Integrated Resource Plan Update

2024

Ameren
MISSOURI

1. Executive Summary

Ameren Missouri continues to execute on the preferred resource plan presented in its 2023 Integrated Resource Plan filing. 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, retiring one of our two remaining coal-fired energy centers by the end of 2032,[1] accelerating the retirement of 1,800 MW of gas-fired peaking generation, including generation affected by environmental laws, 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 2033, accelerating our expansion of renewable generation, with the addition of 2,800 MW of renewable generation by 2030 and reaching total wind and solar generation of 5,400 MW by 2036, and deploying 800 MW of battery energy storage by 2035. Extensive analysis has been performed and reported in the 2023 IRP to ascertain our plan meets our customers' needs reliably in all hours and under all conditions.[2] 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:

- Acquired certificates of convenience and necessity (CCN) and started construction on 550 MW of new solar energy resources: Split Rail Solar (300 MW), Vandalia Solar (50 MW), Bowling Green Solar (50 MW), and Cass County Solar (150 MW). Cass County Solar will be used to support customer subscribers through the Company's Renewable Solutions Program. When completed, these additions will bring the Company's total solar generation to more than 900 MW.
- Filed an application with the Missouri Public Service Commission (MPSC) for a CCN for the 7 MW New Florence Solar Facility to support Ameren Missouri's Community Solar Program.
- Oversaw construction at three new solar facilities: Boomtown Solar (150 MW), Huck Finn Solar (200 MW) and Cass County Solar (150 MW), which received

[1] The Rush Island Energy Center will retire by October 15, 2024, as required by an order from the United State District Court for the Eastern District of Missouri.
[2] File No. EO-2024-0042 1.C; File No. EO-2024-0042 1.D

regulatory approval in 2023 and 2024, respectively. All projects are expected to be operational by the end of 2024.
- Issued a request for proposals (RFP) for wind project bids to continue building out Ameren Missouri's pipeline of available regional wind projects.
- Filed a CCN application with 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.
- 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 to provide customers with the ability to manage their use of energy and reduce their energy bills.
- Filed an application with the MPSC to continue its demand-side management programs pursuant to the Missouri Energy Efficiency Investment Act (MEEIA).
- Continued steps to retire Rush Island Energy Center in October 2024, 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 $3.6 billion of electric infrastructure investments from 2024 through 2028 that, among other things, accelerates our upgrades of aged infrastructure, invests in smart grid technologies, and supports 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 further refined its IRP analysis reflecting MISO's seasonal resource adequacy construct in supporting the Company's 2023 IRP. Ameren Missouri has also continued to perform more detailed reliability analyses in support of its preferred plan with the help of 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.
- Possibility of higher load growth – Mainly due to developments in artificial intelligence, there has been a significant and rapid increase in requests for electricity service, which may result in load growth that has not been realized in

decades. Ameren Missouri is evaluating the requests it has received to date and will determine what additional resources may be needed to provide reliable service to an expanding customer and load base.

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 our preferred plan 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. Compliance Overview

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-2024-0042 establishing special contemporary issues for Ameren Missouri's 2024 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 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 2023 IRP filing, is still appropriate at this time. Should the Company's continued planning and consideration of relevant issues lead to a conclusion that its Preferred Resource Plan is no longer appropriate and should be replaced with a new Preferred Resource Plan, 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 preferred resource plan with its 2023 Integrated Resource Plan filing. In that filing, the Company re-affirmed that its new Preferred Resource Plan includes the addition of 2,000 MW of new wind generation and 2,700 MW of new solar generation and implementation of energy efficiency and demand response programs, as well as continued pursuit of demand side management (DSM) programs throughout the entire planning horizon at the Realistic Achievable Potential level. 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 2023 IRP 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.[3]

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.[4] Figure 2.1 provides the incremental annual net demand load 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 low-income 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). Combined, approvals in EO-2018-0211 represent the largest commitment to DSM in the state of Missouri to date.

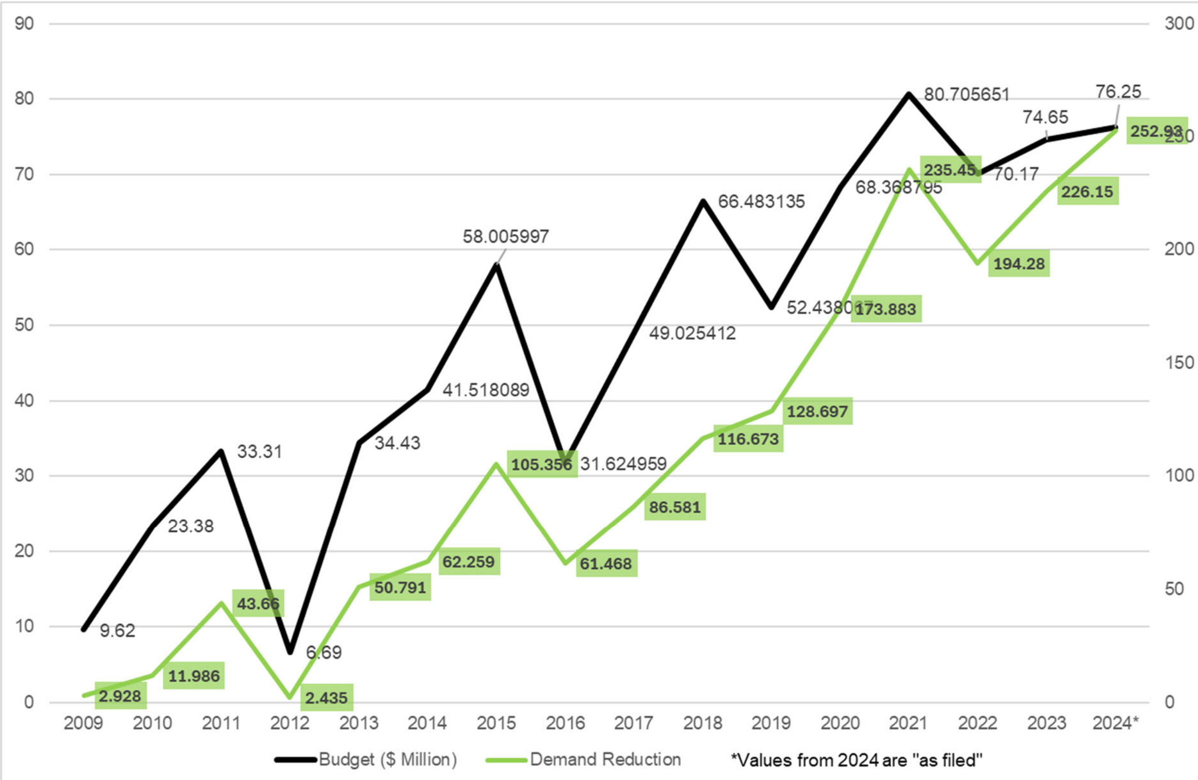
Following negotiation with key stakeholders, an extension to MEEIA Cycle 3 for Plan Year 2024 stipulation and agreement was approved in September of 2023 with the intention to continue negotiation on MEEIA Cycle 4.

Ameren Missouri filed an amended MEEIA 4 application (EO- 2023-0136) on January 25, 2024. The amended MEEIA 4 application, which is in alignment with the DSM portfolio in the Company's current preferred plan, is currently before the Missouri Public Service Commission.

[3] The Commission has provided additional guidance, noting that utilities should "be endeavoring to increase customer participation in energy efficiency programs" and recognized that "benefits from a reduction in a customer's bill is not the only benefit to customers. There are also societal benefits, such as improved health and safety, investment in local economies, and local job creation." See File No. EO-2019-0132, Final Report and Order dated December 11, 2019, at ¶ 36 and ¶ 39.

[4] 2012 served as a "bridge" year, between the Company's pre-MEEIA programs and the Company's post-MEEIA programs.

Figure 2.1: Annual DSM Program Budgets and Net Demand Reductions



Note: The *2009 to 2023 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 has successfully implemented five years of this program cycle, for 2019 thru 2023[5], meeting or exceeding its portfolio savings targets in the first three years and falling short of its targets in its 4th and 5th years. Table 2.1 and Table 2.2 provide the final net energy and demand savings, respectively, as determined by the independent evaluator, Opinion Dynamics.

Table 2.1: Net Energy Savings Compared to Goal, 2019-2023 (MWh)

	2019			2020			2021			2022			2023		
	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%
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%
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%
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%

[5] 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, 2019-2023 (MW)

	2019			2020			2021			2022			2023		
	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	2	51%	5	4	80%	4	6	162%
Residential	57	53	92%	74	77	104%	49	54	110%	26	20	76%	23	19	83%
Business	44	72	162%	89	91	101%	52	46	87%	40	32	80%	34	26	78%
Portfolio Total	104	126	121%	167	171	102%	106	102	96%	71	56	79%	60	51	85%

Opinion Dynamics found that these programs delivered net lifetime benefits to customers of more than $174, $205, $184, $127, and $131 million in 2019, 2020, 2021, 2022 and 2023, respectively, as measured by the Total Resource Cost (TRC) test.

These programs incentivized:

- Over 10.9 million residential LED bulbs
- Over 75,000 residential HVAC systems
- Over 109,000 residential learning thermostats
- Over 60,000 school kits
- Measures at over 10,000 income eligible homes and tenant units, and
- Over 12,300 projects at commercial and industrial facilities.

Opinion Dynamics 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:

- In January 2021 the Company launched its new 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 this innovative new program through 2024. In 2022, the Company launched co-delivery of the program with natural gas utilities.

- Beginning in 2022, the Company transitioned its residential lighting program to become a dedicated low-income program, with the specific purpose of reducing the gap in the penetration and saturation of LED lightbulbs between market rate and low-income customers. This gap was first identified in the 2020 Market Potential Study. The targeted community lighting program provided discounted bulbs in community retailers, in zip codes within the Ameren Missouri service territory where at least 30 percent of the population is at or below 200 percent of the Federal Poverty Level as defined by the U.S. Census Bureau American Community Survey. The community lighting program was discontinued at the end of 2023, in conjunction with EISA legislation updates.
- In 2020, the Company launched a new residential midstream HVAC program. The midstream program provides rebates directly to equipment distributors for high efficiency units (defined as those central air conditioners or heat pump units with a seasonal energy efficiency rating (SEER) greater than 18), with the intent to drive changes in stocking patterns and help accelerate market transformation. Opinion Dynamics found that distributors "have already made stocking changes and are also optimistic, expecting to make even bigger stocking changes next year."[6]

Renewables

Ameren Missouri continued to oversee the construction at its Boomtown and Huck Finn Solar Energy Centers, which received regulatory approval in 2023. Both projects are expected to be in service by the end of 2024. Ameren Missouri also filed a CCN application with the MPSC for a 7 MW solar project to support its Community Solar Program.

Ameren Missouri acquired CCNs and started construction on 550 MW of additional new solar energy resources: Split Rail Solar (300 MW), Vandalia Solar (50 MW), Bowling Green Solar (50 MW), and Cass County Solar (150 MW). Cass County Solar will be used to support customer subscribers through the Company's Renewable Solutions Program. When completed, these additions will bring the Company's total solar generation to more than 900 MW. The Cass County facility is expected to be in service by the end of this year.

Ameren Missouri recently 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. Ameren Missouri is currently evaluating the project bids received as part of this RFP. The

[6] See Opinion Dynamics, "Ameren Missouri Program Year 2020 Annual EM&V Report. Volume 2: Residential Portfolio Report", June 10 2021, at p. 33.

Company expects to file several CCN applications annually as competitive wind and solar projects are developed and acquired on behalf of our customers.

Gas-Fired Generation

Ameren Missouri filed a CCN application with 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. That request is currently before the Commission. Commercial operation is expected to commence by late 2027.

Rush Island Energy Center

The Company has been operating the Rush Island Energy Center as necessary to support grid reliability as outlined by MISO and agreed upon by the U.S. District Court while also implementing the required transmission system upgrades for the retirement of the energy center. The energy center is scheduled to retire in October 2024.

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. Similar projects are being constructed at Sioux and Labadie Energy Centers.

3. Planning Environment

3.1 Environmental Regulations

Ameren Missouri has reviewed its assumptions on the eventual requirements for pending environmental regulations. Table 3.1 summarizes the current and pending environmental regulations for which Ameren Missouri may need to implement mitigation measures, along with expectations for compliance requirements for certain potential 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.

Table 3.1: Current & Pending Environmental Regulations

Regulatory Driver	Summary Requirements	Regulation Status	Compliance Timing
Current CSAPR Regulation	Created Group 3 Ozone Season Allowance Program for 12 states including IL reducing NOx ozone season banked allowances and allowance allocations for IL sources	Revised CSAPR Update was published on 4/30/2021 and went into effect on 6/29/2021. The rule reduces seasonal NOx allocations for IL EGUs for the 2021 ozone season and again in 2022 and 2023.	2021 ozone season and beyond
CSAPR for 2015 Ozone Standard	Requires 23 eastern states (including MO) to reduce emissions that contribute to pollution in other states through SIPs or newly promulgated FIPs.	The final pre-publication rule was published in March, 2023. The final rule was published in the FR during summer, 2023. The SIP Disapproval was stayed in the 8th circuit court for Missouri; therefore, the FIP is on hold.	Stayed
Revisions to National Ambient Air Quality Standards (NAAQS)	Lower PM, NOx and SO_2 limits; Expansion of non-attainment areas	SO_2 final rule June, 2010; EPA proposed redesignation from "unclassifiable" to attainment for area around Labadie based on 2017-2019 data; Redesignation of Jefferson County to Maintenance on 1/28/2022	SO_2: 2017-2020
		Fine particulate (PM2.5) lowered 1/15/2013; Attainment designations 03/2015; Missouri in attainment. EPA retained the current 12 mg/M3 standard in 2020. EPA created new standards in February 2024, lowering the standard to 9 micrograms per cubic meter.	PM2.5: 2028-2032
		Ozone standard lowered, final rule 12/2015;	EPA proposed to retain standard in 2020
		St. Louis/Metro East area bumped up to Moderate nonattainment on 10/7/22. Expected bump up to Serious nonattainment after 2024 ozone season. In August 2024, EPA proposed disapproval of the MO Good Neighbor SIP Supplement.	EPA proposed to retain standard in 2020; GNS litigation ongoing and disapproval of MO GNS stayed by 8th Circuit.
Mercury and Air Toxics Standards (MATS)	Reduction in emissions of Mercury, HCl (proxy for acid gases) and particulate emissions (proxy for non-mercury metals)	New rule update finalized in May, 2024. The rule lowers the standard to .010 μg/m3	Estimated to be 2028
Clean Air Visibility Rule (CAVR)/Regional Haze Rule	Targets reductions in transported SO_2 and NO_x	On July 3, 2024, EPA published in the Federal Register, a proposal to partially disapprove Missouri's State Implementation Plan (SIP) for the regional haze second implementation period.	EPA's Proposed Disapproval of Missouri Regional Haze Plan, if finalized, is the prerequisite for EPA to promulgate a federal plan (within 2 years).

Regulatory Driver	Summary Requirements	Regulation Status	Compliance Timing
Clean Water Act Section 316(a) Thermal Standards	Implementation through NPDES permit conditions	Evaluation covered by NPDES permits	New thermal requirements implemented at Labadie; other plants contain similar requirements in existing NPDES permits.
Clean Water Act Section 316(b) Protection of Aquatic Life	Case-by-case determination of controls required to meet entrainment standards; national standard for impingement	Studies 2015 - 2017; Compliance 2022 - 2024	Labadie NPDES Permit required intake modifications are in-progress. Other Plants NPDES permit requirements to be determined.
Waters of The United States (WOTUS)[7]	Protection of additional streams and tributaries	The EPA and Corps of Engineers finalized revisions and issued the Navigable Waters Protection Rule: Definition of "Waters of the United States".	Final rule recently modified to reflect Supreme Court Sackett Decision.
Revisions to Steam Electric Effluent Limitations Guidelines (ELG)	Dry ash handling and Installation of wastewater treatment facilities; Implemented through NPDES permit conditions	In May, 2024, the EPA issued updates to the ELG rule affecting FGD wastewater, BATW, and CCR leachate.	All major ELG required modifications now complete.
Coal Combustion Residuals (CCR)	Conversion to dry bottom ash and fly ash; Closure of existing ash basins; Dry disposal in landfill	Final determination that CCRs are nonhazardous by EPA in December 2014; final rule April 2015, effective October 19, 2015. Federal legislation (WINN Act) to revise rule signed December 16, 2016. In May, 2024, EPA finalized the CCR Legacy rule, affecting certain legacy impoundments and CCRMU's.	Basin closures and corrective measures in process. Completion in advance of regulatory deadline.
Clean Air Act Regulation of Greenhouse Gases (GHG)/Affordable Clean Energy Rule (ACE)	New Source Performance Standard (NSPS) for new, modified, reconstructed units; state emission limits (CO_2) for existing sources	Clean Power Plan final rule was stayed by Supreme Court 2/9/2016; DC Circuit Court dismissed CPP case in September 2019. On April 25, 2024, EPA issued final actions under Clean Air Act (CAA) section 111 applicable to greenhouse gas (GHG) emissions from power plants.	Various dates; see detailed discussion below.

[7] In the recent Sackett vs EPA decision, the US Supreme Court held that *"the CWA extends to only those "wetlands with a continuous surface connection to bodies that are 'waters of the United States' in their own right," so that they are "indistinguishable" from those waters."* Ameren Missouri will continue to review how this new ruling may affect the current WOTUS regulations.

Clean Air Act Regulation of Greenhouse Gases/Affordable Clean Energy Rule

On June 30, 2022, the Supreme Court of the United States (SCOTUS) issued a ruling regarding the Environmental Protection Agency (EPA)'s authority with respect to how it regulates greenhouse gases under a specific section in the Clean Air Act (West Virginia v. EPA). The June 30th opinion in West Virginia v. EPA held that the Clean Power Plan (CPP), which relied on generation shifting to set GHG standards, is unlawful. However, it retained EPA's threshold authority to regulate GHGs under Section 111(d) of the air law. In May 2023, EPA announced new rules focused on reducing greenhouse gas (GHG) emissions from power plants. These new rules are included under the Clean Air Act Sections 111 (b) & (d), affecting new and existing fossil generation. Ameren submitted comments to the EPA in August 2023. 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, including a stay request currently pending before the Supreme Court of the United States. The rules for existing coal plants base the operational compliance requirements on planned retirement date of the plant:

- Operation beyond January 1, 2039 - requires emissions reductions equivalent to 90% CCS by 2032.
- Coal fired steam units retiring between 2032 and 2039 - require CO_2 emissions reductions equivalent to 40% natural gas co-firing by 2030.
- Coal plants retiring by 2032 - no additional regulations.

For new natural gas fired combustion turbine units, the rule has different categories for compliance. Specifically, the new gas unit rules establish three categories of units based on unit capacity factor or how much the gas units will operate:

- Low load < 20% of maximum annual capacity; intermediate load-between 20-40% capacity; and base load units > 40% capacity.
- Low and intermediate loads are subject to low emitting fuels and efficient design of the units.
- New base load gas units, however, will require 90% carbon capture and storage (CCS) by 2032.

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

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 is 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 of 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. In all, twelve states 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). The rule applied to 23 states. The rule took effect 60 days after publication in the Federal Register. The changes to the rule applied to 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. While the DC Circuit denied a stay request, it agreed to an expedited review of the rule. The Supreme Court, however, granted a stay request as a result of the numerous circuit court stays of the pre-requisite EPA disapprovals of state good neighbor plans. If the FIP is eventually implemented in Missouri, additional control technologies and/or reduced dispatch could be necessary as it was modeled and discussed in the 2023 IRP.

Attainment Designations for NAAQS for Ozone

The St. Louis area was designated as marginal with a marginal area attainment date of August 2021. Based on the 2018-2020 design value the St. Louis area failed to attain the 2015 standard and a bump up to moderate non-attainment was expected. However, because the St. Louis area 2019-2021 design value met the 2015 standard, Missouri DNR submitted a redesignation request in January 2022. Illinois EPA was working on a similar request for the Illinois portion of the St Louis non-attainment area. Unfortunately, prior to Illinois EPA's submission, 2022 ozone data indicated that the St. Louis Area ozone design value for 2020-2022 would show non-attainment. As a result, EPA bumped up the St. Louis Ozone non-attainment area to moderate nonattainment in 2022. Because the 2021-2023 design value (and the 2022-2024 design value) also shows non-attainment, the St. Louis Area has failed to attain the 2015 Ozone standard by the August 2024 moderate area attainment date. As a result, it is expected that EPA will "bump up" the St. Louis Area to Serious Non-attainment shortly. The bump up to Serious will result in a new attainment date of August 2027 and a reduction in the major source thresholds for PSD and Title V purposes. After the bump up to serious, the major source level for NO_x emissions will be 50 tons per year (down from 100 tons per year).

On August 6, 2024, EPA published in the Federal Register, at 89 Fed. Reg. 63,860, a proposed rule disapproving Missouri's Supplemental Good Neighbor State Implementation Plan submission with respect to the 2015 8-hour ozone NAAQS.

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 entered into an agreement in 2015 to install an ambient SO_2 monitoring network in the vicinity of the Rush Island Energy Center. The agreement also includes lower SO_2 emissions limits for the Rush Island, Labadie and Meramec Energy Centers that took effect on January 1, 2017.

EPA has been taking steps to complete the designation process for the SO_2 ambient standard. The EPA entered into a consent order with the Sierra Club and the Natural Resources Defense Council on March 2, 2015, and also finalized the "Data Requirements Rule" on August 21, 2015. In September 2015, the MDNR recommended that the area around the Labadie Energy Center be designated as unclassifiable. In April 2015, Ameren Missouri began operating SO_2 ambient monitors to determine whether the area is in compliance with the SO_2 air quality standard. 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 re-designate the area around Labadie from unclassifiable to attainment. The EPA is expected to finalize the re-designation 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 as well as expected steps necessary to comply with CSAPR.

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 National Ambient Air Quality Standard (NAAQS) from 12 µg/m3 to 9 µg/m3. The revised standard is being challenged in court. %

Based on recent PM2.5 monitoring in the metro St. Louis Area, the St. Louis area will be designated a non-attainment area for the 2024 PM2.5 standard. As a result of a non-attainment designation, Reasonably Achievable Control Technology (RACT) for Particulate Matter (PM 2.5) and precursors (NO_x/SO_2) would be required by the State of Missouri as part of an attainment plan that is required to be submitted to EPA for approval by February 2027.

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 Missouri Department of Natural Resources (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 State Implementation Plan for the regional haze second implementation period.

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. This new rule is not expected to materially affect Ameren'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 is currently in the process of identifying consultants to assist the Company in the facility reviews required by the Rule. The rule is currently being challenged judicially. Ameren 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 basin will be closed by the end of 2026. Closure of the original gypsum pond at Sioux Energy Center is underway and scheduled to be completed by the end of this year. The closure of the ash ponds will reduce our consumption of approximately 11 billion gallon of water per year.

3.2 Supply-Side Resource Review

Ameren Missouri has analyzed the cost and performance characteristics of a wide range of supply side resources in its 2023 IRP and has documented its analysis in Chapter 6 of its 2023 IRP filing. New supply side resources that were evaluated in the alternative resource plans in the 2023 IRP include the following:

- Gas Combined Cycle
- Gas Simple Cycle Combustion Turbine
- Wind
- Solar
- Pumped Hydroelectric Energy Storage
- Battery Storage
- Nuclear

Ameren Missouri has reviewed its assumptions for generating resources and determined that, at this time, the 2023 triennial IRP assumptions are still appropriate.

Development and construction activities related to renewable energy projects remain robust. Ameren Missouri continues to monitor changes in the market for renewable energy projects, both through its own engagement with developers and through evaluation of secondary information sources. While the assumptions for both wind and solar costs are expected to decline, future costs are subject to certain risks as explained in the Company's 2023 IRP filing.

As in other areas of the country, Ameren Missouri is seeing activity in potential new datacenter loads that could meaningfully alter generation resource plans. Data centers require around-the-clock power, and could have a substantial impact on generation planning, especially regarding dispatchable resources that can supplement renewable generation to reliably meet the constant load.

Mothballing Analysis[8] – In response to the Missouri Public Service Commission request for special contemporary resource planning issues, Ameren Missouri analyzed and produced a cost estimate to mothball a generation unit. With the Rush Island retirement in 2024 and the Sioux retirement scheduled for 2032, the analysis focused on estimated costs to mothball Labadie Unit 3. A three-year timeframe was chosen for layup, since the unit would be considered retired after that time frame, and our MISO Interconnection Rights would expire. Costs to mothball additional Labadie generation unit(s) are expected to be similar, but further analysis would be required as common site costs would be allocated between mothballed and operating units.

Using several EPRI references, including a system-specific mothball matrix, three phases of the mothball process were analyzed - Shutdown, Layup, and Restart. Cost estimates were developed for each phase. The Shutdown phase includes extensive cleaning and draining/drying out activities. Layup phase includes one-time equipment costs for dehumidification equipment and piping as well as the labor required to install, operate, and maintain this equipment. The Restart phase consists of various restoration activities and was estimated to require a minimum of 3 months but could take longer to complete. Contingency estimates were added to each phase to cover miscellaneous activities and requirements. The high-level estimate to mothball Labadie U3 is shown in Table 3.2.

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[8] File No. EO-2024-0042 1.B

Table 3.2: Mothballing Costs for One Unit

Cost Category	$Million
Unit Shutdown	$ 3
Layup - Equipment (one-time cost)	$ 2
Layup - Labor (3 years)	$ 5
Restart	$ 4
Total	**$ 14**

Mothballing a large industrial facility is a complex task. Taking one unit out of service does not result in idling one-fourth of the equipment at a site. Since many common units must remain in service, mothballing a fraction of the units at the site adds to the incremental O&M cost of the units remaining in service at the site. This ultimately results in less market opportunity for the remaining units if the non-fuel component is considered.

Even with a well-planned and well-engineered layup plan, many risks will still be evident with mothballing a unit. The dehumidification equipment and associated piping will not be 100% effective in preventing moisture infiltration into the critical Boiler and Turbine-Generator Systems, and it will be impossible to ensure every run of critical piping is fully drained and dry throughout the mothball duration. This could lead to unexpected equipment/piping failures and Boiler tube leaks after the unit returns to service. Due to the criticality of the Turbine-Generator equipment and systems, a more frequent and robust inspection program will need to be implemented to identify issues before they cause a catastrophic failure. Ultimately, mothballing will result in decreased unit reliability and increased yearly O&M costs when the unit returns to service after mothballing.

Large rotating equipment is not designed to sit idle for extended periods, and even a robust mothball and restoration program cannot alleviate stressing and bowing concerns for some large equipment. These issues can create safety and operational risks upon restoration of the equipment. Also, many of the sensors and monitoring equipment associated with the large rotating equipment will likely be less reliable upon restoration than during normal operation, and some DCS, controls, and electrical components could become obsolete.

Pest control costs are included in the miscellaneous layup costs, but keeping rodents and other chewing pests out of long runs of electrical conduit and other control wiring & cabinets is a difficult task. Some miscellaneous costs for issues created by pests have been included in the restoration cost estimate, but significant operational and safety related issues may emerge during and after restoration, even with a robust mothballing plan.

Finally, physical restoration of the generating equipment after a mothball period will be an arduous process, but providing a trained operating staff to operate the restored equipment may be even more difficult. The unit will require significantly more operating intervention and effort upon restoration, and having skilled staff to restart the idled unit while still operating the other units on site will be challenging.

Ameren Missouri's analysis focused on the cost and schedule for mothballing a generating unit, but excluded other items that would need to be considered, including, but not limited to:

- Ameren Missouri review of removing generation unit(s) from service, including impact on reliability and overall generation resource planning
- MISO review of removing generation unit(s) from service, including impact on reliability and grid/voltage support
- Cost recovery for mothballing and related financial impacts from reduced energy and capacity revenue

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 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 recently obtained a CCN for a second solar resource to support the Renewable Solutions Program. Cass County Solar, a 150 MW facility located in Illinois, is expected to come online in late 2024 and was fully subscribed via an auction in May 2024. The first Renewable Solutions Program resource, Boomtown Solar, is also expected to come online in late 2024. 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.

Ameren Missouri submitted a Part I application for the DOE's Title 17 Clean Energy Financing Program under section 1706 Energy Infrastructure Reinvestment in early 2024 and is preparing a Part II application. If selected, the Title 17 Clean Energy Financing Program offers applicants access to more competitive, lower cost financing for clean energy projects like solar, wind and battery storage. Ameren Missouri expects nearly all its planned clean energy investments through 2032 would be eligible for the program.[9]

Securitization

Ameren Missouri announced in December 2021 that it would retire its coal-fired Rush Island Energy Center and indicated in its Notice of Change in Preferred Resource Plan that the units are expected to be retired by the end of 2025, subject to ongoing review of reliability needs by MISO and the issuance of a revised decision by the U.S. District Court. On June 20, 2024, the MPSC issued an order authorizing the Company to securitize approximately $470 million in energy transition costs for Rush Island. In issuing its order, the MPSC found that the Company's decision in December 2021 to retire Rush Island rather than install FGD equipment was prudent.

Battery Storage[10]

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 to which Missouri sells into. 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 maximizing the capacity credit of our resources.

[9] File No. EO-2024-0042 1.G
[10] File No. EO-2024-0042 1.J

Virtual Power Plants[11]

Ameren is aware of virtual power plant (VPP) technology as a potential enabler of future resources. Two types of VPPs are described below:

Demand Response (DR) VPPs: Perhaps the most mature of VPP types since the industry knows them as Demand Response programs. Basically, in this framework, peaks in demand can be met by ramping down aggregated loads in near real-time instead of starting peaking power plants. Today, DR VPPs have the largest commercial presence in the United States and the world. Ameren Missouri's preferred plan includes DR at RAP level.

Mixed Asset VPPs: These are aspirational platforms where any node on the grid represents a potential solution to both regional distribution networks and wholesale transmission grid pool supply and reliability challenges. It promises this broad capability because it would aggregate distributed generators, loads, and energy storage to form a virtual entity that interacts with a DSO and/or an ISO.

Benefits related to VPP scalability

The intermittent nature of renewables and the electrification of whole new industrial sectors such as transportation as well as rapid growth of data centers, amplifies the need for flexible resources. Therefore, VPPs have emerged as a potential solution in markets nationwide for aggregating limited-capacity, demand-side resources as a larger virtual entity capable of providing a variety of grid services. Electricity markets might leverage VPPs with scalable and secure sensing and communication technologies to coordinate generation and load in different time sequences, to monitor the operating status of resources, and to issue precise control over them.

Challenges related to VPP scalability

Component Interoperability - One of the main challenges of building and maintaining VPPs is the interoperability among many assets at scale. Information and operational technology components that make up VPPs require a wide range of interoperability between renewable energy sources, battery storage systems, and cloud-based digital control platforms.

Evolving Market Rules and Regulations - As market rules continue to evolve, creating a robust and cost-effective VPP can be challenging. VPPs are highly dependent upon a viable regulatory framework. Regulations often govern the availability of DERs based on their fuels, size, type, and location on the grid. This is especially true for market

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[11] File No. EO-2024-0042 1.H; File No. EO-2024-0042 1.I

participants who are not well-versed in the minutiae of interconnection processes or new parameters governing grid service payments.

Lack of Incentives - Customers may not be incentivized to participate in VPPs. The industry may need to offer rebates, credits, and other incentives to drive prosumer adoption. In the U.S., the Inflation Reduction Act provides incentives for multiple DERs, but integrating these DERs into VPPs may require more direct market intervention in the form of clear prosumer payments.

Telemetry and Integration Issues - Telemetry requirements and other requirements for a qualified entity to help transact in any energy market may be burdensome and cumbersome, leading to difficulty in following through on system integration steps to create multi-asset, multi-market VPPs.

Data Management - VPPs generate and rely on large amounts of data. It is therefore important to manage this data effectively to ensure that VPPs are running optimally and deliver the precise ancillary services required by the market to keep the grid in balance in real time. As VPPs scale up in size and function, granular data management challenges will grow over time.

VPP Contributions

VPPs may play a crucial role in supporting the grid by providing various benefits to the utility's resource adequacy requirements, grid stability, resiliency, and more. Here are the key contributions of VPPs:

Resource Adequacy Requirements - VPPs may help utilities meet peak demand requirements by aggregating distributed energy resources (DERs) such as solar, storage, and demand response. Further, they may provide a reliable and dispatchable capacity to the grid, reducing the need for peaking plants and supporting resource adequacy. However, this benefit is not operationally different from deploying these DERs in separate locations and operating them as part of a larger portfolio.

Grid Stability - VPPs may help maintain grid stability by providing frequency regulation, voltage support, and ramp rate management. Also, they can respond quickly to changes in grid conditions, ensuring a stable and reliable supply of electricity.

Resiliency - VPPs may enhance grid resiliency by providing backup power during outages and emergencies. They can island and operate in microgrid mode, ensuring critical infrastructure remains operational.

Transmission and Distribution Capacity Deferrals - VPPs can reduce the need for transmission and distribution upgrades by managing peak demand and optimizing energy flow. Further, they also help extend the life of existing infrastructure, deferring costly upgrades and replacements.

Load Management Strategies - VPPs implement load management strategies such as peak shaving, load shifting, and demand response. Additionally, they optimize energy usage, reducing peak demand and strain on the grid.

System Optimization - VPPs optimize energy production, consumption, and storage, minimizing waste and reducing emissions. In their most complete deployments, they use advanced analytics and machine learning to predict energy demand and adjust operations accordingly.

In summary, VPPs could potentially play a role in supporting the grid by providing resource adequacy, grid stability, resiliency, transmission and distribution capacity deferrals, load management strategies, and system optimization.

Limitations of Incorporating VPPs in Utility Planning

While VPPs may offer numerous benefits, there are limitations to incorporating them in utility distribution or resource planning analysis due to challenges in aggregating and dispatching retail and market-participants' DERs. Limitations include:

Data Management and Integration - VPPs require access to real-time data from various DERs, which can be challenging to integrate and manage. Ensuring data accuracy, security, and privacy is crucial, but complex.

Aggregation and Dispatch Complexity - Aggregating and dispatching DERs from multiple sources, with varying capacities and availability, is a complex task. Coordinating and optimizing DER operations to meet grid needs in real-time is a significant challenge.

DER Location and Distribution - DERs are often dispersed across the distribution grid, making it difficult to manage and optimize their output. Location-specific factors, like grid constraints and transmission limitations, must be considered.

Market Participation and Regulatory Framework - VPPs must navigate complex market rules and regulatory frameworks to participate in wholesale markets. Ensuring compliance with market rules and regulations can be time-consuming and costly.

Scalability and Standardization - As the number of DERs grows, scaling VPP operations while maintaining efficiency and reliability becomes challenging. Standardization of DER technologies, communication protocols, and data formats is essential but lacking.

Cybersecurity and Grid Reliability - VPPs introduce new cybersecurity risks, as they rely on advanced technologies and connectivity. Ensuring the reliability and resilience of the grid while integrating VPPs is crucial.

Cost and Investment Recovery - Utilities may need to invest in new infrastructure and systems to support VPP integration. Recovering these costs through rates or other mechanisms can be challenging.

Customer Education and Engagement - VPPs require customer participation and engagement, which can be difficult to achieve. Educating customers about the benefits and requirements of VPPs is essential.

Addressing these limitations will require innovative solutions, regulatory frameworks, and industry collaboration to fully realize the potential of VPPs in utility planning and operation.

Managed Fleet EV Charging & Microgrid

To validate managed fleet EV charging use cases impacting business outcomes relevant to Ameren Missouri's C&I customers, Ameren Missouri is conducting a demonstration project for fleet charging and dispatchable asset control consisting of stationary battery storage, solar PV, and smart EV chargers.

The platform integrates information and operational technologies (IT/OT) to demonstrate available technology that reduces facility demand while ensuring system continuity. Use cases include managed charging for the EV fleet (control via software), resiliency & reliability, demand charge management, and demand response. At its core, primary, secondary and tertiary controllers monitor, process and command hardware components.

Resiliency and Reliability - The facility is electrically islanded in the rare occasion that no power is available from the grid. While off-grid, the facility is fed energy from the battery. The system is seamlessly reconnected to the grid when the power source is restored.

Demand Charge Management - To demonstrate energy surcharge management, a combination of load curtailment and energy from the battery is applied to prevent exceeding prescribed power flow levels from the grid.

Demand Response - To comply with a previously committed reduction in power consumption, a combination of load curtailment and energy from the battery is applied to achieve the necessary reduction in power flow levels from the grid.

Optimum Charger Dispatch - A software platform for managed charging is used by the fleet vehicle operator to optimize vehicle charging based on cost (time of use tariffs), availability (how fast do vehicles need to be charged) and other factors. Energy from the battery may be dispatched based on need and cost to optimize charging.

Just-in-Time Fuel Procurement[12]

Ameren Missouri's fuel procurement strategies primarily rely on a combination of forward hedging, advance deliveries, and on-site storage to address price, volume, and deliverability risks of delivered fuel for generation. These risk mitigation strategies are evident for various fuel types used by the generation fleet and serve to mitigate the need for *just-in-time* (JIT) delivery of fuel. Following is a summary of strategy measures utilized for delivered fuel for generation.

- Nuclear fuel cycle: Forward hedging for price and volume, advance deliveries, fuel assemblies onsite at Callaway months prior to reload
- Coal procurement: Forward hedging for price and volume, advance deliveries, and significant onsite storage
- Fuel oil (used for both fossil plant startups and combustion turbine peaking): Forward hedging for volumes, advance deliveries into onsite storage tanks
- Natural gas: Forward hedging for price and volume, *leased storage – not onsite*

Since the natural gas storage services that the Company leases from various interstate pipelines are located some distance from the gas-fired energy centers and still require delivery of the gas, and because Ameren Missouri does not own any natural gas storage capacity of its own, all Ameren Missouri gas generation could be considered JIT fueled.

Ameren Missouri's gas-fired combustion turbine generator (CTG) fleet, which operates in support of electric load and in response to market price signals, tends to operate infrequently for short periods of time, creating volatile daily demand. This volatile operating profile is generally served with available gas supply on the interstate pipelines, an aspect which reinforces the assessment that the CTG fleet relies on JIT delivery of fuel. There is no viable co-located option of having on-site natural gas available for consumption by the CTG fleet. Fortunately, the Company's CTG sites are located on interstate pipelines with proven records of providing flowing supply of natural gas to the CTGs, apart from during peak cold-weather events.

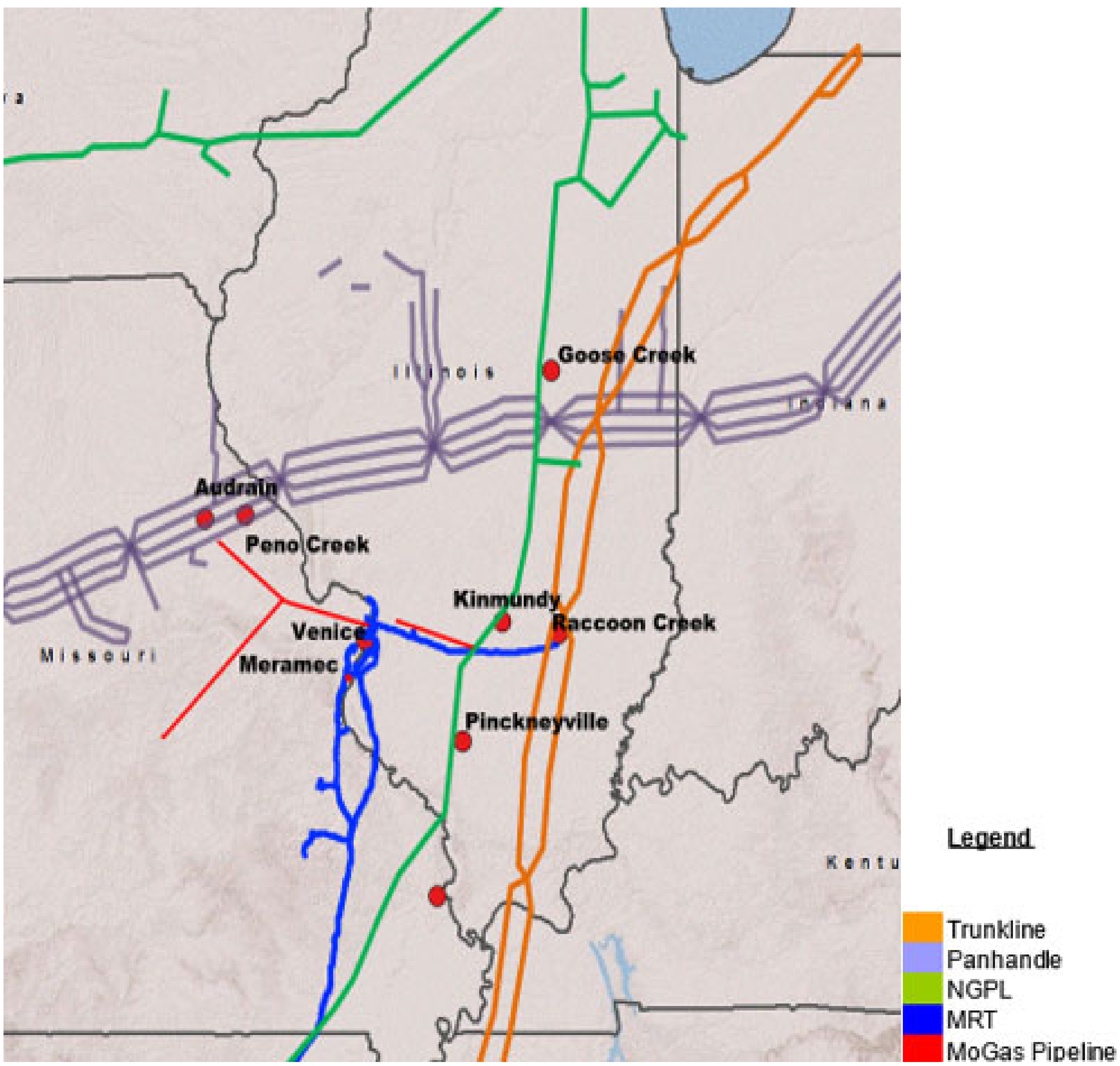
CTG Sites

Ameren Missouri owns and operates the following natural gas-fired generating facilities: Pinckneyville, Kinmundy, Goose Creek, Raccoon Creek, Audrain, Peno Creek, and Venice, which are shown in Figure 1. Total summer gas-fired generation is now 2,556 MW. The units are offered to the MISO market on a Day-Ahead (DA) and Real-Time (RT) basis. The Company subscribes to a portfolio of Firm Transportation (FT), Interruptible Transportation (IT), storage, parking, and balancing services from the pipelines to serve

[12] File No. EO-2024-0042 1.E

these plants. Of these interstate pipelines, several are owned by the same parent company, Energy Transfer. This includes Panhandle Eastern Pipe Line Company, LP on which the Company operates CTGs at Audrain and Peno Creek energy centers. Trunkline Gas Company, LLC, is another Energy Transfer subsidiary on which Ameren Missouri operates the Raccoon Creek energy center. In recent years, Energy Transfer also acquired Enable Mississippi River Transmission, LLC (MRT), on which the Company operates the Venice Energy Center, and also intends to construct the Castle Bluff Energy Center (on the retired Meramec Energy Center site), which will be an addition to the Company's CTG fleet. Finally, the Company owns multiple CTG sites served by the Natural Gas Pipeline Company of America, LLC (NGPL), including the Pinckneyville, Kinmundy, and Goose Creek Energy Centers.

Figure 3.1: Pipelines Serving Ameren Missouri CTGs



Supply Arrangements

Both historical operation and forward market prices indicate that summer is the highest season of demand for the CTGs. However, since their operation is highly dependent upon weather driven electric demand, it is difficult to predict actual days of operation. Since these CTG sites primarily operate during peak conditions and hours, there is no expectation that the units will operate on gas for all 24 hours of any given day. With this operating variability in mind, the Company subscribes for pipeline services that are less than full operating day requirements of the CTG sites.

For example, the Audrain facility located on PEPL consists of eight, 75 megawatt (summer rating) CTGs, each with an approximate 11,500 Btu/kWh heat rate. Operating all eight units in a given hour would consume 6,900 MMBtu of natural gas, and 24-hour operation would require 165,600 MMBtu. The Peno Creek units are also located on PEPL, and with four 50 megawatt units with a 10,000 Btu/kWh heat rate will consume 2,000 MMBtu per hour. A 24-hour run would require 48,000 MMBtu, and this volume, combined with 24-hour Audrain requirements, would total 213,600 MMBtu. But due to the peaking nature of these units, the Company only subscribes to 47,000 MMBtu of FT on PEPL during the summer. When all these units need to operate in the same hours, the Company utilizes a combination of FT, IT, delivered supply purchases, and swing supply packages to fuel the units. This approach not only reduces the fuel supply fixed costs, but it is a combination proven to deliver necessary supply, apart from extreme cold weather events. In addition to this cost-saving approach, the Company will also optimize its existing FT, either via capacity release or Asset Management Agreements (AMA), which also serve as a source of supply during times of CTG operation.

JIT Fuel Exception Events

The notable exception to the reliability of just-in-time fuel arrangements for the CTG fleet is during extreme cold weather events. During extreme cold weather events, it is typical for the interstate pipelines to issue System Protection Warnings (SPW) or Operational Flow Orders (OFOs) due to the high volumes of gas being delivered through the pipelines. During extreme cold weather events when these declarations are issued, the net effect is that pipelines are required to take certain actions: (1) curtail all schedules utilizing Interruptible Transportation, and (2) require all shippers to adhere to tariff provisions requiring ratable flows[13]. It is the ratability provision that generally requires much of the Company's simple cycle fleet to be made unavailable for operation. The Company's Firm

[13] Example ratable flow language from PEPL Critical Notice 2022-01-17: "To ensure system integrity, Panhandle is requiring all Shippers under Rate Schedule EFT, EIT, SCT, GDS or LFT to limit their hourly deliveries to one-sixteenth of the quantity scheduled for delivery on the applicable day. Please refer to the GT&C Section 12.11(g) of the Panhandle Tariff regarding the penalty provisions as it applies to customers in the event of noncompliance with this request."

Transportation contracts could be utilized to make a small number of CTGs available for ratable, 24-hour operation.

To mitigate these pipeline limitations, the Company has recently restored the dual-fuel capability at the Peno Creek and Kinmundy Energy Centers. This allows these units to pivot to fuel-oil firing when natural gas is not available. Similarly, the Company is pursuing a project to establish dual-fuel firing capability at the Audrain Energy Center. In addition, the Company currently operates four 55 MW CTGs with fuel-oil firing capability only. These four sites have fuel oil storage tanks and are not considered to be JIT fueled. Finally, the previously mentioned Castle Bluff project will also incorporate 72 hours of dual-fuel capability at full load, to ensure reliable operation during extreme cold weather events.

Natural Gas Combined Cycle

The Company's generation fleet does not currently contain a natural gas combined cycle (NGCC) generator. Since any new NGCC would have a more efficient heat rate than the simple cycle CTGs, the expectation is that MISO would commit the NGCC similar to a baseload unit, with MISO commitment instructions that span the entire 24 hours, thereby, largely avoiding issues with pipeline ratability restrictions. Based on this expected operation, the Company would seek to procure adequate FT rights on the associated pipelines to supply the NGCC for a full 24-hour commitment. In addition, the Company will explore leased storage options with the associated pipeline to balance month-long supply purchases with the variable MISO commitment, including days when the units are not committed. As the generator operating profile becomes more predictable, i.e. as that of a baseload unit, the pipeline subscriptions will become more robust and tailored towards assuming days with no operation of the units is the exception (for a NGCC), as compared to the peaking operating model of the simple cycle CTGs.

3.3 Transmission and Distribution Review

Smart Energy Plan Update

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

The Missouri Legislature passed Senate Bill 745, that was signed by Governor Parson on June 29, 2022 which enabled Ameren Missouri to maintain our commitment to modernizing the grid through at least 2028. The current plan includes an anticipated $3.6 billion of electric distribution system investments from 2024 through 2028 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 aging electrical grid. 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 have reached and 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 needs of our customers.

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	~3,000*	~31	40
Miles of Subtransmission Overhead Conductor	~4,200	~1,600	~39	45
Substation	~635	~300	~45	50

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

Despite significant investments over the past five 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, like with the widespread flooding in St. Louis in July 2022 due to precipitation which surpassed the record for daily rainfall set in 1915 by 27%. In the summer of 2023, Ameren Missouri experienced its worst storm season in over a decade: waves of severe storms downed trees 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 incorporates 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 increases in electric vehicle use and electrification of operations, additional capacity may 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:

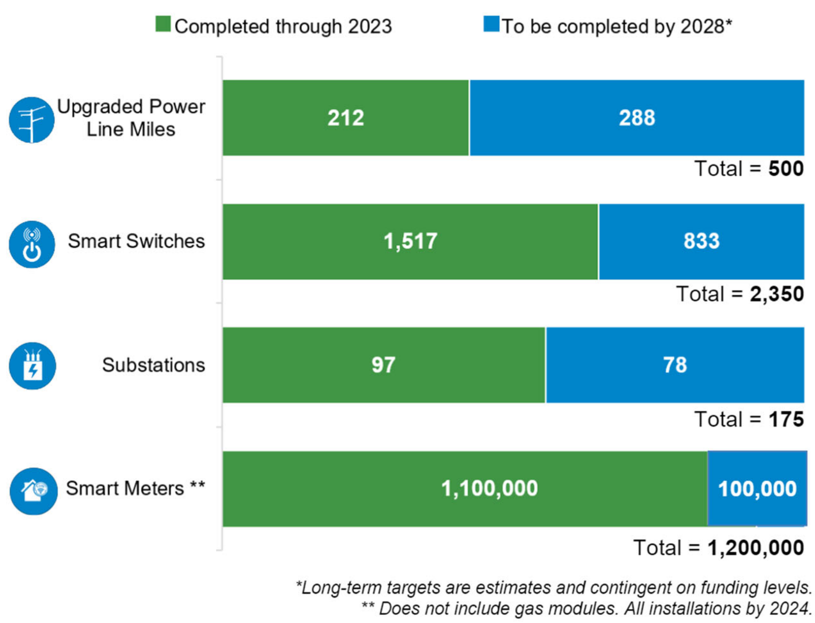
- Automate portions of the electric distribution system by deploying smart switching devices with associated circuit upgrades and accompanying communications technologies to help significantly reduce the length of outages. Since the beginning of the Smart Energy Plan in 2019, Ameren MO crews have installed over 1,500 smart switches throughout the Missouri electric territory. These switches reduce the frequency of outages and lower the duration of outages by up to 40% and have prevented more than 30 million minutes of customer outages since 2021.
- 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 possibility of extended outages from high winds and other severe weather. In December 2021, a line of severe storms including an EF-3 tornado went through the southernmost portion of eastern Missouri. A new storm-hardened line was directly hit by the tornado. Composite poles prevented a cascading collapse and failure, allowing power to be restored in half the time. In the summer of 2023, Ameren Missouri experienced its worst storm season in over a decade. During the 2023 storm season, none of our hardened lines experienced damage from these storms. In 2023, Ameren Missouri upgraded 41 miles of the sub-transmission system, a core asset in reliably delivering energy across the grid.
- Upgrade aging and under-performing assets (e.g., substations, overhead and underground assets). Part of Ameren Missouri's plan is addressing the oldest 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. Additionally, this will allow us to serve customers' future needs that continue to change with the transition to electrification.

- Continue to execute 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 2027.

The below graph shows Ameren Missouri's progress in completing these upgrades from 2019 – 2023 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 28% below Midwest and U.S. averages.

Smart Meter Program

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

- Installing 1.2 million Electric Advance Metering Infrastructure (AMI) meters (residential and commercial/industrial) which can provide greater usage insights and capabilities for customers.
- Installing 132,000 Gas AMI modules (Residential and Commercial/Industrial).[14]
- Deploying a modern RF mesh network, enabling two-way communication.
- Launching an Advanced Meter Data Management System.
- Modernizing the Ameren Missouri Meter Shop to facilitate the receipt and quality testing of purchased meters.
- Creating an Ameren Missouri Network Lab and a Missouri Integrated Operations Center.

These new electric meters and gas modules will upgrade all of the antiquated Automated Meter Reading (AMR) meters/modules, which use meter reading technology that is more than 20 years old and are 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) help customers 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 reduces meter reading costs and expenses associated with contractors who had provided manual disconnect/reconnect services).

Through July 2024, Ameren Missouri has deployed 1,240,000 electric AMI meters. Ameren Missouri has deployed all of the initial devices for the RF mesh network, the meter shop, network lab and integrated operations center. As part of the optimization

[14] Gas module deployments are not funded through the Smart Energy Plan.

process for each operating center, additional devices may be identified and installed by the end of 2025.

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 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%.

Transmission Considerations for Long-term Portfolio Transition

The importance of the long-range planning to foresee a transmission system that can support the energy transition, as noted in the recently published FERC order 1920, has seen MISO's long-range planning produce a new near-final portfolio of projects, Tranche 2.1. These infrastructure investments are necessary to meet the reliability needs of the transmission system based on the Future 2A scenario of the MISO Long Range Transmission Plan (LRTP) study. These future scenarios were created, after a Futures update, using the IRPs of the utilities within MISO and current generation within the MISO queue after analysis indicated an accelerated energy transition. These new projects represent significant expansion and investment in transmission infrastructure within Missouri, that will be needed to support the new physics of the grid, which include a larger percentage of intermittent generation along with dynamic loads. These projects make up a complimentary set of projects 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 $23-27 billion of transmission investment and is likely to be approved in late 2024. Although the Tranche 2.1 portfolio includes 765kV, the projects within Missouri are presently all 345kV. Further tranches may see the need for 765kV investment within Missouri, especially if loads increase significantly due to data centers and electrification.

Further tranches of transmission expansion are planned, including a tranche 2.2, which will likely study the future 3A scenario, with expanded intermittent generation and larger loads, along with a tranche 4 effort, which will look at enhancing the ties between MISO North and South. As a result of some states within MISO more aggressively pushing decarbonization than originally proposed, the need to build transmission is accelerated along the same timelines.

The penetration of intermittent renewable resources continues to grow within the MISO footprint and the energy provided by them is now around seventeen percent of total energy production annually, due to both the addition of new renewable generation and the retirement of existing fossil-fueled generation. The retirement of the fossil-fueled generation within MISO is expected to accelerate over the next few years, due to both federal and state regulations, which will result in a further increase in the percentage of renewable energy. This increase in renewable generation penetration will significantly impact grid performance with complexity increasing sharply after 30 percent renewable penetration levels are achieved, as laid out in MISO's Renewable Integration Impact Assessment (RIIA), which could occur as early as 2026. Wind energy peaked in MISO at 26GW in early 2024, with a maximum share of the load at 35 percent. Significant investment in grid controlling devices such as statcoms, synchronous condensers and fast frequency response devices will be required to maintain grid strength and reliability. The transmission system is at a point where each plant retirement will impact reliability, as seen with the Attachment Y results for the retirement of Rush Island. Investments in grid controlling devices will be required ahead of further plant retirements to maintain the integrity of the grid.

The possibility of extreme weather events necessitates ongoing review of, and planning and investment to ensure, the resiliency of the grid. From forensic dissection of recent winter storms events the grid becomes directionally polarized, which brings new challenges to planning the transmission grid.

Supply chain issues and the increasing wide-spread need for long-lead items, such as transformers continue as multiple entities vie for the products, such as traditional utilities expanding their long-term outlooks, along with large load developers and generator developers. Transformer lead times are approximately 4 years, which has changed the requirements for the system spare strategy, and now lead time for 345kV breakers have also reached 4 years, which, without solid planning, could delay projects, which could reduce reliability or competitiveness on customer projects. One such change is the spare transformer strategy, which includes planning for a larger number of system failures, adding additional spare units, planned movement of in-service units, deployment of mobile transmission transformers, involvement in industry sharing programs and a specific strategy for long lead procurement.

Transmission Costs

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 have not materially changed since the 2023 IRP. These costs can be found in Chapter 7 of the 2023 IRP filing.

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 had included incremental economic development load in its 2023 IRP forecast starting at 40 MW in 2025 and reaching 220 MW in 2031. However, the requests Ameren Missouri has received to date exceeds these additions. Ameren Missouri has determined that the the economic development load increases along with the rest of its forecast assumptions and results are still appropriate, and is in the process of analyzing how much of the additional requests are likely to materialize and should be included in future filings.

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. Table 3.4 and Figure 3.3 below lay out the requested scenarios[15]:

- 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 demand-side rates nor MEEIA (but maintain naturally occurring energy efficiency adoption). Demand-side rates have no effect on total energy consumption, but rather serve as a mechanism to shift demand from on to off peak times during the day.

[15] File No. EO-2024-0042 1.A 1-5

Table 3.4: Summary of Load Forecast Scenarios (MWh - at Meter)

Year	With Demand-side Rates and Continued DSM Implementation (e.g., MEEIA - RAP)	Only Demand-side Rates without Contintued DSM Implementation	Neither Demand-side Rates nor Continued DSM (but with Naturally Occurring Energy Efficiency)	Neither Demand-side Rates nor Continued DSM nor Naturally Occurring Energy Efficiency
2024	30,299,722	30,591,390	30,591,390	30,951,115
2025	30,188,113	30,769,114	30,769,114	31,267,441
2026	30,229,394	31,099,733	31,099,733	31,726,648
2027	30,338,234	31,491,626	31,491,626	32,236,272
2028	30,677,124	32,109,975	32,109,975	32,968,952
2029	30,860,120	32,560,787	32,560,787	33,520,171
2030	30,982,035	32,931,615	32,931,615	34,054,340
2031	30,992,136	33,189,038	33,189,038	34,453,364
2032	31,023,888	33,465,460	33,465,460	34,853,089
2033	31,013,241	33,677,172	33,677,172	35,165,047
2034	31,129,359	34,009,823	34,009,823	35,591,777
2035	31,257,129	34,346,148	34,346,148	36,011,697
2036	31,466,348	34,746,666	34,746,666	36,490,267
2037	31,550,634	34,993,294	34,993,294	36,799,503
2038	31,757,676	35,347,713	35,347,713	37,218,253
2039	32,003,201	35,718,291	35,718,291	37,651,296
2040	32,279,328	36,108,839	36,108,839	38,158,895
2041	32,408,491	36,345,678	36,345,678	38,495,607
2042	32,615,889	36,651,569	36,651,569	38,899,415
2043	32,810,231	36,934,791	36,934,791	39,273,237

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

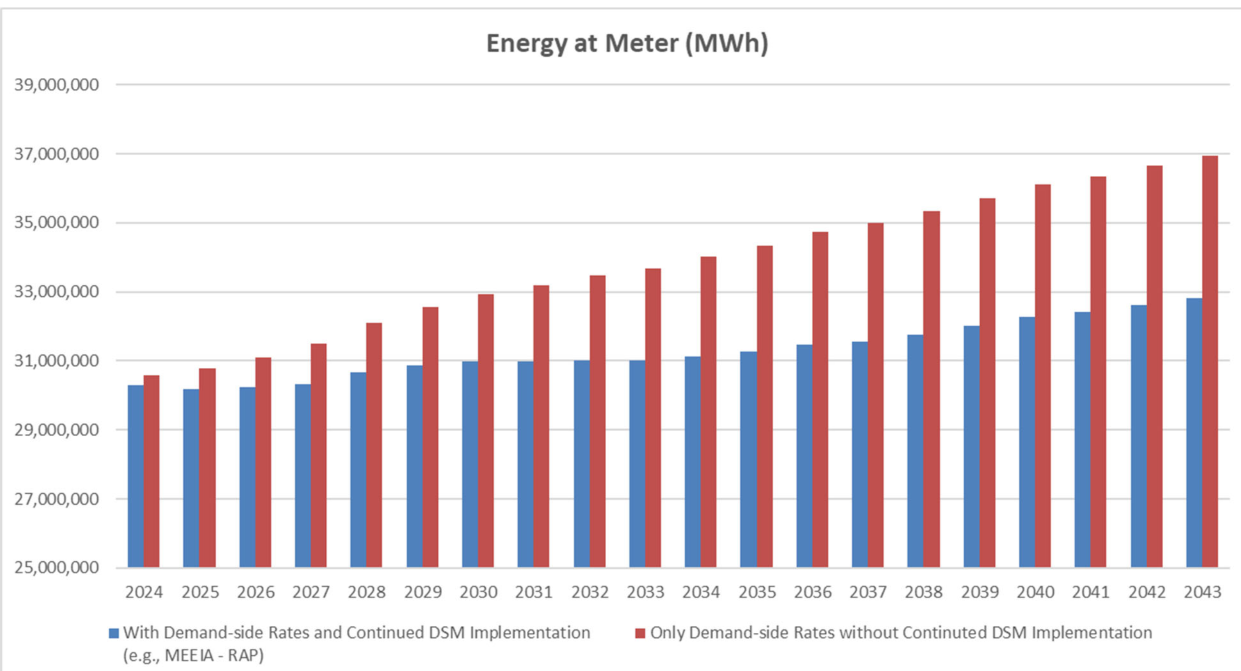
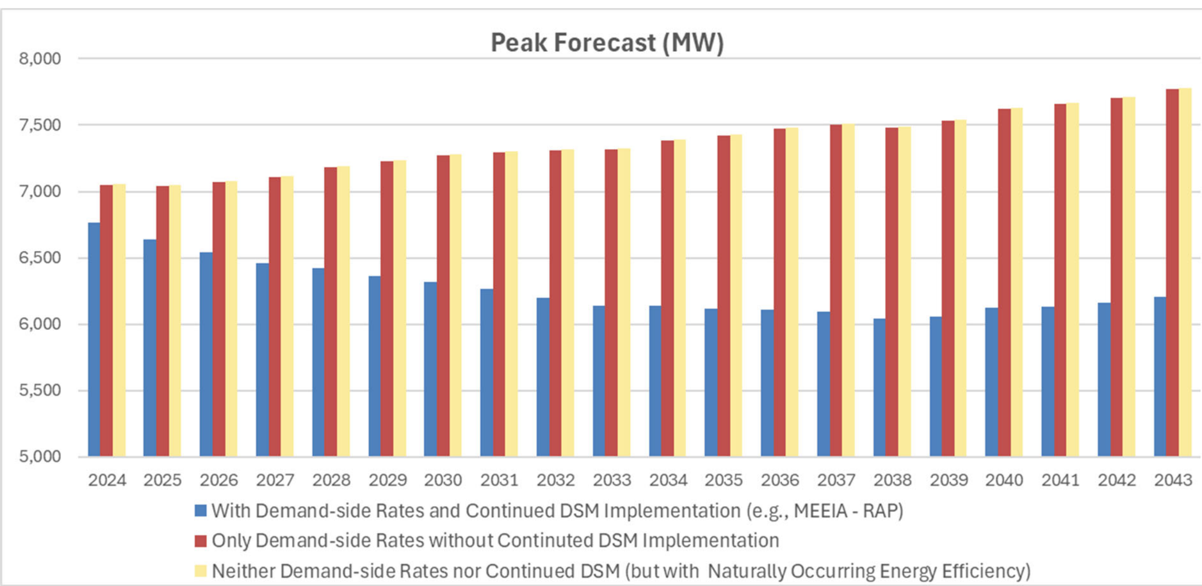


Table 3.5 and Figure 3.4 summarize the peak demand forecast associated with each one of the same scenarios provided above.

Table 3.5: Summary of Load Forecast Scenarios (MW - at Generation)

Year	With Demand-side Rates and Continued DSM Implementation (e.g., MEEIA - RAP)	Only Demand-side Rates without Contintued DSM Implementation	Neither Demand-side Rates nor Continued DSM (but with Naturally Occurring Energy Efficiency)
2024	6,765	7,049	7,054
2025	6,636	7,043	7,050
2026	6,539	7,072	7,079
2027	6,456	7,108	7,115
2028	6,419	7,184	7,191
2029	6,361	7,227	7,234
2030	6,315	7,271	7,277
2031	6,265	7,292	7,299
2032	6,199	7,307	7,314
2033	6,137	7,318	7,325
2034	6,136	7,382	7,388
2035	6,116	7,424	7,430
2036	6,111	7,473	7,480
2037	6,093	7,501	7,508
2038	6,039	7,485	7,491
2039	6,057	7,530	7,537
2040	6,127	7,627	7,634
2041	6,133	7,658	7,665
2042	6,159	7,706	7,713
2043	6,203	7,772	7,779

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



All of these scenarios include estimated savings from naturally occurring energy efficiency, which are shown in Table 3.6 below.

Table 3.6: 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. This remains the case at present day, as many details continue to remain murky, and with many unknowns related to program overlap, “braided” funds, projections of the volume of participation in the programs, savings attribution, and evaluation yet to be determined in a manner that would allow for a reliable analysis of the impacts of the IRA on the potential study. However, the 2023 MPS did attempt to consider the potential impacts of the associated IRA 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 and therefore led directly to an increase in the estimated long-term adoption rate for these eligible measures. 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.

3.5 Demand-Side Resource Review

The Company continues to offer energy efficiency programs. Products available to customers currently include heating and cooling, commercial lighting, efficient products, 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 began planning for the 2023 Market Potential Study (MPS) in the fourth quarter of 2021. Following a similar schedule as in the triennial 2020 IRP, the next MPS will be developed, executed and finalized between the fourth quarter of 2024 and the second quarter of 2026. This lead time is necessary so that results can be included in the 2026 IRP. The next MPS will be developed consistent with the budget approved as part of the PY24 extension, and it will rely on new primary market research regarding customer adoption and willingness to participate factors.

Similar to the 2023 MPS, the 2026 MPS will estimate the maximum and realistic achievable potential (MAP and RAP, respectively) of DSM resources consistent with all applicable rules and regulations. The Company also expects to develop a number of scenarios, with input from stakeholders to the base case MAP and RAP estimates for annual and peak day reductions.

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, or estimate 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.

Third-Party Aggregation[16]

Ameren Missouri included assumptions regarding third party aggregators of retail customers (ARCs) in Chapter 8 of its 2023 IRP filing (page 35). The 2023 MPS included capacity and demand bidding programs to serve as a proxy for the examination of ARCs. The analysis included low, medium, and high participation scenarios of commercial and industrial customers electing to participate in these programs. In the MW potential results shown below in Table 3.7, low case is considered "business-as-usual", medium case as RAP, and high case as MAP. Ameren Missouri assumed that the potential to reduce demand through these two programs are as identified in the 2023 MPS whether they are implemented by the ARC or the Company. If they are implemented by the utility, Ameren Missouri would pay the program costs, and if they are implemented by the ARCs, then Ameren Missouri would pay the ARCs for the demand reduction. Ameren Missouri assumed the cost to implement or the cost to purchase from the ARC are the same as we do not have any better estimates at this time. It is important to note that this assumes Ameren Missouri is able to secure bilateral agreements with the ARCs; however, this is

[16] File No. EO-2024-0042 1.F

not guaranteed. For example, if ARCs aggregate all potential customers in the base scenario (reductions from which are in the Company's preferred plan) and sell this total capacity to another entity other than Ameren Missouri, then the Company's capacity position would be shorter by the RAP values in the table below plus the reserve requirements.

Table 3.7: Capacity and Demand Bidding Participation Savings Potential

MW	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Low	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Base - RAP	131	139	147	154	154	160	152	154	156	154	155	155	155	153	149	147	146	143	142
High - MAP	182	189	210	212	222	221	232	240	248	224	229	221	223	214	211	210	201	199	198

3.6 Reliability[17]

Ameren Missouri's 2023 IRP reflected the Company's planning standard - to ensure that the Company has resources to provide energy for our customers in all hours and under all conditions, including during extreme weather events.[18] The Company's 2023 IRP analysis included evaluation of capacity needs under extreme weather[19] and more granular reliability modeling[20] to evaluate resource reliability both with and without external market support, which is uncertain and subject to decisions by other market participants in MISO and neighboring markets.

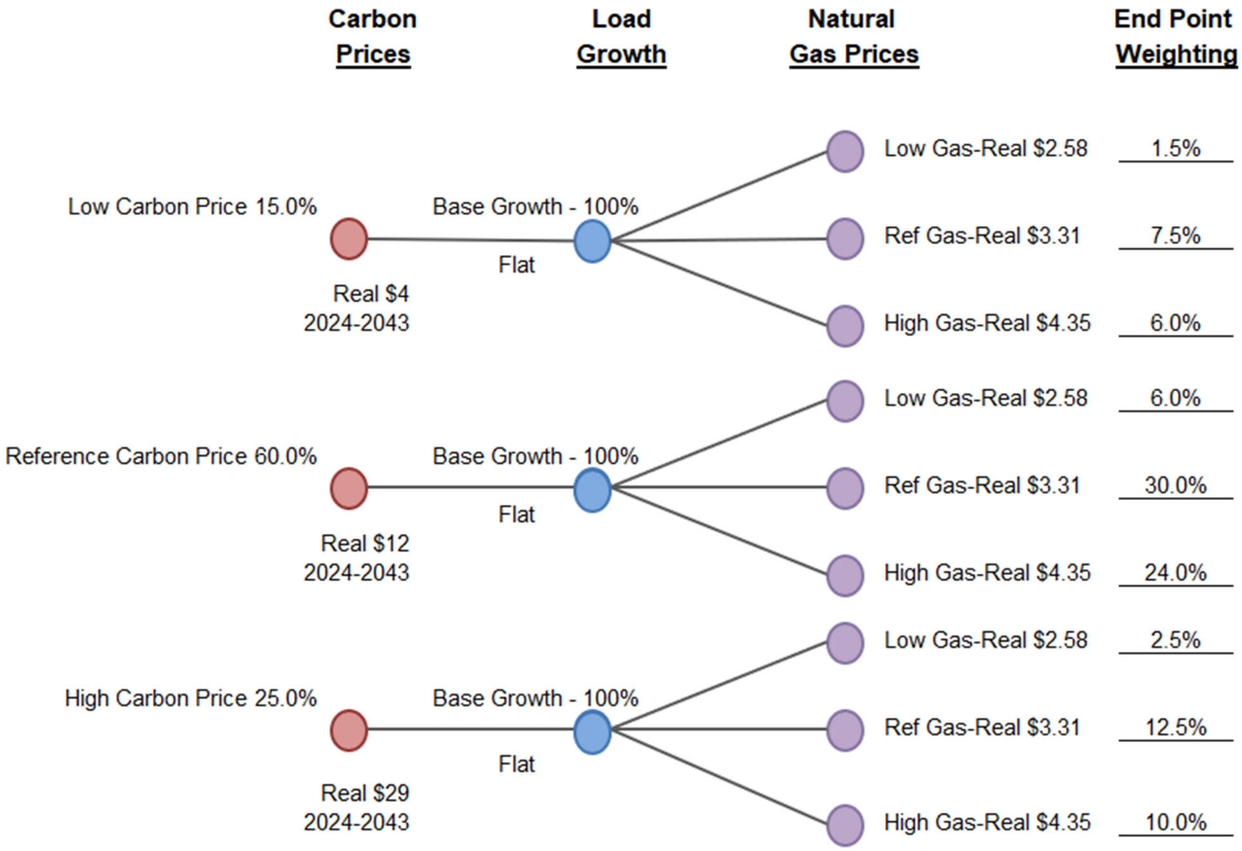
3.7 Uncertain Factors

3.7.1 Price Scenarios

Ameren Missouri has reviewed its assumptions for carbon prices and natural gas prices, which are the major drivers of power prices. As discussed in more detail in this section, Ameren Missouri has determined that its current expectations for the driver variables are within the ranges established in the 2023 triennial IRP. Figure 3.5 shows the scenario tree and the probabilities of each branch from the 2023 IRP.

[17] File No. EO-2024-0042 1.C; File No. EO-2024-0042 1.D
[18] File No. EO-2024-0020 Ameren Missouri 2023 IRP Chapter 2 – Planning Environment, p. 12
[19] File No. EO-2024-0020 Ameren Missouri 2023 IRP Chapter 10 – Strategy Selection, pp. 28-31
[20] File No. EO-2024-0020 Ameren Missouri 2023 IRP Chapter 10 – Strategy Selection, pp. 31-33

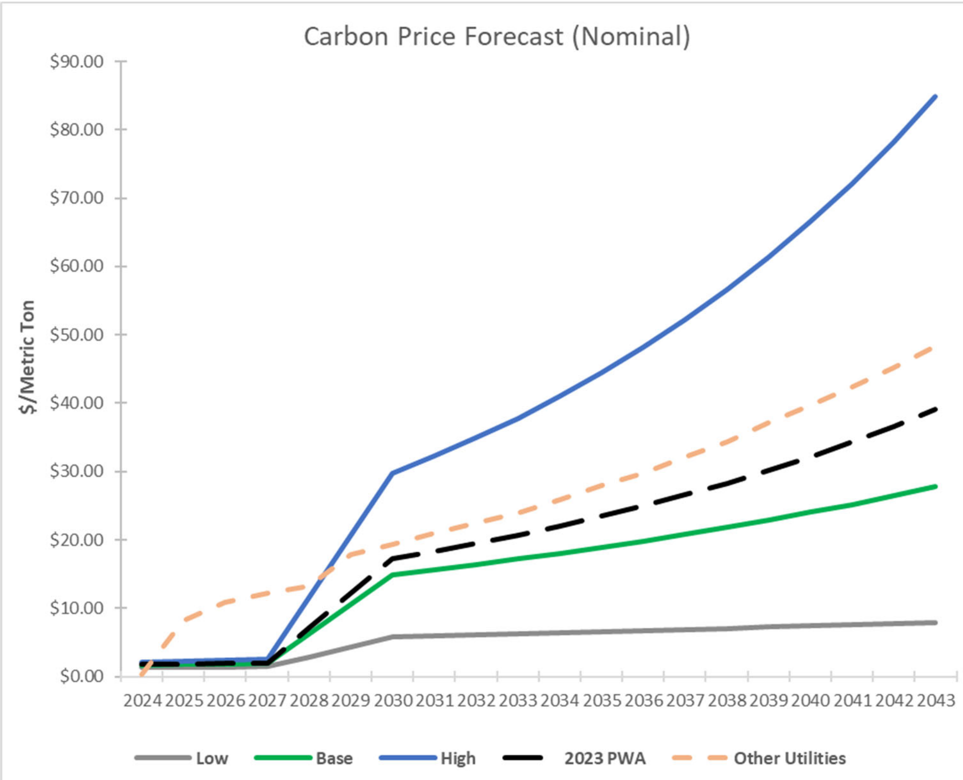
Figure3.5: Scenario Tree



Carbon Dioxide Emission Prices

The carbon price assumptions from the 2023 IRP were reviewed and remain reflective of expectations for the future price of carbon dioxide emissions. The carbon price scenarios and the probability-weighted average (PWA) are shown in Figure 3.6.

Figure3.6: CO_2 Price Assumptions

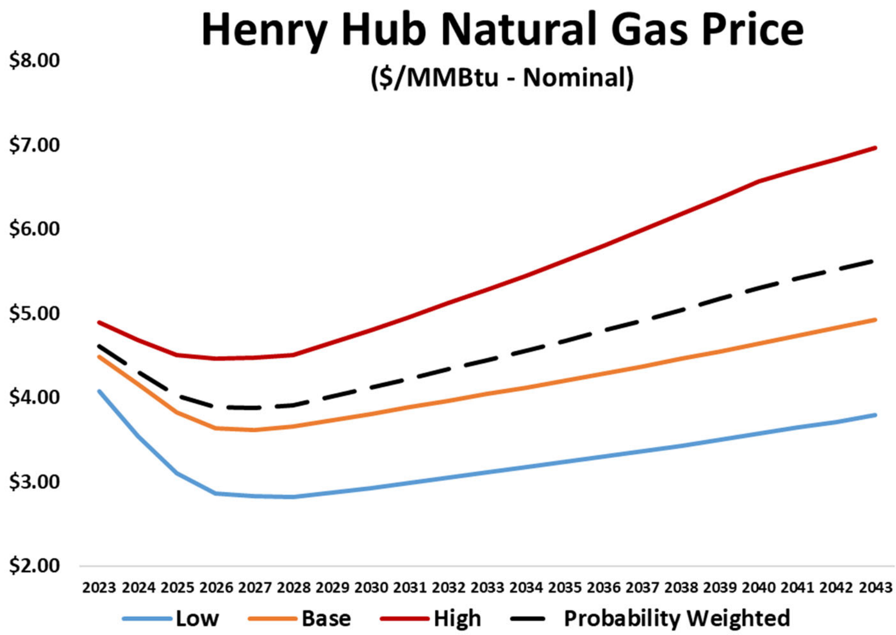


It should be noted that the price assumptions shown do not presume a particular mechanism (e.g., carbon tax, cap-and-trade program, etc.) by which the carbon price is implemented. It can be explicit or implicit and may reflect expectations regarding potential regulations, including those that target 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, particularly in light of recent price increases. Based on management review of supply and demand fundamentals and the risk of a shift in market dynamics due to recent geopolitical events, Ameren Missouri's management has shifted the probabilities for the high, base and low gas price scenarios. Figure 3.7 shows the three price scenarios, the revised probabilities, the new PWA price, and the prior PWA price. Ameren Missouri continues to monitor factors that may affect assumptions for natural gas prices.

Figure 3.7: Natural Gas Price Forecasts



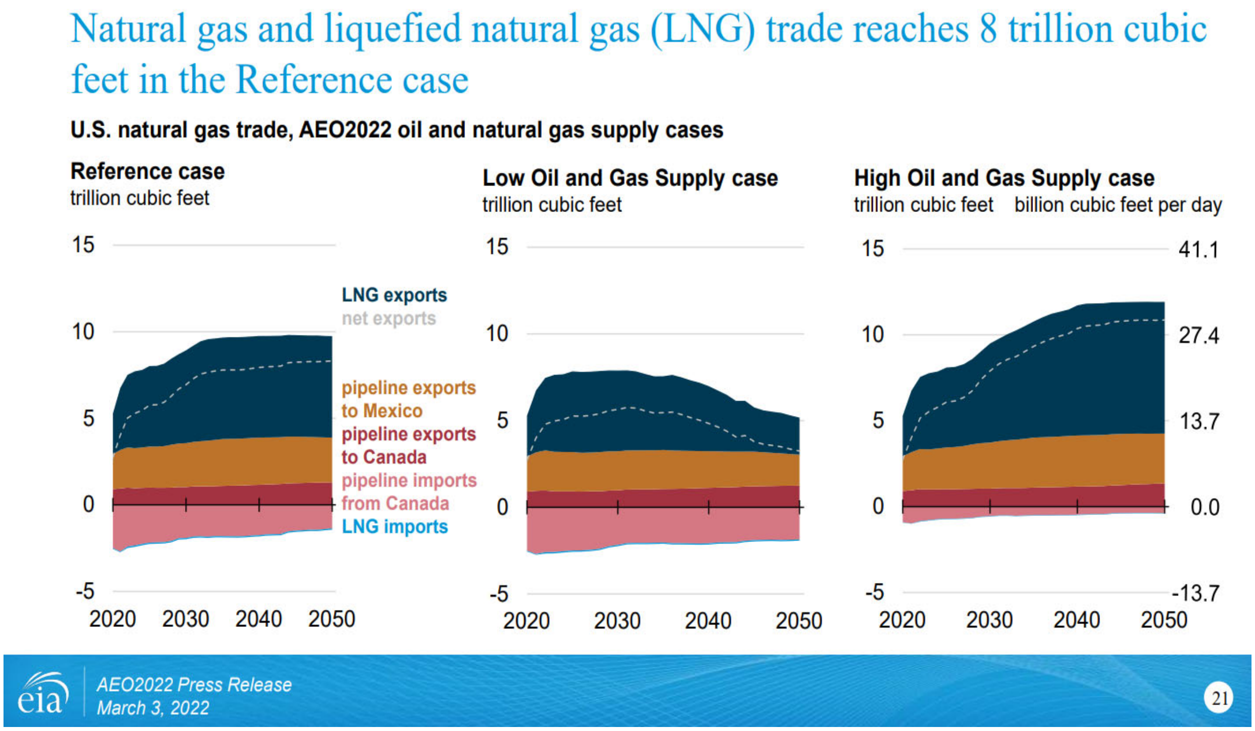
Ameren Missouri considers a number of key natural gas price drivers and risks. For the development of natural gas prices for the Company's 2023 IRP, the following key drivers and risks were examined:[21]

- LNG Exports
- Geopolitical Market Drivers
- Domestic Production and Extraction Costs
- Natural Gas Infrastructure Permitting
- Environmental Regulations for Gas Production and Transportation

The Company examined LNG exports based on information from the U.S Department of Energy's 2022 Annual Energy Outlook, which indicated a wide range of potential LNG exports (see Figure 3.8 below). The Company also considered relevant geopolitical events, including the Russian invasion of Ukraine in early 2022.

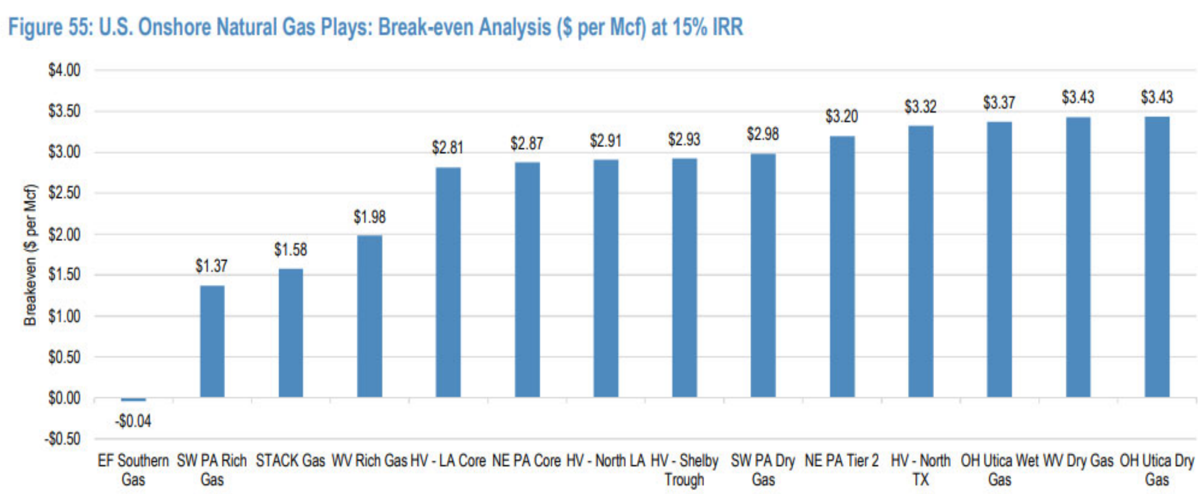
[21] File No. EO-2024-0020 Joint Filing, Resolution for NEE Deficiency 1

Figure 3.8: AEO 2022 US Natural Gas Trade Outlook



The Company also considers natural gas extraction costs in the context of potential increases in demand, including global LNG demand. Figure 3.9 below shows expected break-even costs from U.S. Natural Gas Plays.

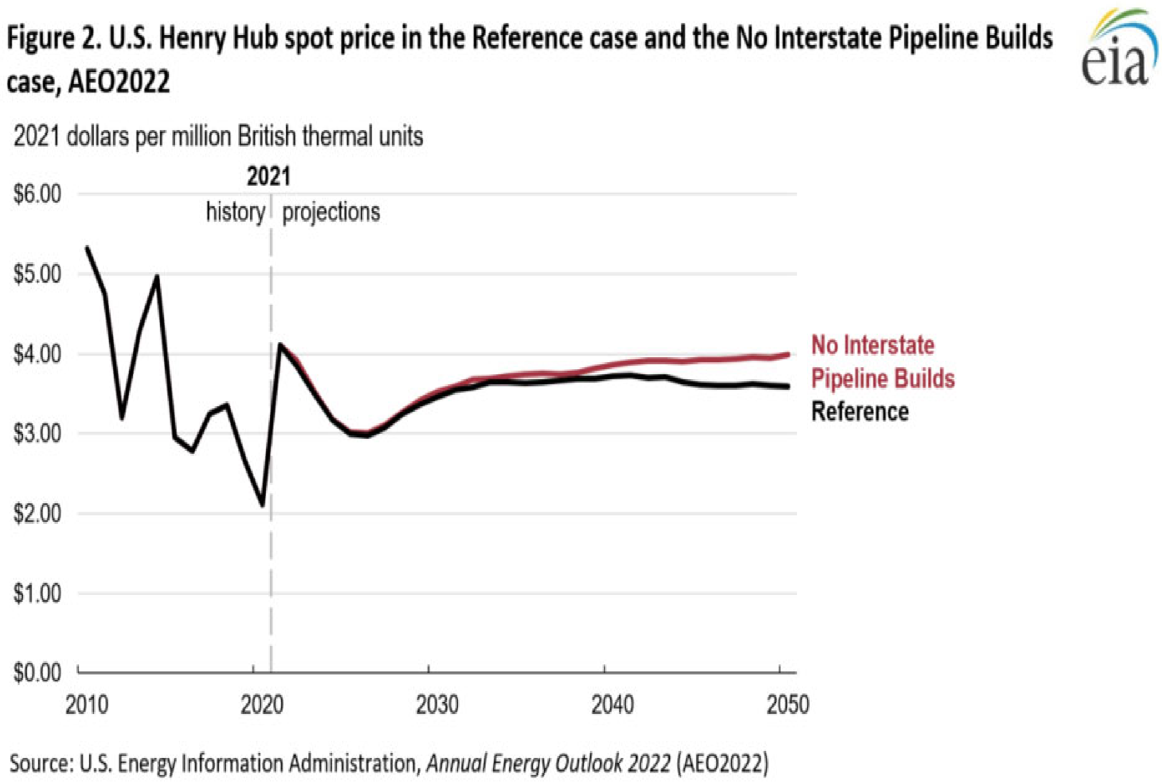
Figure 3.9: J.P. Morgan Natural Gas Play Break-Even Costs



Source: J.P. Morgan estimates, company data

Ameren Missouri also considered potential price impacts associated with constraints on interstate pipeline construction. As shown in Figure 3.10, DOE's analysis presented in AEO 2022 indicated minimal long-term price impact with no interstate pipleline builds.

Figure 3.10: AEO 2022 Price Sensitivity to Interstate Pipeline Construction



In addition to examining the key drivers and risks outlined above, Ameren Missouri reviewed third-party price forecasts and NYMEX market variability from recent history at the time the Company's price assumptions were developed, as illustrated in Figures 3.11 and 3.12 below.

Figure 3.11: AEO 2022 Price Scenarios and NYMEX Prices vs. 2020 IRP Prices

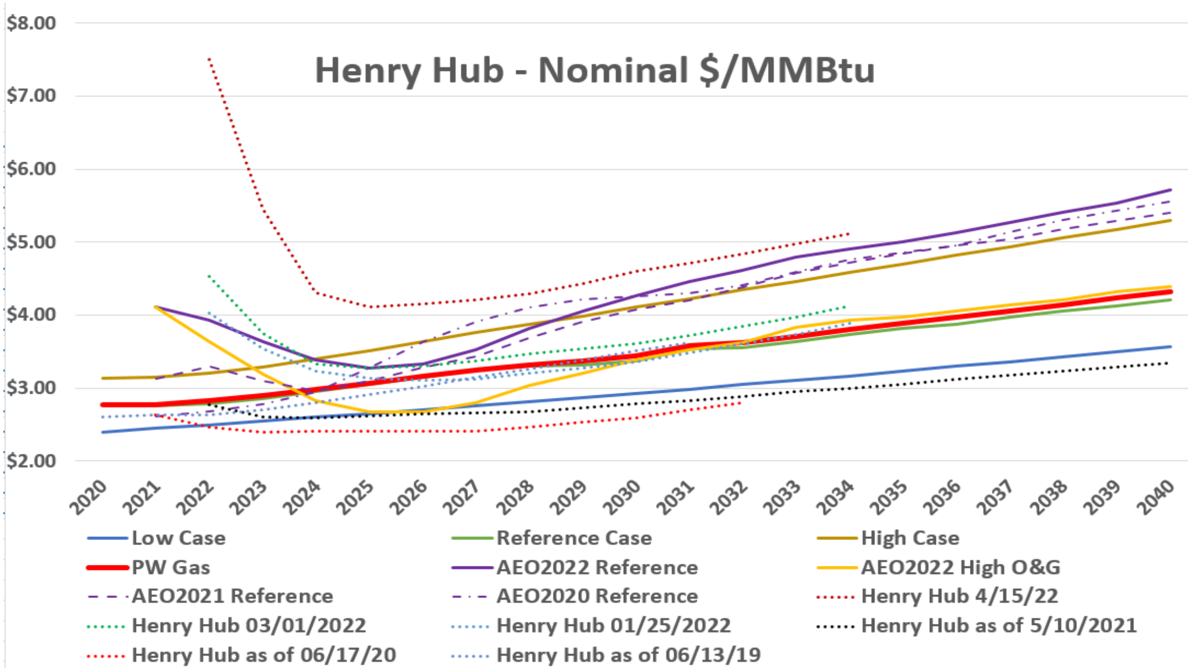
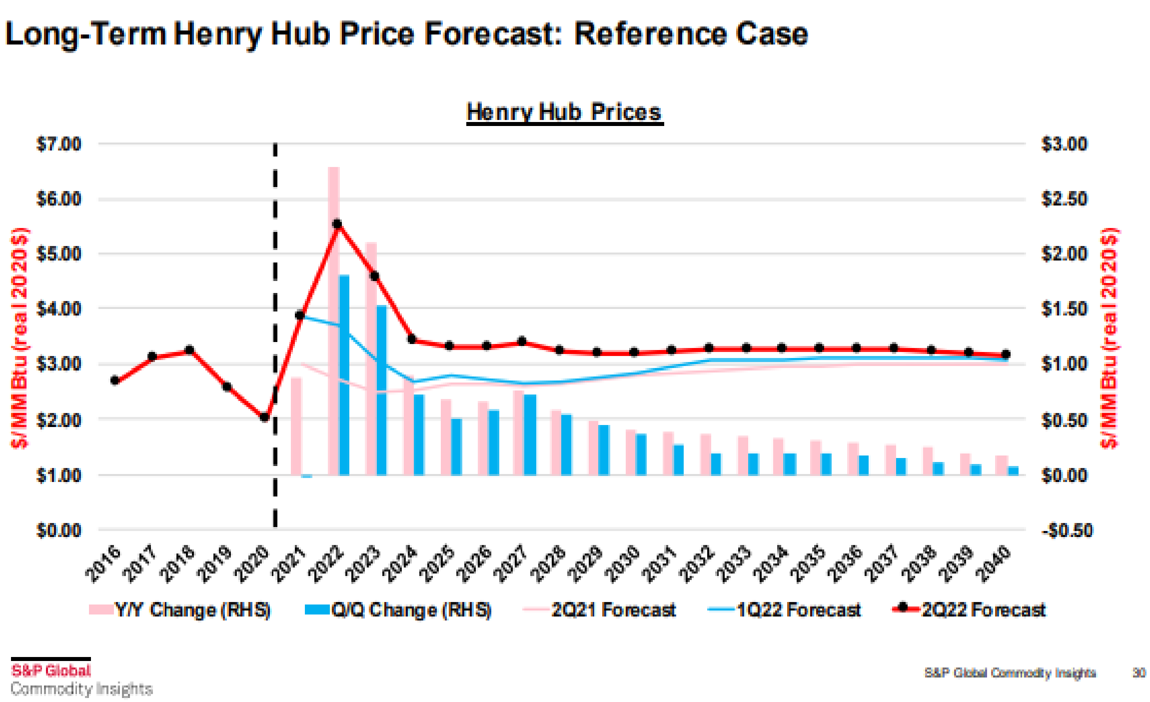


Figure 3.12: Platt's June 2022 Long-Range Natural Gas Price Forecast



The Company also included a price volatility analysis in its 2023 IRP in Chapter 10-Appendix D.

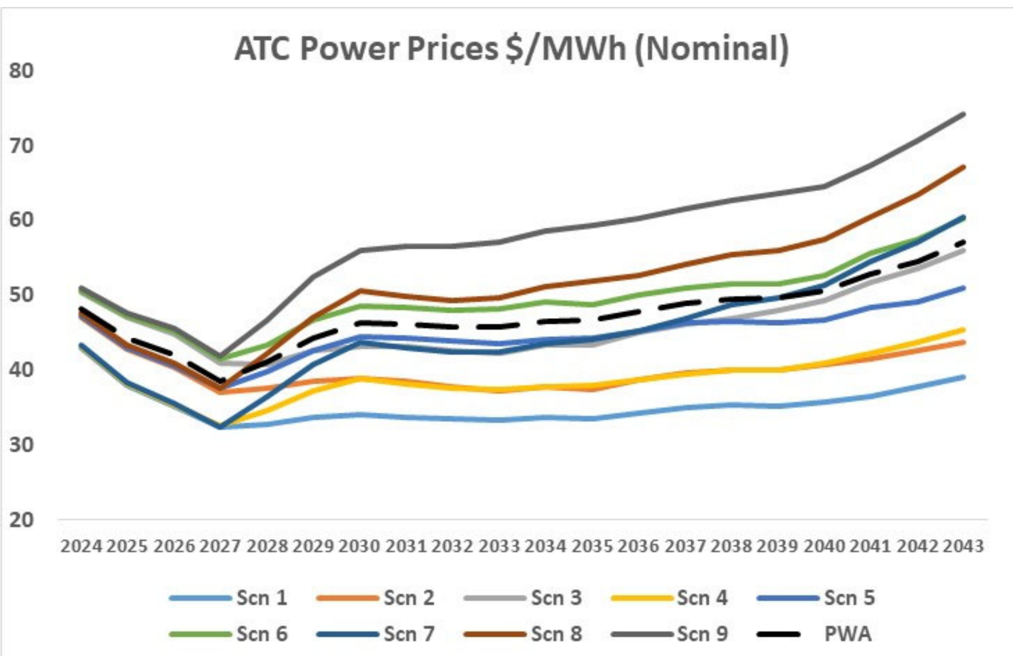
Load Growth

In addition to the scenario variables identified as critical uncertain factors in Ameren Missouri's 2023 IRP, the Company had also examined potential price impacts of load growth and concluded it should not be included in price scenario modeling. With the increase in potential load growth from data centers, the Company is reexamining price impacts from load. To that end, the Company is engaging again with Charles River Associates (CRA) to run additional price modeling scenarios reflecting different levels of load growth from data centers to inform ongoing planning.

3.7.2 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 3.13 below. However, Ameren Missouri is evaluating load growth assumptions related to digital economy at this time and may decide to add additional price scenarios in the near future.

Figure 3.13: **Market Price Scenarios**



3.7.3 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 each uncertain factor are still valid. Nevertheless, Ameren Missouri is getting service requests from data centers and is still evaluating if additional load growth assumption is warranted.

4. Compliance References

All references are to the ordering language in the *Order Establishing Special Contemporary Resource Planning Issues*, in File No. EO-2024-0042, beginning on page 3.