missouri has updated its assessment of these key energy market components to serve as a basis for analysis of resource options and plans.

2.5.1 Natural Gas Market⁸

Our updated assumptions for natural gas prices reflect Ameren Missouri's most current expectations developed by internal subject matter experts on natural gas markets. While Ameren Missouri's general expectations for the fundamentals affecting natural gas supply, demand, and markets are largely unchanged from our 2025 Preferred Resource Plan, our pricing analysis has been expanded to include market sensitivity to natural gas demand, variations from timing of new liquefied natural gas (LNG), natural gas for generation, new pipeline projects, increases in production, and other market impacts. The natural gas industry has continued its improvements in production efficiency, capability,

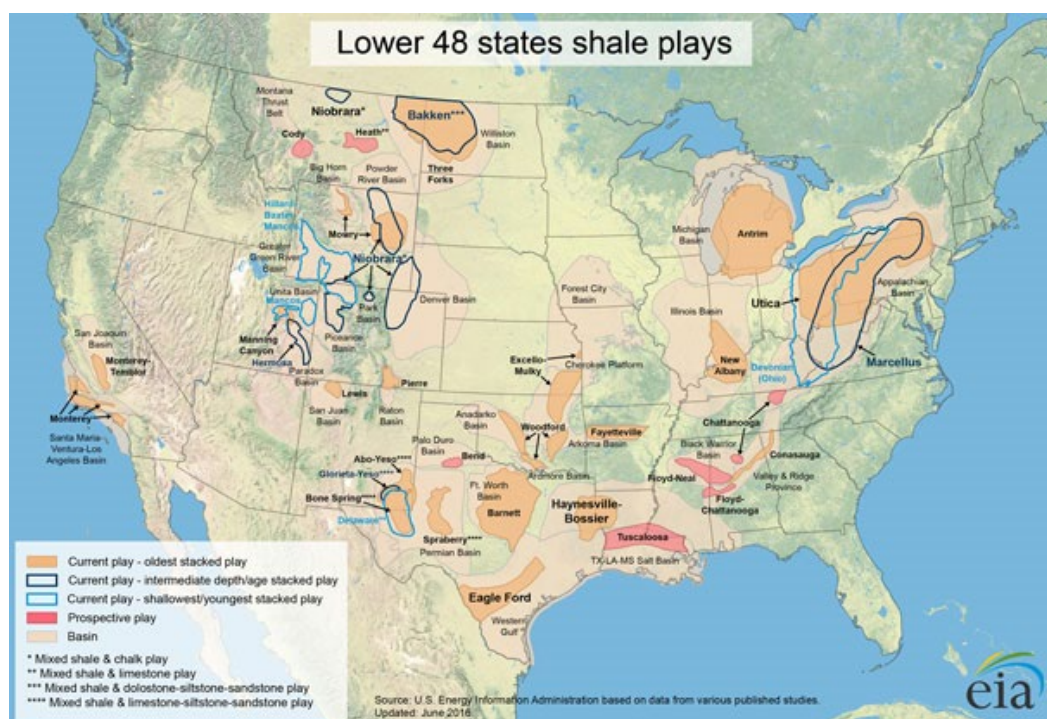
⁸ 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

and pipeline infrastructure investment. Natural gas will continue to be an abundant, reliable, and economic fuel for the long term.

Natural Gas Price Drivers

Supply – The supply of natural gas continues to be robust, with development of resources in the U.S. and in Canada. Key shale plays demonstrate the ability to grow production in time with increases in demand. U.S. production recently topped 110 BCF per day, providing the market with adequate supply. Domestic LNG export facility demand continues to increase with feed gas reaching over 18 BCF per day. Recent production increases are realized through associated gas due to geopolitical issues driving domestic oil demand higher. However, a number of factors will impact natural gas production levels in the future including the new gas-fueled generation resources, duration of increased oil demand, the announcement and completion of additional pipeline infrastructure, and the development of new storage facilities. We expect some price volatility resulting from the timing and magnitude of the continued LNG export demand growth and increased demand for natural gas used for generation, but remain confident that incremental supply will be made available at moderate prices based on recent significant increases to demand with negligible impact to price.

Figure 2.1 North American Natural Gas



Demand – Residential, commercial, and industrial demand remain weather sensitive, with small increases that are minor compared to LNG export growth, which is expected to be 9% in 2027. Electric generation continues to be an important and highly variable

demand driver for gas markets. The growth of renewables in the electricity market combined with federal regulation of fossil fuel generation makes future gas demand difficult to forecast. The penetration and performance of renewables along with the utility industry's response to regulatory outcomes will have significant impacts on natural gas demand.

Infrastructure – The number of proposals for new pipeline projects is growing concurrently with new generation and LNG projects. Projects to provide access to Permian Basin oil and gas production growth comprise most of the planned infrastructure. With production growth limited to Permian Basin, Appalachian, and Haynesville shale, we expect risks related to regional price dislocations to continue. Market conditions are continuously supportive of additional gas storage capacity, yet such opportunity to create storage remains limited. This creates the potential for further price volatility when storage inventories fall below seasonal averages. Volatility will increase further if daily demand exceeds market capabilities in the future

Price - Supply of natural gas is expected to respond to market demand from gas-fired generation and global exports. Long-term, prices are expected to remain moderate and affordable for consumers while the prospect for price volatility as witnessed during the summer of 2022 and winter storm Fern remain. Recent events suggest more short-term price volatility events rather than long-term impacts. Overall, the domestic market is well balanced and agile enough to meet growing demand.

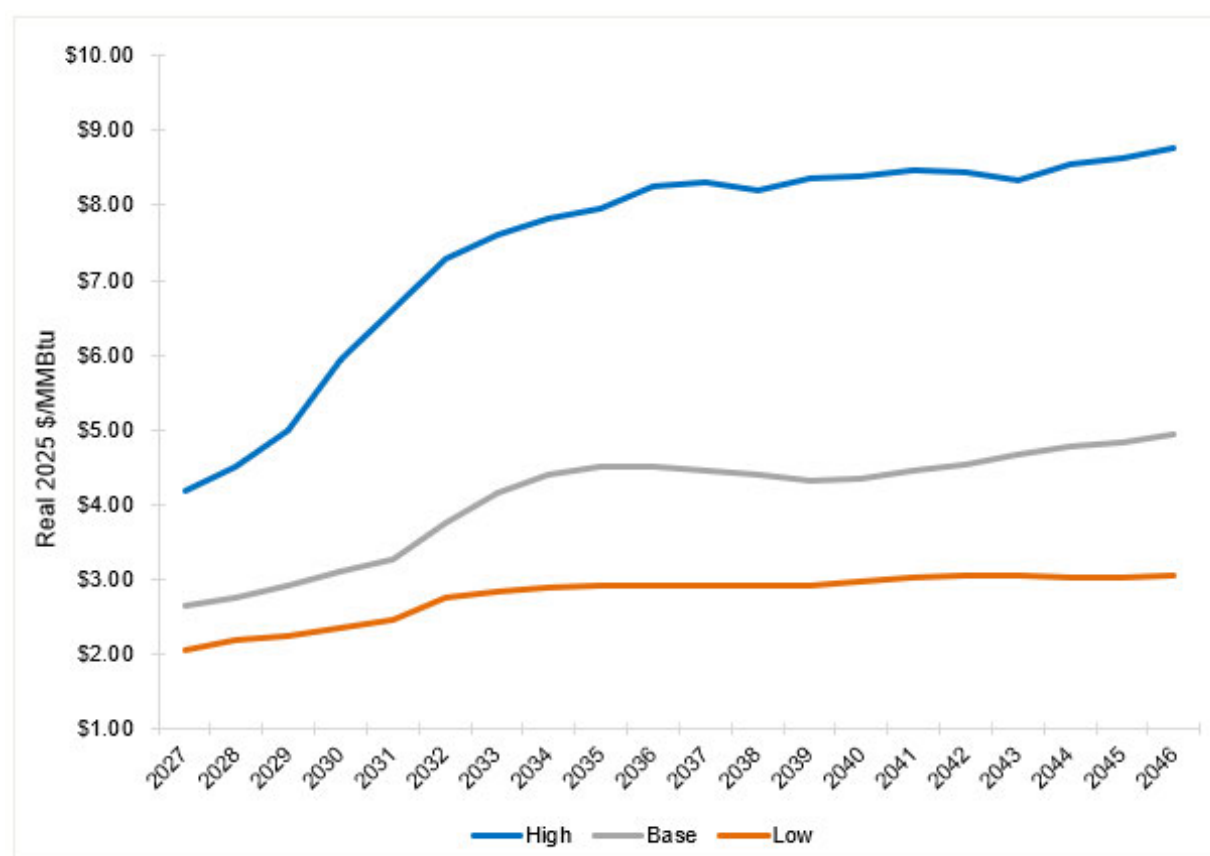
Natural Gas Price Assumptions

To develop our range of assumptions for natural gas prices, Ameren Missouri consulted its internal natural gas market subject matter experts. Several external sources of natural gas price projections have been reviewed in the development of our natural gas price assumptions. These sources include: U.S. Energy Information Administration (EIA), Platts Long-Range Forecasts, and the NYMEX Henry Hub market prices. These services, along with internal market knowledge of the natural gas industry, have helped to frame the long-term assumptions used in this IRP and to identify the drivers of the market. Based upon our assessment of market fundamentals at this time and our long-term market expectations, Ameren Missouri has developed assumptions for future prices for natural gas that are represented by the price levels shown in Table 2.9 and Figure 2.2. These assumptions were also reviewed by 1898 & Co. (1898), the consulting firm used for price modeling for this IRP, as discussed in more detail in Appendix A.

Table 2.9 Natural Gas Price Assumptions (\$/MMBtu)

	2027	2028	2029	2030	Real Gas 2025 \$					
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
High	\$4.19	\$4.51	\$5.00	\$5.94	\$6.61	\$7.29	\$7.62	\$7.82	\$7.97	\$8.25
Base	\$2.66	\$2.76	\$2.92	\$3.11	\$3.26	\$3.74	\$4.16	\$4.40	\$4.50	\$4.50
Low	\$2.06	\$2.17	\$2.25	\$2.36	\$2.47	\$2.74	\$2.83	\$2.87	\$2.91	\$2.92
	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
High	\$8.31	\$8.21	\$8.37	\$8.40	\$8.46	\$8.44	\$8.33	\$8.55	\$8.63	\$8.77
Base	\$4.45	\$4.39	\$4.33	\$4.35	\$4.44	\$4.52	\$4.67	\$4.77	\$4.84	\$4.94
Low	\$2.90	\$2.90	\$2.91	\$2.97	\$3.02	\$3.05	\$3.04	\$3.01	\$3.03	\$3.06

Figure 2.2 Natural Gas Price Assumptions



2.5.2 Coal Market⁹

Ameren Missouri's development of long-term coal price assumptions includes a review of the main drivers that most affect coal production and consumption for electric generation. This process was centered on Powder River Basin (PRB) coal given that the vast majority of Ameren Missouri's current and expected coal supply will be sourced from this basin.

According to the U.S. Energy Information Administration, 2025 U.S. coal production is projected at approximately 520 million tons. Over the next 20 years, U.S. coal supply and demand is expected to see a continued decline. In the next 5 years, U.S. coal supply is estimated to range from 300 to 400 million tons per year. However, there are some forecasts that include new and increased CO₂ taxes as well as new environmental regulations which project even lower U.S. coal demand. All U.S. thermal coal demand will likely be negatively impacted by coal plant retirements and ongoing competition with alternative energy sources. PRB coal production is anticipated to be the least impacted U.S. coal basin. According to S&P Global, long-term supply of PRB coal is expected to be a maximum of 145 million tons in 2040. PRB exports are projected to stay flat and will have minimal impact on demand.

Coal Price Drivers

PRB pricing is influenced by many drivers, including the following:

- Mining strip ratios (overburden vs. coal seam) are expected to increase
- Governmental Imposition charges
- Fixed mining costs being spread across smaller production levels
- Cost of materials, supplies and capital equipment
- Increasing coal haul distances from coal pit to load-out
- Potential interference with the railroad Joint Line in Wyoming
- Productivity improvements
- Coal reserve lease availability and costs
- Natural gas prices
- Labor market constraints

Coal prices may vary from the forecast due to the drivers mentioned above but are not limited to those drivers alone. Examples of other drivers that may impact coal prices are bankruptcies, joint ventures, railroad business models, new mining, generation or environmental technology, changes in the electric grid, and electric load loss/growth.

⁹ 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

Ameren Missouri's current plan to meet emission compliance for SO₂ standards is to utilize installed environmental controls and continue to burn predominately PRB coal. The supply for this product is anticipated to be available in the long-term forecasts. However, factors beyond Ameren Missouri's control may impact availability.

Coal Price Assumptions

In the development of the coal price forecasts for use in the 2026 IRP, low, base, and high price forecasts were utilized for PRB coal (Labadie) and Illinois coal (Sioux, with a blend of PRB and Illinois coal) delivered to the existing coal-fueled Ameren Missouri Energy Centers. This process included an assessment of current and future expectations of coal prices (Free on Board at the mine) and rail transportation costs (including diesel fuel surcharges) for delivery to each of the coal-fueled Energy Centers. Next, coal price projections along with market-based forward curves were utilized to produce low, base and high forecasts are shown in Figure 2.3.

Figure 2.3 Delivered Coal Prices

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2.5.3 Nuclear Fuel Market¹⁰

Nuclear Fuel Price Drivers

Ameren Missouri relied on Ux Consulting Company (UxC) for nuclear fuel forecasts as we have for prior IRP analyses. UxC provided annual price forecasts for uranium (U_3O_8), conversion (UF_6), and enrichment (SWU), front-end fuel components. It used the same approaches with each of the components. However, UxC forecasted spot prices for uranium, while it forecasted base prices for a new term contract for conversion and enrichment. The UxC price forecasts are generated by considering both market fundamentals (supply and demand) as well as an examination of short-term market behavior on the part of speculators and others that can exacerbate price trends set in motion by underlying supply and demand.

Fundamental analysis addresses the level of prices needed to support new production as well as the supply/demand balance in the long-term market. This analysis captures the pressure placed on available long-term supplies and the degree of competition that exists for long-term contracts, which gives an indication of the relative pricing power of producers. The fact that the published long-term price is well above marginal costs attests to the situation where a simple marginal cost price analysis does not necessarily capture the current market dynamics at any point in time.

As it has before, UxC continues to focus on the demand for production, which takes total requirements and nets out secondary supplies such as Highly Enriched Uranium (HEU) feed to derive the underlying need for production. UxC also focuses on the expected balance of supply and demand in the spot market, since we are forecasting a spot price for uranium and conversion. Here, the role of speculators and financial interests become more important as they can represent additional demand. Financial interests may accumulate inventories, thus adding supply to the spot market.

Even more so than the long-term price, the spot price can vary considerably from production costs because it is an inventory-driven price. Ultimately, spot prices are linked to a production cost-based price since an excess or shortage of production causes inventories to rise or fall, respectively, and this in turn causes changes in the spot price, which affects prices received by producers by virtue of it being referenced in long-term contracts.

Nuclear Fuel Price Assumptions

Ameren Missouri uses the nuclear fuel cycle component price forecasts of Ux Consulting Company. UxC was used in this role previously for all IRP filings since the 2008 IRP filing.

¹⁰ 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

The SurfnOnline model by Huxtable Consulting is used by Ameren Missouri for Callaway 1 and is also used with modified engineering specifications for the fuel type associated with the AP1000 nuclear power unit and an SMR 4-module site. Figure 2.4 shows the nuclear price forecast for the nuclear fleet.

Figure 2.4 Nuclear Fuel Price Forecasts

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2.5.4 Electric Energy Market

Ameren Missouri continues to be a market participant within the MISO markets. We purchase energy and ancillary services to serve our entire load from the MISO market and separately sell all of our generation output and certain ancillary services into the MISO market. The vast majority of load and generation is settled in the day ahead market. Only those deviations from the day ahead awards are cleared in the real time market. MISO also operates a capacity market, and while clearing for capacity does impose certain obligations upon capacity resources (e.g., generators) including a must-offer obligation, the sale (or purchase) of capacity in the MISO market does not convey any rights or obligation to energy from the associated resource.

In actual market operation, each individual generator and the aggregate load receives a unique price for each hour in both the day ahead and the real time markets. The model, however, uses the same price for generation and load, given that Ameren Missouri receives an allocation of auction-revenue rights from MISO based on its historical use of the system, which has generally proven to be sufficient to mitigate the price congestion between Ameren Missouri's base load generation and its load.

To develop power price assumptions for the planning horizon and to account for price uncertainty and the interrelationships of key power market price drivers, Ameren Missouri has used a scenario modeling approach as described in section 2.7.

2.5.5 Renewable Energy Standard

One of the considerations in developing alternative resource plans for Ameren Missouri is the need to comply with the Missouri Renewable Energy Standard (RES), which was passed into law by a voter initiative in November 2008. This standard requires all investor-owned regulated Missouri utilities to supply an increasing level of energy from renewable energy resources or acquire the equivalent renewable energy credits (RECs) while subject to a rate impact limitation of 1% as determined by rules set by the Missouri Public Service Commission. The target levels of renewable energy, determined by applying increasing percentage to total retail sales, are:

- 2% in 2011-2013
- 5% in 2014-2017
- 10% in 2018-2020
- 15% starting in 2021

Additionally, a solar carve-out provision is included in the standard and requires that at least 2% of renewable energy be sourced from solar generation. This provision can also be met with the purchase of solar RECs or SRECs. Our analysis of RES compliance is presented in Chapter 9.

2.6 Environmental Regulations

With increasingly stringent regulation of coal-fired power plants, including continuing efforts to regulate greenhouse gas (GHG) emissions, the effects of these regulations on the electric energy market must be considered in assessing potential resource options and portfolios.

A detailed discussion of environmental regulations can be found in Chapter 5. In addition to the regulations discussed in Chapter 5, the potential continues for new and evolving laws and regulation to create a changing landscape for investment decisions over the planning horizon. Therefore, we must also consider potential actions with respect to

climate policy and regulation of GHG emissions beyond the regulations that have been finalized by the EPA. To help frame the ongoing possibilities for carbon policy and regulation of GHG emissions, we examined a variety of sources and considered numerous policy pathways through which carbon prices could be implemented. Through this process an updated set of assumptions was developed to reflect environmental policy through the timing, magnitude and probability of an explicit price on carbon dioxide emissions.

Carbon Dioxide Emissions Prices¹¹

Updated expectations for carbon prices and timing were reviewed and revised for this IRP. The development of an assumed range of carbon prices included a review of several viewpoints on a carbon price including the Social Cost of Carbon, Federal and state climate policy proposals, and various recent utility IRPs including those filed by Xcel, Duke, Georgia Power, AEP, Entergy, and PacifiCorp. Table 2.10 shows the values used in the 2026 IRP analysis. These price assumptions were reviewed by 1898, a discussion of which is included in Chapter 2 - Appendix A.

Table 2.10 Carbon Dioxide Emissions Price Assumptions

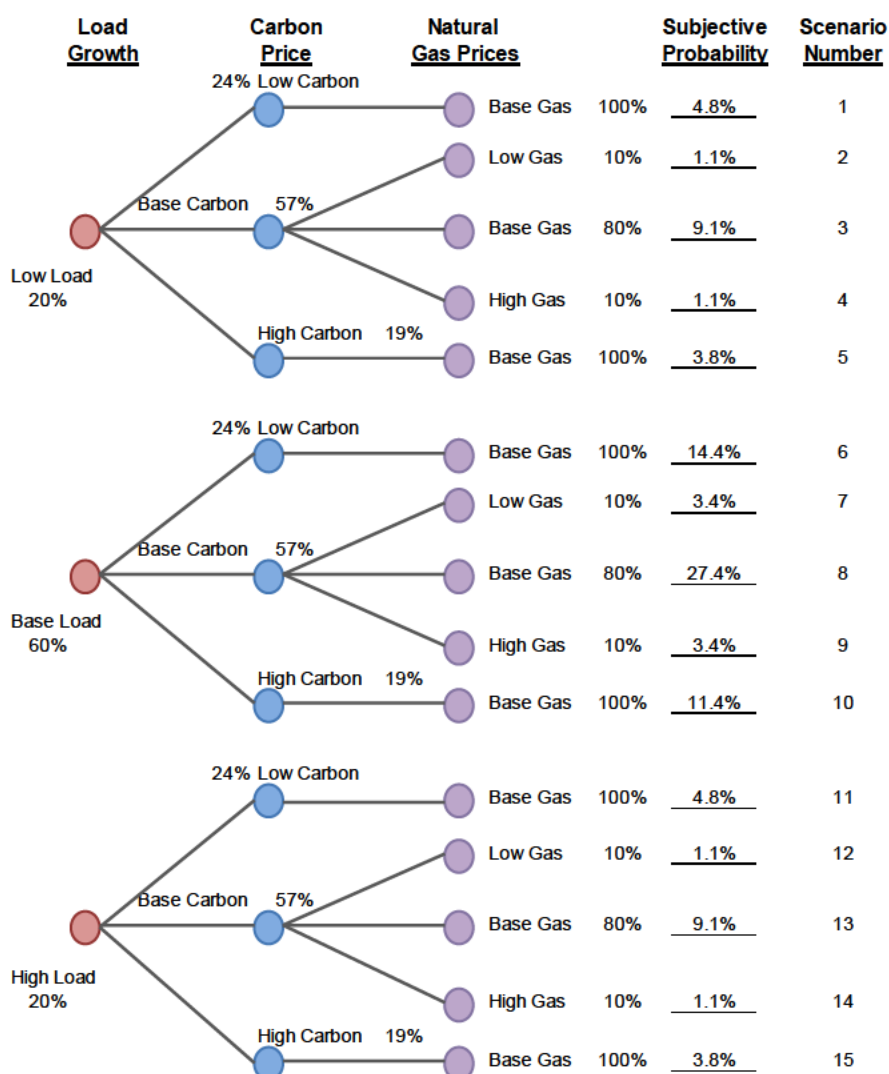
	Real 2025 \$/metric ton			Nominal \$/metric ton		
	Low Case	Mid Case	High Case	Low Case	Mid Case	High Case
2027	\$0.75	\$0.96	\$1.28	\$0.78	\$1.00	\$1.33
2028	\$0.75	\$0.97	\$1.33	\$0.79	\$1.03	\$1.41
2029	\$0.75	\$0.99	\$1.37	\$0.81	\$1.07	\$1.49
2030	\$1.25	\$1.60	\$2.60	\$1.38	\$1.77	\$2.87
2031	\$2.19	\$3.48	\$13.43	\$2.47	\$3.92	\$15.12
2032	\$2.97	\$4.99	\$14.70	\$3.41	\$5.74	\$16.89
2033	\$4.19	\$8.62	\$22.56	\$4.90	\$10.10	\$26.43
2034	\$4.20	\$8.85	\$24.05	\$5.02	\$10.58	\$28.74
2035	\$5.04	\$10.26	\$28.35	\$6.14	\$12.50	\$34.55
2036	\$5.05	\$11.16	\$31.90	\$6.28	\$13.87	\$39.67
2037	\$5.07	\$11.46	\$34.00	\$6.43	\$14.54	\$43.12
2038	\$5.08	\$11.78	\$36.25	\$6.58	\$15.24	\$46.89
2039	\$5.10	\$12.10	\$38.64	\$6.73	\$15.97	\$50.99
2040	\$5.81	\$13.93	\$43.40	\$7.82	\$18.74	\$58.41
2041	\$5.83	\$14.31	\$46.27	\$8.00	\$19.65	\$63.52
2042	\$5.84	\$14.71	\$49.34	\$8.18	\$20.60	\$69.09
2043	\$5.86	\$15.12	\$52.62	\$8.37	\$21.60	\$75.16
2044	\$5.87	\$15.54	\$56.13	\$8.56	\$22.64	\$81.78
2045	\$5.89	\$15.98	\$59.89	\$8.75	\$23.74	\$88.99
2046	\$5.91	\$16.42	\$63.90	\$8.95	\$24.89	\$96.86

¹¹ 20 CSR 4240-22.040(2)(B); 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(D); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(C); 20 CSR 4240-22.060(5)(H); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

2.7 Electric Power Price Scenarios

Power prices are influenced primarily by electric demand, the mix of available generation resources, and natural gas prices. Using our assumptions for carbon prices and natural gas prices, we developed scenarios based on combinations of these assumptions. The development of scenario modeling is best represented by a probability tree diagram and the associated probability of each branch of the tree. Each branch of the tree is used to represent a combination of dependent input variables that can have an impact on plan selection. In order to focus on those combinations with the greatest influence on alternative resource plan performance, potential branches that would be characterized by a significantly low probability of occurrence are merged with adjacent branches to provide a simplified yet still robust set of possible scenarios. This process provides for a wide range of potential future combinations with which we can analyze alternative resource plan performance and risk. Figure 2.5 shows the final scenario tree.

Figure 2.5 Final Scenario Tree



2.7.1 Energy Prices¹²

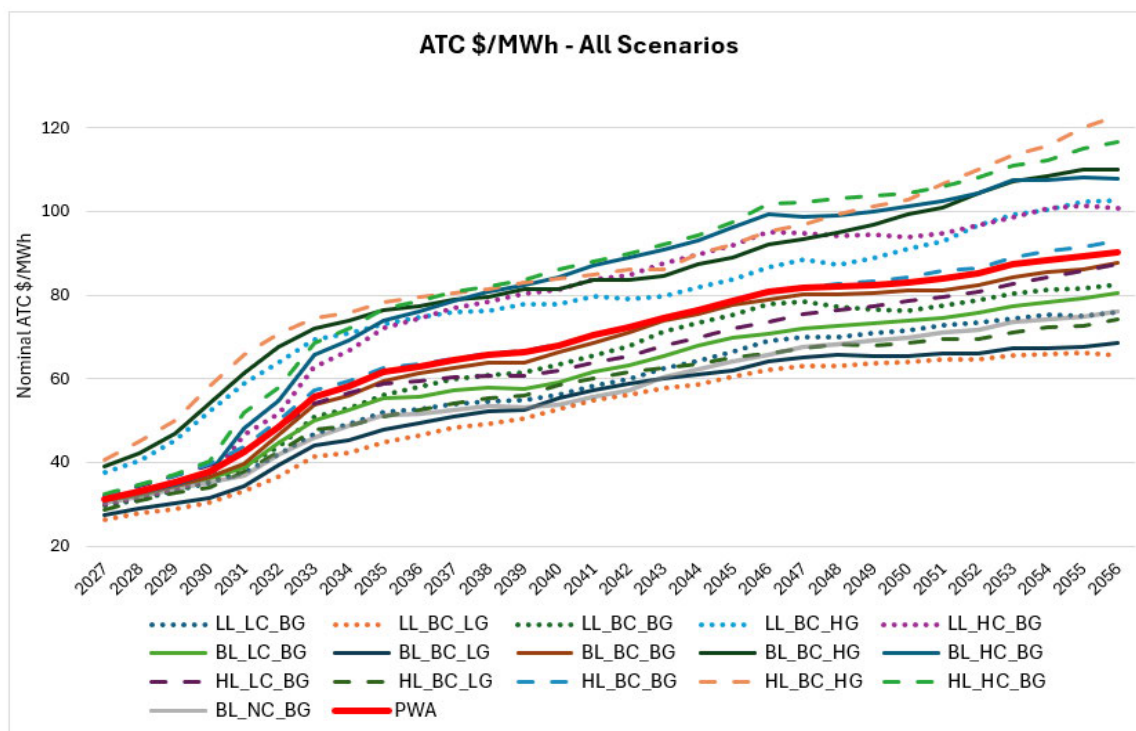
To support our analysis of alternative resource plans, as described in Chapter 9, we engaged 1898 & Co. (1898) to develop forward energy and capacity price forecasts for MISO Zone 5 using the EnCompass modeling software. Appendix A provides a detailed overview of how 1898 utilized EnCompass to develop updated forward prices for Ameren Missouri. To ensure that a range of possible future power prices was incorporated, those inputs determined to be uncertain and impactful enough to warrant the need for a range of possible inputs were varied. These inputs were:

- Natural gas prices
- A price on carbon dioxide emissions
- Load growth

These inputs were varied within the model and audited by 1898 to ensure they were reasonable and comprehensive. This process produced values based on the probability tree shown above in Figure 2.5. The results of this modeling for each branch yield different power price futures, which are shown in Figure 2.6.

These power prices were used in the analysis of alternative resource plans described in Chapter 9.

Figure 2.6 Scenario Power Prices



¹² 20 CSR 4240-22.060(5)(G); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

2.7.2 Capacity Prices

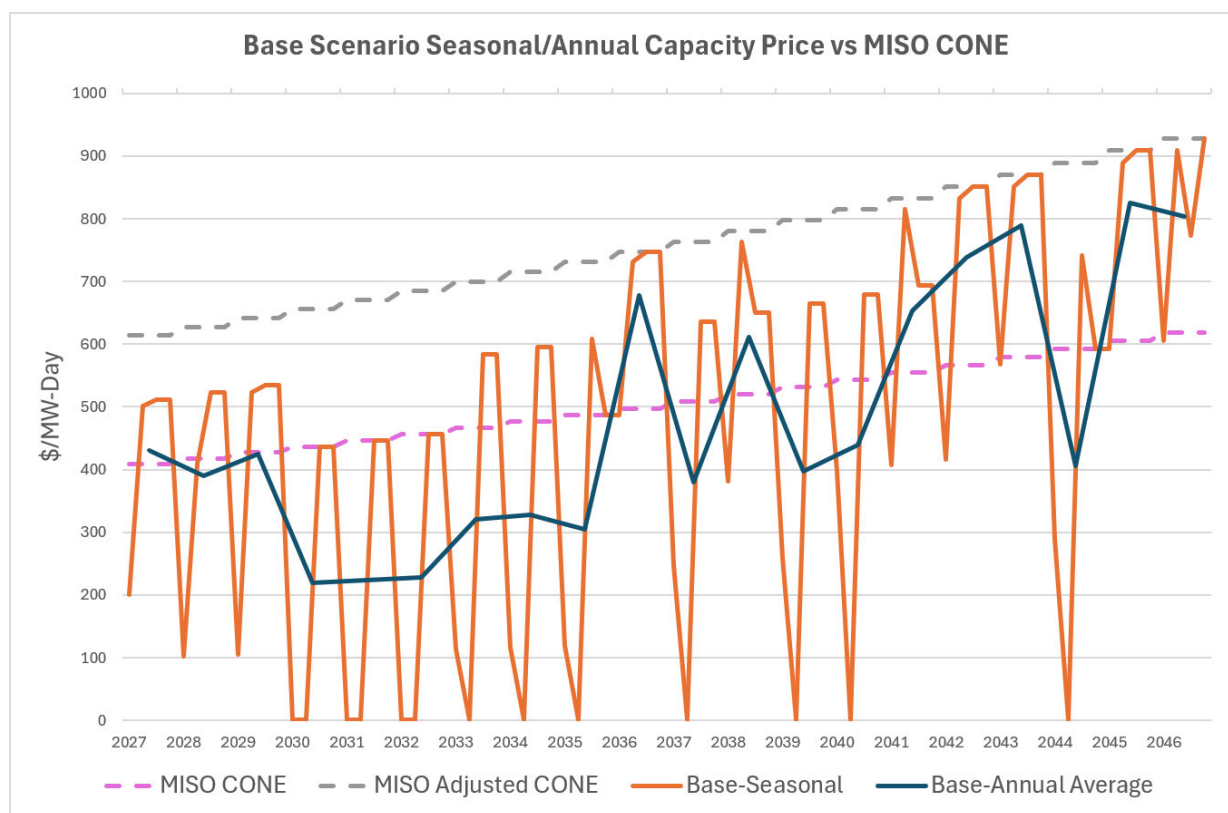
The expected market capacity price forecasts used in the 2026 IRP were also developed by 1898 using the same model used to develop the energy price forecasts. To provide long-term grid reliability beyond daily energy transactions, MISO administers a seasonal capacity market. The fundamental purpose of this market is to procure sufficient generation resources to meet peak demand. This is achieved by balancing expected system demand against capacity offers submitted by resource owners.

MISO's Planning Resource Auction now uses a sloped demand curve, which values incremental capacity based on its contribution to system reliability. Under this structure, capacity prices rise gradually as the region approaches a capacity shortfall and fall gradually as surplus resources become available. The sloped demand curve replaces the vertical construct used previously and is intended to better align prices with the probabilistic LOLE methodology and signal the economic value of additional capacity as system conditions tighten. Under the sloped demand curve, the capacity market can now clear at prices above Cost-of-New-Entry (CONE). The higher end of the curve includes a shortage pricing region, where capacity prices can rise above CONE when the system faces tight reserves or a higher reliability risk.

Historical outcomes from MISO's Planning Resource Auction underscore the broad volatility of capacity prices in the region. For example, in the 2024/2025 auction, most zones cleared at only \$30/MW-day, while one zone cleared at the seasonal CONE following a localized capacity shortfall. In contrast, the 2025/2026 auction, following a tighter accredited capacity balance and introduction of the Reliability-Based Demand Curve, cleared at \$666.50/MW-day for summer across much of the footprint. Prices remained elevated into the 2026/2027 auction, clearing at \$424.30 MW-day for the summer period. This wide range of past clearing prices highlights how sensitive capacity prices are to reserve margins, accreditation levels, unit retirements, and load growth.

This historical volatility underscores the importance of examining both baseline and sensitivity outcomes in long-term planning. Figure 2.7 shows the Base Scenario capacity price outlook as developed by 1898 and included in Appendix A in more detail on both a seasonal and annual average basis. Consistently throughout the study period, prices tend to be higher in the summer and lower in the spring. Capacity prices in the Base Case projection are relatively high on average across the study period, driven mainly by consistent load growth.

Figure 2.7 Capacity Prices – Base Scenario



Forward looking cost curves for energy and capacity are also used in the screening and cost-effectiveness analysis of demand-side resource programs, as discussed in greater detail in Chapter 8. The purpose of a screening or cost-effectiveness analysis is to identify the value of demand-side resources relative to a planning environment without those same demand-side resources. The screening analysis, by definition, must occur before the integration analysis.

To this end, additional capacity price curves for each season were developed and used for the screening analysis included in the DSM Market Potential Study (MPS) using the most current data available at the time of the MPS.¹³ These curves reflect and incorporate Ameren Missouri's capacity position from the preferred resource plan as adopted in February 2025, without further supply-side¹⁴ and demand-side resources. These curves also reflect the then-current CONE values published by MISO.

This method ensures the timely inclusion of cost-effective DSM measures in the portfolios to be analyzed through integration and risk analysis, as described in Chapter 9. The integration and risk analysis then serves as the holistic analytical test of demand-side resource cost effectiveness by comparing the total present value revenue requirement of

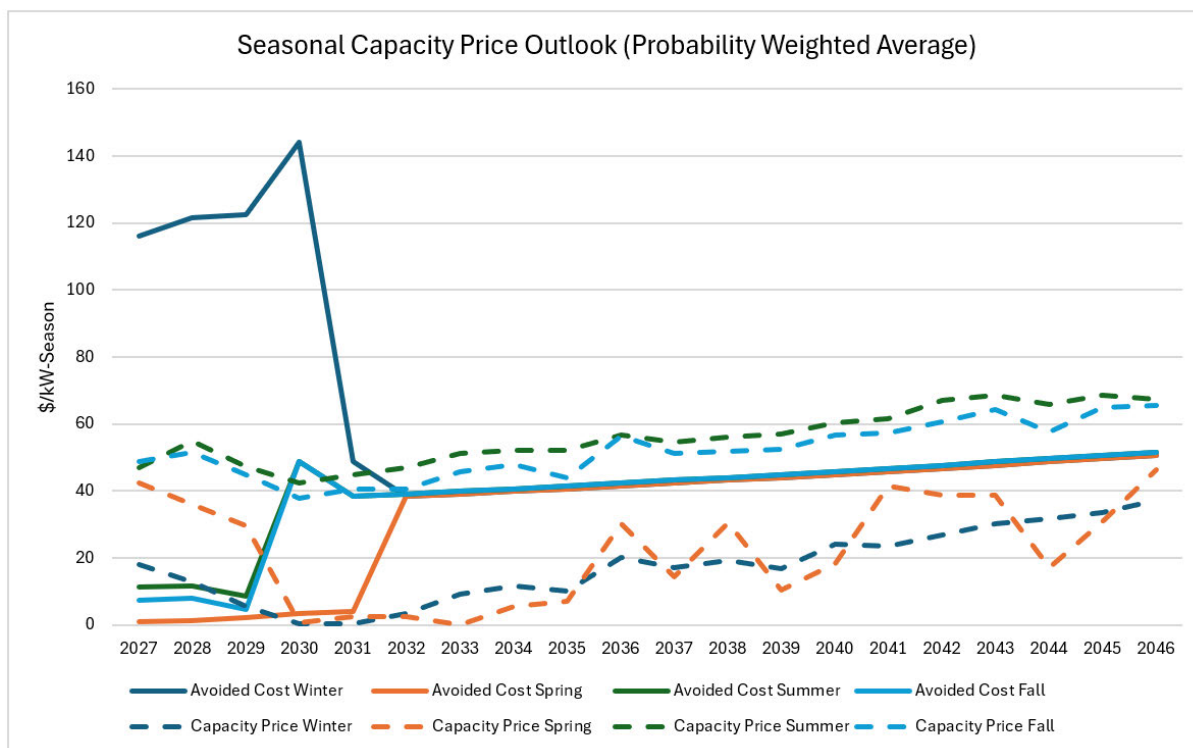
¹³ See Chapter 8 Appendix A

¹⁴ Capacity position included solar additions for RES Compliance and 400 MW battery storage.

both DSM and supply-side resource alternatives as part of integrated alternative resource plans.¹⁵

Figure 2.8 shows the alignment between these two sets of capacity price curves. Specifically, Figure 2.8 shows the seasonal average capacity price curves developed by 1898 (where the base case is presented above in Figure 2.7 as \$/MW-day is now shown in \$/kW-season) as a dotted line, and the seasonal avoided cost curves used in the MPS for screening purposes are shown as a solid line. Note that each 1898 curve shown in Figure 2.8 represents a probability-weighted-average of prices across 15 market scenarios, which represent combinations of low, base, and high levels for natural gas costs, carbon costs and load growth. For additional details on the capacity prices developed by 1898, please see Chapter 2 - Appendix A. Chapter 8 also provides additional detail on avoided cost sensitivities used within the DSM portfolio screening. The purpose of those sensitivities is to further ensure the robustness of screening analysis in developing a robust range of demand-side resources for inclusion in integration analysis.

Figure 2.8 Capacity Price Assumptions (Nominal \$/kW-Season)



¹⁵ As noted in Chapters 8, 9 and 10, any future DSM applications consistent with the preferred resource plan developed and adopted within this IRP will be finalized and tested against the avoided cost curves as defined by this IRP. This sequencing of analytical steps (from screening, to analysis, to implementation application) using the most current data available at each step, ensures that any future implementation plans remain robust and relevant.

2.8 Compliance References

20 CSR 4240-22.040(2)(B)	19
20 CSR 4240-22.040(5)	10, 14, 16, 19
20 CSR 4240-22.040(5)(A)	10, 14, 16
20 CSR 4240-22.040(5)(D)	19
20 CSR 4240-22.060(2)(B)	2
20 CSR 4240-22.060(5)	3, 10, 14, 16, 19
20 CSR 4240-22.060(5)(A)	3
20 CSR 4240-22.060(5)(B)	2
20 CSR 4240-22.060(5)(C)	19
20 CSR 4240-22.060(5)(D)	10, 14, 16
20 CSR 4240-22.060(5)(G)	21
20 CSR 4240-22.060(5)(H)	19
20 CSR 4240-22.060(7)(C)1A	2, 3, 10, 14, 16, 19, 21
20 CSR 4240-22.060(7)(C)1B	3, 10, 14, 16, 19, 21