Ameren MISSOURI

INTEGRATED RESOURCE PLAN UPDATE

2025

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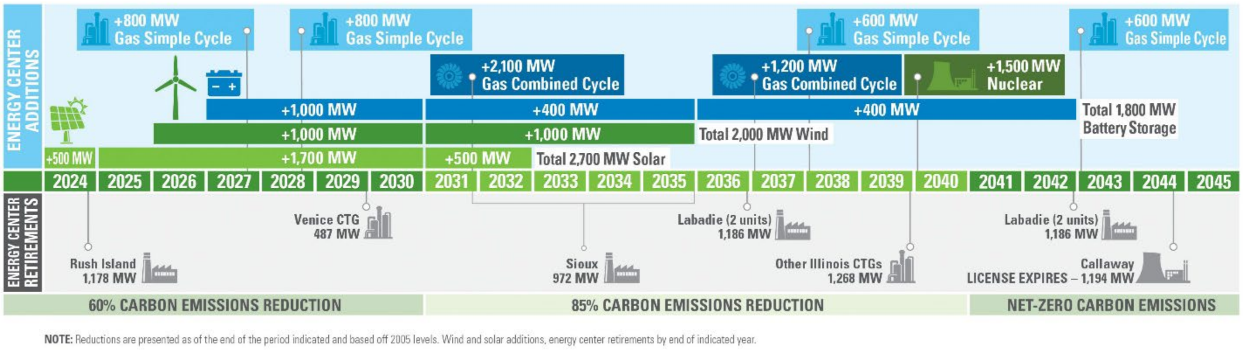
1. Executive Summary

Ameren Missouri selected a new preferred resource plan (PRP) with its 2025 Change in Preferred Plan filing in February 2025 and continues to execute on this resource plan. The timeline in Figure 1.1 shows the PRP planned additions and retirements. The following are changes represented in the Company's new PRP relative to its prior PRP and the rationale:

- The new PRP includes the addition of large loads with cumulative demand reaching 1.5 GW by 2032 and 2.5 GW by 2040.
- The new PRP includes Missouri Energy Efficiency Investment Act (MEEIA) programs through 2043 at levels similar to those recently approved by the Missouri Public Service Commission (MPSC) instead of at the Realistic Achievable Potential (RAP) level.
- The new PRP includes the same total solar additions as the prior PRP – 2,700 MW – but with accelerated timing for the additions to provide energy for new demand growth and clean energy to support the corporate clean energy goals of new large customers.
- The new PRP includes acceleration and expansion of Battery Energy Storage Systems (BESS) to provide flexible capacity for new demand and integrate renewable resources, with 1,000 MW in service by the end of 2030, another 400 MW by the end of 2035, and another 400 MW by the end of 2042. This represents an overall increase in BESS of 1,000 MW relative to the prior PRP, driven by significant new load additions and the reduction in expected demand savings from MEEIA programs.
- The new PRP includes total natural gas and nuclear generation additions of 7,600 MW (3,300 MW natural gas-fired combined cycle (NGCC), 2,800 MW natural gas-fired combustion turbine generator (CTG), 1,500 MW nuclear) compared to 4,400 MW of natural gas (1,200 MW NGCC, 800 MW CTG) and "clean dispatchable" resources (2,400 MW) in the prior PRP.

Figure 1.1: Preferred Resource Plan Timeline



Our plan is focused on transitioning our generation fleet to a cleaner and more fuel diverse portfolio in a responsible fashion and achieves reductions in carbon dioxide (CO_2 or carbon) emissions of 60 percent by 2030, and 85 percent by 2040 compared to 2005 levels, with a goal of achieving net-zero carbon emissions by 2045. The plan includes continued customer energy efficiency program offerings at MEEIA 4 levels approved by the MPSC, retiring one of our two remaining coal-fired energy centers by the end of 2031, accelerating the retirement of 1,800 MW of gas-fired peaking generation, while adding new natural gas peaking generation in Missouri to improve reliability in extreme weather conditions, adding efficient natural gas-fired combined cycle generation by 2032, accelerating our expansion of renewable generation, with the addition of 2,700 MW of renewable generation (including the 500 MW solar placed in service at the end of 2024) by the end of 2030 and reaching total wind and solar generation of 5,400 MW by the end of 2035, and deploying 1,400 MW of battery energy storage by the end of 2035. By executing our plan, we will ensure that our customers' long-term electric energy needs are met in a safe, reliable, cost-effective and environmentally responsible manner.

Key steps that Ameren Missouri has taken since the filing of our 2023 triennial Integrated Resource Plan (IRP) include:

- Placed three new solar facilities in service by the end of 2024: Boomtown Solar (150 MW), Huck Finn Solar (200 MW) and Cass County Solar (150 MW), which received regulatory approval in 2023 and 2024, respectively.
- Acquired certificates of convenience and necessity (CCN) and started construction on new solar energy resources: Vandalia Solar (50 MW), Bowling Green Solar (50 MW), and New Florence Solar (7 MW). Vandalia and Bowling Green Solar will be used to support customer subscribers through the Company's Renewable Solutions Program and New Florence Solar will be part of the Community Solar program. Also acquired CCN approval for Split Rail Solar (300 MW), which is expected to be in service in 2026.
- Issued a request for proposals (RFP) for wind project bids to continue building out Ameren Missouri's pipeline of available regional wind projects.

- Issued an RFP for solar project bids to continue building out Ameren Missouri's pipeline of available regional solar projects.
- Filed a new tariff application with the MPSC in May 2025 for large customers.
- Filed a CCN application and received approval from the MPSC for an 800 MW simple cycle gas-fired energy center at the former Meramec coal-fired generation site to ensure reliability under all weather conditions.
- Filed a CCN application in June 2025 for another 800 MW simple-cycle gas fired energy center along with 400 MW battery energy storage system at the former Rush Island coal-fired energy center.
- Filed a CCN application in August 2025 for another 250 MW solar energy center located near the Callaway nuclear energy center, to be known as the Reform Energy Center.
- Filed an application with MISO for its Expedited Resource Addition Study (ERAS) Process for a solar project and a BESS project, both of which have been accepted into the ERAS Study Cycle 1.
- Took steps towards adding dual fuel capability at three of its natural gas-fired energy centers – Peno Creek, Kinmundy, and Audrain – to enhance the Company's winter generation capacity and to be better prepared for winter weather events.
- Continued to implement customer energy efficiency and demand response programs pursuant to the Company's approved MEEIA program portfolio to provide customers with the ability to manage their use of energy and reduce their energy bills.
- Continued plant closure activities at Rush Island Energy Center, including completion of grid enhancement projects to ensure reliability following retirement of the units.
- Continued projects to close coal ash basins at the Company's coal-fired energy centers.
- Continued to implement our Smart Energy Plan pursuant to Missouri Senate Bill 745, passed in 2022. This forward-looking plan is designed to replace aging infrastructure and modernize the electric grid for the long-term benefit of our customers. The plan includes an anticipated $3.7 billion of electric distribution system investments from 2025 through 2029 that will, among other things, support investments in aging infrastructure upgrades, smart grid technologies, system hardening efforts, and system capacity.

As we continue to execute on our plan, we are mindful of events and evolving issues that could impact our future planning. These include the following:

- More robust assessment of reliability needs – Ameren Missouri has continued to perform more detailed reliability analyses in support of its preferred plan with the help of PowerGEM (formerly Astrapé Consulting). The Company continues to evaluate reliability needs and the resources that will be necessary to ensure reliable year-round service for our customers.

- Load growth uncertainty – Mainly due to developments in artificial intelligence, there has been a significant and rapid increase in requests for electricity service, which resulted in Ameren Missouri adopting a new preferred resource plan in February 2025. Ameren Missouri will be continually monitoring its load growth assumptions and revising its assumptions for expected load growth as appropriate to plan for reliable service to an expanding customer and load base.

2. Compliance Overview

Because resource planning is an ongoing process, we continually monitor and assess the planning environment and how it may affect our continued resource planning. One of the hallmarks of our planning process is maintaining flexibility to respond to changing conditions, mitigate risk, and take advantage of opportunities on behalf of our customers. Should Ameren Missouri determine that changes to some portion or portions of its PRP are appropriate, we will make such determinations in the context of our overall strategy and planning objectives, and in accordance with the MPSC's IRP rules. We will continue to pursue the transition of our resource portfolio to one that is cleaner and more fuel diverse in a responsible manner that benefits customers, shareholders, the environment, and the communities we serve.

2.1 Purpose of Annual Updates

Annual updates are required by 20 CSR 4240-22.080(3). The rules indicate that the purpose of annual updates is to ensure that members of the stakeholder group have the opportunity to provide input and to stay informed regarding the items listed below.

- The utility's current preferred resource plan (see section 1)
- The utility's progress in implementing the resource acquisition strategy (see section 2.3)
- The status of the identified critical uncertain factors (see section 3.6)
- Analyses and conclusions regarding any special contemporary issues identified by the Commission (see Compliance References at the end of this report for the location of specific discussion on each issue)

Ameren Missouri has created this annual update report to satisfy the intended purpose established in the IRP rules and has updated its assessment of general planning conditions. Each item explicitly cited in the rules is addressed in the referenced chapter or section of this report as noted above.

2.2 Ameren Missouri's Approach to its Annual Update

In its Order in File No. EO-2012-0039 establishing special contemporary issues to be evaluated by Ameren Missouri in its 2012 IRP Annual Update, the Commission noted that, "the requirement to examine special contemporary issues should not be allowed to expand the limited annual update report into something more closely resembling a triennial compliance report." The Commission continues to adhere to this view regarding annual updates. Ameren Missouri agrees with the Commission that the scope and depth of an IRP Annual Update should not be comparable to that for a triennial IRP filing. Also, in its Order in File No. EO-2025-0077 establishing special contemporary issues for Ameren Missouri's 2025 IRP Annual Update, the Commission stated if the Company believes it has already adequately addressed some of these issues in its IRP filing or some other filing, then it does not need to undertake any additional analysis because of the special contemporary issue designation. The Commission stated the same approach is acceptable if the Company intends to address any of the issues in a future triennial IRP filing.

On that basis, Ameren Missouri has relied heavily on the groundwork developed in its 2023 IRP and 2025 Change in PRP filings as a basis for reviewing its assumptions and analysis and reporting its findings.

The Company also views the IRP Annual Update in its proper role as just that, an update on the nature of key variables and the conclusions that follow. Based on the conclusions drawn from the review and analysis discussed here, the Company believes that its preferred resource plan, as presented in its 2025 Change in PRP filing, is still appropriate at this time. Should the Company's continued planning and consideration of relevant issues lead to a conclusion that its PRP is no longer appropriate and should be replaced with a new PRP, the Company will notify the Commission of its decision in accordance with 20 CSR 4240-22.080(12).

2.3 Implementation of Current Preferred Resource Plan

Ameren Missouri adopted a new PRP with its 2025 Change in PRP filing. In that filing, the Company re-affirmed that its new PRP includes a total of 2,700 MW of wind generation and 2,700 MW of solar generation, including resources already placed in service. The new preferred plan also includes additional dispatchable resources and implementation of energy efficiency and demand response programs throughout the entire planning horizon at the MEEIA 4 levels approved by the Commission. The Company also indicated that the implementation of future programs will depend on policies that reflect timely cost recovery, proper alignment of incentives, and appropriate earnings opportunities, as required by MEEIA. Also included in the filing was an updated implementation plan. Following is an item-by-item update on the status of the implementation steps listed in the Company's 2025 Change in PRP filing.

Demand-Side Resource Implementation

Ameren Missouri operates its DSM programs under MEEIA. MEEIA requires that utility incentives for DSM programs be aligned with comparable supply side investments in order to help customers use energy more efficiently. MEEIA does this by providing for the timely recovery of program costs, the elimination of the throughput disincentive and creating performance incentive earnings opportunities for successful program implementation.

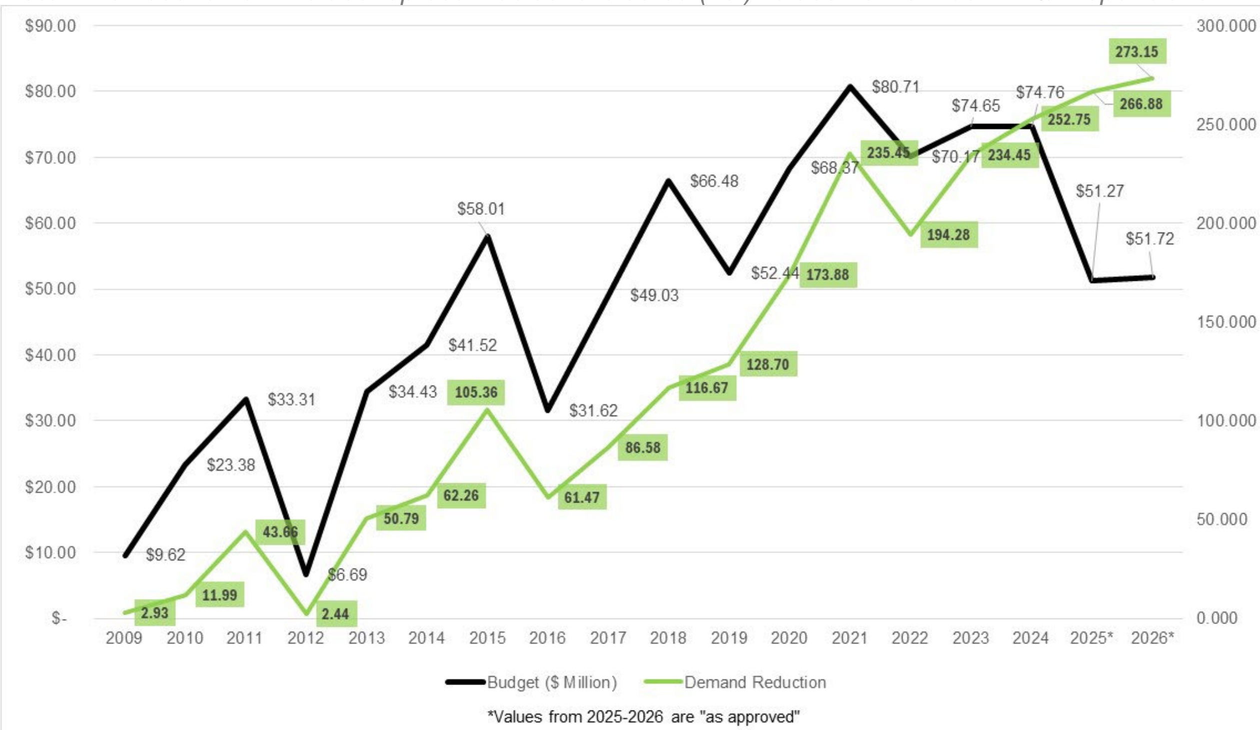
Ameren Missouri has successfully operated DSM programs to the benefit of customers since 2009, consistent with the goals of MEEIA and guidance from the Commission. Figure 2.1 provides the incremental annual net peak demand reductions and the associated program budgets for each year.

In 2018, Ameren Missouri received continued support from the Commission via approval of its third MEEIA cycle, covering the period 2019 to 2021 for its residential, business and demand response programs and the period 2019 to 2024 for its income eligible programs. On August 5, 2020, the Company received approval to extend its current MEEIA cycle to program year 2022 (PY22) for all programs, and on October 27, 2021, the Company received approval to extend its current MEEIA cycle to program year 2023 (PY23). In September of 2023, the Company received approval to extend MEEIA cycle to program year 2024 (PY24) with the intention to continue negotiation on a MEEIA Cycle 4. Combined, approvals in EO-2018-0211 represent the largest commitment to DSM in the state of Missouri to date.

Ameren Missouri filed an amended MEEIA 4 application (EO- 2023-0136) on January 25, 2024. Following negotiation with key stakeholders, a MEEIA Cycle 4 stipulation and agreement was approved in November of 2024 by the MPSC. The approved plan includes continued customer energy efficiency program offerings at reduced levels,

Figure 2.1: Annual DSM Program Budgets and Net Demand Reductions

Note: The *2009 to 2024 values represent actual evaluated (net) values from annual EM&V reports and*



2024 values represent net as filed values approved as part of program filings.

Ameren Missouri successfully implemented the MEEIA 3 program cycles, from 2019 thru 2024[1], meeting or exceeding its portfolio savings targets in the first three years and slightly under its targets in its 4th through 6th years. Table 2.1 and Table 2.2 provide the final net energy and demand savings, respectively, as determined by the independent EM&V evaluators.

Table 2.1: Net Energy Savings Compared to Goal, 2019-2024 (MWh)

	2019			2020			2021			2022			2023			2024		
	Goal Net Savings (MWH)	Ex Post Net Savings (MWH)	% of Goal	Goal Net Savings (MWH)	Ex Post Net Savings (MWH)	% of Goal	Goal Net Savings (MWH)	Ex Post Net Savings (MWH)	% of Goal	Goal Net Savings (MWH)	Ex Post Net Savings (MWH)	% of Goal	Goal Net Savings (MWH)	Ex Post Net Savings (MWH)	% of Goal	Goal Net Savings (MWH)	Ex Post Net Savings (MWH)	% of Goal
Low Income	10,443	4,382	42%	13,858	12,560	91%	15,202	9,939	65%	17,859	17,495	98%	15,562	27,974	180%	14,147	15,389	109%
Residential	112,823	118,985	106%	119,700	153,592	128%	116,246	153,321	132%	56,302	34,846	62%	42,794	33,921	79%	34,128	30,960	91%
Business	78.696	83,458	107%	152,847	120,206	79%	204,544	145,141	71%	158,681	102,741	65%	104,286	77,924	75%	80,113	65,039	81%
Portfolio Total	201,962	206,824	102%	286,405	286,358	100%	335.992	308,402	92%	232,842	155,081	67%	162,642	139,819	86%	128,388	111,388	87%

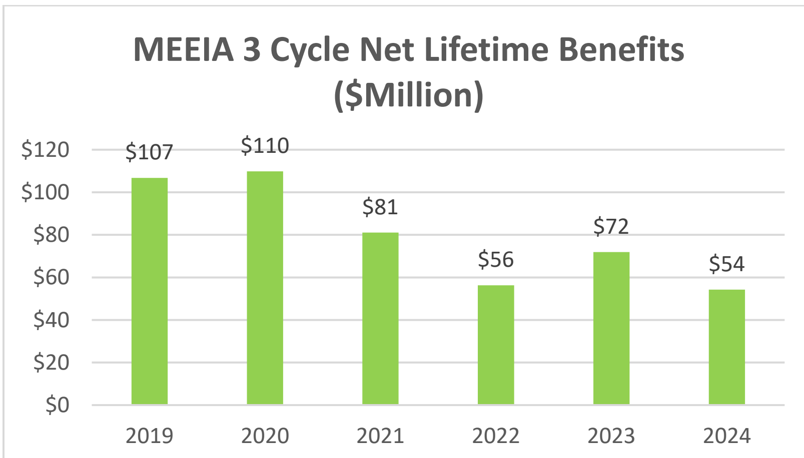
[1] During the COVID-19 pandemic in 2020, the Company modified many of its program offerings to ensure the safety of both customers and contractors, while also focusing on maintaining its best in class program delivery.

Table 2.2: Net Demand Savings Compared to Goal, 2019-2024 (MW)

	2019			2020			2021			2022			2023			2024		
	Goal Net Savings (MW)	Ex Post Net Savings (MW)	% of Goal	Goal Net Savings (MW)	Ex Post Net Savings (MW)	% of Goal	Goal Net Savings (MW)	Ex Post Net Savings (MW)	% of Goal	Goal Net Savings (MW)	Ex Post Net Savings (MW)	% of Goal	Goal Net Savings (MW)	Ex Post Net Savings (MW)	% of Goal	Goal Net Savings (MW)	Ex Post Net Savings (MW)	% of Goal
Low Income	2	1	42%	3	3	89%	4.06	2.06	51%	5.35	4.26	80%	3.58	5.79	162%	3.65	3.94	108%
Residential	57	53	92%	74	77	104%	49.4	54.37	110%	26.18	19.94	76%	22.58	18.63	83%	18.52	18.07	98%
Business	44.37	72	162%	89	91	101%	52.39	45.55	87%	39.89	31.99	80%	33.5	26.23	78%	25.87	21.13	82%
Portfolio Total	104	126	121%	167	171	102%	105.85	101.98	96%	71.42	56.2	79%	59.66	50.65	85%	48.04	43.14	90%

The evaluators found that these programs delivered net lifetime benefits to customers of $480 million, as measured by the Total Resource Cost (TRC) test.

Table 2.3: Lifetime Benefits, 2019-2024 (MW)



These programs incentivized:

- Over 10.9 million residential LED bulbs
- Over 85,000 residential HVAC systems
- Over 130,000 residential learning thermostats
- Over 60,000 school kits
- Measures at over 10,000 income eligible homes and tenant units, and
- Over 14,000 projects at commercial and industrial facilities.

The Evaluators also found that Ameren Missouri's low-income programs saved an average of 19 percent and 28 percent on customer bills, for the single-family and multi-family programs, respectively.

Starting in 2019, the Company made important progress with respect to co-delivering its multi-family and single-family low-income programs, by partnering with natural gas utilities. Notably, the programs have been able to offer incentives that cover up to the full replacement cost for an inefficient natural gas furnace. By partnering on the front end and aligning incentives, the co-delivery program lowers overall administrative and incentive cost and creates important synergies, which provide significant benefits for low-income customers and increases the likelihood of program adoption by residents and multi-family property owners.

Ameren Missouri continues to work with its stakeholders and customers to expand and refine its program offerings. Select highlights include but are not limited to:

- The Company's commitment to offering and advancing meaningful income-eligible programs, providing direct installation of deep retrofit measures for single-family homes in underserved communities, as well as comprehensive retrofits for multifamily income-eligible properties. Additionally, the Business Social Services program is designed to deliver enhanced incentive levels to organizations and non-profits that support communities with the highest need.

- The Company continues to offer its on-bill financing program known as the "Pay As You Save" (PAYS®) program, making it among the first investor-owned utilities in the country to do so. The Company currently has approval to offer the PAYS® program through 2026. In June of 2025, the program launched a new enhancement, FastTrack HVAC, which makes heating and cooling upgrades more affordable for customers.

- The Company continues its growth in demand response with its two existing demand response programs, one for residential customers and one for business customers.
    - The business demand response program continues to partner with manufacturing, retail, schools K-12, colleges and universities, and others through custom curtailment plans specific to the customers' operations to reduce peak demand. Ameren Missouri continued participation in the Midcontinent Independent System Operator, Inc.'s (MISO) Planning Resource Auctions as a Load Managed Resource.
    - The Company successfully registered both residential and business demand response assets in the MISO Planning Reserve Auction (PRA) for 2025/26. This was the first time AMO had the residential demand response asset in the auction, and the first time the business demand response asset will operate in all four seasons.
    - The residential demand response program utilizes customers' smart thermostats to reduce peak demand. The program currently has over 62,000 thermostats enrolled and anticipates increasing participation to over 70,000 customers by the end of 2026.

Renewables

Ameren Missouri placed the Boomtown, Huck Finn and Cass County Solar Energy Centers in service in 2024 and received CCNs for Vandalia Solar (50 MW), Bowling Green Solar (50 MW), and New Florence Solar (7 MW). Vandalia and Bowling Green Solar will be used to support customer subscribers through the Company's Renewable Solutions Program, and New Florence Solar will be part of the Company's Community Solar program. The Company also received CCN approval for Split Rail Solar (300 MW), which is expected to be in service in 2026. When completed, these additions will bring the Company's total solar generation to more than 900 MW.

In 2024, Ameren Missouri solicited competitive proposals from renewable energy developers through a request for proposal (RFP) process for wind projects of at least 100 MW in size to support the continued execution of the generation transition plan. More recently, Ameren Missouri conducted an RFP for solar projects of at least 100 MW to support the continued execution and acceleration of solar energy resources in its generation transition plan, consistent with the PRP. The Company is currently evaluating the project bids received as part of this RFP. The Company expects to file several CCN applications annually as competitive wind and solar projects are developed and acquired to serve our customers.

Gas-Fired Generation and BESS

Ameren Missouri received MPSC approval for a CCN for an 800 MW simple cycle gas-fired energy center at the former Meramec coal-fired generation site in October 2024 to ensure reliability under all weather conditions. Commercial operations are expected to commence by late 2027, and this new resource will be known as the Castle Bluff Energy Center.

Ameren Missouri also filed a CCN application in June 2025 for another 800 MW simple-cycle gas fired energy center along with 400 MW battery energy storage system at the former Rush Island coal-fired energy center, to be known as the Big Hollow Energy Center.

Environmental

The Company continues to implement its plan to safely close ash basins. An industry-leading groundwater remediation pilot project was installed at Rush Island in late 2020, with the full-scale project completed in 2022. A similar project was completed at Sioux Energy Center, and another is in the scope development phase at Labadie Energy Center.

3. Planning Environment

3.1 Environmental Regulations

Ameren Missouri has made significant investments to comply with existing environmental regulations and maintain a sufficient compliance margin. Rules proposed or promulgated since the IRP filing in 2023 include the 2023 update to the Mercury and Air Toxics Standards (MATS), the 2023 Steam Electric Power Generating Effluent Limitations Guidelines (ELG) Update, regulation of greenhouse gas emissions under section 111 of the Clean Air Act (GHG Rule), and the Legacy CCR Rule. The Trump Administration EPA has proposed or is currently considering repeals or modifications to each of these rules. Ameren Missouri continues to stay abreast of these issues and advocates on behalf of its customers for good energy policy to promote reliable and affordable energy.

Clean Air Act Regulation of Greenhouse Gases (GHG)

On April 25, 2024, EPA issued final actions under Clean Air Act (CAA) section 111 applicable to GHG emissions from power plants: a section 111(b) rule governing new stationary combustion turbines; and a section 111(d) rule, governing existing steam-generating units (Final Rules). Many parties, including State Attorneys General, industry groups and rural electric cooperatives, among others, have sought judicial review of the Final Rules.

On June 17, 2025, USEPA published in the Federal Register its proposal to repeal and/or significantly revise the GHG standards for fossil fuel-fired power plants promulgated under CAA Section 111 in 2015 and 2024. Comments to the proposed rule were due by August 7, 2025, and EPA has indicated its intent to finalize the rule by December 2025. Ameren Missouri filed comments in this docket and will watch this issue very closely as changes are promulgated.

Cross States Air Pollution Rule (CSAPR) – Ozone Season

In January 2023, EPA disapproved Missouri's Good Neighbor State Implementation Plan (SIP). The disapproval of the state plan was a pre-requisite for EPA to promulgate a federal implementation plan (FIP) implementing the "Good Neighbor" requirements of the Clean Air Act (CAA) for the 2015 Ozone Standard. However, the State of Missouri, Ameren Missouri, and others challenged the EPA's final rule disapproving the MO Good Neighbor SIP in the 8th Circuit Court of Appeals. The 8th Circuit stayed the EPA's disapproval of the MO Good Neighbor SIP pending the outcome of the ongoing litigation. Recently, The Court of Appeals granted the U.S. Department of Justice request to hold the case in abeyance indefinitely with status reports due every 90 days to allow EPA leadership to review the underlying SIP disapproval. In all, twelve states, including

Missouri, have challenged, and obtained stays of, EPA's disapproval of their Good Neighbor SIPs for the 2015 Ozone Standard. Ameren Missouri will continue to follow the judicial process in this case.

On June 5, 2023, EPA promulgated the "Good Neighbor Plan" (FIP) to require upwind states to reduce emissions of the ozone precursor nitrogen oxide (NO_x) from electric generating units (EGUs) and certain stationary industrial sources, in accordance with EPA’s 2015 ozone National Ambient Air Quality Standards (NAAQS). Disapproval of a state SIP is a necessary predicate to the issuance of a FIP. The FIP applied to 23 states including Ameren Missouri EGUs in both Illinois and Missouri and impacted Ameren Missouri's CSAPR allowances and compliance strategy going forward. The FIP was immediately challenged in the DC Circuit Court of Appeals. On March 10, 2025, EPA filed a Motion to Remand the FIP, stating that EPA has decided to reconsider the FIP including the scope of states and sources included in the FIP and what constitutes "significant contribution." Any proposed action modifying or revising the FIP will be subject to notice and comment and EPA expects to complete the rulemaking by Fall 2026. On June 14, 2025, the court consolidated the remand action with the aforementioned FIP challenge and remanded the FIP back to EPA for reconsideration. Ameren Missouri will follow this issue closely as changes are proposed, as well as the SIP case abeyance.

Attainment Designations for NAAQS for Ozone

The St. Louis area was previously designated as moderate non-attainment for the Ozone standard in 2022. Because the 2021-2023 design value (and the 2022-2024 design value) initially indicated non-attainment, the St. Louis Area failed to attain the 2015 Ozone standard by the August 2024 moderate area attainment date. As a result, EPA "bumped up" the St. Louis Area to Serious Non-Attainment in 2024. On January 24, 2025, the State of Missouri filed a Petition for Reconsideration with the EPA for the direct final rule "Finding of Failure to Attain and Reclassification of the Missouri Portion of the St. Louis Nonattainment Area as Serious for the 2015 Ozone National Ambient Air Quality Standards" promulgated on November 25th, 2024. In conjunction with the petition for reconsideration, the State of Missouri also challenged the final rule in the Eighth Circuit Court of Appeals. The State of Missouri also requested a stay of the "bump up" of the St. Louis Ozone Non-Attainment Area to Serious Non-Attainment in the Petition for Reconsideration, which was eventually granted. As such, the St. Louis region is currently in moderate non-attainment. On June 20, 2025, EPA published in the Federal Register a proposed rule to reconsider and take comment on EPA's bump up of the Missouri portion of the St. Louis Ozone Non-Attainment Area. Ameren Missouri provided comments in this docket.

Ameren Missouri's coal units are already subject to, and meeting, Reasonably Achievable Control Technology (RACT) for the 2015 Ozone Standard as required by Consent

Agreements in the Missouri State Implementation Plan. No additional NO_x control requirements are expected for the coal units if the area is eventually designated back to serious non-attainment. If the region is eventually bumped up to serious non-attainment, the major source level for NO_x emissions will be 50 tons per year (down from 100 tons per year for moderate non-attainment) for new resources.

Attainment Designations for NAAQS for SO_2

The EPA lowered the SO_2 ambient standard to 75 ppb on June 2, 2010. Initial attainment designations were finalized on August 5, 2013, and included the designation of two areas in Missouri as nonattainment. The two nonattainment areas included an area in the vicinity of Kansas City (portions of Jackson County) and an area around Herculaneum (portions of Jefferson County). In December 2017, the MDNR submitted a formal request to the EPA to re-designate the Jefferson County SO_2 nonattainment area to attainment. On January 28, 2022, EPA published in the Federal Register a formal redesignation of the Jefferson County, MO SO_2 nonattainment area to attainment. As a part of MDNR's state implementation plan for the Herculaneum area, Ameren Missouri agreed to lower SO_2 emissions limits for the Rush Island, Labadie and Meramec Energy Centers that took effect on January 1, 2017.

On June 30, 2016, the EPA issued a final determination of "unclassifiable" for the area around the Labadie Energy Center. Data collected from the ambient SO_2 monitors indicates that air quality in the vicinity of the Labadie Energy Center complies with the EPA standards. In September 2020, the EPA proposed to redesignate the area around Labadie from unclassifiable to attainment. The EPA is expected to finalize the redesignation by the end of the year. Ameren Missouri continues to operate the monitoring systems and submit the data to both the MDNR and the EPA. Based on monitoring data gathered to date and the EPA proposal to designate the area as attainment, we have assumed the area around Labadie will ultimately be designated as "attainment". Ameren Missouri's assumptions for compliance regarding SO_2 emissions reflect this expectation.

For purposes of the Company's 2025 Change in PRP analysis, compliance at LEC was evaluated with either flue gas desulfurization (FGD) retrofit or 40% natural gas co-firing starting in 2030.

NAAQS for Fine Particulate Matter

Based on current data, St. Louis and Metro East in Illinois are both in attainment with the 2012 PM2.5 standard. The Clean Air Act requires the EPA to review all of the ambient standards on a periodic basis. In December 2020, the EPA finalized a rule to retain the current standard for fine particulate matter. On February 7, 2024, the EPA promulgated a final rule reducing the primary annual PM2.5 NAAQS from 12 µg/m3 to 9 µg/m3. The revised standard is being challenged in court.

The Challenge to the Revised Fine PM National Ambient Air Quality Standard was fully briefed and oral argument held on December 16th, 2024. On February 18, 2025, EPA filed an unopposed request for a 60-day abeyance of challenges to the rule revising the Standard, which was granted on February 5, 2025. The case is currently being held in abeyance, and EPA stated in a recent filing that, "…it expects to sign a proposed *{new}* rule in the Fall of 2025 after review by the Office of Management and Budget." Ameren Missouri will continue to watch this case and the expected new rule and will likely provide comments to reflect Ameren Missouri's position.

For purposes of the Company's 2025 Change in PRP analysis, compliance at LEC was evaluated with either FGD retrofit or 40% natural gas co-firing starting in 2030.

Clean Air Act Regional Haze Requirements

The goal of the Regional Haze Rule is to set visibility equivalent to natural background levels by 2064 in Class I areas. Class I areas are defined as national parks exceeding 6,000 acres, wilderness and national memorial parks exceeding 5,000 acres and all international parks in existence on August 7, 1977. There are currently 156 Class I areas, two of which are in the State of Missouri (Hercules Glade and Mingo). As part of the first planning period (2008-2018), states have developed implementation plans necessary to meet the glide path for the first 10-year planning period. In addition, the Regional Haze Rule requires compliance with Best Available Retrofit Technology (BART) for SO_2 & NO_x for the first planning period. The EPA has determined that compliance with CSAPR meets the BART requirements. Ameren Missouri is fully compliant with CSAPR, and thus, is compliant with the BART requirements. On August 26, 2022, the MDNR submitted its State Implementation Plan to EPA for approval. As part of this SIP, Ameren Missouri entered into agreements with MDNR to assure continued use of existing control technology. On July 3, 2024, EPA published in the Federal Register, at 89 Fed. Reg. 55,140, a proposal to partially disapprove Missouri’s SIP for the regional haze second implementation period. EPA recently changed its policy for reviewing SIPs. This new policy creates a presumption that a state is making reasonable progress if it fulfills the four statutory factors and its visibility conditions are below the Uniform Rate of Progress (URP). In other recent Regional Haze SIPs, EPA has now proposed approvals.

For purposes of the Company's 2025 Change in PRP analysis, compliance at LEC was evaluated with either FGD retrofit or 40% natural gas co-firing starting in 2030.

CWA, Steam Electric Effluent Limitation Guidelines Revisions

In May 2024, the EPA finalized regulations generally known as the Steam Electric Effluent Limitations Guidelines (ELG) Rule that govern certain discharge limitations in the Steam Electric Power Generating category. The ELG Rule establishes technical requirements and discharge standards for wastewaters generated at coal-fired power plants such as flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate. The ELG rule also establishes a new set of definitions and new effluent limitations for various legacy wastewaters, which may be present in surface impoundments. Changes to this ELG rule are currently being contemplated by the EPA. This current rule and any upcoming changes are not expected to materially affect Ameren Missouri's generating fleet.

Coal Combustion Residuals

Ameren Missouri is executing its compliance strategy in advance of the regulatory deadlines. On May 8, 2024, EPA finalized changes to the CCR regulations for inactive surface impoundments at inactive electric utilities, referred to as "legacy CCR surface impoundments". Within tailored compliance deadlines, owners and operators of legacy CCR surface impoundments must comply with all existing requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. In addition, through implementation of the 2015 CCR rule, EPA found areas at regulated CCR facilities where CCR was disposed of or managed on land outside of regulated units at CCR facilities, referred to as “CCR Management Units", or CCRMUs. Ameren Missouri is performing the facility reviews required by the Rule. The Rule is currently being challenged judicially, and on February 13, 2025, EPA filed an unopposed motion to hold the case in abeyance for 120 days in *City Utilities of Springfield v. USEPA* (D.C. Cir.) to allow new EPA leadership to review the rule. The motion was granted on February 13, 2025. In a statement dated March 12, 2025, EPA announced that it is reviewing the 2024 Legacy Rule and intends to complete rule changes within one year.

Ameren Missouri plans to closely watch the current judicial processes and adjust its planning accordingly.

Ash Basin Closure Initiatives

Ash basin impoundments at the Rush Island, Labadie, and Sioux Energy Centers are now complete. Remaining Meramec Energy Center ash basins are expected to be closed by the end of 2026. Closure of the original gypsum pond at Sioux Energy Center is now complete. The closure of the ash ponds will reduce our consumption of approximately 11 billion gallons of water per year.

Mitigation Costs[2]

Capital cost assumptions for environmental mitigation technologies evaluated in the 2025 Change in PRP filing are shown in Table 2.1. Ameren Missouri evaluated co-firing 40% natural gas at its four coal-fired Labadie units, and installment of ESPs, SCRs and FGDs at two units. Ameren Missouri also used the same carbon capture and sequestration assumptions that were shared in its 2023 IRP. The results can be found in the 2025 Change in PRP filing. The need and timing of these mitigation technologies due to EPA regulations remains uncertain.

Table 2.1: Capital Cost Assumptions for Mitigation Technologies ($2024)

$Million (2024$)	Base Capex (Overnight)
ESP	$279
SCR	$637
FGD	$935
Wastewater Treatment for FGD	$65
Cofiring Boiler Modifications	$159

3.2 Supply-Side Resource Review

Ameren Missouri has reviewed the cost and performance characteristics for candidate resources for its February 2025 PRP filing and determined that changes in cost assumptions are appropriate for wind, natural gas simple cycle, and natural gas combined cycle resources; those changes were reported in that filing.

Development and construction activities related to generation projects remain robust. Ameren Missouri continues to monitor changes in the market, both through its own engagement with developers and through evaluation of secondary information sources.

Renewable Energy Offerings

Ameren Missouri has developed several programs that are designed to increase access to renewable energy for all customers. Since filing the 2023 IRP, Ameren Missouri has made meaningful progress on these programs:

Community Solar: Ameren Missouri included an application for approval of a permanent Community Solar Program within the electric rate review filed in March 2021. The program features a variety of improvements to enhance the participation experience for

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[2] File No. EO-2025-0077 1.D; File No. EO-2025-0077 1.I

customers. This proposal was approved as part of the electric rate review settlement agreement, and, as a result, the permanent Community Solar Program was rolled out to residential and small commercial customers in the latter half of 2022. The program redesign expands access and affordability by (1) lowering the program enrollment fee, (2) enabling customers to match up to 100% of their usage with solar energy, and (3) accelerating new facilities construction timelines. In May 2024, Ameren Missouri filed a CCN for the 7.0 MW New Florence Solar Facility, which will be the third solar resource to support Community Solar and the first active under the permanent program.

Renewable Solutions: Ameren Missouri placed in service two solar resources to support the Renewable Solutions Program. Cass County Solar, a 150 MW facility located in Illinois, came online in late 2024 and was fully subscribed via an auction in May 2024. Boomtown Solar was also placed in service in late 2024. The Company expects to add the Bowling Green and Vandalia solar projects to support subscribing customers through this program as well. The Renewable Solutions Program is designed to offer Ameren Missouri commercial and industrial customers and communities a pathway to meet their sustainability goals with local renewable energy while reducing cost and risk for all Ameren Missouri customers.

Battery Storage

Ameren Missouri is actively exploring energy storage deployment strategies to enhance grid reliability, grid resiliency, and support renewable energy integration. One such initiative includes a pilot project utilizing advanced lead-acid batteries to evaluate their safety and performance in medium and large-scale energy storage. This approach utilizes highly recyclable components and supports the local Missouri lead-acid battery recycling industry. Further, it uses lead from the mineral market into which Missouri sells. We also continue to follow advancements in EV battery recycling to determine applicability for repurposing these batteries for grid-scale energy storage vs. recycling them into new batteries. This is a rapidly growing industry with new companies entering the space to provide these services.

Ameren Missouri continuously evaluates new renewable energy integration methods and technologies that include stand-alone renewables, stand-alone storage, and hybrid approaches. Our goal continues to be to provide safe, reliable, and cost-effective electric service to our customers while taking advantage of the capacity credit of our resources.

Supercritical Carbon Dioxide Power Cycle[3]

Ameren Missouri conducted research on supercritical carbon dioxide (sCO_2) power cycle plants as supply-side resource candidates sCO_2 technology presents both opportunities

[3] File No. EO-2025-0077 1.E.

and challenges for integration into utility-scale resource planning. Key findings are: sCO_2 technology has achieved demonstration milestones

- Commercial deployment faces timing uncertainties, with first utility-scale projects now initially expected in 2029
- Technology offers efficiency advantages (50%+ thermal efficiency) and a reduced environmental footprint
- Federal policy changes create uncertainty around sCO_2 development

Technology Overview and Current Development Status

sCO_2 power cycles represent an approach to power generation that uses sCO_2 as a working fluid. The technology is expected to offer advantages over conventional steam cycles, including higher thermal efficiencies, smaller machinery footprint, reduced water consumption, and enhanced operational flexibility.

A recent milestone was achieved with the completion of Phase 1 testing at the 10-megawatt Supercritical Transformational Electric Power (STEP) demonstration facility in San Antonio, Texas.[4] This $169 million project achieved full operational parameters including 27,000 revolutions-per-minute turbine operation at 500° Celsius and 250 bar pressure, generating 4 megawatts of grid-synchronized power.[5] These technological breakthroughs address scaling challenges that previously limited commercial viability.

Commercial Deployment Timeline and Market Context

Another commercial sCO_2 project is NET Power's 300-megawatt Allam-Fetvedt cycle plant planned for construction near Odessa, Texas[6]. Originally scheduled for 2026 operation, this facility has been delayed to early 2029 due to technical complexities and supply chain challenges. The project install cost has increased from $1.1 billion to $2.0 billion.[7]

The project will use an oxy-fuel combustion process in a supercritical CO_2 environment, claiming 97% emission reduction, minimal water usage, and carbon capture capabilities.[8] NET Power's technology offers projected thermal efficiency of up to 59% at lower heating

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[4] https://www.gti.energy/step-demo/
[5] https://www.powermag.com/breakthrough-for-sco2-power-cycle-as-step-demo-completes-phase-1-of-10-mw-project/
[6] https://www.powermag.com/net-powers-first-allam-cycle-300-mw-gas-fired-project-will-be-built-in-texas/
[7] https://www.wavy.com/business/press-releases/cision/20250530DA99860/net-power-shareholder-alert-claimsfiler-reminds-investors-with-losses-in-excess-of-100000-of-lead-plaintiff-deadline-in-class-action-lawsuit-against-net-power-inc-npwr/
[8] https://netpower.com/

value for natural gas applications. The company has secured partnerships with Baker Hughes, Occidental Petroleum, and Constellation Energy.

Grid Integration and Reliability Considerations

For Ameren Missouri's electric system, sCO_2 technology could provide valuable dispatchable capacity, supporting grid reliability, while reducing negative environmental impacts. The compact design of sCO_2 systems could reduce transmission constraints. Industrial applications could benefit from combined heat and power configurations using waste heat recovery.

Risk Assessment and Mitigation Strategies

The primary risks associated with sCO_2 include technology maturity, cost uncertainty, and supply chain constraints. While demonstration projects have proven viable, commercial-scale deployment remains unproven. Actual performance, maintenance requirements, and lifecycle costs remain to be seen.

Cost risks can be mitigated through phased deployment strategies, beginning with smaller-scale applications or industrial installations before proceeding to large utility-scale projects. Partnership with technology developers and equipment manufacturers can provide performance guarantees and technical support during initial deployment phases.

Supply chain risks require careful vendor evaluation and alternative sourcing strategies for critical components. The specialized nature of sCO_2 equipment creates longer procurement timelines compared to conventional technologies. Additionally, recent federal policy changes bring uncertainty into sCO_2 project development.

Policy and Financing Considerations

The DOE cancelled nearly $4 billion in energy project grants.[9] The grants were primarily for programs to capture carbon emissions and store them underground, directly impacting the funding environment for carbon management and power generation technologies.

The news was a follow-up to plans the DOE announced earlier to review 179 funded projects, totaling over $15 billion, that were awarded by the Office of Clean Energy Demonstrations created under the 2021 bipartisan infrastructure law.[10] While specific sCO_2 projects were not explicitly identified in the cancelled awards, the cancellation of projects

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[9] https://apnews.com/article/climate-energy-projects-funding-canceled-cf3e9b5da749eb76a71c901ded20d711
[10] https://www.carbonbrief.org/daily-brief/14bn-in-clean-energy-projects-have-been-cancelled-in-the-us-this-year-analysis-says/

in-kind cast doubts on technologies that previously relied on federal support. Projects that had planned to leverage federal tax credits, grants, or loan guarantees may face financing gaps or halt altogether.

Ameren Missouri will not consider sCO_2 power cycle technology as a supply-side candidate resource at this time, however, we will be monitoring commercial deployment outcomes, federal policy developments, and cost evolution to determine the appropriate role, if any, that sCO_2 technology may play in Ameren Missouri's future generation portfolio.

Long Duration Energy Storage[11]

Ameren Missouri regularly meets with long duration energy storage (LDES) vendors, participates in EPRI programs that study new LDES technologies, and follow the LDES Council for recent developments. However, Ameren has so far not commenced any independent pilots or research projects. At such time as a technology appears sufficiently mature, further consideration will be given.

Ameren Missouri has done very preliminary modelling to examine the efficacy of long duration battery storage. Data center loads were not included in these simulations. The results are indicative only. More detailed inputs for a greater number of years will have to be modelled before firm conclusions may be drawn. Keeping these caveats in mind, the initial results show that battery capacity had a greater impact on LOLE than run hours. Battery run hours greater than 25 did not show much improvement in LOLE. Improvement in LOLE was slightly greater for batteries than for long duration pumped hydro that was also modelled. This was due to the faster ramp rate of batteries compared to pumped hydro.

Non-chemical storage technologies (other than pumped hydro) are in a nascent phase and not sufficiently mature for consideration as a candidate resource.

It is possible that renewables (such as wind or solar) may combine synergistically with storage to enhance system reliability. There are limitations on this since increasing penetration of storage results in declining capacity and reliability benefits. This is a well-known phenomenon. Also, in MISO, there is no rule or procedure that would allow for increased capacity accreditation of renewables due to the addition of storage.

Listed below are some potential LDES technologies which may be considered in the future. Their efficiencies may be compared to that of lithium-ion batteries, roughly 85-95%.

Pumped Hydro Storage: A well-known and widely used LDES technology. During a time of higher energy prices, water flows from an upper reservoir through a turbine to

[11] File No. EO-2025-0077 1.H

generate electricity. When prices are low water is pumped back from the lower reservoir to the upper. Ameren Missouri continues to monitor pumped hydro as a storage option and include it as a candidate resource in its IRP planning. Advancements in battery storage systems, along with permitting difficulties associated with pumped storage push the technology out of contention as a primary storage resource for now.

Compressed Air Energy Storage: Air is compressed and injected into a large storage space, such as a geologic cavern. When used, the air is expanded, and energy is added by heating with burning fuel. The flow is passed through a turbine to drive an electric generator. Efficiencies are low due to compression losses, 40%-70%.

Recent deployments of CO_2 batteries indicate momentum for a different approach to the implementation of compressed air energy storage (CAES). The pressure and temperature differential of CO_2, in gaseous and liquid form, drive electric generation. CO_2 stored in an expandable "indoor-tennis-court" dome is drawn into a compressed storage unit. The phase change from gas to liquid generates heat and pressure. Reversing the process, changing the CO_2 from liquid form to gaseous form, releases the stored heat and pressure to spin a generator's turbine. The dome is then re-inflated with CO_2. Its advantages include a worldwide supply chain of basic steel and concrete components. It does not require cavernous-underground storage areas like that of liquid air energy storage (LAES) nor does it require minerals like those of lithium-ion batteries. Its disadvantages include landscape requirements, 10 acres per 20 MW, much of which is taken up by the dome which stores CO_2 in gas form.

Energy Dome, a company based out of Milan, Italy, energized its first 2.5 MW CO_2 battery in Sardinia, Italy in 2022. Energy Dome is designed with a duration of 8 to 16 hours, an efficiency rating of 75%, and a nameplate capacity of 20 MW per module, with modules "strung" together to create a total nameplate capacity of 200 MW. Additional Energy Domes are slated for construction with utilities in Western Europe. Energy Dome's first US installation is scheduled for construction in 2026 with Alliant in Wisconsin.

Hydrogen: Produced by electrolysis is used in a fuel cell or turbine to generate electricity. Large storage volume, such as a geologic cavern, or pipeline will be required. Round trip efficiency 25-45%.

Flow batteries: Liquid electrolyte in 2 tanks is pumped through a membrane where ions are exchanged to produce electricity. Storage can be increased by making tanks larger, but the facility can become complex and expensive because of pumps and plumbing. These are fire safe and expected to endure for thousands of cycles. They have low energy density and high upfront costs. Efficiencies 65-85%.

Gravity Based Storage: Weights are moved to a high elevation. Potential energy is converted to electricity when weights are lowered back down. They are still in development with very few installations in service in the US. There are a few in other countries, notably China. Efficiencies are projected to be 70-85%.

Flywheels: Massive wheels spin at tens of thousands of revolutions per minute. Energy is withdrawn by slowing the wheel. These are not ideal for storing a lot of energy but can provide short duration, extremely fast response. They are ideal for frequency regulation. Efficiencies are 85 to 95%.

Molten Salt: Molten salt is stored at high temperatures. This can be used to produce steam to drive a turbine for generation. These systems have high energy density, and they can store large amounts of energy for extended periods; they are not well suited for fast response to load. Initial costs are high and constant heat input is required to maintain the temperature. The salts eventually degrade and there are safety concerns; systems must be carefully designed to prevent human and environmental exposure to hot, corrosive materials. Round trip efficiency is estimated to be 60-88%.

Iron Air Batteries: This technology utilizes the oxidation of iron (rusting) to produce electrical current. When discharging, metallic iron reacts with oxygen from the air to form iron oxide (rust), releasing electrons that generate electricity. When recharging, an electrical current is applied to reverse the rusting action. Main advantages are low cost and readily available raw materials, potential for long duration storage, safety (no fire risk) and environmentally friendly with only oxygen as the effluent. Disadvantages include low energy density, possible electrolyte degradation, electrode instability, and slow charge and discharge rates. They are heavier and require more space (0.5 acre/MW) than lithium-ion batteries (0.14 acre/MW). The technology has not yet been demonstrated at grid scale, but the company Form Energy is expecting to bring a 10 MW/1000 MWh demonstration system online by the end of 2025. Efficiencies are estimated at around 50%.

3.3 Transmission and Distribution Review

Smart Energy Plan Update

Ameren Missouri is in year seven of the Smart Energy Plan (SEP). The SEP commenced in 2019 and is a forward-looking plan to ensure customers have safe, reliable and increasingly cleaner energy to meet their growing needs and expectations.

The Missouri Legislature passed Senate Bill 4, that was signed by Governor Kehoe on April 10, 2025, which enabled Ameren Missouri to maintain our commitment to modernizing the grid through at least 2035. The current plan includes an anticipated $3.7 billion of electric distribution system investments from 2025 through 2029 that will, among other things, support investments in aging infrastructure upgrades, smart grid technologies, system hardening efforts, and system capacity.

The SEP provides critical support for Ameren Missouri in its efforts to combat an increasingly at risk electrical grid due to age, condition, and capacity limitations. Much of Ameren Missouri's existing system was built during the 1950s and 1960s. This build out was driven by an increase in electricity usage due to: 1) suburbanization, 2) increased use of air conditioning, and 3) industrial growth in Ameren Missouri's service territory. Today, decades later, many of these assets are near or have exceeded their engineered lives as seen in Table 3.3 below, and Ameren Missouri must upgrade them, not only to reduce the risk of equipment failures, but also to meet the expanding and resurgent needs of our customers driven by increased electrification and economic development.

Table 3.3: Summary of Distribution Asset Average Age

Asset Name	Asset Count	Assets Past Expected Life	Average Age	Expected Life
Miles of Underground Cable	~8,000	~2,700*	~31	40
Miles of Subtransmission Overhead Conductor	~4,200	~1,700	~40	45
Substation	~645	~314	~46	50

**The numbers provided are the sum of the distribution and subtransmission*

Despite significant investments over the past six years, there is still a large proportion of assets on our system which are past expected life. For example, nearly half of our distribution substations still contain either a transformer or circuit breaker (critical components) installed more than 50 years ago. These aged substations serve hundreds of thousands of our customers today.

While aged infrastructure is being modernized, weather patterns and changes in customer needs/expectations impact what types of upgrades are being made. Weather is becoming more of a challenge with new records being routinely set. Through May of 2025, Ameren Missouri has already experienced 43 tornados in the St. Louis area, which is twice the annual average over the last 35 years. These waves of severe storms downed trees, damaged homes and businesses, and disrupted service to hundreds of thousands of customers. To combat extreme weather events, aged assets are being upgraded with storm-hardened alternatives and with larger capacity to support grid flexibility when the grid is damaged and outages do occur. In addition, Ameren Missouri is incorporating resiliency into new designs that provide sufficient capacity to allow for the system to be reconfigured to prevent catastrophic failures if there are significant system stresses, like during extreme weather events.

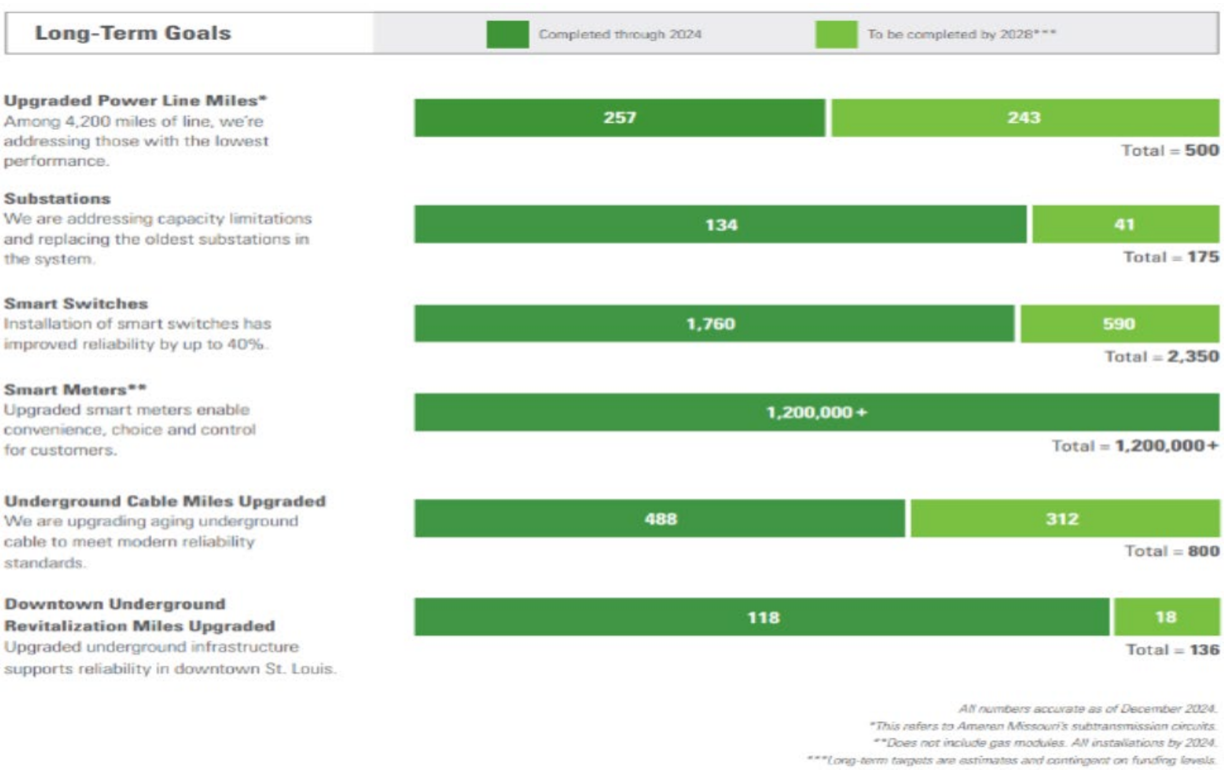
Upgrades are also being impacted by changing customer expectations. Where customers have committed to economic development, increases in electric vehicle use, data centers and electrification of operations, additional capacity will be required in some areas of the distribution system to handle the increased load. As assets are upgraded, this additional capacity is considered, especially on assets which have expected lives of 45+ years and will likely be required to handle additional load in the future due to these customer changes. Customers are also increasingly requiring constant power supplies and becoming less tolerant to any type of interruption – including momentary outages. In fact, some high-impact customers like hospitals, manufacturing and airports rely on technology which cannot tolerate even a momentary outage. To combat this, Ameren Missouri is upgrading assets on the sub-transmission system to improve reliability and eliminate disruptive outages. Underpinning Ameren Missouri's efforts are a number of outcome-driven strategic goals:

- Automate portions of the electric distribution system by deploying smart switching devices with associated circuit upgrades and accompanying communications technologies to help significantly reduce the length of outages. Since the beginning of the Smart Energy Plan in 2019, Ameren MO crews have installed more than 1,700 smart switch devices on the grid. This technology can automatically detect an outage and quickly reroute power, reducing outages from hours or days to minutes or even seconds and improving reliability by up to 40%. Since Ameren Missouri began tracking their performance in 2021, these switches have saved over 330,000 outages and 90 million minutes of outage time.
- Harden the 34kV and 69kV electric distribution system with a stronger, more secure energy delivery backbone, strategically using stronger wood and composite poles, standoff insulators, shield wire, and wind resistant conductor that will better withstand severe weather, including winds of more than 70 MPH. Hardened circuits are designed to avoid momentary outages due to lightning strikes, as well as the risk of extended outages from high winds and other severe weather. During this decade Ameren Missouri and its customers have seen the benefits of these investments on several occasions, including but not limited to the following examples: In the summer of 2023, Ameren Missouri experienced one of the worst storm seasons in over a decade during which none of our hardened lines experienced damage from these storms. In the first half of 2025 the St. Louis metro area experienced twice the number of tornadoes as it normally sees in a full year including several EF-2 and EF-3 tornadoes with winds reaching and exceeding 135mph. During these events, the hardened lines performed as intended with composite poles limiting the scope of damage by preventing cascading failures and enabling faster restoration.

- Upgrade aging and under-performing assets (e.g., substations, overhead and underground assets). Part of Ameren Missouri's plan is addressing the poorest condition and worst performing circuits across its service territory to support reliability for its customers.
- Employ smart grid technologies (e.g., relaying, monitoring, fault information, communications) as Ameren Missouri upgrades aging and end of engineered life infrastructure to improve reliability, capacity for customers, and mitigate risk.
- Improve operating flexibility, increase capacity, and enable a bi-directional flow of power from future DERs by upgrading substations and lines and adding smart switches. When severe weather or other events occur, customers can have power restored through switching to prevent or reduce extended outages, but only if lines and substations have the capacity to serve additional load. Part of this work includes the strategic conversion of some 4 kV areas to a system-standard of 12 kV. This allows for the use of standardized equipment and increased operational flexibility through the ability to add ties between circuits to allow switching to occur and support load growth.
- Continue to execute the final portions of the underground revitalization program in the City of St. Louis and surrounding communities. The program significantly reduces reliability concerns with aging and end of engineered life infrastructure, some of which is over 100 years old, while increasing route diversity, thus reducing the risk of very long and widespread outages due to a single incident. Our target date for completion is 2028.

Figure 3.2 below shows Ameren Missouri's progress in completing these electric upgrades from 2019-2024 and planned upgrades through 2028.

Figure 3.2: Upgrades Completed and Planned



As the grid of the future is built, Ameren Missouri is keeping electric rates as low as possible by controlling costs while investing to support long-term energy reliability and resiliency for customers. Ameren's overall residential electric base rates are approximately 27% below Midwest and U.S. averages.

Smart Meter Program

The Ameren Missouri Smart Meter Program substantially completed the upgrade of all electric meters, gas modules, and the associated communication network in the Missouri service territory in 2025. The system will be fully deployed this year, with network optimization continuing through the end of the year. This work includes:

- Installed 1.3 million Electric Advance Metering Infrastructure (AMI) meters (residential and commercial/industrial) which can provide greater usage insights and capabilities for customers.
- Installed 140,000 Gas AMI modules (Residential and Commercial/Industrial).[1]
- Deployed a modern RF mesh network, enabling two-way communication.
- Launched an Advanced Meter Data Management System.
- Modernized the Ameren Missouri Meter Shop to facilitate the receipt and quality testing of purchased meters.

- Created an Ameren Missouri Network Lab and a Missouri Integrated Operations Center.

These new electric meters and gas modules replaced all of the antiquated Automated Meter Reading (AMR) meters/modules, which used meter reading technology that was more than 20 years old and was past their expected life of 15 to 20-years.

These distribution upgrades have a number of benefits associated with them:

- Smart sensors, switches, self-healing equipment and smart meters work together to rapidly detect and isolate outages and more quickly restore power in the event of a service disruption.
- Smart meters enable Ameren Missouri to pinpoint outages, quickly restore customers' service, and inform customers of restoration progress.
- Smart meter rate options (e.g., time-of-use rates) provide the opportunity for customers to manage their bills and shift load from peak to off-peak times to benefit the system.
- Improved mobile and web-based tools provide customers with greater visibility into their energy usage and greater control to manage their energy costs.
- Customer rates are kept affordable through a reduction in meter infrastructure operating costs (e.g., eliminating the existing AMR system reduced meter reading costs and expenses associated with contractors who had provided manual disconnect/reconnect services).

IIJA Grant

In 2022, the Department of Energy announced a $3.5 Billion investment in America's Electric Grid, Deploying More Clean Energy, Lowering Costs, and Creating Union Jobs. In 2023, Ameren Missouri applied for and was awarded a $47 million Grant from the U.S. Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) Smart Grid Program for a Rural Substation Modernization proposal. Ameren Missouri will be able to fast-track infrastructure upgrades in rural areas across our service territory, while improving reliability for our customers. Coupled with the company's own investment of ~$69 million, Ameren Missouri is planning on implementing a ~$116 million total investment in the energy future of rural Missouri. Funds will be used to upgrade 16 aged substations with modern designs and smart technology to increase resiliency and improve reliability by up to 40%. Ameren Missouri remains in negotiations with the DOE regarding terms and conditions of the grant, including the allowed start date of the program. In 2025, Ameren Missouri applied for and was awarded a $3 million Grant managed by the Missouri Department of Natural Resources. The Grant is part of the U.S. Department of Energy's Grid Resilience Formula Funding program. In addition to the company's own investment of $3.5 million, Ameren Missouri is planning to invest a total of $6.5 million in two aged and poor performing rural substations with upgrades to modern designs and smart technology. Ameren Missouri remains in negotiations with the DOE regarding terms and conditions of the grant, including the allowed start date of the program.

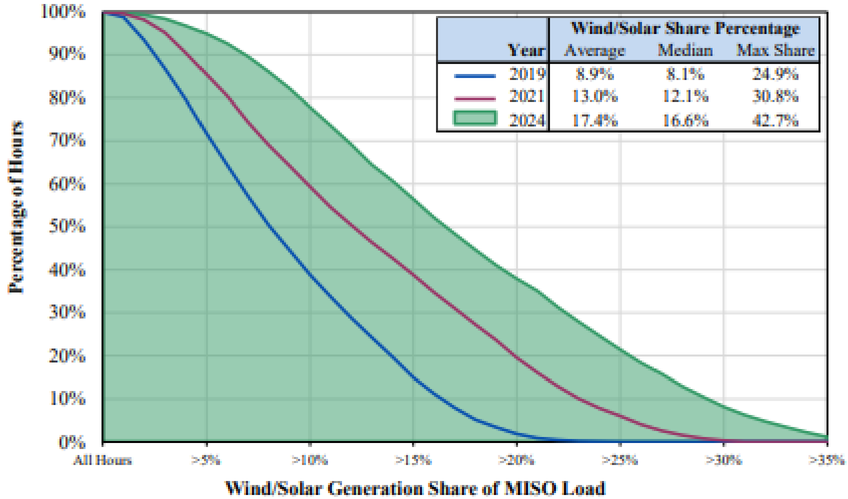
Transmission Considerations for Long-term Portfolio Transition

In December 2024, MISO approved its Long-Range Transmission Plan (LRTP) Tranche 2.1 set of reliability projects based on MISO's Future 2A scenario load models. These projects are complimentary to the MISOs Tranche 1 projects, which were approved in July 2022. The estimated cost of the entire portfolio will be in the range of $21.9 billion of transmission investment, with $818 Million allocated to Missouri. The MISO Tranche 2.1 approved projects within Missouri are all at 345 kV, however the portfolio itself includes projects at 765 kV in nearby MISO states. Tranche 2.1 will continue to improve transfer capability into, out of, and across the state, increase transmission headroom for generation interconnections, and also support the reliability and resiliency of Eastern Missouri load, including the St. Louis region.

It was expected that a further set of transmission projects would follow Tranche 2.1 using MISO's Future 3A scenario, but MISO elected instead to update the futures load forecast, the previous version of which had been exceeded due to rapidly increasing load related to data centers, reshoring and electrification. Upon completion of MISO's revised Futures analysis, a prospective set of projects based on these new futures is expected to necessitate building 765 kV projects in Missouri.

MISO's interconnection queue, Definitive Planning Phase (DPP) continues to grow, with the Missouri interconnects for the DPP22 and DPP23 cycles being the largest to date at 1,345 MW and 3,345 MW, respectively. To account for this new generation, and based on the results of the DPP22 queue, there will be a corresponding expansion and investment in transmission infrastructure. Ameren Transmission Planning changed its Criteria and Guidelines to reflect the updated generation mix and to speed up interconnection study timelines. Ameren and MISO are further investigating what can be done to speed up the other DPP phases to maintain compliance with FERC order 2023. Connecting new generation to meet the needs of new load will require continuous investment in transmission, however with unknowns on both the location of the load and of the generation, a definitive plan for the ultimate build of the transmission system will include both long term scenario planning, such as MISO LRTP along with more near term planning to connect load and generation to meet their in-service dates.

Figure 3.3: Share of MISO Load Served by Wind and Solar Generation



The penetration of intermittent renewable resources continues to grow within the MISO footprint, and the energy provided by them is now around 17.4% percent of total energy production annually in MISO. This is due to the addition of new renewable generation, the addition of DER, particularly in nearby states such as Illinois, and the retirement of existing fossil-fueled generation. Wind and solar energy peaked in MISO with a maximum instantaneous share of the load at 42.7%. To complicate matters further, new data center load is unlikely to have the same characteristics as traditional industrial motor-based load. This increase in renewable generation and power electronic load can significantly impact grid performance. MISO identified that the complexity of grid control increases sharply after 30 percent renewable penetration levels are achieved, as laid out in MISO's Renewable Integration Impact Assessment (RIIA).[12] Significant investment in grid controlling devices such as statcoms is required to control voltage, the lack of which was a driving cause behind the 2025 Iberian Peninsula blackout. Although Ameren is adding synchronous resources, there will be times during the year, such as spring and fall, where the reliability of the system will depend upon grid controlling devices. Ameren Transmission continues to develop new tools for their engineering team to use in the study of the power system when sourced from power electronic based devices, with emphasis on verifying interconnection customers' models.

Ameren Transmission Planning continues to evaluate and work with our neighboring Transmission Owners (TO) and Regional Transmission Organization (RTO) neighbors and to find projects of high value to our customers and have jointly developed a project across mid-Missouri. This new project will increase transfer capability between RTOs, improve Missouri reliability, enable expanded transmission access for generation and for

[12] Published in February 2021.

load, along with increasing resiliency by mitigating potential risks of extreme weather events.

Ameren Missouri has a very active large load queue, and many customers have requested very aggressive in-service dates. These projects entail rapid planning and detailed design phases to meet the customers' connection needs without negatively impacting the overall reliability of the transmission system.

In early 2025, Ameren kicked off a project to investigate the use of dynamic line ratings on its transmission system to maximize its utilization under favorable weather conditions, with the equipment to be installed in late 2025. Along with implementation of ambient adjusted ratings, this project will allow for a comparison of technologies for higher system ratings, potentially mitigating system upgrade projects for new interconnections and reducing seasonal system congestion. Ameren hopes to complete an analysis on the technology, including when and where to install the sensors, after viewing its performance in every season.

Although supply chain issues have eased in general, certain utility equipment such as transmission transformers and 345 kV breakers continue to have long lead times as multiple entities vie for the products. Along with the generator interconnection customers competing with traditional utilities for equipment, large load developers who operate on much shorter timelines than traditional utilities have put new pressure on equipment manufacturers. Transformer lead times continue to be approximately 4 years, which reinforces Ameren's commitment to both EEI-STEP[13] and NATF-RESTORE,[14] national industry sparing programs designed to help recover from disasters. Ameren Missouri has to be very proactive in equipment purchases to meet large load customers' aggressive in-service dates. These customers compete across the US for interconnection, and Ameren Missouri wants to be proactive in attracting new customers to Missouri.

Transmission Costs[15]

Ameren Missouri's expectations on transmission interconnection costs for new supply-side resources as well as the transmission system upgrade costs that might be incurred following retirement of its other existing coal-fired energy centers are currently under review and will be revised as needed for the 2026 IRP. The cost assumptions used in the 2025 Change in Preferred Plan filing can be found in Chapter 7 of the 2023 IRP and in section 2.2 of the 2025 Change in Preferred Plan filings.

[13] Edison Electric Institute Spare Transformer Equipment Program.
[14] North American Transmission Forum, Regional Equipment Sharing for Transmission Outage Restoration.
[15] File No. EO-2025-0077 1.F

MISO Interconnection Queue[16]

Using values from MISO's Generator Interactive Queue, the average number of days from the time an Ameren - Interconnection Customer (IC) submits an application to the time the Generator Interconnection Agreement (GIA) is executed is 1,167 days. The variation between generator types is negligible: wind 1,130 days, gas 1,171 days, solar 1,187 days. These values include Ameren Missouri, Ameren Illinois and Ameren Transmission Company of Illinois, collectively "Ameren", as the identified Transmission Owner (TO).

The averages do not include the number of days from when the IC submits an application to the Commercial Operation Date (COD). Ameren's in-service date identified in the GIA does not indicate that the IC has met their COD, only that Ameren has met its obligations and that the Ameren facilities are in place for the IC to connect to and inject power to MISO.

At times, the IC's delay their project and request to amend the GIA to move their COD, which lengthens the project timeline. Table 3.4 below displays MISO queue durations that focus on each queue cycle by year and only on MISO Central projects. The number of projects continues to grow year over year, increasing the backlog.

Note, while an IC submits its application to MISO and the submittal date is time-stamped, MISO doesn't begin formally reviewing the application until the Definitive Planning Phase (DPP) Kick-Off date (or Start Date). Put another way, the IC is ready to run the race from their front door, but MISO waits to fire the starting gun until all ICs are lined up at the track.

What started around 1.5 years to execute a GIA in 2016 has lengthened to over 4 years for the 2020 queue cycle. The DPP timelines don’t consider when the project was filed with MISO, the gap from filing date to DPP kick-off date is also growing. For example, the DPP process for the 2023 cycle hasn't yet started. As of August 18, 2025, the DPP Start Date for the 2023 cycle is September 12, 2025. The data shows that it's taking years for MISO to produce DPP1 results, results which allow the IC customer to identify estimated network upgrade costs. IC's dropping out at various points within the queue causes re-studies and further delays.

Network upgrades begin after an executed GIA. TO's see significant delays in starting upgrades due to long lead times for equipment. Some TO's are quoting 2-3 years for the completion of network upgrades for new generating projects. The IC's also see significant lead times for high demand items such as breakers, generators and transformers. These items are not procured/ordered until the GIA is negotiated and the interconnection costs/risks are known and accounted for. These timelines are adding up as the queue

[16] File No. EO-2025-0077 1.G

within MISO continues to grow. MISO queue cycle 2021 could see electrification dates for their projects in 2029 (5 years for the DPP process, 2 years for long lead items and 1 year for construction).

Table 3.4: MISO-Central DPP Schedule[17]

Region	Study Cycle	Number of Projects	MWs	DPP Start	DPP 1 Completion	DPP 2 Completion	DPP 3 Completion*	GIA Execution*	Current Stage/Status
Central	DPP-2018-APR	34	7,344	4/22/2019	1/7/2020	3/10/2021	1/8/2024	6/6/2024	GIA Complete
	DPP-2019-Cycle	81	13,216	6/23/2020	8/5/2021	5/20/2022	1/26/2024	5/13/2024	GIA Complete
	DPP-2019-Cycle (Restudy)	69	10,988			5/21/2024	1/24/2025	5/23/2025	GIA Complete
	DPP-2020-Cycle	43	7,035	3/15/2021	7/14/2023	8/30/2024	3/13/2025	7/26/2025	DPP 3
	DPP-2021-Cycle	95	13,840	12/8/2021	10/7/2024	9/19/2025	11/14/2025	3/29/2026	DPP 2
	DPP-2022-Cycle	283	51,762	3/27/2023	7/29/2025	11/8/2025	1/3/2026	5/18/2026	DPP 1
	DPP-2023-Cycle	207	37,035	9/12/2025	12/21/2025	4/2/2026	5/28/2026	10/10/2026	Application
	DPP-2025-Cycle	-	-	1/5/2026	4/15/2026	7/26/2026	9/20/2026	2/2/2027	Application

To further accelerate the speed with which these studies are performed, MISO has performed parallel testing for new software called the Suite of Unified Grid Analyses with Renewables (SUGAR), developed by Pearl Street Industries. SUGAR has performed early test-runs of the Phase 1 studies and may expand into Phase 2 studies. MISO expects the Phase 1 results to be available for TO review within 30 days of the study Kick-Off when using SUGAR. FERC recently approved MISO's Expedited Resource Addition Study (ERAS) process, with MISO noting that it, "will accept ERAS interconnection requests between August 6 - 11, 2025, and will be studied on a first-come, first-served basis. The first quarterly study will begin on September 2. The full schedule of application cycles and deadlines, the ERAS informational guide, and the online application tool can be accessed on MISO's website."[18]

Ameren Missouri is reviewing its assumptions for project length for all supply-side resources and will be revising them as needed for the 2026 IRP.

3.4 Load Forecast Review

Ameren Missouri, like many utilities all over the country, has been receiving requests from large customers – mainly data centers – to receive its energy services. Ameren Missouri filed its change in PRP in February 2025, which included 1,500 MW of large load addition by 2032, and another 1,000 MW by 2040 in addition to the incremental economic development load and three levels of (low-base-high) electrification included in its 2023

[17] Source, updated monthly: https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Schedule629192.pdf

[18] https://www.misoenergy.org/meet-miso/media-center/2025---news-releases/ferc-approves-misos-expedited-resource-addition-study/

IRP forecast. Table 3.5 below shows the annual peak demand additions assumed in the February 2025 filing for modeling alternative resource plans. Note that the timing of load additions, including in the near term, is still uncertain. Ameren Missouri will be closely monitoring its load assumptions and will include any changes in future filings.[19]

Table 3.5: Large Load Addition Scenarios

@Transmission	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
500 MW	300	500	500	500	500	500	500	500	500	500	500	500	500	500	500
1500 MW	300	500	700	1,000	1,200	1,400	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
2000 MW	300	700	1,000	1,300	1,600	1,900	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
2500 MW	300	500	700	1,000	1,200	1,400	1,500	1,625	1,750	1,875	2,000	2,125	2,250	2,375	2,500
3500 MW	300	700	1,000	1,300	1,600	1,900	2,000	2,200	2,400	2,600	2,800	3,000	3,200	3,400	3,500

As part of this annual update, several scenarios were requested in the Commission's special contemporary issues order for added clarity on the load forecast analysis.[20] Table 3.6 and Figure 3.3 below lay out the requested scenarios:

- With demand-side rates and traditional demand-side management investments (i.e., MEEIA). This is the ultimate forecast in the Company's preferred plan.
- Only demand-side rates without MEEIA investment.
- Neither MEEIA investment nor naturally occurring energy efficiency adoption

Table 3.6: Summary of Load Forecast Scenarios (MWh - at Meter)

Year	With Demand-side Rates and Continued DSM Implementation (e.g., MEEIA 4)	Only Demand-side Rates without Continued DSM Implementation	Only Demand-side Rates without Continued DSM Implementation & Naturally Occurring EE
2025	30,589,393	30,769,114	31,267,441
2026	33,103,353	33,333,533	33,960,448
2027	34,933,625	35,214,626	35,959,272
2028	37,004,632	37,336,455	38,195,432
2029	39,624,143	40,006,787	40,966,171
2030	41,447,558	41,866,815	42,989,540
2031	43,148,850	43,613,438	44,877,764
2032	44,155,496	44,665,060	46,052,689
2033	45,228,008	45,776,922	47,264,797
2034	46,466,837	47,040,323	48,622,277
2035	47,728,642	48,307,398	49,972,947

[19] File No. EO-2025-0077 1.C
[20] File No. EO-2025-0077 1.A 1-5

Year	With Demand-side Rates and Continued DSM Implementation (e.g., MEEIA 4)	Only Demand-side Rates without Continued DSM Implementation	Only Demand-side Rates without Continued DSM Implementation & Naturally Occurring EE
2036	49,074,089	49,679,466	51,423,067
2037	50,184,296	50,816,044	52,622,253
2038	51,443,434	52,101,213	53,971,753
2039	52,749,203	53,402,541	55,335,546
2040	54,115,825	54,774,839	56,824,895
2041	54,303,539	54,960,678	57,110,607
2042	54,618,648	55,266,569	57,514,415
2043	54,898,388	55,549,791	57,888,237

Figure 3.3: Summary of Load Forecast Scenarios (MWh at Meter)

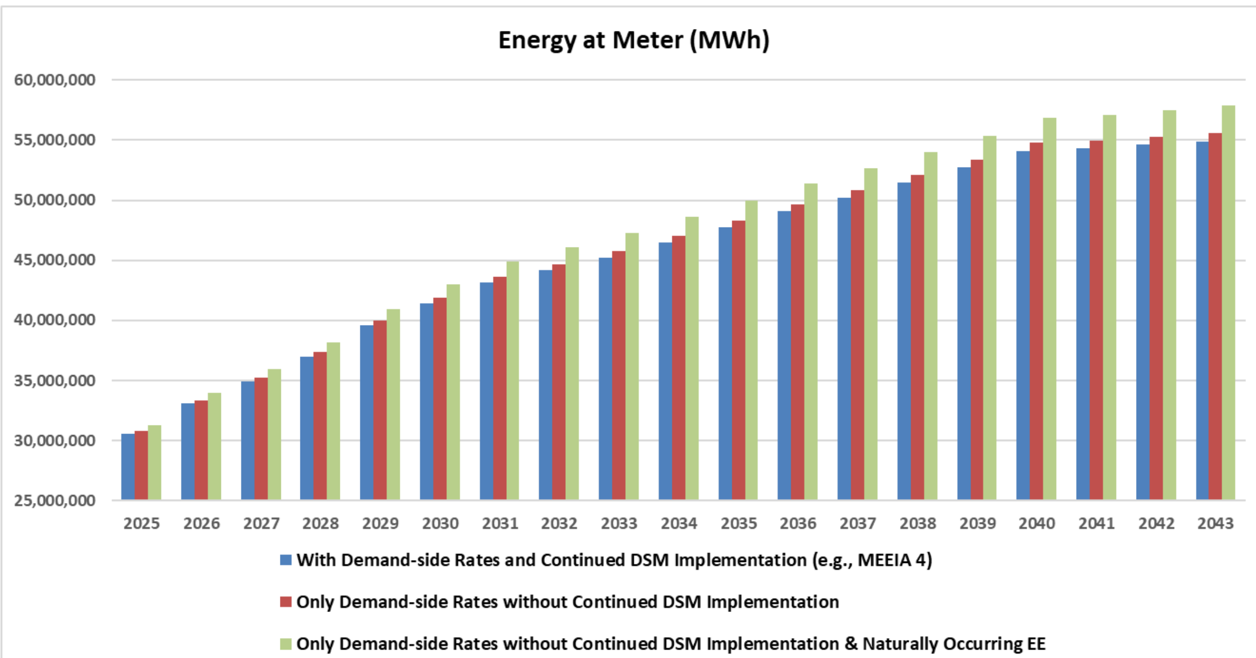


Table 3.7 and Figure 3.4 summarize the peak demand forecast associated with each one of the same scenarios provided above in addition to a scenario without the inclusion of time-of-use rates. It should be noted that demand-side rates are considered to be long-term options for implementation; having customers opt-in and/or adjust their usage patterns to make a change in resource adequacy requirements all take time, and therefore, are not suitable as short/medium term solutions.

Table 3.7: Summary of Load Forecast Scenarios (MW - at Generation)

Year	With Demand-side Rates and Continued DSM Implementation (e.g., MEEIA 4)	Only Demand-side Rates without Continued DSM Implementation	Only Demand-side Rates without Continued DSM & Naturally Occurring Energy Efficiency	Without Demand-side Rates & Continued DSM & Naturally Occurring Energy Efficiency
2025	6,704	7,043	7,158	7,164
2026	7,010	7,379	7,519	7,526
2027	7,220	7,619	7,782	7,789
2028	7,477	7,900	8,084	8,091
2029	7,803	8,249	8,450	8,457
2030	8,040	8,497	8,729	8,736
2031	8,248	8,723	8,981	8,987
2032	8,347	8,840	9,120	9,126
2033	8,469	8,979	9,276	9,283
2034	8,648	9,170	9,484	9,490
2035	8,810	9,340	9,667	9,674
2036	8,975	9,517	9,856	9,863
2037	9,119	9,672	10,021	10,028
2038	9,219	9,784	10,140	10,147
2039	9,395	9,958	10,323	10,330
2040	9,615	10,182	10,568	10,575
2041	9,646	10,213	10,618	10,625
2042	9,696	10,261	10,684	10,691
2043	9,760	10,327	10,767	10,774

Figure 3.4: Summary of Load Forecast Scenarios (MW at Generation)

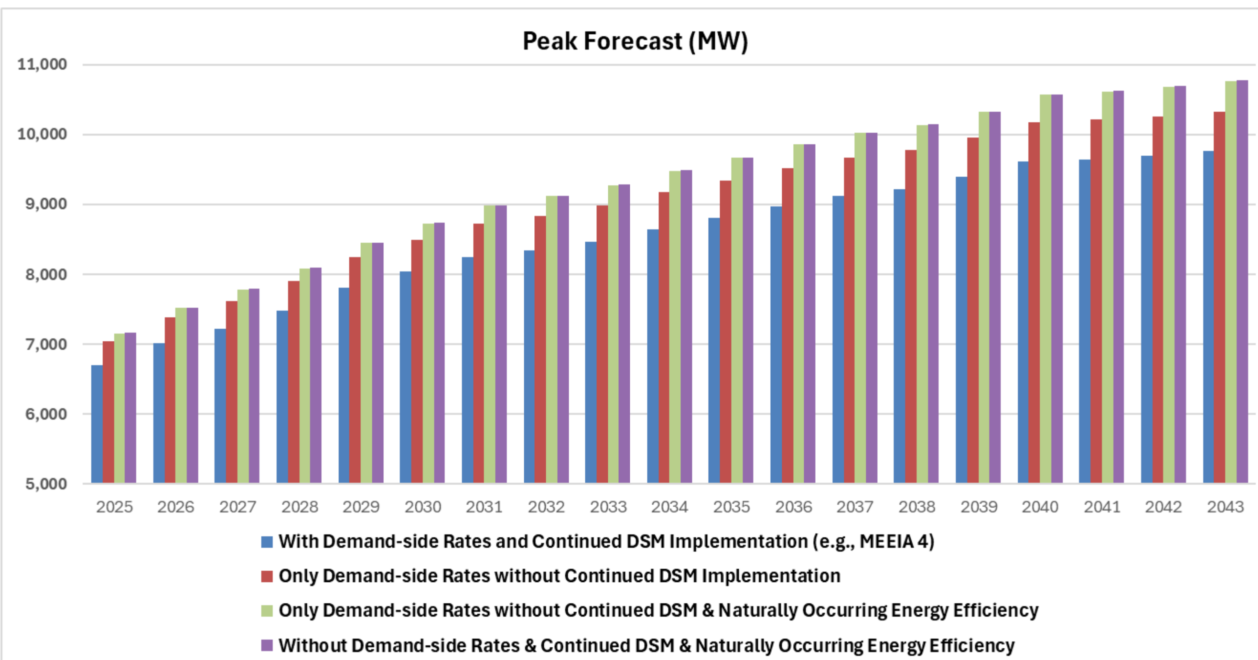


Table 3.8 below display the estimated savings from naturally occurring energy efficiency.

Table 3.8: Savings from Naturally Occurring Energy Efficiency

Year	Energy (MWh - at Meter)	Peak Demand (MW at Gen)
2024	-359,724	-83
2025	-498,327	-115
2026	-626,914	-144
2027	-744,646	-171
2028	-858,978	-196
2029	-959,384	-218
2030	-1,122,725	-254
2031	-1,264,326	-285
2032	-1,387,629	-311
2033	-1,487,876	-332
2034	-1,581,953	-352
2035	-1,665,549	-369
2036	-1,743,601	-384
2037	-1,806,209	-397
2038	-1,870,540	-406
2039	-1,933,005	-417
2040	-2,050,056	-443
2041	-2,149,929	-464
2042	-2,247,846	-484
2043	-2,338,446	-503

At the time of the 2023 MPS, many details regarding the rollout of the Inflation Reduction Act and other federal funding and state programs were unknown. That was still the case at the time MEEIA 4 level DSM portfolio was constructed, as many details continued to remain murky. While the MEEIA 4 portfolio budget and savings were reduced to a great extent from the RAP portfolio, there wasn't an attempt to change how federal tax incentives were treated as was in the 2023 MPS, which did attempt to consider the potential impacts of the tax credits, by reducing the total amount of measure costs (for eligible energy efficiency measures and solar PV) that were covered by a combination of utility incentive and/or tax credits. The implications of these tax credits were included in the base case economic screening and analysis. With a higher percentage of the measure cost being offset, additional measures passed the economic screening. As a result of the inclusion of tax credits in the core analysis, the potential impacts with and without these tax credits is not reported.

Review of Data Center Load Forecasting Best Practices[21]

Ameren Missouri engaged the firm Charles River Associates (CRA) to review current best practices in data center load forecasting; full report can be found in Appendix A. Utilities

[21] File No. EO-2025-0077 1.B

use various approaches to forecasting data center loads and planning for resources to meet their needs. Some limit their projections to contracted or under-construction facilities within their service territory. This approach helps mitigate over-forecasting risk but may underrepresent future capacity needs. Other utilities apply arbitrary derating factors or "haircuts" to data center projects in the pipeline. While this approach attempts to account for uncertainty, it lacks transparency and consistency, making it difficult to benchmark across jurisdictions.

Forecasting Methods

Key data center load forecasting approaches identified are highlighted in the following.

<u>Top-Down adjustment of Commercial Load Class</u> - In this approach, utilities assume that data centers are a subset of the commercial customer class and apply macro-level adjustments to reflect anticipated growth. This method is easier to implement in regions with less data center activity. This method may understate emerging demand.

<u>Bottom-Up deterministic Forecasting</u> - This approach relies on detailed, site-specific information. Utilities use this data to pinpoint when and where facilities will come online and, through segmentation, model their expected electrical demand (MW) and energy usage (MWh) profiles. This method enables highly accurate, location-specific, near-term forecasts. However, it offers limited visibility into long-term trends or unannounced developments.

<u>Stakeholder-Informed Forecasting</u> - Utilities work directly with data center developers, industry associations, state energy offices, and economic development agencies to access semi-public or confidential data under non-disclosure agreements (NDAs). By integrating these insights, utilities can construct more granular and forward-looking forecasts that reflect near-term market dynamics. Even with robust collaboration, data gaps and project attrition risks remain, limiting the completeness and certainty of the resulting forecasts. Increasingly, utilities are also seeing speculative proposals without confirmed end users, reducing data quality and project viability.

<u>Probabilistic Modeling</u> - This forecasting methodology employs probabilistic modeling to simulate a distribution of potential data center build-out scenarios over time. Rather than relying on point forecasts, the model executes thousands of Monte Carlo simulations. This stochastic approach enables planners to quantify uncertainty, assess tail risks, and evaluate system flexibility requirements under a range of plausible futures. This technique is increasingly adopted by utilities operating in high-growth, mature data center markets where deterministic methods fall short in capturing volatility and scale. Rigorous validation, transparent documentation, and stakeholder alignment are critical to ensure credibility and regulatory acceptance.

Planning for Load Growth

IRPs are evolving to account for the temporal mismatch between resource planning cycles and data center project developments. Utilities are increasing the cadence of forecast revisions—moving from biennial or triennial to annual or even quarterly updates.

In response to unprecedented load growth, utilities are rapidly evolving their procurement strategies to ensure system reliability, affordability, and alignment with long-term clean energy goals. Many utilities are also accelerating the addition of dispatchable resources such as natural gas peakers and BESS to address near-term reliability concerns.

Entergy Louisiana is pursuing an expedited route to dispatchable generation, filing directly with the commission in Louisiana for expedited Certificates of Public Convenience and Necessity (CPCN) for two natural gas-fueled power plants. This goes around the traditional IRP process but Entergy argues that it is necessary to meet the immediate and substantial needs of data centers.

As another strategy, utilities are extending the lives of existing assets—particularly coal and gas units—through operational modifications or delayed retirements to ensure sufficient firm capacity while newer resources are developed.

Expanded Demand Side Options

Traditionally, data centers have not considered flexible loads. However, large-scale operators are increasingly exploring Geographic Load Balancing (GLB), where computational workloads are dynamically shifted across multiple sites based on regional grid conditions, energy prices, or carbon intensity. While GLB offers potential for grid-interactive flexibility, its effectiveness is constrained when multiple regions face simultaneous stress, limiting redispatch options. Additionally, some data centers may be exploring partial co-location of backup generation. In these configurations, facilities offset grid demand using on-site generation rather than curtailing load. This could be integrated into broader grid planning frameworks.

Load Queue Management

Effective load queue management enables utilities to organize, prioritize, and evaluate interconnection requests. By identifying project readiness, grouping similar applications, and applying standardized review procedures, utilities can reduce delays, alleviate processing bottlenecks, and ensure fair access for all load customers.

To address the varied approaches to large load integration nationwide, NERC has launched the Large Load Task Force (LLTF) to assess the reliability impacts of emerging large loads on the bulk power system (BPS). The LLTF will begin by identifying the unique characteristics and risks of these loads, then prioritize and validate them. It will also pinpoint gaps in current planning and operational practices.

Risk Mitigation Strategies

Flexible and phased infrastructure investment is a strategic approach utilities are using to manage uncertainty and reduce financial risk associated with large load additions. Rather than committing to large, capital-intensive infrastructure upgrades based on speculative forecasts, utilities are designing systems that can expand in stages as actual demand materializes. This includes deploying modular resources like small gas turbines, reciprocating engines, and battery energy storage systems (BESS) that can be added incrementally.

On the transmission and distribution side, utilities are phasing upgrades to substations, feeders, and lines based on confirmed customer milestones, such as interconnection payments, permits, or construction progress. Some use mobile or temporary substations to provide near-term service while permanent solutions are underway. In substation design, utilities often install only a portion of the full buildout initially but plan for future additions by reserving space, installing expandable equipment, and standardizing design templates. Additionally, each large load customer is required to enter into an electric service agreement (ESA) with Ameren Missouri detailing mutually agreed upon load additions by year to ensure that capacity can be reliably supplied. This form of contract, although not yet formally approved by the MPSC, also provides Ameren Missouri with a potential 5-year period to achieve the customer's full load demand. In other words, Ameren Missouri does not necessarily commit to providing full load demand immediately; Ameren Missouri begins with delivery of a base load and increases the supply of electricity over a potential 5-year period until the customer's full load demand is met. These practices ensure that upgrades can be efficiently scaled as demand grows, without the need for major redesign or permitting delays.

Ameren Missouri is currently using a combination of approaches consistent with those identified by CRA. This includes active engagement with prospective customers regarding site locations, project sizes, expansion plans and ramp schedules, and construction contracts for site interconnection. The Company included plans and contingencies at different expected demand levels in its February 2025 Notice of Change in PRP to account for the uncertainty of demand and the number and types of resources that need to be deployed in the near term to serve different levels of demand. Near-term resources include the kinds of modular resource described above – gas turbines and BESS – to meet demand along with accelerated solar renewable resources to help meet increased energy needs of existing and new customers and also satisfy the clean energy preferences of new large customers, including through new programs proposed by the Company in its Large Load Tariff application.[22]

[22] File No. EA-2025-0184.

3.5 Demand-Side Resource Review

The Company continues to offer energy efficiency and demand response programs. Products available to customers currently include those related to heating and cooling, commercial lighting, smart thermostats, direct install energy efficiency measures, building shell, compressed air, food service, motors, refrigeration, and demand response. Energy efficiency programs have been promoted for both residential and business customers, and programs have been tailored specifically for income eligible customers.

The Company is currently conducting its 2026 Market Potential Study (MPS). The MPS, which gathers primary research data from residential and business customers, is scheduled for completion in the first quarter of 2026 to ensure timely inclusion of results in the development of the Company's 2026 IRP. This study includes portfolio options that are consistent with the MEEIA 4 budget parameters and incorporates updated market research regarding customer adoption and participation.

Similar to the 2023 MPS, the 2026 MPS will estimate the maximum achievable potential (MAP) and realistic achievable potential (RAP) of DSM resources consistent with all applicable rules and regulations. The study will also model and analyze at least one portfolio with budgets and energy and demand savings that are less than those for RAP level portfolio, consistent with the current approved MEEIA 4 plan.

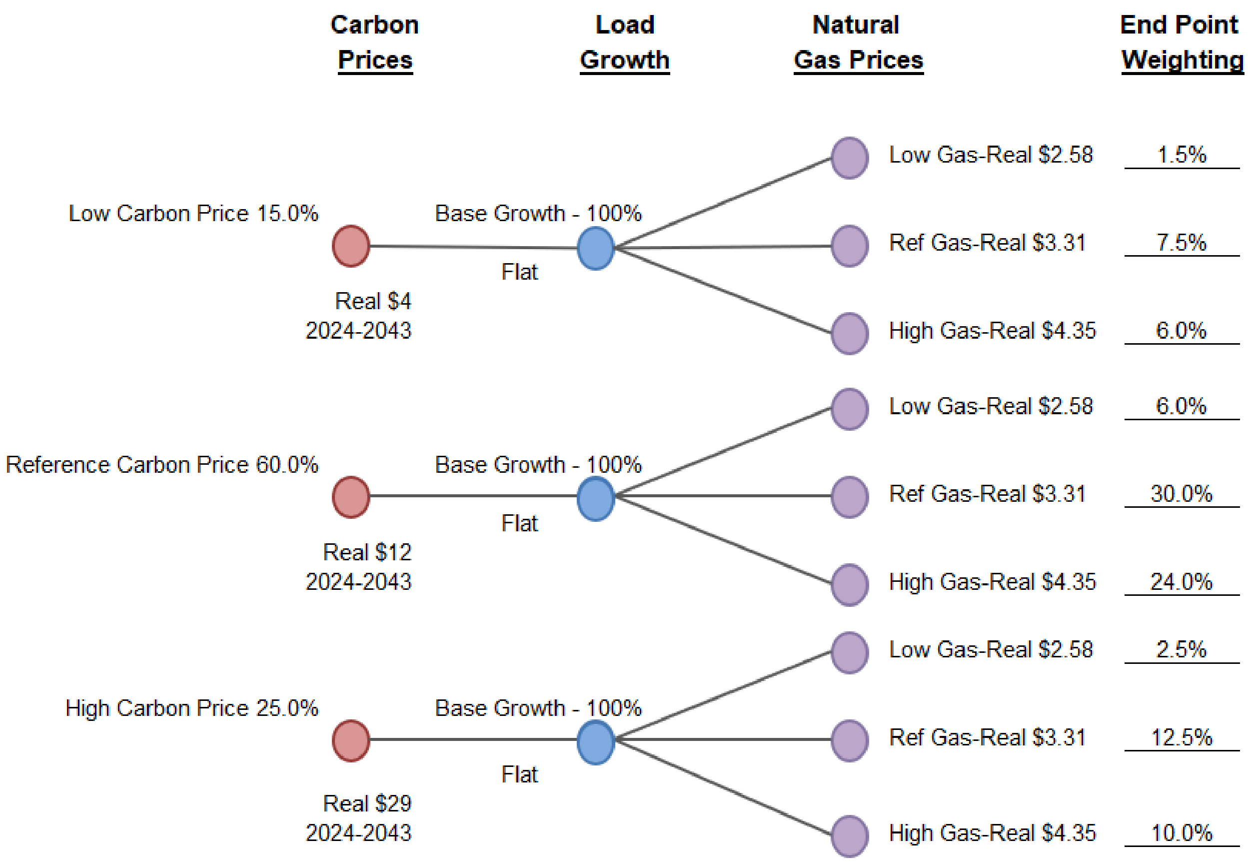
The 2026 MPS will continue to explore the potential of DSM resources to support system operations. This will include estimates of flexible load potential to better match load and supply and estimates of the DSM resource potential available to help reduce load during specific daily or seasonal periods of operational need. This research will continue to support the longer-term development of integrated resource and distribution plans and the evolution towards more targeted DSM measures.

3.6 Uncertain Factors

3.6.1 Price Scenarios

Ameren Missouri is reviewing its assumptions for carbon prices, load growth and natural gas prices, which are the major drivers of power prices for its 2026 IRP filing. As discussed in more detail in this section, for its 2025 Change in PRP filing, Ameren Missouri has determined that its current expectations for the driver variables are still within the ranges established in the 2023 triennial IRP as supplemented with the additional analysis of large load impacts conducted by CRA in 2024 and documented in the Company's February 2025 Notice of Change in PRP. As described in that document, the Company found that inclusion of large loads in price scenarios did not significantly impact the conclusions of the sensitivity analysis included in its 2023 IRP, as discussed in the next section of this report. Figure 3.5 shows the scenario tree and the probabilities of each branch from the 2023 IRP.

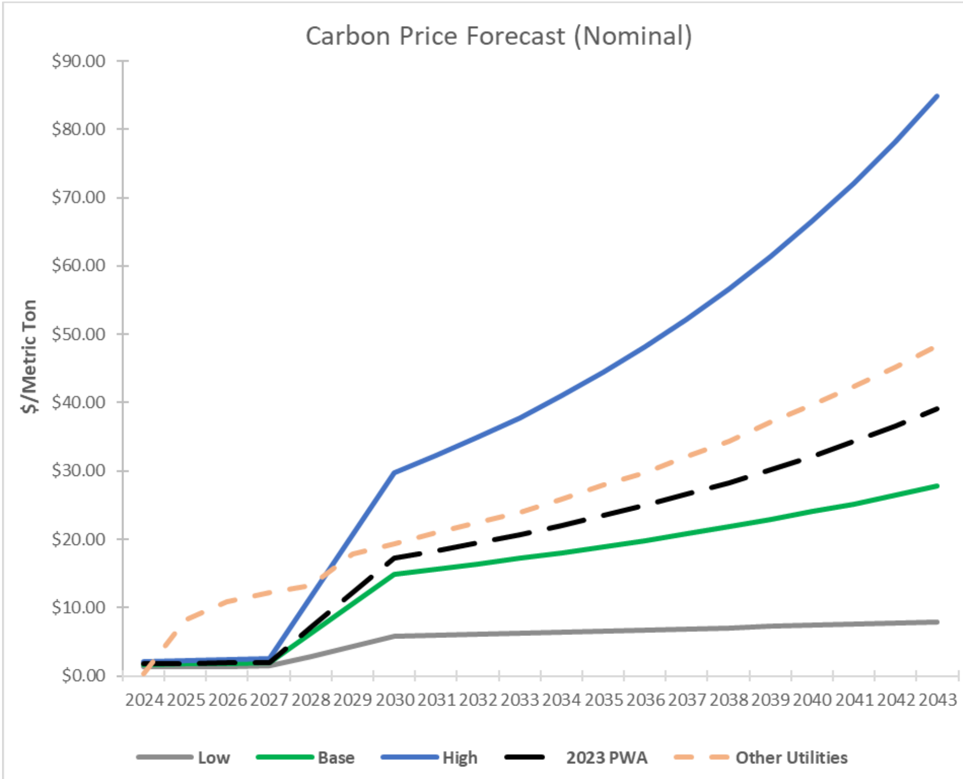
Figure 3.5: Scenario Tree



Carbon Dioxide Emission Prices

For the 2025 Change in PRP filing, the carbon price assumptions from the 2023 IRP were reviewed and found to be reflective of expectations for the future price of carbon dioxide emissions. The Company is currently preparing assumptions for use in the development of its 2026 triennial IRP and has concluded that expected carbon prices are still within the range identified in its 2023 IRP. The carbon price scenarios from the Company's 2023 IRP and the probability-weighted average (PWA) are shown in Figure 3.6.

Figure 3.6: CO_2 Price Assumptions

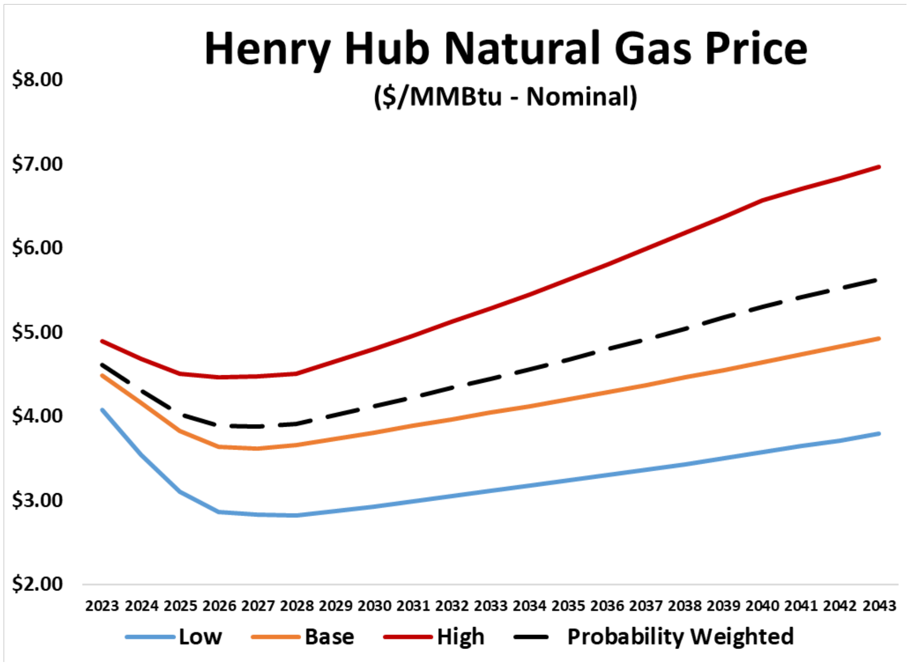


It should be noted that the price assumptions shown do not presume a particular mechanism (e.g., carbon tax, cap-and-trade program, etc.) by which the carbon price is implemented. It can be explicit or implicit and may reflect expectations regarding potential regulations, including those that target other emissions associated with carbon-emitting resources. Ameren Missouri continues to monitor policy proposals and developments that may affect assumptions for carbon pricing.

Natural Gas Prices

Ameren Missouri has also revisited its assumptions for natural gas prices for its 2025 Change in PRP filing. As with carbon prices, the Company is also currently preparing assumptions for use in the development of its 2026 triennial IRP and has concluded that expected natural gas prices are still within the range identified in its 2023 IRP. Figure 3.7 shows the three natural gas price scenarios from the Company's 2023 IRP and the PWA price. Ameren Missouri continues to monitor factors that may affect assumptions for natural gas prices.

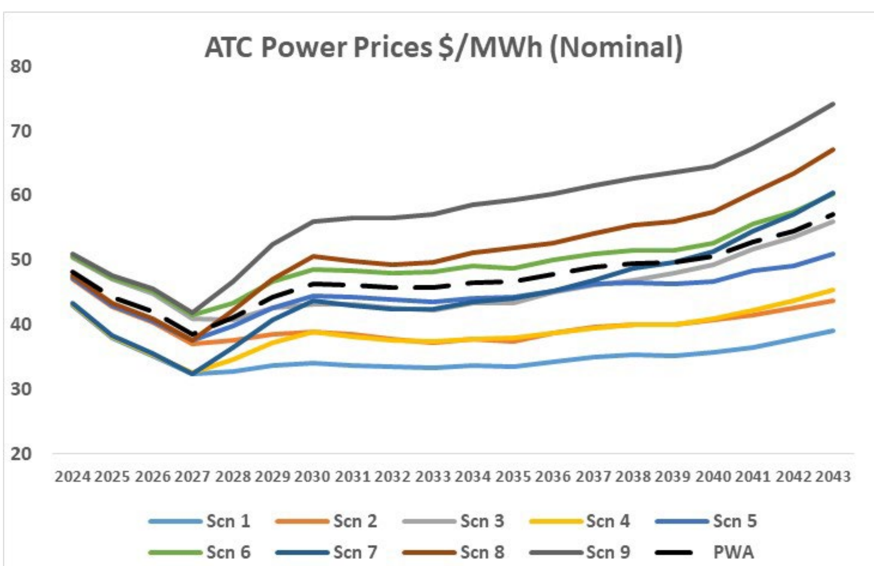
Figure 3.7: Natural Gas Price Forecasts



3.6.2 Scenario Modeling

Since current assumptions for the key driver variables described in section 3.7.1 are within the ranges defined in the 2023 IRP, there is no change to the power price forecasts for the scenarios modeled for the 2023 IRP and probability-weighted average prices, which are presented in Figure 3.8 below. However, and as previously mentioned above, Ameren Missouri has added additional scenarios due to large load additions for its 2025 Change in PRP filing, which is discussed in the next section.

Figure 3.8: **Market Price Scenarios**



Sensitivities for Data Center Load Levels

With the recent surge in data center load potential, not only within Ameren Missouri's service territory but across other regions in the United States, it is important to consider the sensitivity of market prices to the rapid addition of large loads. To evaluate the sensitivity of plan performance to different levels of data center load in the broader Eastern Interconnect and the MISO market, Ameren Missouri contracted with Charles River Associates (CRA) to analyze three scenarios of data center load and provide resultant market prices for energy and capacity. Section 2.5.2 of the 2025 Change in PRP filing shows the data center load for high, middle and low scenarios for both MISO and PJM.

For price scenario modeling, CRA analyzed the following combinations of assumptions using the Company's 2023 IRP scenarios for natural gas prices and carbon prices and load scenarios reflecting the data center load assumptions as follows:

- High Scenario – 2023 IRP high carbon and gas prices, loads with high assumptions for data center additions
- Middle Scenario – 2023 IRP base carbon and gas prices, loads with middle assumptions for data center additions
- Low Scenario – 2023 IRP low carbon and gas prices, loads with low assumptions for data center load additions

The resultant market prices for energy are shown in Figure 3.8, and the resultant capacity prices are shown in Figures 3.9 to 3.11. The sensitivity to power prices is discussed in Section 3.

Figure 3.8: Market Energy Prices for Data Center Load Scenarios

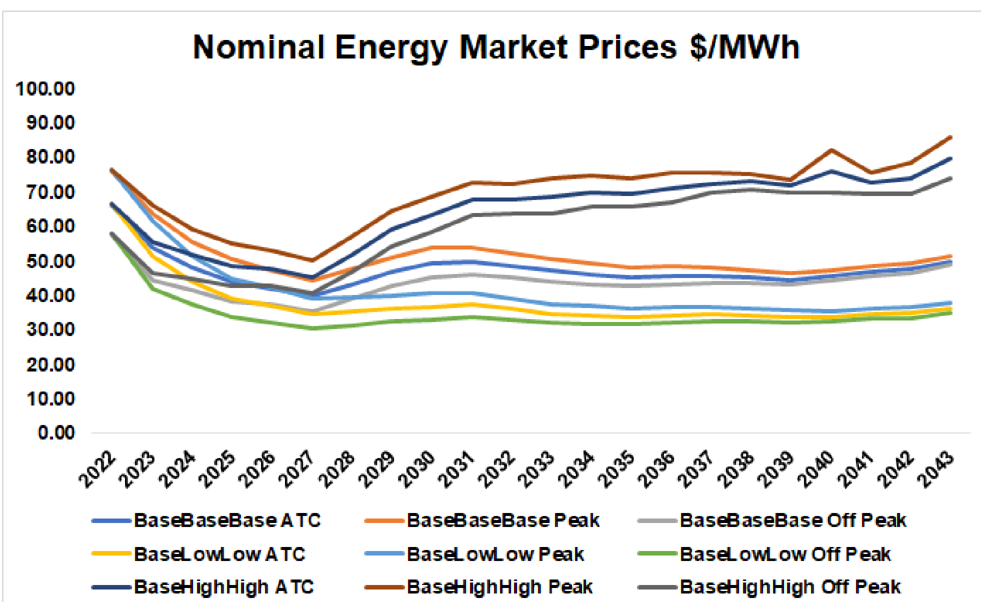


Figure 3.9: Market Capacity Prices for High Data Center Load Scenario

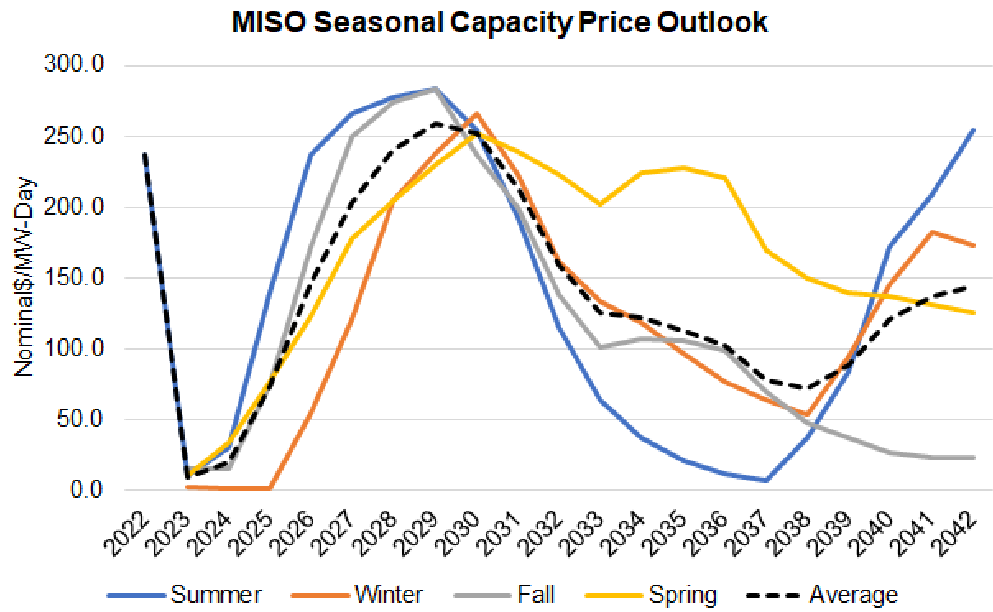


Figure 3.10: Market Capacity Prices for Middle Data Center Load Scenario

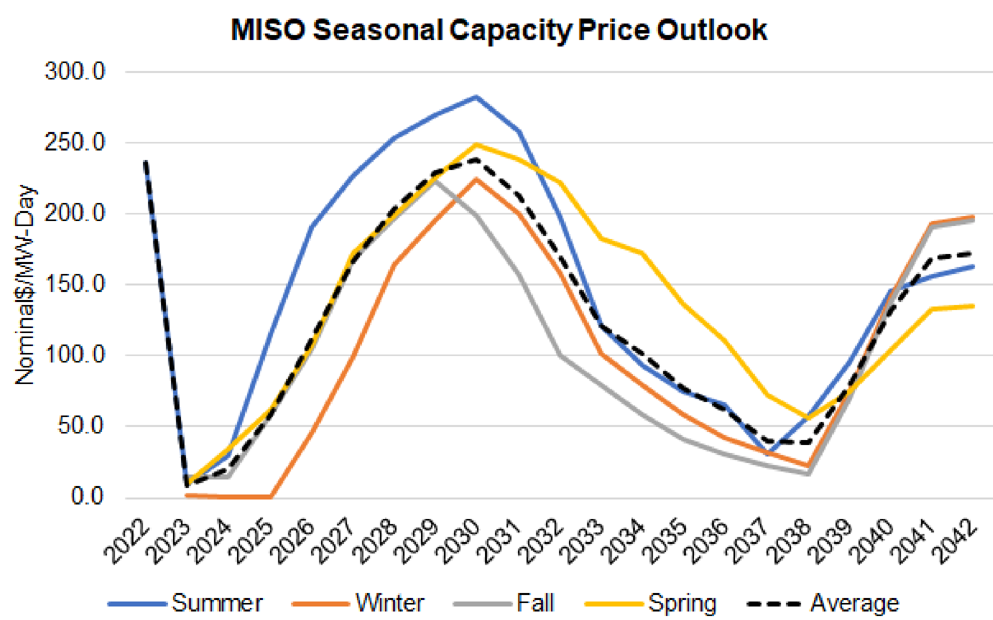
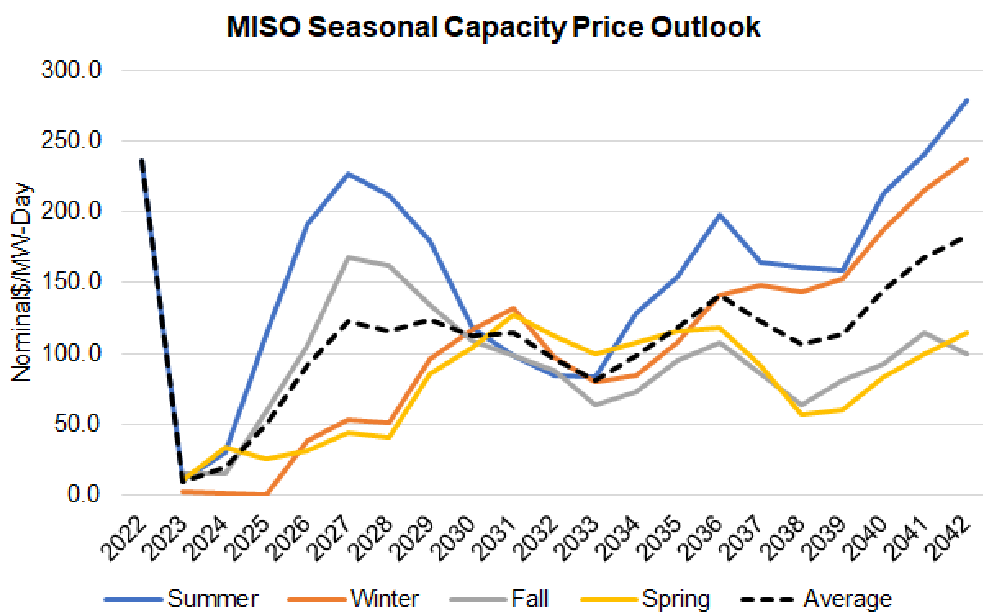


Figure 3.11: Market Capacity Prices for Low Data Center Load Scenario



3.6.3 Independent Uncertain Factors

Ameren Missouri reviewed a broad range of uncertain factors in its 2023 triennial IRP and selected two independent uncertain factors to be included in the risk analysis and presented in the 2023 IRP: project costs and load forecast. The Company reviewed its expectations and previous value ranges for these critical uncertain factors, and determined the percentage deviations for the low-base-high values from the expected values of for project costs are still valid. The low-base-high forecasts for load -not including additional large loads- are also still valid, and Ameren Missouri has included various levels of large load additions in its 2025 Change in PRP filing.

4. Model Considerations

Commercially available capacity expansion models from four vendors were reviewed for available features and capabilities. Anonymized results are presented to protect confidentiality in Table 4.1 below.[23]

[23] File No. EO-2024-0020 2023 IRP Joint Filing Attachment A-NRDC Deficiency 1, NEE Deficiency 2, SC Deficiency 1

Table 4.1: Capacity Expansion Model Comparison

Feature	Vendor 1	Vendor 2	Vendor 3	Vendor 4
Application delivers an automatically selected list of optimized potential expansion resources, sorted by some selection criterion such as NPV.	Yes	Yes	Yes	Yes
Describe the process flow for the various optimization steps.	App uses a mathematical optimization routine to optimize investment, commitment, and dispatch of resources.	Components: Given assumptions on generation and transmission candidates along with retirement candidates, app will provide the optimal portfolio. Production cost module runs the 8760 hourly commitment and dispatch for a defined portfolio. Nodal analysis and resource adequacy analysis are also possible.	Expansion planning calls the 8760-hour production cost run at all levels of the optimization	In the Capacity Expansion step, many combinations of candidate resources are simulated to calculate NPV of revenue requirements. In a production cost modelling step, more granular detail on parameters such as fuel cost, emissions, etc., is produced. In the 3rd step and in a separate program the reliability indices (like LOLE) will be calculated. Combinations will be ranked on PVRR and reliability.
Optimize Emissions	Yes, environmental analysis and compliance	Global or generator limits; sets of generators; seasonal or monthly, daily, etc.	Emissions are likely to be optimized as meeting global annual constraint (e.g., tons) subject to unit level constraint (hours, rolling average, etc.)	This may be done through the capacity expansion model and limiting emissions on a monthly or annual basis or emissions may be controlled through the global constraints model.
Co-optimize with Transmission	Yes, economic, congestion, constraints, shift factors, reliability, seams	Yes	Upcoming feature to add increasing tie limits as a candidate technology	Transmission costs are modelled as additional costs associated with a generation project.
Optimize Fuel Blending	Fuel analysis and optimization	It will optimize resources that use blended fuels; it can be a single unit using different fuels.	Would likely be modeled as different candidate technologies (one with fuel blend "A", one with fuel blend "B")	Fuel blending is optimized in the economic dispatch model that is run before the capacity expansion model.
Optimize retirement dates	Retirements are either age-based (by technology), based on information gleaned from research and first year available for economic retirements.	It will select retirement dates in a plan. Or you can set a date or latest date	Yes, retirements would be modeled as a resource candidate for life extension (extend life = No results in retirement)	Retirements are modeled in a similar way to new assets but instead of there being a capital cost for the new resource, decommissioning costs are considered.
Ancillary services	Can co-optimize energy and ancillary service requirements	It does model most ancillary services	Regulation, spinning, load following, non-spinning requirements are modelled.	Ancillary requirements can be modeled in the capacity expansion model.
Reserve shutdowns	Yes	Yes	Can identify offline months as an input, maintenance dates as an input, or allow App to optimize maintenance periods given unit rates	Reserve shutdowns are not modeled in the capacity expansion model.
Chronological 8760 rather than load duration curve model	Yes, hourly, sub-hourly	Need to use some block dispatch for Capacity Expansion due to run size.	Yes	Yes
Storage logic to handle multiple times per day as well as weeks and seasons	Storage cycling limits would be represented by an energy limit.	Yes	Users can specify cycles per day, month or year.	Batteries or pumped storage can cycle more than once per day in App. App assumes you are free to switch between charge and discharge without

Feature	Vendor 1	Vendor 2	Vendor 3	Vendor 4
				commitment time.
Capture the interplay between storage and renewables	Storage buildout and operation is co-optimized with renewables	Can link wind or solar to charge a battery	Yes	The interplay between storage and renewables is captured though the dispatch of storage resources and price signals.
Model storage characteristics such as degradation	Yes, there is a dedicated section for storage-related inputs. Degradation can be represented with a reduction in the capacity.	You can input time varying capacities; power and or capacity MW degradation; input as rates	Yes	The maximum capacity and efficiencies may be input on time varying basis.
Tie storage charging to a specific technology	Yes, a dependent resource can be assigned to restrict charging sourced from a specific source	Yes	Yes	Yes. There can be POI restrictions set for renewable plus storage such that the storage is forced to charge from the co-located asset.
Capture the variable capacity credit of renewable energy sources	Yes, a declining marginal ELCC curve can be used to represent a reduction in ELCC with increased penetration.	Yes, dynamic capacity accreditation; ELCC surface - portfolio accreditation depends on resource selection;	Yes, expansion planning app models LOLE directly avoiding the need for ELCC or PRM as inputs (targets 0.1 LOLE per year)	The capacity accreditation of resources can vary seasonally based on inputs to the capacity expansion model.
Capture effects of Demand-Response, DER, EVs	Yes, demand-side technologies can be modeled as a load or as a resource.	Yes, can optimize charge/discharge of EV	Yes	The effect of Demand Response and electrification can be captured though either their impact on capacity requirements or energy demand.
Non-linear and negative escalation rates	Escalation rates can be defined for the time series, and the rate can vary over time	Escalation rates can be defined for the time series, and the rate can vary over time	Escalation rates can be defined for the time series, and the rate can vary over time	Escalation rates can be defined for the time series, and the rate can vary over time
Market price forecasting	App includes built-in tools to distribute monthly or annual forecasts for demand and on-peak/off-peak energy price forecasts to the hourly level, using either historical or future hourly profiles.	It could be created.	Can report 8760 hourly market prices by weather year solved portfolio. For the market price forecast, that is the result of the commitment and dispatch in the 8760 production cost run.	App offers price forecasts for MISO, as well as all other major US markets.
Easy data input and output for modelers	Many users set up integration or automation to various internal systems to make repetitive tasks or reporting more efficient.	Yes	Yes	The transfer of data between the dispatch model and the capacity expansion model is handled within the application.
Transparency: Access to inputs and outputs for stakeholders	Application was intentionally designed to make data-sharing amongst stakeholders easier.	Share files.	Yes	A read-only copy of the model can be shared with regulators or stakeholders.
Stochastics	All time series-based data in the application may be treated as an uncertainty variable for stochastic treatment.	Stochastic or deterministic scenarios are possible, can get LOLE stats	Yes, stochastic runs are possible including weather and outage draws.	Weather, load, renewables generation, and prices are varied stochastically.
Risk Analysis	Some examples of risk analysis: App can support portfolio and risk management activities. The flexible resource modeling in the app allows for	Stochastic or deterministic scenarios may be run, can get LOLE stats; an ISO uses for reliability	Yes	Risk is often reported though an at-risk metric like margin at risk, but other metrics are available.

Feature	Vendor 1	Vendor 2	Vendor 3	Vendor 4
	various future technologies and initiatives to be evaluated.			
What is the size of the user base?	More than 50 clients, including utilities, developers, coops, state regulators, environmental advocacy groups, an ISO, as well as consulting/advisory firms	More than 40 clients including IRPs, consultants, and 5 ISO's	A small but growing pool of Capacity Expansion software users.	More than 18 users
Cloud based or local servers?	Application may be deployed on a local machine or local client/server or deployed on the cloud	Cloud is preferred deployment	May be deployed local servers but cloud is preferred	Cloud based deployment only
Automated reports?	Yes, reports can also be automated via scripting.	Can set up various reporting options	Yes	Automated reports are available for capacity expansion.
Data visualization	Yes, data may be visualized in a variety of ways.	Yes	No	App has visualizations for capacity, energy, emissions, new builds, and many other outputs of interest.
How is tech support provided?	Implementation and training are generally provided between a mix of on- site and remote activities. There is a support address and a client portal for accessing documentation and other "self-serve" training materials.	24x5, email or phone, portal	5 Days per week 8 hours per day	Tech support is provided by the analyst team who are experts in both capacity expansion and production cost.
Are scripting/batch runs possible?	Yes, scripting is commonly used for various tasks database management, running simulations or processing results, etc.; Python is a typical language used for scripting.	Use Python or set up runs in interface (need API for Python)	No	Yes
Capture cost of different live alternatives	Economic Carrying Charge End Effects Period Endogenous decision to reinvest at the end of life Automatic replacement	Yes	Yes, inputs may be input as levelized cost ($/kW-yr) to address differing book lives and planning horizon end effects	App allows users to configure many alternatives of resources with different asset lifetimes though which the capacity expansion model can select the optimal combination of resources.
Describe how the software might be used to aid in asset siting	Analyze changes between the two cases such as LMPs, congestion, transmission line flows, curtailment, generator operations and profitability, etc. Capacity Expansion capability of App will forecast on a zonal level the type, timing, and size of proposed resources. Transmission is analyzed in zonal mode as a single link between zones while in the nodal model grid equipment, including generators, transmission circuits, and transformers are modeled at individual buses. Generators of any	App can help evaluate where there is Available Transfer Capacity (ATC) - which nodes have the capability to transfer energy to the rest of the system. App can help evaluate congestion, basis risk, and where good siting locations would be from an economic perspective. What if analysis - you can run scenarios to understand the impact on the system by potentially adding assets to different locations	App can identify the resource mix that achieves reliability and cost objectives, from there we'd recommend our complementary software packages to assist in siting. This would give an idea of thermal injection capacity. There is a model available which is an 8760 representation of the transmission system as well.	App aids in siting assets though economic valuation to demonstrate where there is value in new assets. The app uses the vendor's market Intelligence forecasts (or another provided forecast) to simulate nodal prices and valuation of resources to build the case for the best siting of assets.

Feature	Vendor 1	Vendor 2	Vendor 3	Vendor 4
	technology can be modeled in the zonal or nodal model.			
Program that may also work for other modeling groups	Model has some level of capability to analyze transmission	Model has some level of capability to analyze transmission	Model has some level of capability to analyze transmission	Model has some level of capability to analyze transmission
Intuitive interface making it easy to transition from current model	Each model has an interface, usefulness is in the eye of beholder	Each model has an interface, usefulness is in eye of beholder	Each model has an interface, usefulness is in eye of beholder	Each model has an interface, usefulness is in eye of beholder
Dedicated software support	Each vendor provides tech support	Each vendor provides tech support	Each vendor provides tech support	Each vendor provides tech support
Reasonable model run time	Run times will vary greatly depending on study being run	Run times will vary greatly depending on study being run	Run times will vary greatly depending on study being run	Run times will vary greatly depending on study being run
Straightforward error checking (messaging or other notification)	Each model outputs some sort of error log	Each model outputs some sort of error log	Each model outputs some sort of error log	Each model outputs some sort of error log

5. Grain Belt Express Analysis[24]

Background

On October 17, 2024, Ameren Missouri, Grain Belt Express (GBX) and other parties entered into a stipulation and agreement regarding the Company's application for a CCN for the construction of simple cycle gas turbines at the Castle Bluff Energy Center. The stipulation was approved by the MPSC on October 30, 2024. Included in the stipulation and agreement is a requirement for Ameren Missouri to model and report on plans that include Kansas wind and solar resources delivered to Ameren Missouri's service territory via a High Voltage Direct Current (HVDC) line. Specific requirements for the analysis are:

- Use generic data for Kansas wind and solar resources
- Ownership and delivery cost based on discussion between Ameren and GBX
    - Firm cost or range from GBX within 30 days of final Order in CCN case[25]
- Use the same base year and inflation assumptions for delivery costs for both Kansas resources and MISO resources[26]
- MISO resource delivery costs should include realistic assumptions for tie-line costs and affected system costs[27]

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[24] File No. EA-2024-0237 Stipulation and Agreement paragraph 5.h
[25] A range of delivery costs for Kansas resources was provided to Ameren Missouri by GBX on November 27, 2024.
[26] Ameren Missouri has used 2025 as the base year for both GBX and MISO delivery costs and an annual inflation rate of two percent. Ameren Missouri has used the central value of the range for its analysis.
[27] GBX provided suggested assumptions for tie-line costs and affected system costs on June 26, 2025. Ameren Missouri has used those suggested cost assumptions for its analysis.

The stipulation and agreement also requires Ameren Missouri, either in its supply side resource analysis or in its assessment of alternative resource plans to, "weigh the reliability, resiliency and operational benefits of the HVDC transmission facilities themselves, including but not limited to those outlined in Exhibit 11, Schedule AP-2, Section 6 "Operational Improvement Value of HVDC Resources" in Docket No. EA-2023-0017." Ameren Missouri retained the services of CRA to evaluate the reliability and resiliency benefits of the HVDC line and Kansas resource portfolio, including those benefits outline in the referenced exhibit. CRA's report is attached as Appendix B.

Analysis

Ameren Missouri analyzed four different alternative resource plans including Kansas wind and solar resources delivered via HVDC line into Ameren Missouri's service territory. Each assumes Ameren Missouri ownership of 500 MW of capacity on the HVDC line. Ameren Missouri also analyzed modified versions of its PRP for purposes of comparison to the four alternative resource plans with Kansas resources – these modified PRP plans include the use of generic wind and solar resource costs developed by CRA both with and without production tax credits (PTCs).

The alternative plans with Kansas resources reflect either a total of 500 MW or 800 MW of Kansas renewables to either displace MISO renewables or reduce the size of the first NGCC placed in service in 2032 in the Company's PRP. The sizes of displaced MISO resources were determined based on accredited capacity amounts equal to the assumed accredited capacity of Kansas resources. Capacity accreditations for both Kansas renewable resources and MISO renewable resources reflect the results of a study by PowerGem (formerly Astrapé) and provided by GBX. Capacity accreditation for NGCC is based on MISO's indicative DLOL accreditation estimates for the 2025-2026 planning year. Capacity equivalence between Kansas and MISO resources is based on winter accredited capacity values since Ameren Missouri's capacity needs are determined primarily by needs in the winter season. When substituting Kansas solar resources for MISO solar resources, the same gross capacity value was used since the PowerGem accreditation results attribute essentially zero accredited capacity value to solar in the winter season. All resources receive capacity revenue in all seasons, with Kansas resource accreditations based on the aforementioned PowerGem study. Table 5.1 summarizes the additions/displacements by each plan analyzed.

Table 5.1: SPP vs MISO Resources

Installed Capacity (MW)	Addition Kansas Resources		Displacement MISO Resources		
	Wind	Solar	Wind	Solar	CC
A-2025 PRP B-2025 PRP-Generic MISO Rnwb Costs	Not Applicable		Not Applicable		
C-GBX-500MW KS Rnw Replacing MISO Rnw	375	125	483	125	-
D-GBX-800MW KS Rnw Replacing MISO Rnw	600	200	773	200	-
E-GBX-500MW KS Rnw Replacing CC	375	125	-	-	163
F-GBX-800MW KS Rnw Replacing CC	600	200	-	-	261

For plans D and F, additional revenues from energy sales to SPP were included in order to account for sales to SPP when generation from Kansas renewables exceed the HVDC line capacity and cannot be delivered to MISO.

To reflect the avoided costs of assumed tie-line and affected system costs for MISO resources in plans C, D, E, and F, Ameren Missouri included a reduction in transmission costs as a partial offset to the investment in the HVDC line.

Plans were analyzed with and without PTCs for resources placed in service after 2027. Table 5.2 summarizes the present value of revenue requirements (PVRR) of each plan analyzed and differences from the Company's preferred resource plan with and without PTCs using generic capital costs for MISO wind and solar[28]. Adding the GBX HVDC line and replacing MISO renewables or NGCC with SPP renewables results in higher cost to customers by **[redacted]** relative to the Company's PRP adjusted with generic costs for MISO renewables.

Ameren Missouri has included revenue for sales into SPP when resource delivery is constrained by the HVDC line. Additional costs and revenues related to potential price arbitrage opportunities between MISO and SPP have not been included in the analysis results. GBX has provided evidence from SPP that injection into SPP from GBX-connected resources could cost between zero and approximately $100 million for up to 2,500 MW. CRA estimated price arbitrage value to Ameren Missouri of approximately $33 million based on a 50/50 sharing of margin opportunity with affected generators.

[28] Capital costs changed for 800 MW wind and 200 MW solar.

Table 5.2: Analysis Results - PVRR & Difference from PRP with Generic MISO Costs

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In addition to the potential for higher accreditation of Kansas wind and solar resources, GBX has asserted that it may also be possible that the HVDC line itself could receive accreditation value from MISO for its ability to deliver energy from SPP at times when MISO would otherwise be short of meeting its load requirements, SPP has available energy to sell into MISO, other paths into MISO are constrained, and the HVDC line has available capacity. While accreditation for transmission lines is not part of current industry practice and would require approval from FERC, Ameren Missouri has estimated the potential benefit of line accreditation based on the aforementioned PowerGem report and assuming displacement of accredited capacity in MISO. Based on the PowerGem report, the 2,500 MW HVDC line into MISO could receive a stand-alone accreditation of 500 MW. Using the same 500 MW line ownership by Ameren Missouri assumed for the analysis above, that would yield 100 MW of additional accredited capacity for Ameren Missouri in meeting its resource adequacy obligation. This then translates into a potential reduction of NGCC capacity of 117 MW and an associated reduction in NPVRR of approximately **________**. As is evident from the results shown in Table 5.2, including this benefit would still result in a higher cost to customers from the displacement of MISO resources by Kansas resources **________________________**.

Conclusions

Based on the Company's analysis, the economics of generic Kansas renewable resources delivered by HVDC do not appear to provide net benefits to customers based on the assumptions used in the Company's analysis, many of which were provided by GBX. Accreditation for resources by MISO continues to evolve, and the accreditation of resources external to MISO remains uncertain. The potential for ascribing accredited capacity to transmission lines alone, HVDC or otherwise, appears to be far less certain. Even accounting for these uncertain benefits, the Company's analysis indicates that displacing MISO resources with Kansas resources and including reasonable costs for delivery would result in a significant increase in costs to customers.

6. Compliance References

File No. EA-2024-0237 Stipulation and Agreement paragraph 5.h 51
File No. EO-2024-0020 2023 IRP Joint Filing Attachment A 47
File No. EO-2025-0077 1.A 1-5 34
File No. EO-2025-0077 1.B 37
File No. EO-2025-0077 1.C 34
File No. EO-2025-0077 1.D 17
File No. EO-2025-0077 1.E 18
File No. EO-2025-0077 1.F 31
File No. EO-2025-0077 1.G 32
File No. EO-2025-0077 1.H 21
File No. EO-2025-0077 1.I 17