2021 INTEGRATED RESOURCE PLAN UPDATE

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1. Executive Summary

Ameren Missouri continues to execute on the preferred resource plan presented in its 2020 Integrated Resource Plan ("IRP") 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 50 percent by 2030, and 85 percent by 2040 compared to 2005 levels, with a goal of achieving net-zero carbon emissions by 2050. The plan includes continued customer energy efficiency program offerings, accelerating retirement of four coal-fired generating units, and expansion of renewable generation, with the addition of 2,700 MW of wind generation and 2,700 MW of solar generation by 2040. 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 2020 IRP include:

- Acquired 400 MW High Prairie wind facility in northeast Missouri in December 2020 and 300 MW Atchison wind facility in northwest Missouri in January 2021.
- Continued to work with developers for the acquisition of solar projects.
- Continued to develop and finalize plans for a new subscription-based renewable program for customers.
- Applied for one-year extension for the energy efficiency programs and the addition of demand response programs under the Missouri Energy Efficiency Investment Act ("MEEIA").
- Continued projects to close coal ash basins.
- Published our report on climate-related risks, *Committed to Clean: Transformational Changes Toward Net-Zero*, in May 2021.
- Continued to implement our Smart Energy Plan pursuant to Missouri Senate Bill 564, passed in 2018. 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 $6.8 billion of electric and $1.1 billion in wind investments from 2019 through 2023 that, among other things, accelerates our investment in smart grid technologies and renewable energy as we build the grid of the future, while keeping electric rates stable and affordable. The plan also accelerates smart energy infrastructure construction that is driving job creation and economic development in Missouri.

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:

- Consideration of climate-related legislation in the United States ("U.S.") Congress – Congress has considered, and continues to consider, a number of measures that may affect the economics of our transition to cleaner energy sources. These include extensions and expansions of clean energy tax credits, federal funding for development of new clean energy technologies, and mechanisms that encourage or require increases in the amount of clean energy delivered to customers.
- Recent court opinion regarding our Rush Island Energy Center – In August, the Eight Circuit Court of Appeals affirmed a District Court's liability determination, but partly reversed the remedial portion of its order regarding violation of the Clean Air Act's ("CAA") New Source Review ("NSR") provisions at Rush Island. The Company is evaluating options in light of this opinion.
- Illinois clean energy legislation – In September, the Illinois General Assembly passed the Climate and Equitable Jobs Act. The Company is reviewing the various provisions of the law and assessing potential impacts on Ameren Missouri's resource planning.
- Recent assessments by the Midcontinent Independent System Operator ("MISO") indicate a need for significant transmission investments in the coming years to facilitate the transition of the resource portfolio in its footprint to one that includes much greater reliance on intermittent renewable resources.

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 MoPSC'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." 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-2021-0069 establishing special contemporary issues for Ameren Missouri's 2021 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 IRP filing.

On that basis, Ameren Missouri has relied heavily on the groundwork developed in its 2020 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 2020 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 2020 IRP filing. In that filing, the Company indicated that its new Preferred Resource Plan includes the addition of 2700 MW of new wind generation and 2700 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 the 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 2020 IRP filing.

Demand-Side Resources 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.[1]

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.[2] Figure 2.1 provides the incremental annual net 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 2019-2024 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. Combined, approvals in EO-2018-0211 represent the largest commitment to DSM planning in the state of Missouri to date.

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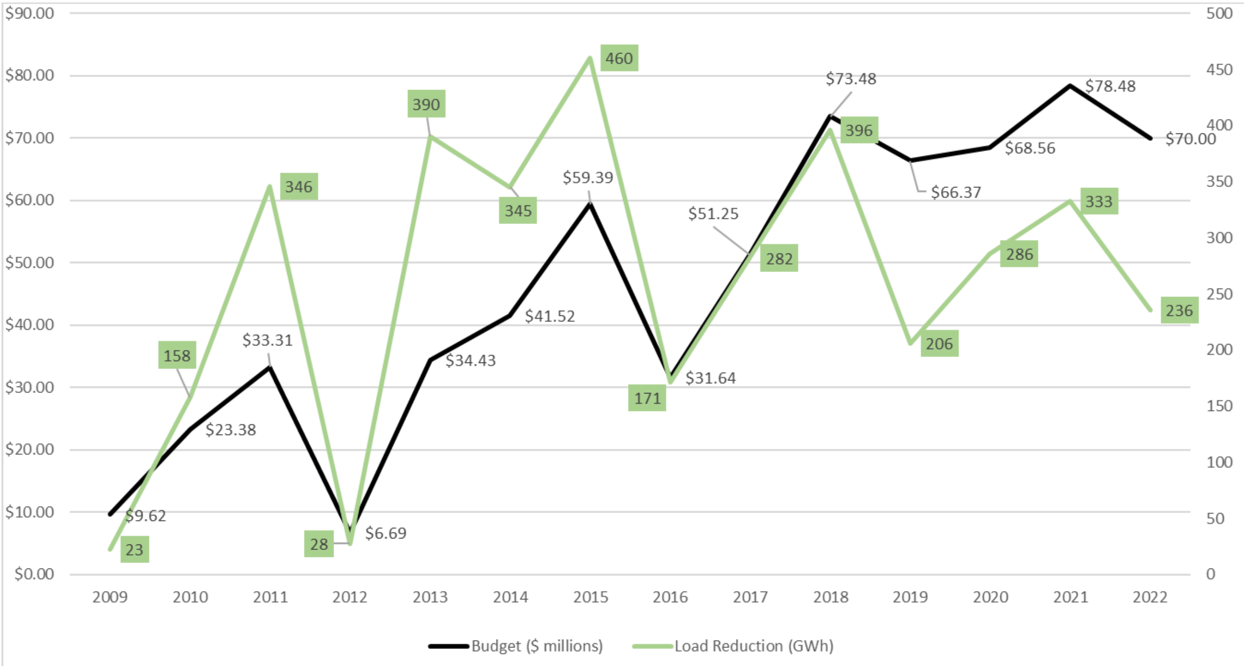
[1] In recent years, the Commission has provided additional guidance, noting that utilities should "be endeavoring to increase customer participation in energy efficiency programs" and recognized that "benefits from a reduction in a customer's bill is not the only benefit to customers. There are also 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.

[2] 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 Load Reductions



Note: This figure was originally provided as 8.4 in Chapter 8 of the 2020 IRP. It has been updated to include actual savings for program year 2020. Values for 2021 and 2022 represent net as filed values approved as part of program filings.

In July 2021, the Company filed a request with the MO PSC for another one year extension of its current MEEIA programs.[3] The extension would apply for program year 2023 ("PY23"). Budgets and savings targets for PY23 largely represent a continuation of the approved PY22 framework and are consistent with, but below, the levels required to reach the realistic achievable potential ("RAP") identified in the 2020 IRP as part of the preferred resource plan. While current budgets and savings are below RAP, this extension maintains current program momentum and keeps the Company on a path to achieve the preferred resource plan. This is discussed in greater detail at the end of this section.

Ameren Missouri has successfully implemented the first two years of this program cycle, for 2019 and 2020,[4] meeting or exceeding its portfolio savings targets in both 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.

[3] At the time of the filing of this annual update, Ameren Missouri, Staff and OPC agreed that extension through 2023 could be implemented and filed a non-unanimous stipulation and agreement with the Commission.

[4] 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 2.1: Net Energy Savings Compared to Goal, 2019 and 2020 (MWh)

	2019			2020		
	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%
Residential	112,823	118,985	106%	119,700	153,592	128%
Business	78.696	83,458	107%	152,847	120,206	79%
Portfolio Total	201,962	206,824	102%	286,405	286,358	100%

Table 2.2: Net Demand Savings Compared to Goal, 2019 and 2020 (MW)

	2019			2020		
	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%
Residential	57	53	92%	74	77	104%
Business	44.37	72	162%	89	91	101%
Portfolio Total	104	126	121%	167	171	102%

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

These programs incentivized:

- Almost 6 million LED bulbs;
- Over 25,000 residential HVAC systems;
- Over 30,000 learning thermostats;
- Over 35,000 school kits;
- Measures at over 3,000 income eligible homes and tenant units; and
- Over 5,000 projects at commercial and industrial facilities.

Opinion Dynamics also found that Ameren Missouri's low income programs saved an average of 17 percent and 27 percent on customer bills, for the single family and multifamily programs, respectively.

In 2020, the Company also made important progress with respect to co-delivering its multifamily 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 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.[5] The Company currently has approval to offer this innovative new program through 2022 and has applied for extension through 2023 and will continue to work with stakeholders and other utilities to develop the necessary framework for co-delivery and evaluation of this new program.
- Beginning in 2022, the Company will transition its current lighting program to become a dedicated low income program, with a 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 new targeted community lighting program will provide 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.
- In 2020, the Company launched a new midstream HVAC program. The midstream program provides rebates directly to equipment distributors for high efficient 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

[5] On August 5, 2020, the Commission approved a unanimous stipulation and agreement in File No. EO-2018-0211. Chapter 8 of the 2020 IRP provides an overview of some of the program changes anticipated for PY22.

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 acquired the Atchison Renewable Energy Center ("AREC") and High Prairie Renewable Energy Center ("HPREC") in order to meet Missouri's Renewable Energy Standard ("RES") requirements as laid out in the preferred resource plan. As of July 2021, all wind turbines are in-service at the HPREC and all wind turbines, with the exception of one, are in-service at the AREC. Ameren Missouri applied for a CCN for the Montgomery Community Solar Energy Center, and the Commission granted it in April 2021. The Montgomery Community Solar Energy Center is expected to be in-service by the end of 2021.

Ameren Missouri solicited competitive proposals from renewable energy developers through a request for proposal process for wind and solar projects in order to support the execution of our IRP preferred resource plan. Ameren Missouri is working to finalize a contract for a solar project in Southeast Illinois and expects to file an application for a CCN in the fourth quarter of 2021. Ameren Missouri continues to negotiate for additional renewable projects.

Ameren Missouri filed the non-pilot Community Solar program as part of the pending Electric Rate Review. Ameren Missouri also filed a 60-day notice for the Renewable Solutions tariff program and CCN in April 2021.

Meramec Energy Center

Ameren Missouri reaffirmed its decision to retire the Meramec Energy Center by the end of 2022 in the 2020 IRP and is taking the necessary steps for retirement, including the implementation of transmission system upgrades and required notifications to MISO.

Ameren Missouri is developing The Missouri Technical Application Center ("MOTAC") on the Meramec site. The MOTAC intended to provide a controlled environment in which to conduct comprehensive testing of electric grid automation and innovative customer technologies below 100 kV. MOTAC will serve three distinct purposes:

- **Staging & Demonstration** – Show stakeholders how the electric grid works, and demonstrate the benefits of grid automation and innovative customer applications by showcasing already field-proven technologies;

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

- **Testing & Validation** – Provide a platform for the testing and commissioning of new grid products, automation technologies, and electrification-based equipment in a controlled environment ahead of full-scale deployment; and
- **Research & Exploration** – Explore emerging technologies with industry, innovation, customer, and university partners as a means of pursuing a more "intelligent" grid and greater levels of energy efficiency with customers.

Ultimately, there are three major physical elements associated with the MOTAC concept – 1) a building housing multiple testing laboratories, a customer technology center, and associated technical personnel, 2) a distribution substation supplying outdoor 12kV overhead and underground feeder testbeds, and 3) a micro-grid with both controllable and intermittent generation sources, a battery storage system, and associated controls. The three elements are functionally independent of each other, each providing distinct benefits.

Environmental

The Company continues to implement its plan to safely close ash basins. As part of that plan, dry fly ash systems and new wastewater treatment plants have been implemented at Labadie, Rush Island, and Sioux Energy Centers. A new state-of-the-art ash basin cover system was recently completed at Rush Island, while similar projects at Labadie, Sioux, and Meramec are on-target to be completed this year and through 2023. An industry-leading groundwater remediation pilot project was installed at Rush Island in late 2020, and is already producing outstanding results. Similar projects are now being planned at the other energy centers for implementation beginning in 2021.

3. Planning Environment

3.1 Federal and State Energy and Climate Policy

Federal Energy and Climate Policy

Since the filing of our 2020 IRP, the federal policy landscape has been changed by the changes in control of the U.S. Congress and the presidency. Addressing climate-change is a top priority for the Biden administration and the Democrat controlled Congress. Given this priority, the U.S. rejoined the Paris Agreement and committed to an economy-wide 50 percent to 52 percent reduction of carbon emissions by 2030, with an ultimate goal of achieving net-zero carbon emissions by 2050. In light of this commitment, the Biden administration and other policymakers have called for the power sector to reduce its carbon emissions far more aggressively than other sectors of the economy. Notably, the power sector is being called on to achieve net-zero carbon emissions by 2035 and reduce carbon emissions by 80 percent below 2005 levels by 2030.

To achieve these goals, the Biden administration and some members of Congress inextricably link the need for significant action on climate change, energy infrastructure and income tax policies. In particular, the creation of a clean energy standard ("CES") continues to be considered as one option to significantly lower carbon emissions whereby standards are established that require that a certain percentage of the energy delivered to retail customers for electric service comes from "clean" energy resources (e.g. wind, solar, hydro, nuclear, and potentially natural gas). A CES is broader than a renewable energy standard because it includes diverse categories of clean energy beyond renewable energy.

In addition to focusing on a CES, the administration is simultaneously proposing that Congress pass an infrastructure bill that includes clean energy tax credits and significant federal funding for research, development and deployment of clean energy technologies. To help pay for these and other objectives of the Biden administration, increases in the corporate income tax rate, as well as changes to the dividend tax and capital gains tax rates, among other things, are being considered. Most recently, Congress has begun pursuing the enactment of some or all of these proposals via a process known as "reconciliation", which would only require a simple majority vote to be passed in the Senate. The "reconciliation" process has certain restrictions on the types of items that can be passed using that process, notably the need to have the provision be related to the federal budget and/or revenues. Thus, the ability to move a CES under reconciliation depends on how it is structured to comply with these restrictions.

Draft legislation currently under consideration in Congress includes a Clean Electricity Performance Program ("CEPP"), which provides grant payments for the achievement of annual increases in clean energy generation as a percentage of retail sales. The CEPP in its current form calls for retail electric suppliers to achieve annual increases in clean energy as a percentage of retail sales of 4 percent in each of the years 2023 through 2030. In any year in which this increase is achieved, the retail electric supplier would receive grant payments of $150/MWh for each MWh in excess of a 1.5% increase (2.5% in the first year). In any year in which this increase is not achieved, the retail electric supplier would be required to pay a shortfall payment of $40/MWh for each MWh short of the 4% increase target. Retail electric suppliers would be able to elect to defer grants and/or shortfall payments for up to two consecutive years, then settle the determination of grants or shortfall payments based on the average of the increase in clean energy percentage for the current year and each of the immediately preceding years in which deferral was elected. The determination of grants or shortfall payments in 2023 would be measured against a baseline determined by averaging the actual clean energy percentage of retail sales for years 2019 and 2020. Subsequent years clean energy increases would be measured against the highest clean energy percentage of any prior year. The current proposed language includes a requirement for DOE to conduct a rulemaking to establish additional details for the operation of the program.

Ameren Missouri's preferred resource plan achieves approximately 65% clean energy as a percentage of retail sales. Should the CEPP or similar proposal be enacted, Ameren Missouri may need to acquire greater levels of renewable resources to meet the indicated targets. Whether such a proposal is ultimately enacted, the proposed extension and expansion of renewable tax credits – the production tax credit ("PTC") and investment tax credit ("ITC") – would further bolster the benefits to customers of our planned resource portfolio transition as outlined in our IRP preferred plan. The current proposal under consideration in Congress includes extension of the PTC and ITC through 2031 at their full amount, with a subsequent phase-out in 2032 and 2033. It also includes the ability to use the ITC for stand-alone energy storage projects and the option to use the PTC for solar resources as an alternative to the ITC. In addition to tax credits for renewable energy resources, the current proposal also includes a 30% ITC for high voltage transmission investments, such as that needed to integrate renewable energy additions, and a production tax credit for existing nuclear generation resources.

While these proposals have not yet been enacted, we are mindful of the recent and continuing trend in sentiment among customers, investors, policy makers and the general public toward favoring cleaner energy resources. As we continue to monitor the policy landscape and consider potential impacts on our resource decisions, we must consider that while specific policy proposals may or may not come to fruition, the drivers of policy continue to point toward a cleaner and more sustainable energy future. As a result, we must continue to execute on our planned transition to best position our portfolio for success and ensure the benefits of reliable affordable service for our customers now and in the future.

State Energy and Climate Policy

In September of this year, the Illinois General Assembly passed the Climate and Equitable Jobs Act. The law includes requirements for emissions reductions from fossil-fueled generators, among other provisions. The Company is reviewing the various provisions of the law and is assessing potential impacts on Ameren Missouri's resource planning.

3.2 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 must 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 September of 2020 include revisions to the Clean Power Plan ("CPP"), final attainment designations for the national ambient air quality standards for ozone, revisions to the Coal Combustion Residual Rule, and implementation by Missouri of the Regional Haze Rule.

Table 3.1: Current & Pending Environmental Regulations

Regulatory Driver	Summary Requirements	Regulation Status	Compliance Timing
Cross-State Air Pollution Rule ("CSAPR")	Reduction in NOx and SO2 allowances vs. CAIR; New allowances for trading program (state level caps)	EPA implemented Phase 1 starting on 1/1/2015. On September 7, 2016 EPA finalized an update effective December 27, 2016 to lower the seasonal NOx (May-Sept) allocations beginning with the 2017 ozone season.	Compliance plan implemented and ongoing
Revised CSAPR Update	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
Revisions to National Ambient Air Quality Standards ("NAAQS")	Lower PM, NOx and SO2 limits; Expansion of non-attainment areas	SO2 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 attainment pending final action.	SO2: 2017 - 2020
		Fine particulate ("PM2.5") lowered 1/15/2013; Attainment designations 03/2015; Missouri in attainment. EPA retained the current 12 $\mu g/M^3$ standard in 2020. EPA announced it would conduct another review of the standard beginning in 2021.	PM2.5: 2025 - 2028
		Ozone standard lowered, final rule 12/2015; Attainment designations complete April 2018; St. Louis/Metro East area marginal nonattainment and size of area reduced.	EPA proposed to retain standard in 2020
Mercury and Air Toxics Standards ("MATS")	Reduction in emissions of Mercury, HCl (proxy for acid gases) and particulate emissions (proxy for non-mercury metals)	Final rule effective April 16, 2012. Compliance required by April 16, 2015.	Rush Island and Sioux Energy Centers compliant on Apr 16, 2015; Labadie and Meramec (units 3 & 4) Energy Centers received MDNR approved 1-yr extensions and compliant on Apr16, 2016.

Regulatory Driver	Summary Requirements	Regulation Status	Compliance Timing
Clean Air Visibility Rule ("CAVR")/Regional Haze Rule	Application of Best Available Retrofit Technology ("BART"); Targets reduction in transported SO2 and NOx; status of CSAPR may require state to change approach.	EPA issued revisions in Jan 2017 and guidance in 2018; MO working with affected sources and federal land managers to develop an approvable state plan in early 2021. States submit plans for second compliance period in 2021.	MDNR consulting with Federal Land Managers on a draft state plan. Missouri state plan required to be submitted to EPA by July 31, 2021.
Clean Water Act Section 316(a) Thermal Standards	Implementation through NPDES permit conditions	Evaluation covered by NPDES permits	Submittal for Labadie in 2020; other Energy Centers in 2021 & 2022
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	EPA revised rule effective October 2014; Study plans 2014; Studies 2015 - 2017; Compliance 2022 - 2024	Field work complete; Labadie submittal in 2020; Rush Island and Sioux submittals with permit renewal applications.
Waters of The United States ("WOTUS")	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" in April 2020.	Final rule effective June 21, 2020
Revisions to Steam Electric Effluent Limitations Guidelines ("ELG")	Dry ash handling and Installation of wastewater treatment facilities; Implemented through NPDES permit conditions	EPA linked ELG rule to CCR rule; EPA has stayed certain compliance deadlines during rulemaking to revise the final rule.	Implementing dry fly ash handling and wastewater treatment systems; coordinating with CCR compliance plan.
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. USEPA rulemakings in progress to revise regulation in response to Court and to implement the WINN Act.	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	New unit NSPS re-proposed Jan 2014; final rule effective 12/22/2015. EPA proposed revisions to rule in December, 2018; comments closed 3/18/2019. Challenges in DC Circuit Court held in abeyance.	New unit NSPS applies 1/8/2014; issuance of final rule pending.
		EPA issued final rule for modified and reconstructed units effective 12/22/2015. EPA proposed revisions to rule in December 2018; comment period closed 3/18/2019. Challenges in DC Circuit Court held in abeyance.	Modified/reconstructed applies 6/18/2014; issuance of final rule pending.
	State emission limits for existing sources	Clean Power Plan final rule was stayed by Supreme Court 2/9/2016; EPA finalized repeal and replacement of CPP with ACE rule in 2019; DC Circuit Court dismissed CPP case in September 2019. DC Circuit Court Vacated the ACE rule and CPP repeal on January 19, 2021 and remanded the rule to EPA. States and Industries have petitioned the Supreme Court to take the DC Circuit Court decision on appeal.	CPP was not implemented due to Supreme Court stay Final ACE rule effective September 2019 and vacated by DC Circuit court January 2021.

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

In 2015, the EPA issued the Clean Power Plan ("CPP"), which would have established CO_2 emissions standards applicable to existing power plants. The CPP was challenged in the DC Circuit Court of Appeals, however, the United States Supreme Court stayed the rule in February 2016, before the case was heard. As a result, the CPP was never implemented. The EPA promulgated the Affordable Clean Energy ("ACE") rule as a replacement for the CPP in September 2019, repealing the CPP in the process. The ACE rule established emission guidelines for states to follow in developing plans to limit CO_2 emissions from coal-fired electric generating units. The ACE rule defined certain efficiency measures that could be applied directly to coal fired boilers as the Best System of Emission Reduction ("BSER"). The DC Circuit Court vacated the ACE rule on January 19, 2021. Petitions for certiorari have been filed before the United States Supreme Court to hear the appeal of the DC Circuit Court decision.

Attainment Designations for the National Ambient Air Quality Standard ("NAAQS") for Ozone

The air quality in the St. Louis area continues to improve. The EPA re-designated the St. Louis and Metro-East Illinois area to be in attainment with the 2008 eight-hour ozone standard. The EPA further lowered the ambient standard for ozone from 75 ppb to 70 ppb in December 2015 (2015 ozone standard). The EPA made final designations for about 85 percent of the country in November, 2017, however those designations did not include the St. Louis/Metro-East Illinois area. The EPA released final designations for the St. Louis/Metro-East Illinois area as well as the other remaining areas of the country on April 30, 2018. The final designation for the St. Louis area reduced the size of the nonattainment area by removing Jefferson County in Missouri and Monroe County in Illinois, as well as all but a small portion (Boles Township) of Franklin County in Missouri. However, on July 10, 2020, the DC Circuit Court of Appeals remanded to EPA the final designations for Jefferson County, MO and Monroe County, IL in Clean Wisconsin vs. EPA. On May 24, 2021, EPA promulgated a final rule in response to the remand designating Jefferson County and Monroe County as nonattainment for the 2015 ozone standard.

The St. Louis area was designated as marginal, which is the least severe category. Marginal areas have ozone design values from 71 ppb to 81 ppb. The St. Louis area has a design value of 72 ppb based on three years of monitoring data used for the designation. However, because the St. Louis area is expected to fail to attain the 2015 ozone standard by the marginal area attainment date of September 2021, the area is likely to be designated moderate nonattainment in 2022.

Coal Combustion Residuals

The federal Coal Combustion Residuals ("CCR") rule was published April 17, 2015, and became effective October 19, 2015. It establishes national standards for the management of CCRs. The CCR rule is self-implementing, and the Company continues to fully comply with the Rule requirements. The EPA has recently initiated a series of rulemakings to revise the federal CCR rule in accordance with the Water Infrastructure Improvements for the Nation ("WIIN") Act as well as recent court decisions.

Ameren Missouri is executing its compliance strategy in advance of the regulatory deadlines. The Company continues to monitor the potential for further changes in regulations that may impact resource planning decisions.

Groundwater Remediation

In late 2020 Ameren Missouri partnered with an outside consulting firm on a groundwater remediation project at the Rush Island Energy Center. This pilot project is set up to ultimately improve groundwater quality around the site by using a pump and treat method. Groundwater removed through extraction wells is treated in an above ground structure, then discharged through injection wells back into the ground. Removing groundwater impurities mechanically in conjunction with natural attenuation will speed up reductions of groundwater constituents. To date, this pilot project has shown exceptional results well below the UIC permit limits. Ameren Missouri plans to execute similar projects at both the Sioux and Labadie Energy Centers starting late 2021.

Ash Basin Closure Initiatives

In 2020, Ameren Missouri completed closure of the ash basin impoundment at Rush Island Energy Center, and attained substantial completion of the impoundments at Labadie Energy Center. Closure of the remaining impoundments at Sioux Energy Center will be completed in 2021, as well as two impoundments at Meramec Energy Center. After retirement of the Meramec Energy Center, the remaining CCR basins will be closed in 2023. The closure of these ash basins coincides with our conversion of coal-fired energy centers to dry ash handling, which will reduce our consumption of approximately 11 billion gallons of water per year. With regard to groundwater and drinking water concerns, extensive analyses and tests have been undertaken by an independent third party expert (many of which are beyond regulatory requirements).

Those tests have concluded:

- There is no significant adverse impact on human health or the environment from our CCR management practices.
- There is no evidence of CCR impacts in rivers or streams close to our facilities or in groundwater used for drinking water.

While mitigation has been included in our analysis for current and certain potential future regulations, further changes in regulations are possible. The Company continues to monitor the potential for further changes in regulation that may impact resource planning decisions. Table 3.2 below shows the cost assumptions for environmental mitigation.

Table 3.2: **Environmental Mitigation Costs**

Facility	Environmental Mitigation	Regulation	In-Service Year	Cost (2021 & beyond incl. AFUDC) $ Million	Annual O&M $ Million
Meramec	Ash Pond Closure	CCR	2024	34	0.1
	Groundwater Improvements	CWA	2025	6	0.4
Meramec	Total Environmental			40	0.5
Labadie	Landfill Cells	CCR	2028*	76	-
	Aquatic Life	CWA 316	2023	30	-
	Groundwater Improvements	CWA	2023	20	1.1
Labadie	Total Environmental			125	1.1
Rush Island	Traveling Screens	CWA 316 (b)	2026	28	-
	Groundwater Improvements	CWA	2021	17	0.4
Rush Island	Total Environmental			44	0.4
Sioux	Ash Pond Closure	CCR	2021	27	0.2
	Landfill Cells	CCR	2024**	26	-
	Traveling Screens	CWA 316 (b)	2026	14	-
	Groundwater Improvements	CWA	2023	16	0.1
Sioux	Total Environmental			83	0.3
TOTAL	Total Environmental			**293**	**2.3**

Rush Island NSR

In August 2021, the U.S. Eighth Circuit Court of Appeals (Appellate Court) affirmed the prior ruling of the U.S. District Court of the Eastern District of Missouri (District Court), which had found that certain projects implemented at the Rush Island Energy Center had violated the NSR provisions of the CAA. The Appellate Court reversed in part the District Court's remedy for the violation and remanded the case to the District Court for further proceedings consistent with the Appellate Court opinion. Specifically, the Appellate Court reversed the District Court's requirement that pollution controls be installed at the Labadie Energy Center. The Company is currently considering options in light of the Appellate Court opinion.

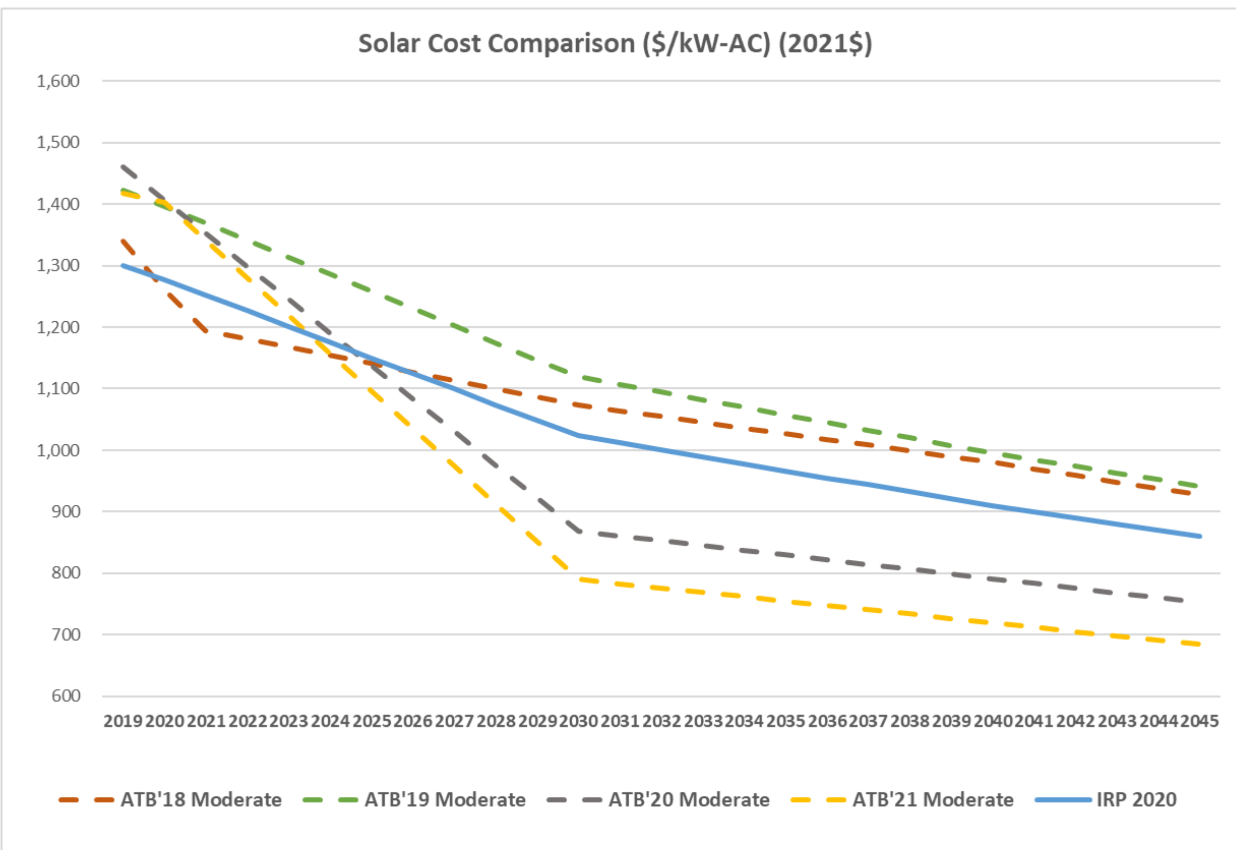
3.3 Supply-Side Resource Review

Ameren Missouri has analyzed the cost and performance characteristics of a wide range of supply side resources in its 2020 IRP and has documented its analysis in Chapter 6 of its 2020 IRP filing. New supply side resources that were evaluated in the alternative resource plans in the 2020 IRP include the following;

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

Since the development of costs for supply side resources for the 2020 IRP, Ameren Missouri's expectations associated with owning these resources, with the exception of batteries, have not materially changed.

Figure 3.1: 2020 IRP vs ATB Solar Capital Cost



Ameren Missouri expects, as when the 2020 IRP was filed, that solar costs will continue to decline in real terms. The 2020 IRP utilized the National Renewable Energy Laboratory ("NREL") 2019 Annual Technology Baseline ("ATB") data, specifically the moderate capital cost curve, to estimate expected costs. Shortly before the 2020 IRP filing, NREL released an updated version of the ATB for 2020, which features new capital cost curves, and have since followed up with an additional release for 2021. The updated 2020 and subsequent 2021 moderate curves show much steeper cost decline projections than in the 2019 moderate case. Figure 3.1 shows the various ATB moderate capital cost curves along with the 2020 IRP assumptions.

After reviewing the new assumptions that led to this update, in addition to comparing NREL's estimates with recently received Request for Proposal ("RFP") responses for regional utility-scale solar resources, Ameren Missouri intends to continue to utilize the solar capital cost curve used for its 2020 IRP for future analyses. Prior to filing the next full IRP, solar capital cost curves will be reevaluated using the most current recommendations available at that time.

Figure 3.2: **2020 IRP vs ATB Battery Storage Capital Cost**

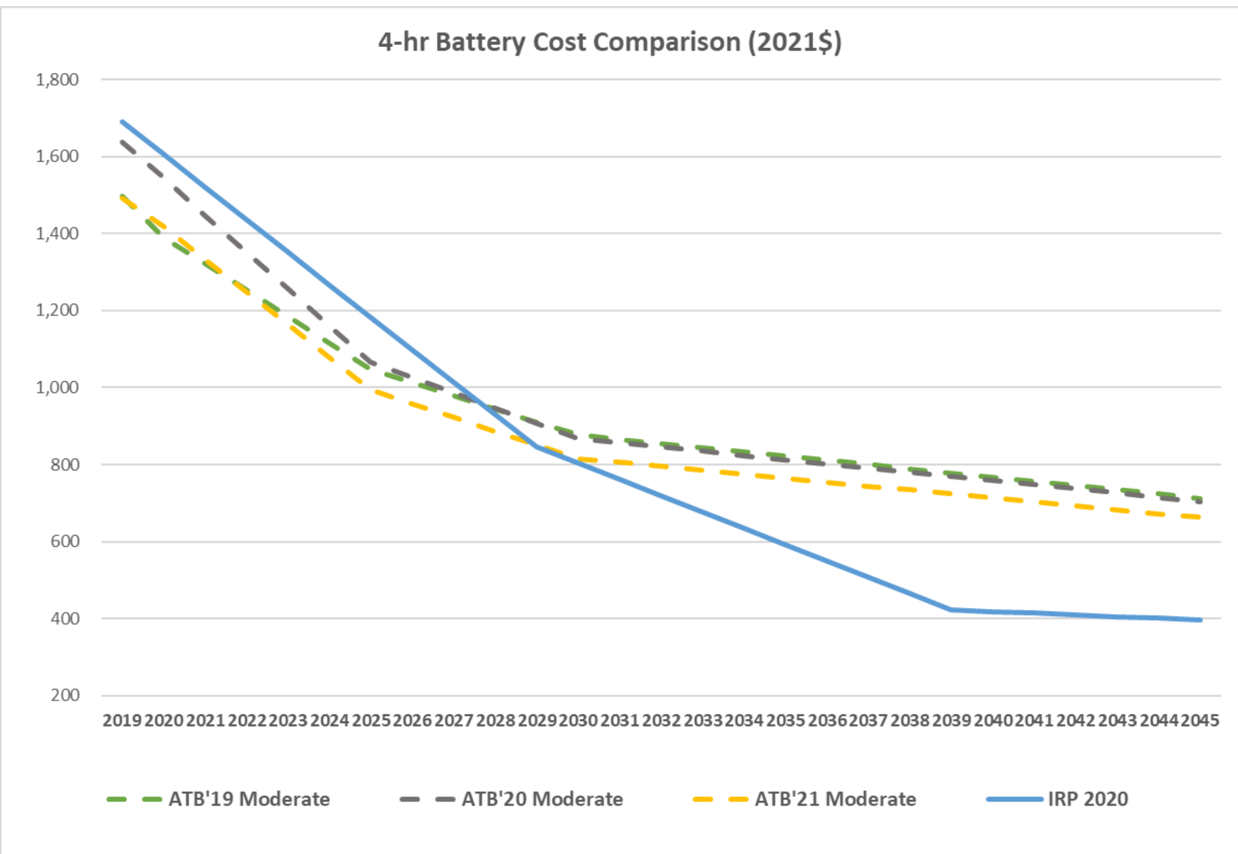
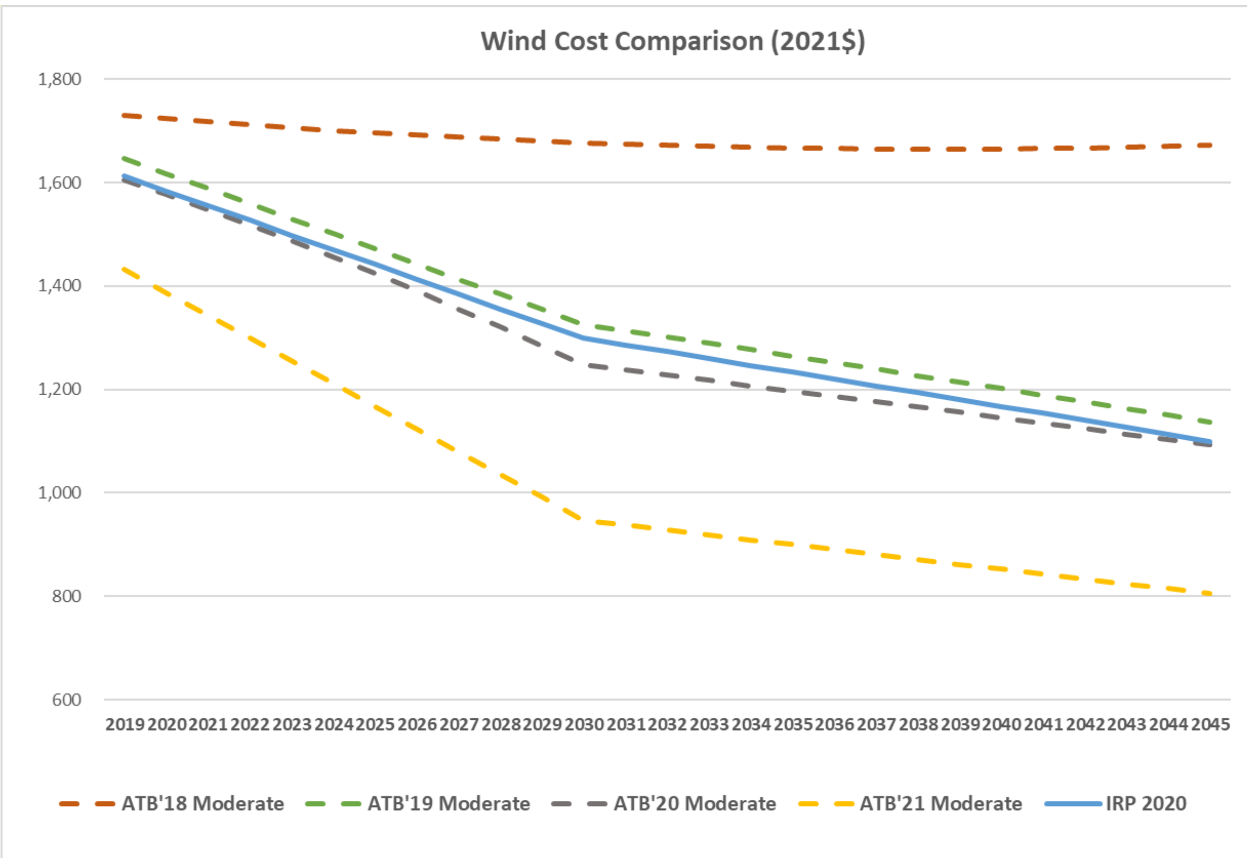


Figure 3.2 displays the 4-hour battery storage cost curves from various ATBs and the 2020 IRP. For further analyses involving battery storage, Ameren Missouri is updating its capital cost assumptions to the 2020 moderate curve for 4-hour battery storage while also continuing to monitor longer duration battery storage costs.

Table 3.3: 2021 Annual IRP Update Battery Characteristics (2021$)

Resource Option	Plant Output, MW	Project Cost with Owner's Cost, Excluding AFUDC ($/kW)	First Year Fixed O&M Cost ($/kW-year)	Assumed Annual Capacity Factor (%)	LCOE (Cents/kWh)
Li-Ion Battery 4-hour duration	10	$1,448	$1	16.7%	$15.97

Figure 3.3: 2020 IRP vs ATB Wind Capital Cost



Ameren Missouri is not changing its regional wind cost assumptions at this time. Cost assumptions for a PPA for Grain Belt Express, including investment in wind resources and commensurate investment in the HVDC transmission line, would be similar to what we assumed in the 2020 IRP with Ameren Missouri owning it, resulting in an LCOE of **____** cents/kWh including 60% PTC assumption.[7]

Even though Ameren Missouri is not changing the resource cost assumptions, the changes in federal tax incentives as of July 2021 would result in a reduction in the present value of revenue requirements ("PVRR") of about $63 million through implementation of the renewable resources shown in its preferred plan, all resulting from extension of the solar ITC.

Because this is an annual update and not a full IRP, and because no changes in assumptions are expected to affect a screening analysis of supply side resources, Ameren Missouri has not performed a new screening analysis. A new supply side screening analysis will be performed as part of the development of Ameren Missouri's 2023 IRP. This will include both renewable and energy storage resources, which will be screened for inclusion in alternative plans, including any plans reflecting alternative retirement dates for existing coal-fired resources.

Renewable Energy Offerings

Ameren Missouri has developed, and the Commission has approved, a number of programs that are designed to increase access to renewable energy for all customers. Since filing the 2020 IRP, Ameren Missouri has made meaningful progress on these programs and has initiated one new program offering:

Neighborhood Solar: The Neighborhood Solar Program aims to site solar generation at customer partner sites that will inclusively benefit customers through renewables education, visibility, and workforce opportunities. Ameren Missouri will own and operate all Neighborhood Solar systems for the benefit of all customers; host participants provide site access to the partnership. Since the 2020 IRP filing, Ameren Missouri has completed one Neighborhood Solar site and is in the process of developing two additional sites. The sites are as follows:

- Habitat for Humanity (192 kW-AC): In-service August 2021
- Southern Missouri State University (1.2 MW-AC): In-service expected April 2022
- City of Maryland Heights Community Center (approximately 500 kW-AC): In-service expected March 2023

Community Solar: In May 2020, Ameren Missouri received approval to expand its successful Community Solar Pilot Program. Shortly after the 2020 IRP filing, Ameren Missouri filed an application for a CCN for a 5.7 MW-AC solar system in Montgomery County to support the pilot program expansion, which the Commission approved in May

[7] File No. EO-2021-0069, Order, p.4, ¶ 1(D), Issued November 4, 2020.

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2021. The project is expected to come online in early 2022. In addition to the pilot expansion, 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. If approved, the permanent Community Solar Program will be available to residential and small commercial customers, and will enable them to match 100% of their usage with solar energy.

Subscription Renewables: Ameren Missouri expects to file an application for approval of a subscription renewable program with the MoPSC, as well as an application for a CCN for a solar project to support Phase I of the program in the fourth quarter of this year. The program will be a voluntary renewable energy subscription program designed for larger commercial, industrial, and municipal customers. Many of Ameren Missouri's larger customers have publicly expressed their desire for near-term access to renewable energy in the form of sustainability goals for both carbon dioxide emission reduction and renewable energy supply. The program is designed to offer those customers a pathway to meet their sustainability goals with local renewable energy while producing net benefits for all Ameren Missouri customers.

Small Modular Reactors[8]

Although the new nuclear plants in the current global nuclear expansion are large scale reactors employing advanced safety features and enhanced reliability, the United States nuclear industry is considering a different approach by turning toward smaller reactors.

Small modular reactors ("SMR") have a number of characteristics that illustrate the unique role that they can play in our future energy mix: (1) SMRs are relatively small in power output, (approximately 300 MWe), versus large-scale reactors that can have a power output of more than 1,000 MWe; and (2) SMR designs are modular. Unlike traditional reactors, SMRs would be manufactured and assembled at a factory and shipped to the construction site as nearly complete units, resulting in much lower capital costs and much shorter construction schedules. SMRs also permit greater flexibility through smaller, incremental additions to baseload electrical generation, and more SMRs can be added and linked together for additional output as needed.

The U.S. Department of Energy ("DOE") has provided $400 million in funding since 2014 for the development of SMRs. NuScale Power's SMR received the U.S. Nuclear Regulatory Commission's ("NRC") design approval in 2020. The NRC is currently taking

[8] File No. EO-2021-0069, Order, p.3, ¶ 1(B), Issued November 4, 2020

public comments on a proposed rulemaking for the NuScale SMR design certification through mid-October.

The NuScale Power Module is a 77 MWe advanced light-water SMR. Each power plant can house up to 12 modules, which will be factory-built and about a third of the size of a large-scale reactor. Its unique design allows the reactor to passively cool itself without any need for additional water, power or even operator action.[9]

DOE is supporting the siting of the nation's first 12-module SMR plant at Idaho National Laboratory. Operation is expected to begin in 2029. Ameren Missouri is following advancements in the SMR arena as well as other supply-side resource options and plans to include SMR as a candidate resource option in its 2023 IRP.

Long Duration Storage[10]

In our traditional framework of electrical energy generation, transmission and distribution: energy is consumed at the same time is being produced. This reality is based on the fact that electric energy travels at nearly the speed of light and must be converted to other forms (e.g., chemical, mechanical) to be stored.

For decades, regional balancing authorities have had the ability to ensure, in real time, that power system demand and supply are finely balanced. This balance is needed to maintain the safe and reliable operation of the power system. If demand and supply fall out of balance, local or even wide-area blackouts can result. In our service territory, MISO maintains appropriate operating conditions for the electric system by ensuring that a sufficient supply of electricity is available to serve expected demand, which includes managing transfers of electricity with other balancing authorities. Balancing authorities are responsible for maintaining operating conditions under mandatory reliability standards issued by the North American Electric Reliability Corporation ("NERC") and approved by the U.S. Federal Energy Regulatory Commission. These operators monitor the grid to identify potential problems before a situation becomes critical.

The decreasing cost of renewable energy generation is resulting in increasing participation in MISO's control area. However, wind and solar are non-dispatchable generators. At best, they can be curtailed. Then, the need for a stabilizing system component arises. Entrepreneurs and technology providers have been offering multiple stationary battery technologies to fill that role. Island electrical systems, which are less stable due to their weak inertia, have successfully used energy storage in recent years.

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[9] https://www.energy.gov/ne/articles/nrc-approves-first-us-small-modular-reactor-design
[10] File No. EO-2021-0069, Order, pp.4-5, ¶ 1(E), Issued November 4, 2020.

East and west coast control areas have opened their frequency regulation markets to enable the participation of utility-scale energy storage.

Ameren Missouri is observing peer utility deployments and is concluding that they are driven by:

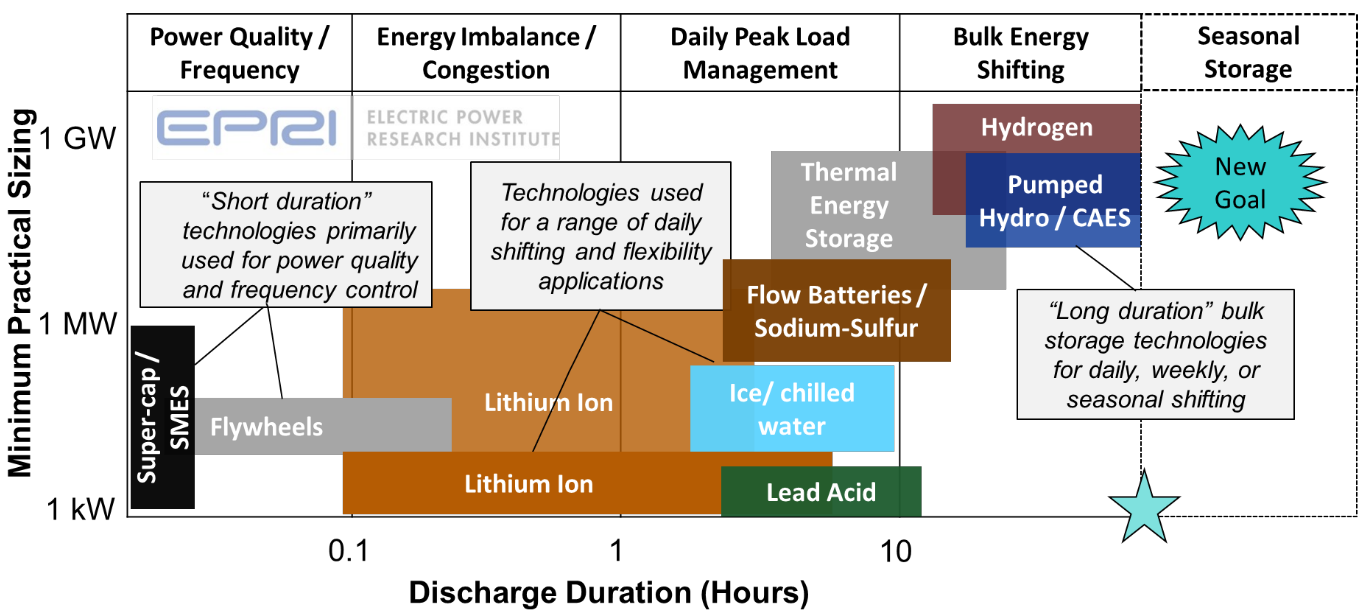
- Technology cost reductions
- The emergence of new products and improvement of existing ones
- Continued growth of wind and solar generation
- Changes in regulatory and policy environments

We are following outcomes from recent commercial deployments for the following applications around the country:

1. Distribution resilience and reliability (power quality)
2. Frequency regulation and energy imbalance
3. Load peak management (demand charge management)
4. Utility solar plus storage (energy shifting)

In February of 2021, the Electric Power Research Institute ("EPRI") published the mapping of technologies that address the above applications today (or are likely to address them in the future).

Figure 3.4: Battery Technology Applications



(Illustration Source: EPRI Report # 3002019019
Link: https://www.epri.com/research/products/000000003002019019)

Over the years, lithium-ion batteries, flywheels, and super-capacitors have addressed the short duration operational needs in our industry (see the first and second columns in Figure 3.4 above). Li-ion battery CapEx and O&M costs have declined consistently. However, all these three technologies are classified as "power batteries." They are intrinsically capable of charging/discharging at high power flow for short periods of time. Stacking of Li-Ion batteries have reached practical limits in the range of 4 to 6 hours.

Moving forward, and for the next 20 years, our industry is challenging technology providers to address the need for long duration batteries. This operational and business need would be covered by technologies having the techno-economic capability to charge and discharge for long periods of time. While there is no consensus in terms of the length of time for charging/discharging, long duration batteries would support a load for greater than 6 hours. Following are brief descriptions of key technologies under consideration:

Pumped-Storage Hydropower - Contributing mostly to manage peak load, Ameren Missouri owns and operates a pumped-hydro storage facility in Taum Sauk. It is capable of generating 440 MW for up to 8 hours.

Lead Acid Batteries – Since 2015, Ameren Missouri has been supporting applied research and the actual piloting of this technology at the Missouri University of Science and Technology in Rolla, MO. Today, we are designing, procuring, and deploying this technology in two distinct applications within Ameren Missouri sites:

- Managed Charging for Fleet electric vehicles ("EV") [long duration; low cyclic capability]
- Flexible Datacenter Load & Green Load Response [short duration; high cyclic capability]

Ameren Missouri is committed to supporting our region's economic development by helping bring to market lead-acid battery products that are mined, processed, manufactured, marketed, and recycled in our state.

Gravitational Energy Storage ("GES") - Gravity-based energy storage systems consist of thousands of stackable concrete composite blocks, a six-armed crane, trolleys, reversible hoist motor-generators, sensors and cameras, and control software (see Figure 3.5 below). Potential energy is stored by lifting the blocks from a ground-level stack to a tall stack using the reversible direct-current ("DC") hoist motor-generators in motor mode. Kinetic energy is released and converted to electricity when the high-stack blocks are returned to the ground by gravity, with the hoist motor-generators operating in generator mode. In essence, the process involves building a tall tower of blocks from squat towers of blocks and subsequently deconstructing it. The velocity with which the blocks are lifted and lowered can be varied to control the rate of load absorption and power release, respectively.

The leading company commercializing this technology is Energy Vault. They offer storage of energy for several hours using low-cost materials that can be locally sourced almost anywhere. Designed to be deployed in 10 MWh blocks, the system can be configured to either 2-6 hours duration or 6-12 hours. A demonstration project rated at a nominal 5 MW of power and 35 MWh of energy was built in July 2020 and connected to the grid in Switzerland. While this technology is currently implemented at relatively small scales for electric utility application, Ameren Missouri will continue to monitor developments that may warrant inclusion of this technology in future resource screening analyses.

Figure 3.5: Energy Vault Storage System - Fully Charged to Fully Discharged

(Illustration Source: Business Wire
Link: https://www.businesswire.com/news/home/20181106006096/en/Energy-Vault-Announces-Commercial-Availability-of-Transformative-Utility-Scale-Energy-Storage-Technology-Yielding-Unprecedented-Economic-Benefits-to-Global-Energy-Providers)

Value of Solar

There are many challenges associated with conducting a value of solar study that informs efforts related to integrated resource planning. First and foremost, value of solar studies, while relatively limited in maturity, are typically used to develop the rate of compensation that a utility would pay customers for behind the meter solar generation. Furthermore, a value of solar compensation rate helps to define the benefit which accrues to a customer who decides to install behind the meter solar generation, and therefore informs a customer's private decision making process. It is difficult to see how a value of solar study directly informs integrated resource planning, because the value informs the decision made independently by each customer. The Company's most recent Demand

Side Management Market Potential Study showed that behind the meter solar failed the total resource cost test, indicating that Company involvement in the promotion of behind the meter solar generation would result in an increase in revenue requirements. Nonetheless, the Company has conducted a detailed review of the literature cited by the Commission and an evaluation of the value of solar in the Company's service territory; this analysis can be found in Appendix A.[11] Ameren Missouri is open to continued discussion about the appropriate compensation rate for behind the meter solar generation, but ultimately believes those conversations should occur in a public policy forum and not within the IRP process. A revised policy approach to solar compensation would then feed back into the resource planning process in future years as a variable impacting expected behind the meter solar adoption and therefore energy and capacity needs for the system in future years.

Solar Panel Direction[12]

Currently, the majority of customers with solar generation engage with the Company with respect to their excess generation through net energy metering. This existing tariff framework could potentially be adapted to encourage west-facing installations, which may reduce total energy output relative to south-facing installations, but increase the capacity value of the resource due to higher resource availability associated with west facing installations late in summer afternoons when capacity needs are greatest. However, certain issues and potential barriers exist to making the modifications to net metering that would achieve this goal. Those issues will be discussed further below.

Net metering, as applied to the Company's historical flat rate structure, provides the incentive for customers to maximize total energy output, irrespective of the time of generation, which implicitly incentivizes south-facing installations. The Company is in the middle of the deployment of a number of Time of Use ("TOU") rate options that value energy differently depending on the time when customers use (or, potentially in the future, generate) it. Aligning the time periods and rate levels of the TOU rate structure with the underlying cost structure of the utility by time of day, and having those rate structures become available, and applicable, to net metered customers, is likely the most effective way to encourage customers to make decisions around solar installations that balances the energy and capacity value of behind the meter resources to the benefit of the system and all customers.

In order for this solution to be effective, there are two considerations that should be highlighted. First, it is important for the TOU peak periods to be defined based on time

[11] File No. EO-2021-0069, Order, p.5, ¶ 1(H)(2), Issued November 4, 2020.
[12] File No. EO-2021-0069, Order, p.5, ¶ 1(H)(1), Issued November 4, 2020.

periods when the *net* system load peaks (net system defined as system load net of variable renewable generation – both customer and utility owned sources). This is because the rate is applicable to the customer's net load, and the customer-generator's contribution to the *net* system load is what really must be planned for and balanced by the dispatchable resources on the system. To that end, the Company has proposed in its ongoing rate proceeding (File No. ER-2021-0240) to make a modest change to better align the peak period of one of is TOU rates (Smart Savers) with the expected net system load profile on a forward looking basis. The Smart Savers rate, with the adapted peak time period proposed by the Company, would place a premium on late afternoon (3-7 p.m.) usage (and, potentially in the future, generation), which would tend to encourage west-facing installations that generate more energy in the hours that occur as the sun declines in the west relative to the existing flat rate.

The second issue with respect to utilizing TOU rates in conjunction with net metering relates to the fact that Ameren Missouri's more sophisticated TOU rates are not currently being made available to net metered customers. This fact arises from the existing net metering statute, which essentially requires utilities to net all energy usage and generation across the entire billing period equally, which is counter to the nature of TOU rates that value energy usage and generation differently based on the time period it occurred. While the Company would prefer to make its TOU rates available to net metered customers, as these rates best reflect the cost of serving customers, it believes that the statute must be amended in order to offer TOU rates to net metered customers in a manner that appropriately conveys the TOU price signals. So while the Company is currently not able to utilize its TOU rates to promote a more balanced consideration of energy and capacity needs in the design of customer generation systems, it is interested in pursuing a path that would enable such an outcome.

Virtual Power Plant[13]

A virtual power plant ("VPP") captures the concept that the monitoring, analysis, optimization, and dispatch of aggregated distributed energy resources ("DER") can provide the same essential services as a traditional centralized power plant. The framework provides a strategy to manage the increasing two-way complexity in accommodating diverse DERs.

Today and in the future, electric utilities around the country have and will have distinct DER portfolios. These differences are dictated by factors such as climate and geography. Further, stakeholders are at very different stages of awareness around technology, business and regulatory frameworks. While recognizing a wide divergence in thoughts

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[13] File No. EO-2021-0069, Order, p.3, ¶ 1(A), Issued November 4, 2020.

about what exactly constitutes a VPP, Ameren Missouri proposes that **supply-side VPPs** be defined as:

> *An aggregation of distributed generators that form a virtual entity that interacts with a distribution system operator ("DSO") and/or an independent system operator ("ISO"). Through telemetry and software, the energy, capacity, and flexibility in all DERs are aggregated to achieve meaningful levels (tens to hundreds of MW & MWh)*

Further, the industry recognizes two other types of VPPs described as follows:

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.

Mixed Asset VPPs: Aspirationally, they will be a platform 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.

Recent utility stakeholder surveys show that peer utilities are seeking to modernize legacy demand response programs and widen the pool of integrated DER assets ranging from dispatchable loads to distributed generators as well as from energy storage to EV chargers.

Ameren Missouri is embarking on a phased approach to integrate an increasing number of DERs. The scaling of the future platform would include multiple DER types to achieve meaningful power and energy sizes (i.e., hundreds of MWs and MWhrs). From the beginning, the VPP platform will be capable of integrating DER in front of the meter or behind the meter (customer-owned).[14]

The business and technical capability that a VPP requires is included as a subset of functions that an enterprise Distributed Energy Resource Management System ("DERMS") would offer. Through a procurement event in 2022, Ameren Missouri will seek to partner with the most capable technology provider that has the ability to customize an

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[14] Ameren Missouri believes current levels of customer-owned solar generation are sufficient to include in a VPP implementation.

enterprise solution specific to the business and technical requirements of Ameren Missouri's near and long term DER portfolio plan.

An essential part of Ameren Missouri's 2022 procurement process will be the techno-economic analysis of the value stack that VPPs can offer through:

- Grid services to its own T&D operations
- Grid services to MISO

Existing Resources

A detailed analysis for Ameren Missouri's existing resources was included in the 2020 IRP along with evaluation of alternative resource plans that included various options for early retirement of its coal-fired energy centers. Ameren Missouri's preferred plan accelerates retirements of Sioux Energy Center and Rush Island Energy Center by five and six years, respectively. Figure 3.6 shows the total variable costs (fuel and non-fuel) for coal energy centers in the MISO market. With the exception of Meramec Energy Center, which is scheduled to retire by the end of 2022, all Ameren Missouri coal-fired energy centers are in the lowest and/or second-lowest quartile of the coal-fired plants within the MISO footprint.

Figure 3.6: MISO Coal Plant Variable Cost (Fuel and Non-Fuel)[15]

** [redacted] **

Conversion of Combustion Turbine Units to Combined Cycle Units[16]

For the 2021 Integrated Resource Plan Update, Ameren Missouri utilized subject matter experts and historical studies to consider, to the extent applicable, the potential for converting existing combustion turbine ("CT") units to combined cycle ("CC") units as resource candidates in supply-side resource analysis.

The Meramec, Fairgrounds, Mexico, Moberly, and Moreau CTs are excluded from this conversion consideration. As noted in Chapter 4 of the 2020 Integrated Resource Plan,

[15] Source: FERC Form 1 via SNL (Major 500 – 514 for Individual Energy Centers)
[16] File No. EO-2021-0069, Order, p.4, ¶ 1(C)(1), Issued November 4, 2020.

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CTs at those locations are over 40 years old and are currently planned for retirement by the end of 2026.

A multitude of factors can impact the feasibility of such a conversion, and can include relatively static factors such as CT size and site geography, and more dynamic factors such as applicable laws and regulations. For this 2021 IRP Update, fundamental requirements that would be essential for CT to CC conversion were considered, and include availability of fuel, water, and transmission, as well as physical space requirements for the additional equipment. Table 3.4 outlines the potential for CT to CC conversion at each site, based on these fundamental requirements. Such a consideration serves as an initial screening to narrow the range of options that could warrant more detailed studies and analyses.

Fleet wide, natural gas supply and transmission capabilities exist at each location, though site capacity increases would require additional studies. The actual transmission capability of each site would be determined through the MISO Generation Interconnection process, but none of the CTG sites currently have the existing transmission capability to support 1,000 MW of CC generation. While most sites have adequate acreage to support a CT to CC conversion, the location and orientation of the current CTs and switchyards may impose construction and/or cost constraints that render a conversion unfeasible. Additional potential constraints on the viability of CT to CC conversion lie with the existing CT technology and capability.

Table 3.4: Potential for CC Conversion

Unit	Capacity (MW)	CC Conversion Potential Water	CC Conversion Potential Transmission	CC Conversion Potential Land	CC Conversion Potential Existing CTG Cond	CC Conversion Potential Gas Availability
Pinckneyville 1	44		Additional transmission capability determined through MISO GI process	Y	Low capacity; No ramp capability	Y
Pinckneyville 2	44					
Pinckneyville 3	44					
Pinckneyville 4	44					
Pinckneyville 5	35	Water constraints			Existing CT technology dated; Low capacity; No ramp capability	
Pinckneyville 6	35					
Pinckneyville 7	35					
Pinckneyville 8	35					
Kinmundy 1	105	Water constraints	Additional transmission capability determined through MISO GI process	Y	Low capacity	Y
Kinmundy 2	105					

Unit	Capacity (MW)	CC Conversion Potential Water	CC Conversion Potential Transmission	CC Conversion Potential Land	CC Conversion Potential Existing CTG Cond	CC Conversion Potential Gas Availability
Goose Creek 1	72	Water constraints	Additional transmission capability determined through MISO GI process	Site layout constraints	Y	Y
Goose Creek 2	72					
Goose Creek 3	72					
Goose Creek 4	72					
Goose Creek 5	72					
Goose Creek 6	72					
Peno Creek 1	48	Additional water supply needed for inlet chillers	Additional transmission capability determined through MISO GI process	Y	Low capacity; No ramp capability	Y
Peno Creek 2	48					
Peno Creek 3	48					
Peno Creek 4	48					
Audrain 1	76	Water constraints; Additional water supply needed for inlet chillers	Existing transmission constraints; Additional capability determined through MISO GI process	Site layout constraints	Y	Y
Audrain 2	76					
Audrain 3	76					
Audrain 4	76					
Audrain 5	76					
Audrain 6	76					
Audrain 7	76					
Audrain 8	76					
Raccoon Creek 1	77	Water constraint; Additional water supply needed for inlet chillers	Additional transmission capability determined through MISO GI process	Site layout constraints	Y	Y
Raccoon Creek 2	77					
Raccoon Creek 3	77					
Raccoon Creek 4	77					
Venice 2	49	Y	Additional transmission capability determined through MISO GI process	Site layout constraints; CTs separated	Dissimilar units, Likely only Units 3 & 4	Need additional gas line capacity ($45M in 2009)
Venice 3	170					
Venice 4	170					
Venice 5	105					

Venice units 2 and 5 are different CTs and physically separated from units 3 and 4, which are identical. CTs at Peno Creek, Kinmundy, and Pinckneyville have units or with low capacity or low overall site capacity, little or no ramp capability, and dated equipment. With the exception of Venice, availability of an adequate supply of cooling water is a potential constraint at each location. A previous conversion study for Venice determined a substantial investment would be required to supply sufficient gas to a CC unit.

Additional analysis of any potential CT to CC conversion would be required to gauge the cost-effectiveness of such a conversion against other potential generation alternatives, and include consideration of age and condition of existing CTs, and capability and capacity of existing peripheral systems, equipment, and structures. The total cost of the conversion and the incremental generation from the steam turbine should be compared against other potential generation alternatives.

The preceding analysis provides an overview of the potential for converting these existing CT units to CC units. Further analysis would require more detailed studies and evaluation of additional variables and constraints, including transmission requirements, firm transport contracts for fuel capacity in winter months, existing emission and fuel-burn permits, limitations, and regulations, potential laws establishing sunset dates on gas generation, and expected per units costs of incremental generation.

Redevelopment of Fossil-Fueled Generation Sites[17]

As an alternative to the conversion to combined cycle units, fossil-fueled generation sites that are either set for retirement or may require environmental mitigation could be redeveloped for opportunities to integrate lower or zero-emitting energy production, including storage. Although multiple lower or zero-emitting technology alternatives exist, consideration for potential redevelopment of these sites in this 2021 Integrated Resource Plan Update is focused on those estimated to be most feasible based on site characteristics and current lower or zero-emitting technology cost estimates.

Due to the geographical dispersion and relatively small land area available at each of the CT sites, redevelopment of the CT sites with lower or zero-emitting technology other than the CC conversions noted above are limited. Battery storage is an option, but this technology typically has been utilized in the U.S. for grid stabilization, and pairing with renewables or deployment as a stand-alone resource would be analyzed and evaluated as part of project implementation.

The seven CT sites shown in Table 3.4 above reside on a combined total of approximately 660 acres. Given an optimistic NREL estimate[18] of 5 acres/MW of solar capacity and 90% land utilization factor, solar redevelopment of the CT sites could provide a total of around 120 MW of solar generation capacity, an average of about 17 MW per site. Solar plus storage is another option for redeveloping these sites. Although more expensive than solar-only installations, solar plus storage may be an option if additional studies indicate value in grid-stabilization capabilities at certain locations.

Per the 2020 IRP, two coal-fired generation sites are scheduled for retirement within the next ten years, Meramec and Sioux, and are thus the focus of consideration for redevelopment in this 2021 Integrated Resource Plan Update. Due to the relatively small areas of these two sites, wind generation is not considered as a viable redevelopment option.

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[17] File No. EO-2021-0069, Order, p.4, ¶ 1(C)(2), Issued November 4, 2020.
[18] https://www.nrel.gov/docs/fy19osti/72470.pdf

The Meramec site encompasses roughly 375 acres in south St. Louis County, sharing borders with the Mississippi and Meramec rivers. Grid support projects at the location are currently underway, and the site has ample water and transmission access to support a CC facility. A natural gas line currently feeds Units 1 and 2, with the capacity to support around 240MW of generation. Future studies on the potential to install a CC facility at this site would need to include costs for additional fuel capacity. The redevelopment of the Meramec site with solar generation is another consideration. Using a conservative 7 acres/MW[19] and 90% land utilization factor, developing the entire Meramec site could accommodate slightly less than 50 MW of solar generation capacity. Considering land requirements for a new training center to be constructed at Meramec, the aforementioned grid project, utilization of currently cleared areas of the property, and easements along the riverfronts, solar generation capacity of 30 MW is more probable. The potential for energy and capacity beyond daylight hours could be extended with the addition of battery storage, and any future studies could consider the incremental cost and benefits of such storage.

The Sioux Energy Center rests on almost 1,000 acres between the Missouri and Mississippi Rivers north of St. Louis. Redevelopment of the entire Sioux site for solar generation could provide up to approximately 130 MW of solar generation capacity, although a significant portion of the site is currently utilized for agricultural purposes. The Sioux site also has ample land, water, and transmission access to support redevelopment of the site to a CC facility. Although sufficient gas is not presently onsite to support a CC unit, a Spire natural gas line with potential capacity to support a CC facility runs adjacent to the Sioux property boundary, greatly reducing fuel pipeline costs for a new CC facility. Future studies on potential redevelopment of Sioux to CC generation should reflect that fuel pipeline cost, as well as utilization of existing water treatment and cooling water systems, and transmission infrastructure.

As the Ameren Missouri generation portfolio is further diversified and additional renewable generation is integrated into the Ameren and MISO service areas, Ameren will continue to evaluate supply-side generation options to supply reliable energy in a cost-effective manner, and those evaluations will be included in future IRPs.

Securitization[20]

Ameren Missouri believes that the prospects for using securitization to advance the retirement of coal generation assets and channel the savings into more economical investments are favorable, provided that it can be effectively implemented by the

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[19] Ibid.
[20] File No. EO-2021-0069, Order, p.5, ¶ 1(F), Issued November 4, 2020.

Commission. Utilizing securitization legislation as a means to retire coal-fired generation is complicated and depends on proper consideration of critical details. A feasible securitization plan must protect the interests of bondholders, customers and the electric utility. Bondholders need adequate assurance that the bonds they issue to support securitization will be repaid. Customers need to be sure that repayment of the bonds is a reasonable means of covering the costs to be securitized. Electric utilities need to be sure that utilizing securitization as a means to retire coal-fired generation will not have an adverse financial impact on them. If these interests can be protected, securitization can work for the benefit of all stakeholders.

As indicated in the MoPSC Order in File No. EO-2021-0069, some point to securitization as a potential tool for transitioning utility generation fleets from coal to renewable generation. While there are likely to be significant complexities when it is executed, the concept itself is relatively straightforward, and securitization has been used by utilities or proposed for the recovery of costs in the context of utility restructuring, retirement of coal and nuclear generation, investments in pollution controls, and disaster recovery due to major events such as storms and fires. For the specific application of securitization referenced in the MoPSC Order, the process includes the following steps:

- The utility determines that accelerated retirement of a coal-fired generator or generators is appropriate.
- The utility establishes a Special Purpose Entity ("SPE") to issue bonds backed by a statutorily guaranteed revenue stream via a non-bypassable charge on utility customers' bills; the bonds thus carry the highest ratings from the rating agencies.
- The SPE issues the bonds and exchanges the net proceeds (after issuance costs) for the remaining balance of the utility coal assets being retired.
- The principal and interest payments on the bonds are serviced by the guaranteed customer revenue stream via a trust.
- The utility uses the proceeds received from the SPE to invest in renewable generation assets.

As is evident, the employment of securitization in this context is dependent on the successful implementation of the recently-passed legislation, followed by several key decisions on the part of the utility. First, the utility must determine that it is appropriate to accelerate the retirement of coal-fired assets. As with any resource planning decision, a decision to accelerate the retirement of coal generation includes consideration of long-term economics, customer rate impacts, emission reduction goals, and other objectives as well as risks including those associated with reliability, system operations, financing, and regulation. Such considerations were accounted for in the Company's 2014 decision to accelerate the retirement of its Meramec Energy Center and the depreciation of its associated plant investment.

Second, the utility must determine that it is appropriate to expand its investment into renewable generation in conjunction with the aforementioned accelerated coal retirement. Such a decision necessarily includes consideration of those factors mentioned above in the discussion of coal retirement decisions. It may also include consideration of compliance with renewable portfolio standards, such as Missouri's RES, programs offering customers the option of meeting their energy needs with renewable energy, such as the subscription renewable program expected to be filed later this year, or other planning and policy drivers.

Third, the utility must determine that the use of the securitization approach outlined above is an appropriate step for executing on the first two decisions. By its nature, securitization is a complex undertaking that involves coordination among the utility seeking to execute the strategy, rating agencies who establish the ratings for the bonds, and the MoPSC, which reviews and approves the securitization plans. Because implementing securitization is complex, it is extremely important that the decisions regarding coal retirement, renewable investment, and the securitization strategy are meticulously planned. The utility must also consider other alternatives for achieving its objectives with respect to potential accelerated coal retirements and additional investments in renewable generation. Such alternatives may include accelerating the retirement date of coal units and increasing the annual depreciation expense as a result, traditional financing, and tax equity financing.

At this time, Ameren Missouri has not yet made decisions with regard to further accelerating the retirement of coal generation beyond the retirement dates reflected in our preferred plan. While no such decisions have yet been made, the availability of securitization as a potential tool for accelerated coal retirements and renewable investments could provide another viable option and additional planning flexibility for utilities when considering such decisions. We have performed a basic analysis of securitization in which coal-fired unit retirement is accelerated, the existing rate base securitized, and the proceeds invested in renewable generation. That analysis shows that under certain circumstances and based on certain assumptions, securitization could result in benefits to customers.[21] Ameren Missouri will continue to consider and evaluate options for using securitization.

[21] Our high level analysis is included with this report as a confidential work paper.

3.4 Transmission and Distribution Review

Integrated Distribution Planning[22]

Ameren Missouri believes that Integrated Distribution Planning ("IDP") will, in the long-term, play an important role in managing distribution system investments to maintain reliability and maintain affordability for Ameren Missouri customers. To that end, Ameren Missouri is developing an IDP approach, which will become an important part of our distribution investment strategy as the grid moves towards a state of greater technological maturity and as the situation on the ground more fully warrants it. Currently Ameren Missouri is focused on making foundational investments needed to upgrade aging infrastructure and implementing modern technologies. These foundational investments are providing us with the ability to more efficiently and effectively operate the grid today, while allowing the grid to accommodate customer-owned DERs as they become more prevalent in the future.

Ameren Missouri believes that integrated distribution planning will ultimately be important once the grid truly starts to transition from a large utility-owned central supply-side structure to one with significant penetration of DERs owned by customers and other stakeholders on the distribution system. As reflected in the 2020 IRP, it is our expectation that the vast majority of supply-side resources will be provided at utility scale through 2040 with only 100 MW of customer-owned DER supply by 2024 and 703 MW of DER supply by 2040, or less than 10% of total system capacity.

At full maturity, the IDP process will provide a framework for investments in the distribution system, which includes foundational asset investments along with effectively integrating DERs and demand-side tools and programs. The current process also provides benefits through foundational investments in poles, wires, transformers, substations, communications, etc. needed for safe and reliable service and also including some implementation of modern technologies to remotely or automatically monitor and operate the grid via smart devices. Additionally, smart meters are currently being installed across our service territory, with full deployment expected by the end of 2024, which will increase visibility of grid operations at localized levels. Further, as prices of batteries, solar and other technologies are expected to continue to decline, we see a future where it may be economically viable to optimize location specific integration of DERs and other demand side tools and programs into the grid. This would enable continued safe and reliable grid operation, and improved efficiency of the grid by smoothing the overall demand curve and

[22] File No. EO-2021-0069, Order, p.5, ¶ 1(G), Issued November 4, 2020.

deferring otherwise needed capital investments. It could also help facilitate more competitive energy markets as envisioned through FERC Order 2222.

Currently Ameren Missouri is in the early stages of developing the IDP process described above, as are most other distribution grids in the U.S. Put simply, the speed of IDP development will depend on the state of the grid and our efforts to modernize it, broader economic and technological trends that will drive the speed of DER adoption, and our customer needs. Today, we are focused on upgrading aging and foundational infrastructure and implementing modern technologies to allow for expanded remote or automated grid operations. Once the current smart meter deployment is complete, our ability to accurately track and measure the impact of various programs like customer adoption of various TOU rates, energy efficiency, or demand response will be greatly enhanced and provide us with the necessary information to properly execute the IDP process described above.

Ameren Missouri is also actively monitoring the quantity and location of DERs on our system and annually evaluates technology maturity and other economic and market drivers of change. As we see indication of acceleration, we will adjust our IDP process accordingly to enable grid and customer benefits described above. No matter the pace of smart meter and TOU rate deployment, DER adoption, or other demand-side programs, our grid investments are both foundational and critical to establishing robust infrastructure that is ready to support the integration of future grid technologies and programs at the optimal time.

Smart Energy Plan Update

In continuance of infrastructure investments, and compliance with Missouri Senate Bill 564, the Company filed its updated Smart Energy Plan in February 2021. This forward-looking plan is designed to transform the grid to ensure customers have safe, reliable and increasingly cleaner energy to meet their growing needs and expectations. The plan includes $7.9 billion of electric[23] investments from 2021 through 2025 that will, among other things, support our investment in smart grid technologies, system hardening efforts, and upgrading infrastructure. These efforts translate into a number of outcome driven strategic goals:

- Automate the electric distribution system by deploying smart switching devices and accompanying communications technologies to help significantly reduce the length of outages.
- Harden the electric distribution system with a stronger, more secure energy delivery backbone that will better withstand severe weather.

[23] Planned investment level assumes Ameren Missouri receives SB-564 extension approval.

- Upgrade aging and under-performing assets (e.g., substations, overhead and underground assets). As part of our plan, we are addressing the lowest performing circuits across our service territory to improve reliability for our customers.
- Employ smart grid technologies (e.g., relaying, monitoring, fault information, communications) as we upgrade existing infrastructure and install new substations to improve reliability and capacity for customers and mitigate risk.
- Add capacity by upgrading substations, lines, and switching ability to improve flexibility to enable flow of two-directional power from a DER installation.
- Expand the scope of underground revitalization program to include a larger footprint of underground in the city. The added scope provides for route diversity for our 34kV feeders near bulk substations, which reduces or eliminates risk of very long outages due to a single incident.
- Develop a communications network to monitor and enable analytics from connected grid devices.
- Provide Smart Meter time-of-use rates, improving customer options for managing their bills and shifting load from peak to off-peak times to benefit the system.

As we build this grid of the future, Ameren Missouri is keeping electric rates stable and predictable. Accelerated infrastructure from the Smart Energy Plan also continues to drive job creation and economic development.

Smart Meter Program

Through June 2020, Ameren Missouri read all 1.2 million electric and 132,000 gas meters with an antiquated, one way Automated Meter Reading ("AMR") system. The system was installed between 1995 and 2000 and uses meter reading technology that is more than 20 years old. It delivers information (daily usage, meter flags and outage detection), but the system does not have the bandwidth for additional data or capabilities readily available in today's energy landscape. Moreover, the AMR modules in the meters are projected to have a 15 to 20 year life and are rapidly approaching end of life.

The Ameren Missouri Smart Meter Program is upgrading all electric meters, gas modules, and the associated communication network in the Missouri service territory over approximately six years, 2019 through 2024:

- Installing 1.2 million Electric Advance Metering Infrastructure ("AMI") meters (residential and commercial/industrial) providing greater usage insights and capabilities for customers.

- Installing 132,000 Gas AMI modules (Residential and Commercial/Industrial).[24] This does not include new gas meters, only the communication module of the meters).
- 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 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, so we can quickly restore customers' service and keep customers informed of restoration progress.
- Improved mobile and web-based tools and two-way information flow will provide customers with greater visibility into their energy usage, education and comparison of energy options and, ultimately, greater control to manage their energy costs.
- Smart Meter rate options such as time-of-use rates are providing improved customer options that help customers manage their bills and shift load from peak to off-peak times to benefit the system.
- Customer rates kept affordable through reduced meter infrastructure operating costs (e.g., eliminating the existing AMR system reduces meter reading) once fully implemented.

Many customers are already experiencing the benefits of this program. Ameren Missouri installed the first AMI meters in July 2020 and then rolled out a suite of five rate options by the second quarter of 2021. Continued deployment of this program will soon allow all residential and commercial customers to experience the flexibility and control afforded by these upgrades, as well as potentially assist in the compliance of FERC Order 2222.

FERC Order 2222[25]

FERC Order 2222 enables DER aggregators to compete in all regional organized wholesale electric markets. DERs are located on the distribution system, a distribution subsystem or behind a customer meter. They range from electric storage and intermittent

[24] Gas module deployments are not funded through the Smart Energy Plan.
[25] File No. EO-2021-0069, Order, p.6, ¶ 1(I), Issued November 4, 2020.

generation to distributed generation, demand response, energy efficiency, thermal storage and electric vehicles and their charging equipment.

The final rule enables these resources to participate in the regional organized wholesale capacity, energy and ancillary services markets alongside traditional resources. Multiple DERs can be aggregated to satisfy minimum size and performance requirements that they might not meet individually. Under the new rule, regional grid operators must revise their tariffs to establish DER aggregators as a type of market participant, which would allow them to register their resources under one or more participation models that accommodate the physical and operational characteristics of those resources. To comply with Order 2222, closer coordination between distribution utilities and ISOs/RTOs will be needed.

Order No. 2222 did not affect the ability of relevant electric retail regulatory authority ("RERRA") to prohibit retail customer aggregators from including demand response resources in bidding into the RTO/ISO markets. A number of public interest organizations filed requests for rehearing and clarification, which FERC addressed in detail in Order No. 2222-A. FERC's decision focuses on the demand response "opt-out," which blocks grid operators from accepting offers from aggregated demand response in states where the practice is not allowed.

FERC argued that the opt-out goes against the goals of Order No. 2222 because it would reduce the diversity of aggregated DERs. As part of the order, FERC also issued a notice of inquiry seeking comments on any possible burdens on states caused by the decision. More specifically, the agency sought input on what the impact will be if states lose their ability to prevent demand response resources from participating in organized wholesale markets.

As a result of the March 18 order, the opt-out would no longer have applied. However, FERC, on June 17, 2021, paused its March decision that would have prevented states from refusing to accept demand response as part of DER aggregations under its landmark Order 2222. FERC will further evaluate whether to allow demand response participation in the context of a broader notice of inquiry ("NOI") proceeding, which is considering whether to remove the demand response opt-out altogether. Ameren Missouri will monitor further proceedings on these matters at FERC.

FERC Order 2222 will have immediate effects on distribution system metering/telemetry systems and commercial settlements processes. The Order is expected to have less immediate effects on electric power distribution circuits and equipment. Ameren Missouri presently maintains/upgrades primary distribution circuits (at the Company's expense) to provide net-metered retail service for customer-owned solar photovoltaic installations. Ameren Missouri serves larger independent power producing installations at higher voltage and requires facility owners to financially support distribution system upgrades needed to ensure safe and effective system operation. Existing system upgrade practices are sufficient, but expenditures are expected to rise as DER penetration increases. Increasing difficulty in managing voltage quality and circuit loading may well require the introduction of new control mechanisms (such as circuit DER capacity limits, volt/VAR control of smart inverters, and time-of-use DER operation). Over the next decade, a system-wide DERMS will likely be required to interact with distribution system components and DER/DSM equipment to maintain adequate system operating conditions. The company has begun developing functional specifications for a DERMS that will meet its evolving technical needs and support interactions between DER/DERA, DSO/TSO, and RTO/ISO organizations per FERC Order 2222 requirements.

Transmission Considerations for Long-term Portfolio Transition

Ameren and the electric industry have made significant progress in the clean energy transition by significantly reducing carbon emissions over the last decade. Through 2019 (pre-pandemic), Ameren and the industry had reduced carbon emissions by approximately 30 percent to 35 percent below 2005 levels. This has largely been done through systematic retirements of older coal-fired power plants and additions of natural gas-fired generation and renewable energy. Another key enabler of this clean energy transition has been a robust transmission system that has served as the backbone of the energy grid. In particular, across the country, meaningful investments have been made in larger, regional transmission projects to enhance the reliability and resiliency of the energy grid and enable the clean energy transition. Over the past decade, Ameren has made approximately $2 billion of investments in large, regional projects in the MISO footprint.

As noted in the federal policies and economic policies section of this document, much has changed in terms of policy proposals to significantly accelerate the clean energy transition since our IRP filing in September 2020. Much of the discussion among policymakers and other key stakeholders have generally focused on actions to reduce carbon emissions, including the need to accelerate the deployment of significantly greater levels of zero or low carbon emitting generation resources (e.g., wind and solar) and the retirement of fossil fuel energy resources (notably, coal). These policy discussions, coupled with the continued improvement of renewable energy economics and technologies, have driven many electric energy providers to meaningfully revise their generation strategies and accelerate their carbon emission reduction goals over the last year, largely by accelerating their investment plans in intermittent renewable energy resources and retiring baseload coal-fired generation.

In light of the expected significant changes in sources of electricity being considered by energy providers to meet customers' needs in the MISO footprint, as noted above, MISO completed two reports that represent preliminary assessments of the impact that these changes would have on the energy grid in MISO's footprint. The objective of MISO's first report, the Renewable Integration Impact Assessment ("RIIA'), was to assess the potential impact on the reliability and resiliency of the grid resulting from significantly greater levels of intermittent, renewable energy sources (e.g., wind and solar) being used to meet the energy needs of customers as baseload fossil energy resources (e.g., coal) are retired. Key findings of that report include:

- Current transmission infrastructure is inadequate to support the significant addition of renewable energy and retirements of conventional baseload generation.
- Increasing renewable generation penetration will significantly impact grid performance with complexity increasing sharply after 30 percent renewable penetration levels.
    - In 2020, renewable energy provided approximately 13 percent of MISO's total energy needs, while baseload coal and natural gas provided 33 percent and 34 percent, respectively. Nuclear generation provided 20 percent.
    - To achieve net-zero carbon emissions in the future, renewable generation will need to provide in excess of 50 percent of the energy needs in MISO.
- Achievement of the transformational goals of the clean energy transition will require significant transmission expansion and investment, changes in current operating, market and planning practices, and additional coordinated actions with other RTO's, regulators and local, state and federal agencies.

Following the issuance of the RIIA, in April 2021, MISO issued a draft Long-Range Transmission Plan ("LRTP") report. The objective of this report was to outline a potential regional transmission roadmap of projects through 2039 that would be necessary to ensure the energy grid remains reliable, resilient and efficient to meet a range of carbon emission reduction scenarios. Notably, this study took into consideration the integrated resource plans, state mandates, and announced goals for carbon reductions by companies that operate in MISO. In addition, this report included insights on transmission needs from Ameren and other transmission owners in MISO. In particular, MISO looked at three future scenarios, and focused on the Future 1 and Future 3 scenarios. MISO's Future 1 is the scenario that resulted in an approximate 60 percent carbon emission reduction below 2005 levels by 2039, and Future 3, is the scenario that resulted in an approximate 80 percent carbon emission reduction below 2005 levels by 2039.

Key findings from LRTP include the following:

- Significant regional and local transmission investments will be needed over the next 10 to 20 years to ensure the reliability and resiliency of the energy grid.

- Under the Future 1 scenario future transmission investments are estimated to be approximately $30 billion in MISO.
- Under the Future 3 scenario future transmission investments are estimated to be approximately $100 billion in MISO.

To put these potential investments in context, as a result of MISO's last regional transmission planning process, approximately $6.5 billion of regionally beneficially projects were constructed over the last decade. Ameren Transmission completed approximately $2 billion or 30 percent of these projects. As noted previously, the LRTP is a preliminary report and is only one step in a multi-step process that will take place over time (in some cases, many years) before the regional transmission projects identified in the Future scenarios move forward. Key next steps in this process include the following:

- MISO has requested comments from key stakeholders on the LRTP.
- Based on those comments, MISO will submit a draft MISO Transmission Expansion Plan ("MTEP") for comment to key stakeholders in the third or fourth quarter of 2021. The MTEP is prepared annually by MISO and is subject to approval by its independent Board of Directors.
- Key elements of this process include transmission planning and prioritization, as well as determination of cost allocation among MISO companies. We are actively working with MISO and other key stakeholders on these important issues.
- Ameren is working with other interested stakeholders (MISO transmission owners, MISO, generation developers and others) to identify an optimal set of projects that can be approved quickly through the MISO MTEP process to facilitate the clean energy transition.

Which future scenario unfolds for the transition to clean energy resources is unknown. However, it is clear that under any scenario, significant expansion of the nation's electric transmission system will be necessary to support the clean energy transition, and transmission investments in Ameren's service territories will be multiples of current investment levels. Successfully planning, engineering, constructing and later operating and maintaining the portfolio of necessary transmission investments will require new strategic partnerships, contracting methods, administrative programs and strategies to ensure the skilled people, materials and components are available when and where needed to complete projects safely, on-time and within budgets.

3.5 Demand Side Resource Review

The Company sought and received an extension for programs in 2022 and has requested an extension through 2023 to ensure seamless program delivery for customers, while the Company developed, filed, and discussed the 2020 IRP filing with stakeholders. This is an important and necessary step, because the IRP defines the avoided costs that will be used to evaluate cost-effective measures for inclusion in the next resource portfolio.

In contrast, filing a MEEIA plan concurrently with an IRP creates risk that changes to avoided costs in either filing would require changes in the other. The Company and stakeholders made important progress towards a future filing and agreed on a plan to address the avoided costs in the next market potential study.[26]

It can take up to 12 months to develop a multi-year MEEIA plan and filing. The Company will begin planning for its MEEIA 4 cycle in late 2021 for filing in late 2022 or early 2023. This will allow time for review and Commission approval, ahead of the start of the 2024 program year. At this time, future resource plans are expected to be consistent with maintaining progress towards RAP levels of DSM, as defined by the preferred resource plan identified in the 2020 IRP. Such plans will also take into account program changes made during the planning and implementation of the 2022 and 2023 program years, particularly with respect to the role of lighting and behavioral programs.

At the same time, the Company will begin planning for the 2023 Market Potential Study ("MPS") in the fourth quarter of 2021. Following a similar schedule as in the 2020 IRP, the next MPS will need to be developed, executed and finalized between the second quarter of 2022 and the second quarter of 2023. This lead time is necessary so that results can be included in the 2023 IRP. The next MPS will be developed consistent with the budget approved as part of the PY22 extension, and it will rely on the market research regarding customer adoption and willingness to participate factors developed as part of the 2020 MPS.

Similar to the 2020 MPS, the 2023 MPS will estimate the maximum and realistic achievable potential ("MAP" and "RAP", respectively) of DSM resources on an annual and peak day basis, 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.

To the extent that budget and resources are available, the 2023 MPS may also begin to explore the potential of DSM resources to support system operations. This may 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 distribution plans and the evolution towards more targeted DSM measures.

[26] File No. EO-2021-0021, Joint Filing, filed June 18, 2021.

Electric Vehicles and Charging Infrastructure

Our electrification strategy includes efforts to implement policies and programs that invest in infrastructure to promote and enable EV adoption, including charging opportunities for multi-family dwellings, underserved communities, public transportation and fleet electrification.

According to the Edison Electric Institute ("EEI"), there are more than 1.5 million EVs driven on U.S. roads today, and that number is expected to grow to 18.7 million by 2030. Ameren Missouri has taken a particular interest in the emergence of EVs and is actively engaged in opportunities to drive EV adoption and contribute to the region's overall preparedness.

To help drive and support transportation electrification, Ameren Missouri offers incentives for businesses to install EV charging stations at workplaces, multi-family apartment buildings and in publicly accessible locations. Specifically, Ameren Missouri's Charge Ahead program provides incentives for Missouri businesses to install 1,000 EV charging stations at 350 locations across the state. The program also provides incentives for 14 fast-charging EV stations to be located near highways. The fast-charging stations are part of a multi-state coalition of energy companies that are committed to working together to build a vast network of Midwest EV charging stations by the end of 2022. Longer term, we will extend our efforts beyond EVs to commercial and industrial equipment where electrification will deliver similar benefits to customers and the environment.

To support cleaner alternatives in public transportation, Ameren Missouri partnered with Metro Transit in launching its first 60-foot battery electric bus. Through this partnership, Ameren Missouri built a new substation next to the Brentwood MetroBus facility to serve the growing electric needs of Metro Transit and the surrounding communities.

Ameren Missouri sponsored the SILVERS project, a collaboration with Forth (a nonprofit organization focused on advancing electric, smart and shared mobility), the City of St. Louis, and the DOE. This project is designed to show how community-based organizations nationwide can use electric vehicles to deliver their services more efficiently and cost-effectively. The project has a goal of helping to develop a model for providing electric vehicles and charging stations to social service agencies that provide transportation and delivery services to low-income senior citizens.

Leading by example, Ameren has committed that 100% of new light-duty vehicle purchases by 2030 will be electric. In addition, 35% of our overall vehicle fleet including light-, medium-, and heavy-duty trucks, along with forklifts, and ATVs/UTVs will be electrified by 2030. Ameren has also proactively installed EV charging stations at its corporate headquarters and at an expanding number of operating centers to support its growing electric fleet and the EVs of early-adopting employees.

To stay at the forefront of technology updates, best practices and challenges that affect customers, Ameren collaborates with a diverse group of stakeholders that align with supporting transportation electrification efforts including Alliance for Transportation Electrification ("ATE"), EEI, EPRI, utilities, automotive companies, electric vehicle supply equipment companies, and engineering/consulting firms.

3.6 Uncertain Factors

3.6.1 Price Scenarios

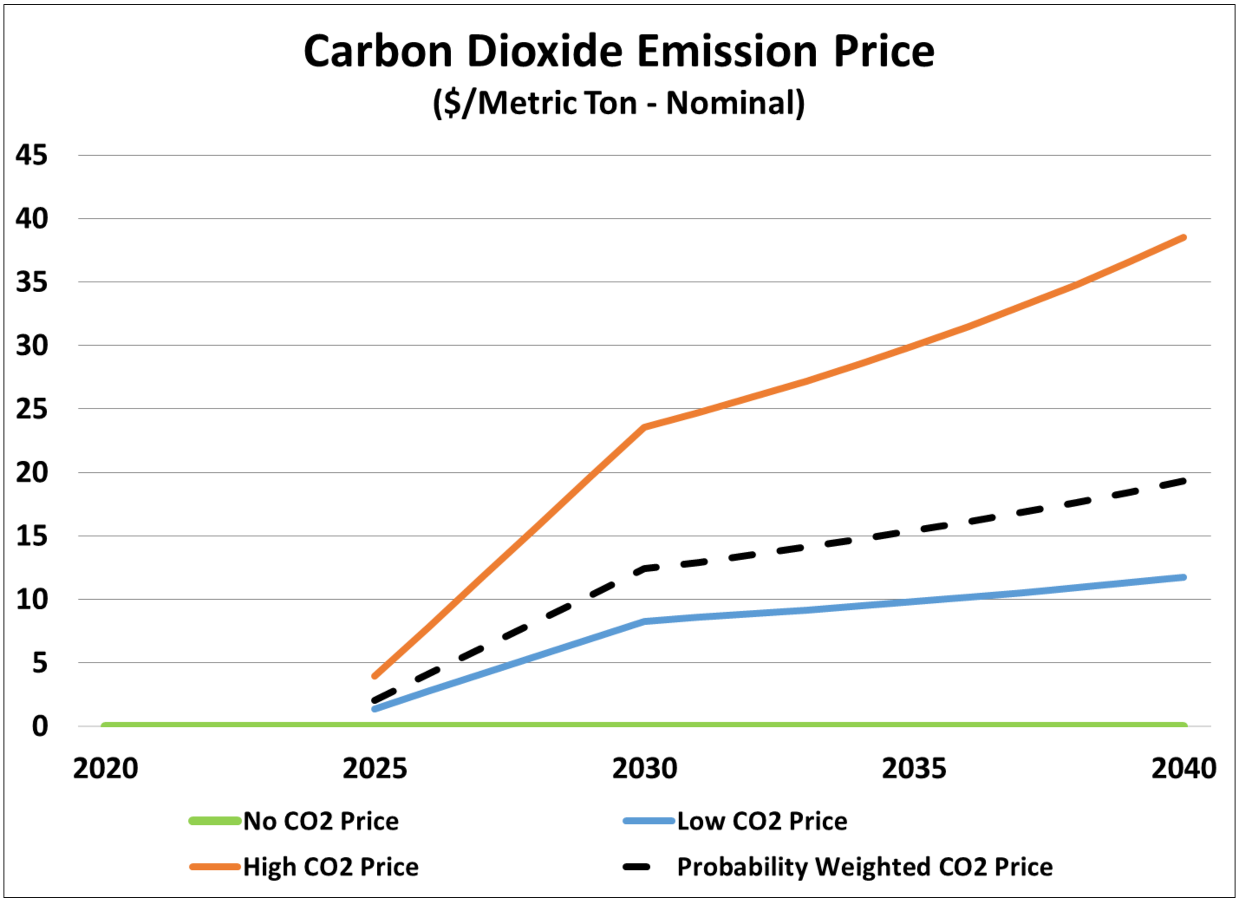
Ameren Missouri has reviewed its assumptions for, carbon prices, and natural gas prices, which are the major drivers of power prices. As discussed in more detail in this section, Ameren Missouri has determined that its current expectations for these driver variables are within the ranges established in the 2020 IRP. As a result, it is not necessary to update our power price scenarios. Each unique combination of uncertain factors is probability weighted and allows for analysis over a wide range of potential future conditions. Figure 3.7 shows the scenario tree from the 2020 IRP.

Figure 3.7: Scenario Tree

Carbon Dioxide Emission Prices

Figure 3.8 shows the carbon price assumptions assumed in the 2020 IRP. These carbon price assumptions were reviewed and remain reflective of expectations for the future price of carbon dioxide emissions. The near term value remains zero in all cases prior to 2025 given the near-term political considerations and constraints of any legislative policy change.

Figure 3.8: CO_2 Price Assumptions



It should be noted that the price assumptions shown represent an explicit price on CO_2 emissions, not necessarily an estimated cost to comply with CO_2 emission regulations. While these prices may factor into the cost of compliance, the cost to comply is necessarily a function of the form of the regulation and the compliance options available.

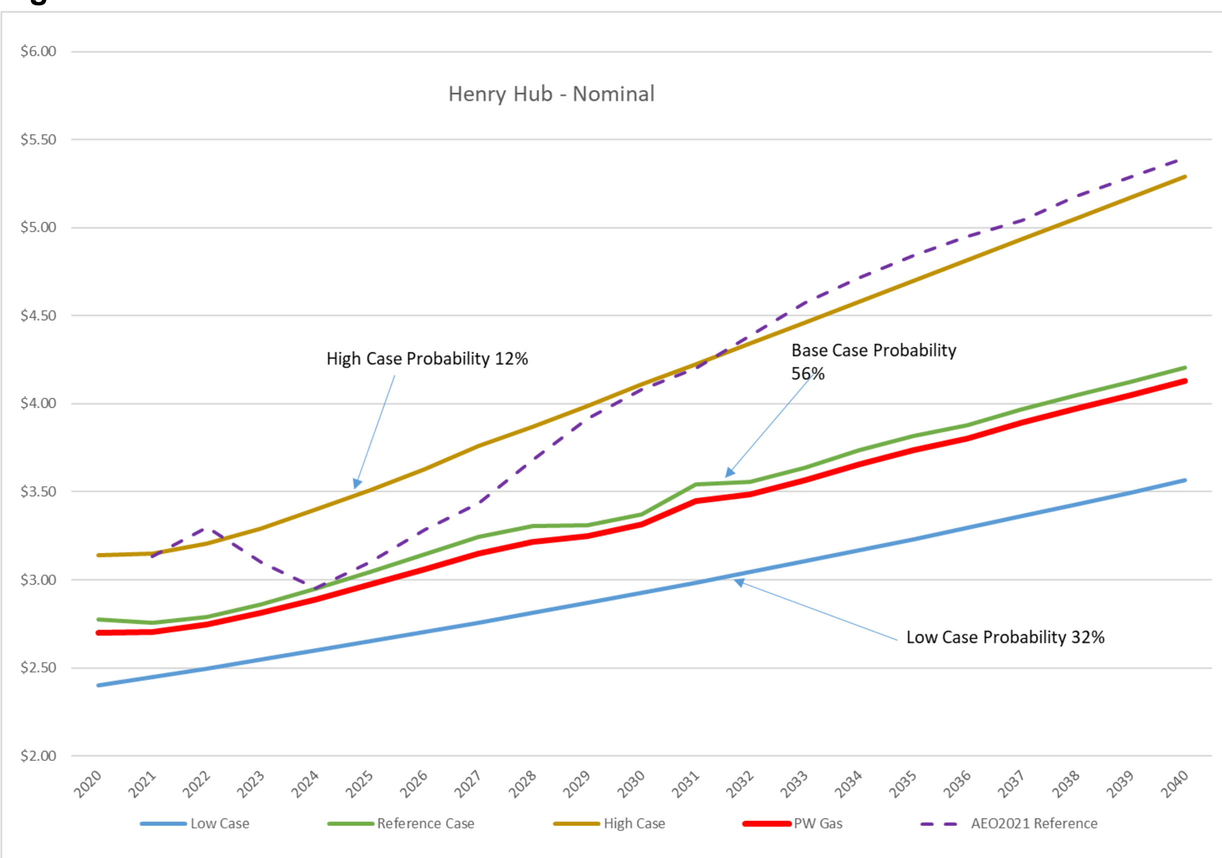
Natural Gas Prices

Supply – According to 2021 EIA AEO, domestic natural gas production is expected to return to pre-pandemic levels starting in 2023. In the long term, production continues to grow during the entire projection period, driven by end use consumption and opportunities to sell natural gas internationally through LNG exports.

Shale gas and associated natural gas from oil plays are the primary contributors to this long-term growth. More than half of the growth in shale gas production between 2020 and 2050 comes from shale gas plays in the Appalachian Basin in the East region, and most of the remaining growth comes from plays in the Gulf Coast and Southwest regions. Due to the drop in crude oil production, associated natural gas (natural gas produced in primarily oil formations) also decreased in 2020 because of the relatively low crude oil and natural gas prices. EIA projects associated natural gas February 2021 U.S. Energy Information Administration | AEO2021 Narrative 23 will return to 2019 levels in 2024 and then steadily increase at a modest rate through 2050, primarily driven by increased drilling in the Permian Basin. Our current long term expectations for natural gas supply remain consistent with the 2020 IRP.

Demand – In reviewing the drivers of demand, we continue to see several drivers shaping it long term. The drivers are energy efficiency programs, coal to gas switching, industrial growth and LNG exports. Upward pressure on demand will result from expanded coal to gas switching, industrial growth and global exports of LNG with only efficiency having a moderating impact. The 2021 EIA expects U.S. LNG exports to more than double between 2020 and 2029 in the Reference case. Our current long term expectations for natural gas demand remain consistent with the 2020 IRP.

Figure 3.9: Natural Gas Price Forecasts



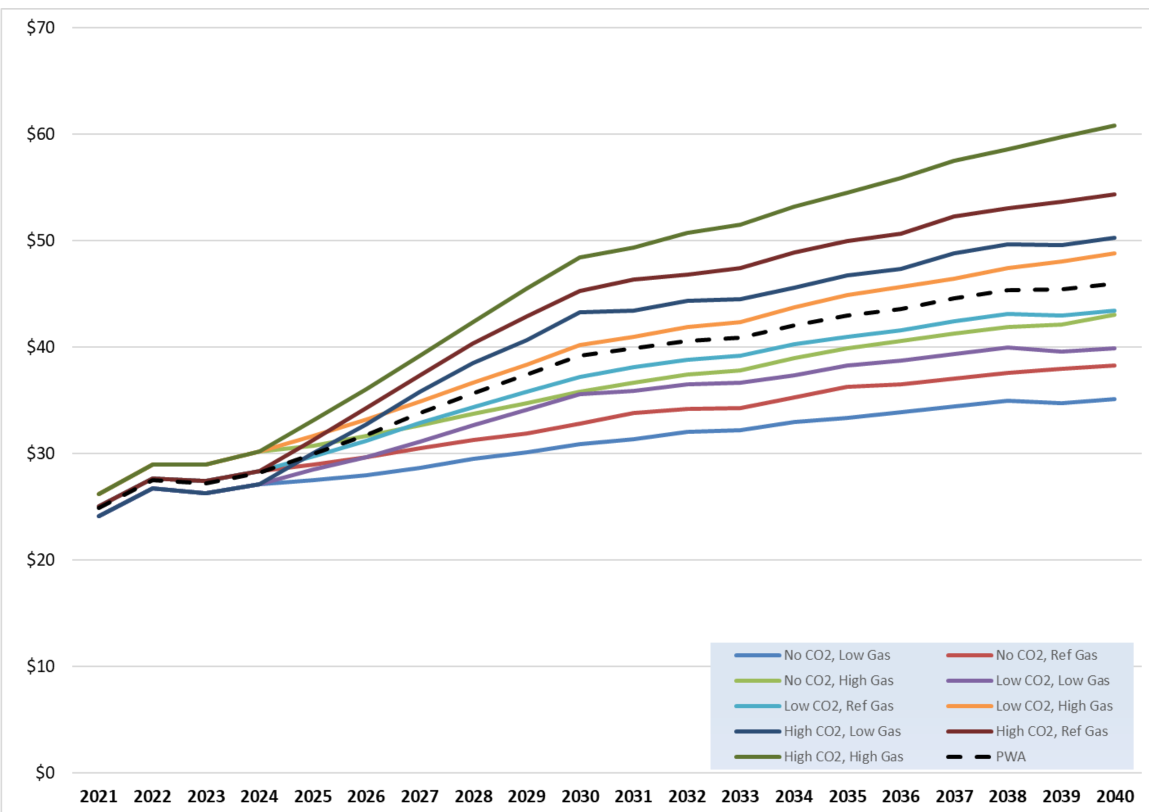
Infrastructure – The expectations for infrastructure remain consistent with the 2020 IRP. The developments in large gas production in the Marcellus and Utica shale reserves in the Northeast continue to create a dramatic shift in flow. These changes in the interstate pipeline system will occur as the supply pool from the Northeast grows. Natural gas will be directed toward the growing demand from: the petro-chemical industry in the Southeast, gas-fired generation throughout the Midwest and East, and LNG exports in the Gulf Coast.

Price – Current expectations are for prices to trend closer to the low end of our IRP range in the near term. However, as we move forward in time demand from LNG exports, coal-to-gas switching and increased industrial demand could drive higher prices in later years. As demonstrated in Figure 3.9, EIA's 2021 Annual Energy Outlook reflects future gas prices that are within the range used in the 2020 IRP for the next 10 years and track closely with our 2020 IRP high case thereafter.

3.6.2 Scenario Modeling

Because current assumptions for the scenario variables described in section 3.3.1 are within the ranges defined in our 2020 IRP, no updated scenario modeling is warranted at this time. The power price forecasts for the scenarios modeled for the 2020 IRP are presented in Figure 3.10 below.

Figure 3.10: **Market Price Scenarios**



3.6.3 Independent Uncertain Factors

Ameren Missouri reviewed a broad range of uncertain factors in its 2020 IRP and selected two independent uncertain factors to be included in the risk analysis and presented in the 2020 IRP: DSM 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.

4. Compliance References

All references are to the ordering language in the *Order Establishing Special Contemporary Resource Planning Issues*, in File No. EO-2021-0069, beginning on page 3.