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Issue(s):	Big Hollow Planning and Need
Witness:	Matt R. Michels
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Sponsoring Party:	Union Electric Company
File No.:	EA-2025-0238
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EA-2025-0238

SURREBUTTAL TESTIMONY

OF

MATT R. MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
January, 2026

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SURREBUTTAL TESTIMONY

OF

MATT R. MICHELS

FILE NO. EA-2025-0238

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matt R. Michels. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

Q. By whom and in what capacity are you employed?

A. I am employed by Ameren Services Company as the Director, Corporate Analysis.

Q. Are you the same Matt R. Michels that submitted direct testimony in this case?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. To what testimony or issues are you responding?

A. I am addressing Integrated Resource Plan ("IRP")-related approval conditions proposed by Missouri Public Service Commission Staff ("Staff") in its Rebuttal Report, purported issues with the Company's IRP analysis and assumptions raised in Staff's Rebuttal Report, concerns associated with reliance on natural gas-fired generation raised by Renew Missouri witness Jessica Polk Sentell in her rebuttal testimony, and concerns regarding the need for the Big Hollow projects raised in the rebuttal testimonies of Office of the Public Counsel ("OPC") witnesses Dr. Geoff Marke and Jordan Seaver. The fact that I did not address other points made in the Staff's Rebuttal Report or these rebuttal testimonies does not indicate that I agree with such points.

Q. What specific recommendations are you making in your surrebuttal testimony?

A. The Commission should approve the Company's request for Certificates of Convenience and Necessity ("CCNs") for the Big Hollow projects and should certify the Big Hollow projects as Replacement Reliable Electric Generation ("RREG") for purposes of compliance with § 393.401, RSMo.

III. RESPONSE TO THE STAFF

Q. In its Rebuttal Report, Staff alleges that the Company has not explained why natural gas combined cycle ("NGCC") could not be implemented instead of "capacity only" resources to meet the need for resources identified in this case.[1] Is that accurate?

A. No. The Company has never stated in its IRP filings that NGCC could not be used to meet capacity needs instead of "capacity only" resources, nor does the Company use the term "capacity only" resources. Presumably, Staff is using the term to mean resources like NGSC and battery energy storage system's ("BESS"), such as the Big Hollow projects. Ameren Missouri has characterized such resources as providing *primarily* capacity benefits, but never *only* capacity benefits. In its 2023 IRP, the Company evaluated alternative resources plans with various combinations of resources to meet customer demand, including plans that allowed for direct comparison of NGCC and NGSC

[1] File No. EA-2025-0238, *Staff Rebuttal Report*, p. 2, lines 11-13, filed December 12, 2025.

in both the nearer term and the long term. This is evident in the Company's 2023 IRP Chapter 9 (Schedule MM-S1). Table 9.6 lists 23 plans, including Plans C and M, with the only difference being the inclusion of NGCC in 2040 in Plan C and the inclusion instead of NGSC in 2040 in Plan M. Plan U is the same as Plan C with the exception that it substitutes NGSC for NGCC in 2033.

I have also addressed the potential for substituting NGCC for NGSC at Big Hollow in this case. In my direct testimony, I specifically described why NGSC is better for implementation in the near term, stating that, "Relative to NGCC, NGSC can be implemented more quickly and easily to keep pace with rising demand, partly because NGSC does not require access to a large and continuous source of water for steam turbine operations that is an integral part of NGCC facilities."[2] I go on in my direct testimony to describe why NGCC resources are also important and are therefore included in the Company's Preferred Resource Plan ("PRP"). Staff admits in footnote 5 in its Rebuttal Report that it has not verified whether the former Rush Island site, at which the Big Hollow resources are intended to be built, is suitable for combined cycle generation. As Company witness Chris Stumpf explains in his direct testimony, and as Staff recognizes in its discussion of environmental compliance in its Rebuttal Report, the former Rush Island site is expected to be subject to emission constraints that limit the operation of the planned Big Hollow NGSC to a maximum capacity factor of about 20 percent.[3] The added expense of

[2] File No. EA-2025-0238, Matt Michels Direct Testimony, p. 20, ll. 6-9.
[3] File No. EA-2025-0238, Chris Stumpf Direct Testimony, p. 14, ll. 2-14. Staff also appears to recognize this as a constraint at p. 37, lines 18-22 of its Rebuttal Report. Mr. Stumpf's Surrebuttal Testimony also explains that regardless of these other issues, from a timing perspective a NGCC plant simply cannot substitute for the Big Hollow projects.

NGCC would make no sense under such a constraint. NGCC is expected to operate in a more baseload manner, taking advantage of its higher operating efficiency.

Q. Does Staff support the kind of integrated analysis approach used by the Company in its IRP filing and using the kinds of alternative plans you described above to test the relative economics of different resources?

A. Presumably so, given its recommendation that the Commission require the Company to "consider and explain alternatives to addressing overall system needs rather than the piecemeal approach of simultaneously but separately addressing capacity (i.e. peaking plants and batteries) and energy resources (i.e. renewable generation)"[4] and to "provide analysis comparing the viability of building combined-cycle power plants for future IRP and CCN dockets that propose building capacity resources."[5]

Q. Staff's Rebuttal Report recommends several conditions that relate to the Company's IRP analysis. What are they?

A. Staff lists seven conditions that they categorize as "economic conditions" as follows:

1. In future IRP dockets and CCN cases, Ameren Missouri will consider and explain alternatives to addressing overall system needs rather than the piecemeal approach of simultaneously, but separately, addressing capacity (i.e. peaking plants and batteries) and energy resources (i.e. renewable generation) and compare the proposed project(s) with those alternatives on the basis of cost and benefits.

2. Ameren's future IRP filings shall consider alternative timelines for resource additions.

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[4] File No. EA-2025-0238, *Staff Rebuttal Report*, p. 2, ll 14-16, filed December 12, 2025.
[5] File No. EA-2025-0238, *Staff Rebuttal Report*, p. 2, l 20 to p.3, l 2, filed December 12, 2025.

3. Ameren's future IRP filings shall replace generic with potential site assumptions.

4. In future IRP dockets and CCN applications Ameren Missouri should demonstrate that the proposed projects or solutions are financially viable and cost-effective with respect to alternative solutions to the identified need.

5. Ameren Missouri shall provide thorough explanation of the exclusion of alternative generation types to address identified needs in future IRP and CCN cases.

6. Ameren's future IRP filings shall include an evaluation of system reliability under stress conditions (e.g., prolonged storms).

7. Ameren Missouri shall file sensitivity analyses in the future IRP cases that model the impact on customer rates under various scenarios, including the non-materialization of large load customers and the persistence of high battery costs.[6]

Q. Does Ameren Missouri already perform its IRP analysis in a manner that addresses these recommendations?

A. As it relates to most of the proposed conditions, yes. As I mentioned previously, Ameren Missouri performs an integrated analysis of alternative plans or portfolios that include different combinations of resources which also allow for direct comparison of different resource alternatives as part of fully integrated portfolios, including different timing of resources. This addresses Conditions 1, 2, and 4. Condition 5 is also addressed in the Company's established IRP process, which recognizes technology and implementation constraints by imposing "no sooner than" dates for implementation, depending on technology availability and implementation timelines, and possibly other

[6] File No. EA-2025-0238, *Staff Rebuttal Report*, p. 92, ll. 5-22, filed December 12, 2025.

factors. I noted earlier in my surrebuttal that NGCC would not be a viable option in the near term or for the former Rush Island site, citing discussion in the direct testimonies of both Mr. Stumpf and myself. The Company has emphasized analysis of reliability under extreme weather conditions beginning with its 2023 IRP, in the wake of Winter Storms Uri and Elliott, and the general consensus that these kind of extreme weather events will be more common going forward and thus must be planned for and addressed. This kind of analysis and assessment addresses Condition 6. The Company's February 2025 PRP filing, which I presented and discussed in my direct testimony and which is included as Schedule MM-D1, explicitly analyzed multiple cases for large load additions, including several that assume loss of large loads in the longer term.

The nature of Staff's proposed Condition 7 is not clear from the language of its Rebuttal Report. However, Staff has recently distributed draft IRP rules to Missouri utilities for review and has included a provision that appears to be aligned with its proposed Condition 7, which would require sensitivity analysis of alternative resource plans at a rate class level, ostensibly to understand the impacts of different resource alternatives and alternative plans on class-level rate trajectories. This would be simultaneously complex and burdensome to implement and, also, unlikely to yield information that is helpful to the Company's consideration of long-term resource planning decisions or to the Commission in assessing the Company's resource planning decisions. It would be especially problematic to implement as part of the Company's 2026 triennial IRP compliance filing, due by October 1st of this year, because it would require the Company to create new modeling tools from scratch while it is already in the process of preparing its IRP filing. Presumably, this would have to be performed for alternative resource plans under all possible assumptions for variables like fuel prices, environmental regulations, projects costs, and a host of other uncertainties to arrive at risk-adjusted results.[7] Even if developing such tools at this late stage were reasonable or practical, the kind of sensitivity analysis that appears to be contemplated would necessarily rely on existing established cost allocation factors that almost certainly will change in the future, particularly if maintaining current allocation factors would result in what one or more parties to future rate cases believe to be an unreasonable cost burden. Mr. Wills further discusses the Company's concerns with such a requirement in his surrebuttal testimony.

Finally, Condition 3 indicates a desire to use project-specific cost assumptions rather than generic assumptions. While the Company strives to use the most representative resource cost information available, including responses to Company request for proposal's ("RFPs"), site-based engineering estimates, and the latest third-party sources, it is often not feasible to use project specific data – and the IRP rules specifically recognize this by calling for the use of generic information. In the near term, the IRP is used to establish a need for various types of resources, and an RFP process is used to assess specific projects that can fulfill those resource needs. Using such project-specific data would effectively require the Company to pre-determine what projects it would use to fulfill various needs as part of its portfolio as part of its IRP process. In the longer term, it would be even more problematic as numerous decisions would remain regarding siting, and changes in the grid (a grid that is dynamic and constantly changing) could alter the feasibility and economics of resource

[7] Risk-adjusted results account for the probabilities of values for uncertain variables across a defined probability range. Utilities in Missouri are required to evaluate the performance of alternative resource plans using probabilistic ranges for such uncertainties and providing probabilistic results across those ranges to assess risks affecting the performance of alternative resource plans. Shortcutting such considerations of risk to perform a much more simplified version of the rate sensitivity analysis Staff appears to be proposing would render such considerations less important to the Company's consideration of alternative resource plans and its selection of a PRP.

options in the long term. Absent language to bring Condition 3 in line with these kinds of resource implementation considerations, it is simply not workable.

Aside from the issues I've described with Conditions 3 and 7, the Company is already including the kinds of analysis and discussion in its IRP and CCN filings that Staff suggests are needed. There is no need to further complicate what should be done in an IRP by adding "conditions" which may be generally clear in overall intent, but are not very clear in the specifics and, given what we already do, are completely unnecessary. Further, and I as mentioned previously in my surrebuttal testimony, Staff is in the process of developing new IRP rules to implement the requirements of Senate Bill 4 ("SB4"). The new IRP rules may, and likely will, address the kinds of requirements Staff seeks to impose on the Company through this CCN docket. Because the rulemaking process has not yet been completed, and in fact is just beginning, such requirements should be considered as part of that rulemaking to ensure consistency for all Missouri utilities in future IRP filings rather than imposed as piecemeal conditions in a CCN docket.

Q. Staff's Rebuttal Report raises purported issues with the Company's consideration of BESS resources. What are they?

A. Staff raises issues with the Company's consideration of BESS resources that appear to boil down to concerns about the Company's assumptions for the cost of BESS[8] and the near-term impact on customer rates of capital-intensive resources like BESS.[9] The discussion also includes some puzzling assertions about the effects of arbitrage saturation on the Company's reported levelized cost of energy ("LCOE") for BESS[10] and assertions

[8] File No, EA-2025-0238, *Staff Rebuttal Report*, p. 47, ll. 3-11 and p. 48, ll. 8-11, filed December 12, 2025.
[9] File No. EA-2025-0238, *Staff Rebuttal Report*, p. 39, ll. 8-12, filed December 12, 2025.
[10] File No. EA-2025-0238. *Staff Rebuttal Report*, p. 38, ll. 13-17, filed December 12, 2025.

about the Company's lack of consideration of declining arbitrage value and self-discharge losses, neither of which are accurate.[11]

Q. Please explain why you say the last points about LCOE, arbitrage value, and self-discharge losses are not accurate.

A. The change in LCOE cited by Staff is purely a function of the change in the Company's assumptions for the cost of the resource itself and have nothing to do with arbitrage saturation. The Company's modeling accounts for long-term changes in price differentials as part of the sophisticated price modeling used for IRP analysis, as described in the 2023 IRP Chapter 2 Appendix A, including the potential for declining price differentials. The Company's modeling also accounts for BESS losses through an efficiency factor that recognizes the need for a higher level of energy to charge than is available when the BESS discharges onto the grid.

Q. Do capital intensive resources necessarily result in higher near-term rates than other resources?

A. No. While it is true that the capital revenue requirement for any investment starts "high" and declines over time, and while it is true that the primary cost driver of BESS is the capital investment, there are still operations and maintenance expense (O&M) costs and power market revenues that affect its contribution to revenue requirements.

Q. Are Staff's points regarding the cost of BESS resources valid?

A. The BESS costs Staff presents are not adjusted for inflation to represent comparable year costs. Regardless, the Company's estimated cost for the Big Hollow BESS presented by Company witness Scott Wibbenmeyer and included in the analysis I

[11] File No. EA-2025-0238, *Staff Rebuttal Report*, p. 42, ll. 8-11, filed December 12, 2025.

presented in my direct testimony represents a project-specific estimate and is therefore the best available estimate for the cost of the project.

IV. RESPONSE TO RENEW MISSOURI

Q. Does Ms. Polk Sentell recommend against Commission approval of the Company's request for CCNs in this case?

A. No. Ms. Polk Sentell supports Commission approval of a CCN for the Big Hollow BESS. While she raises concerns regarding the Company's reliance on natural gas-fired generation, she does not oppose approval of a CCN for the Big Hollow NGSC.

Q. What concern does Ms. Polk Sentell raise with respect to the Company's reliance on natural gas-fired generation and fuel price volatility?

A. Ms. Polk Sentell discusses natural gas price volatility at pages 9-12 of her rebuttal testimony and cautions the Commission against over-reliance on natural gas-fired generation in part due to the perceived risk of natural gas price volatility.

Q. Has Ameren Missouri assessed the risk of natural gas price volatility as part of its IRP planning?

A. Yes. The Company's IRP process includes consideration of a range of natural gas prices over the planning horizon. Several levels of future gas prices are included in integrated price scenarios as described in the Company's 2023 IRP Chapter 2,[12] and power prices are derived through detailed modeling to be consistent with those different levels of gas prices and other scenario variables like carbon prices, as described in Appendix A to Chapter 2 of the 2023 IRP.[13] These ranges of pricing assumptions are used in the Company's analysis of alternative resource plans, as described in Schedule MM-

[12] Attached as Schedule MM-S2.
[13] Attached as Schedule MM-S3.

S2. Those same ranges of prices were used in the analysis supporting the Company's February 2025 PRP filing (Schedule MM-D1).

While the Big Hollow NGSC relies on natural gas for fuel, and while prices for natural gas can be volatile, particularly in the kinds of extreme winter weather conditions we've seen in the last few years, its expected limited operation and low capacity factor means that the exposure is also limited. The Company's operating practices for natural gas purchases for generation mean that there is the potential to reap significant margins during times of high volatility, as the Company described in its 2023 IRP in Chapter 10, Appendix D, which is attached as Schedule MM-S4. In such situations, the Big Hollow BESS facility can also benefit from arbitrage opportunities during times of large power market price differentials.[14]

V. RESPONSE TO OPC

Q. What does Dr. Marke contend regarding the Company's case supporting the approval of CCNs for the Big Hollow projects?

A. Dr. Marke contends that 1) the Company's analysis of compliance with the watt-for-watt requirements of SB4 should not be relied upon as a basis for approving the Company's request for CCNs for the Big Hollow projects,[15] and 2) the Company should withdraw its 2045 "Net Zero Pledge" regarding greenhouse gas emissions.[16]

Q. To what is Dr. Marke referring in mentioning the Company's "Net Zero Pledge?"

[14] Mr. Meyer also addresses the natural gas price volatility concerns raised by Ms. Polk Sentell in his surrebuttal testimony.
[15] File No, EA-2025-0238, Dr. Geoff Marke Rebuttal Testimony, p. 3, l. 18 to p. 4, l. 4.
[16] File No. EA-2025-0238, Dr. Geoff Marke Rebuttal Testimony, p. 17, l. 25 to p. 19, l. 5.

A. As shown in Figure 1.1 in Schedule MM-D1, the Company has set goals for greenhouse emissions reductions and a target to achieve net zero greenhouse gas emissions by 2045. These goals are dependent on the development and commercial availability of technologies to reduce and eliminate or offset greenhouse gas emissions by that date. Figures 1.3 and 1.4 show the Company's expected emissions and carbon intensity under its PRP, respectively.

Q. What basis does Dr. Marke provide for recommending that the Company withdraw its "Net Zero Pledge?"

A. Dr. Marke notes that the Company's current and planned additions of natural gas-fired generations represent an increase in the amount of such generation included in the Company's long-term portfolio and that explicit costs for mitigation technology have not been included.

Q. Is he correct on these two points?

A. Yes, but that does not tell the whole story. The Company includes assumptions for a price on carbon in its IRP planning analysis. This has the effect of reducing production from carbon-emitting resources and increasing overall costs relative to what they would be in the absence of such price assumptions. In that respect, these carbon prices are a "stand in" for the cost of mitigation. The Company's greenhouse gas emission goals are primarily *led by* its IRP process rather than acting as an imposition *on* the IRP process. The Company will continue to assess its resource needs as part of its 2026 IRP triennial filing preparation, which necessarily includes consideration of the Company's greenhouse gas emissions goals and its net zero target, as it has since first adopting such goals. That assessment may or may not lead to changes in those goals or the target.

Q. You mentioned earlier in your surrebuttal testimony that you are recommending that the Commission certify the Big Hollow projects as RREG. On what basis is the Company requesting this certification?

A. I presented the Company's rationale for need for Big Hollow as the RREG for Sioux in my direct testimony. While the current plan is to keep Sioux in operation until essentially right after a natural gas combined cycle plant goes into service at the end of 2031, there absolutely are circumstances that could arise that force an earlier retirement of Sioux and/or that delay the combined cycle plant beyond when Sioux can be kept in operation. If that happened, we would be forced to navigate other provisions of the statute that include compressed timelines and significant additional action by the Commission, all of which can be avoided if the Commission simply recognizes that accredited capacity from the Big Hollow projects can be certified as the RREG now. That would not mean that from an operational perspective a few years from now the combined cycle won't, practically, "replace" Sioux and its energy production, but it will mean that the intent of the statute has been respected: we will have incremental accredited dispatchable capacity on our system that is more than Sioux's accredited capacity *before* we retire Sioux. Regardless, whether the Big Hollow projects are or are not certified as RREG for purposes of the statute, the projects are needed and otherwise meet all of the Tartan Factors, a conclusion with which the Staff agrees.

Q. Why does Dr. Marke recommend against reliance by the Commission on the watt-for-watt requirement for RREG in SB4 as a basis for establishing a need for the Big Hollow projects?

A. He lists three reasons. First, he notes that costs for resources like the Big Hollow projects have increased in part due to high demand. Second, he encourages the Commission to be skeptical regarding resource plans represented in utility IRPs, noting that the Company's IRP preferred plan has changed significantly over the last five years.[17] Third, he suggests that the retirement of coal-fired power plants may be delayed based on his assessment of the current environment.

Q. Do you agree that these are valid reasons for ignoring the potential need for RREG to comply with the watt-for-watt requirement?

A. No. First, there is no exception for the requirement based on cost. Second, resource planning is ongoing precisely because circumstances are always changing, so the mere fact that the Company's plans have changed does not relieve it of the obligation to plan for meeting the watt-for-watt requirement. Third, the Sioux Energy Center is nearing the end of its useful life. Planned retirement dates have fallen consistently in a five-year window over multiple IRP cycles – from 2028 to 2033. This can be seen in the IRP resource timelines presented in the rebuttal testimony of OPC witness Jordan Seaver (pages 12-13). While the Company's current PRP indicates that Sioux may be retired as late as 2035, it also indicates that this retirement date could be as early as 2031. The watt-for-watt requirement is a statutory requirement that includes little flexibility. For that reason, the Company must take steps to ensure that it has sufficient RREG in advance of any retirement to ensure compliance.

Q. Mr. Seaver also addresses the watt-for-watt requirement. What issues does he raise?

[17] Which is exactly why resource planning is an ongoing exercise, and why we filed to change our PRP in 2025.

A. Mr. Seaver asserts that (1) the Company has not asked that the Commission certify the Big Hollow projects as RREG to replace Sioux, (2) the retirement of Sioux during a time of rapidly increased demand would likely be imprudent, (3) the planned NGCC is expected to replace Sioux, and (4) if the NGCC is delayed, then the retirement of Sioux should be delayed.[18]

Q. How do you respond?

A. First, while I did not use the term "request" in my direct testimony, my intention in providing testimony regarding why the Big Hollow projects should be certified as RREG for replacing the Sioux units because they qualify as such was the intent of my direct testimony. For clarity, the Company is making that request in this docket.[19] That later generation might also qualify is irrelevant as the statutory requirement as it pertains to Sioux will have been satisfied.[20] Second, determinations of prudence are made by the Commission, and the Company cannot rely on speculation by any witness about what the Commission will determine, based on the facts that actually exist when a decision to actually retire Sioux is made. It's my understanding that under the applicable prudence standards, that decision will be presumed to be prudent and other parties (including OPC) will be free to produce evidence that the party claims creates a serious doubt about the decision, but this is all speculation at this point – yes, we *plan* to retire Sioux within the timeframe just noted, but as of now, it is a plan, not a final decision. Third, given its age and its technology (e.g., cyclone boilers that have experienced more operational issues than

[18] File No. EA-2025-0238, Jordan Seaver Rebuttal Testimony, p. 11, ll. 5-23.
[19] As Mr. Meyer's direct testimony shows, the combined accredited capacity of the Big Hollow projects is expected to be between approximately 926 and 985 MW, substantially more than even the nameplate capacity of Sioux (the accredited capacity of which is even less), which means that the Big Hollow projects easily satisfy the statutory requirements for RREG for Sioux.
[20] Subsequent generation, such as the planned NGCC in 2031, can be used to satisfy the RREG requirement for the subsequent retirement of units at the Labadie Energy Center.

we see with boilers such as those in place at Labadie), we do believe that Sioux is very much approaching the end of its useful life – it will, after all, be about 70 years old in the early 2030s – and it does seem highly probable that from a reliability and cost perspective, it will simply need to be retired in that timeframe. Fourth, regardless of the current political and regulatory environment, there is a risk that future environmental regulations could force the earlier retirement of Sioux or impose costs that render its continued operation uneconomic. Fifth, depending on its implementation, the planned NGCC may not be in service before the Sioux units are retired, and for the reasons stated here, relying on the ability to further delay the retirement of Sioux – an ability that may not exist at all -- represents an unacceptable risk when considering the statutory watt-for-watt requirement and the uncertainties to which the Company's planning is subject.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric	)	
Company d/b/a Ameren Missouri for Permission and	)	
Approval and Certificate of Public Convenience and	)	File No.: EA-2025-0238
Necessity Authorizing it to Construct a New Generation	)	
Facility and Battery Energy Storage System	)	

AFFIDAVIT OF MATT R. MICHELS

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Matt R. Michels, being first duly sworn on his oath, states:

My name is Matt R. Michels, and hereby declare on oath that I am of sound mind and lawful age; that I have prepared the foregoing *Surrebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Matt R. Michels
Matt R. Michels

Sworn to me this 16th day of January 2026.

9. Integrated Resource Plan and Risk Analysis

Highlights

- *Ameren Missouri has developed a robust range of alternative resource plans that reflect different combinations of energy efficiency (EE), demand response (DR), various types of new renewable and conventional generation, energy storage, and retirement of each of its existing coal-fired generators.*
- *In addition to the scenario variables and modeling discussed in Chapter 2, one critical independent uncertain factor has been included in the final probability tree for risk analysis: project cost.*
- *Our risk analysis also includes the evaluation of a range of load growth.*

Ameren Missouri's modeling and risk analysis consisted of a number of major steps:

1. Identification of **alternative resource plan attributes**. These attributes represent the various resource options used to construct and define alternative resource plans – demand side resources, new renewable and non-renewable supply side resources, and retirement of existing supply side resources.
2. Development of the **baseline capacity position**, which reflects forecasted peak demand, reserve requirements and existing resources.
3. **Pre-analysis** to determine certain base elements for alternative resource plans. This included analysis of various retirement dates for Sioux Energy Center and the addition of selective catalytic reduction (SCR) at two units at Labadie Energy Center.
4. Development of **planning objectives** to guide the development of alternative resource plans.
5. Development of the **alternative resource plans**. The alternative resource plans were developed using the plan attributes identified in step 1, the base capacity position developed in step 2, and the planning objectives identified in step 3.
6. Identification and screening of **candidate uncertain factors**, which are key variables that can influence the performance of alternative resource plans.

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7. **Sensitivity analysis** and selection of critical uncertain factors, which are key variables that are determined to have a significant impact on the performance of alternative resource plans.
8. **Risk analysis** of alternative resource plans, which is used to evaluate the performance of alternative resource plans under combinations of the scenarios discussed in Chapter 2 and the critical uncertain factors identified in step 7.

This chapter describes these various steps and the results and conclusions of our integration and risk analysis.

9.1 Alternative Resource Plan Attributes[1]

Development of alternative resource plans include considering various combinations of demand-side and supply-side resources to meet future capacity needs. However, alternative resource plans may also include elements or attributes that serve the other planning objectives described in Section 9.3. Including these elements can significantly affect the capacity position that needs to be considered when developing alternative resource plans. Figure 9.1 includes the attributes considered during the development of resource plans.

Figure 9.1 Attributes of Alternative Resource Plans[2]

Retirements (End of Year) - Sioux Retired 2028/2030/2032 - Labadie Retired 2036-2042 - Labadie Retired 2036-2039 - Labadie Retired 2036-2036 - Labadie Retired 2031-2031 - Rush Island Retired 2024	**Demand-Side Management** - Maximum Achievable Potential (MAP) - Realistic Achievable Potential (RAP) - Load Flexibility - RAP (DR only) - Load Flexibility - MAP (DR only) - Missouri Energy Efficiency Investment Act (MEEIA) Cycle 3 Only
New Supply-Side Types - Combined Cycle* (Nat. Gas) - Simple Cycle (Nat. Gas) - Nuclear (Small Modular) - Pumped Hydro Storage - Solar - Wind - Batteries	**Renewable Portfolios** - Missouri Renewable Energy Standard (RES) with RAP DSM - RES with MAP DSM - RES with No Future DSM - Renewable Expansion - Renewables for Capacity Need - Renewable Expansion Plus

* With and without carbon capture

[1] 20 CSR 4240-22.060(1); 20 CSR 4240-22.060(3)
[2] In the modeling, retirement was assumed to be by the end of 2025. The change in retirement date has no appreciable impact on any of the analyses or conclusions in this filing, which were completed before the expected retirement date was known.

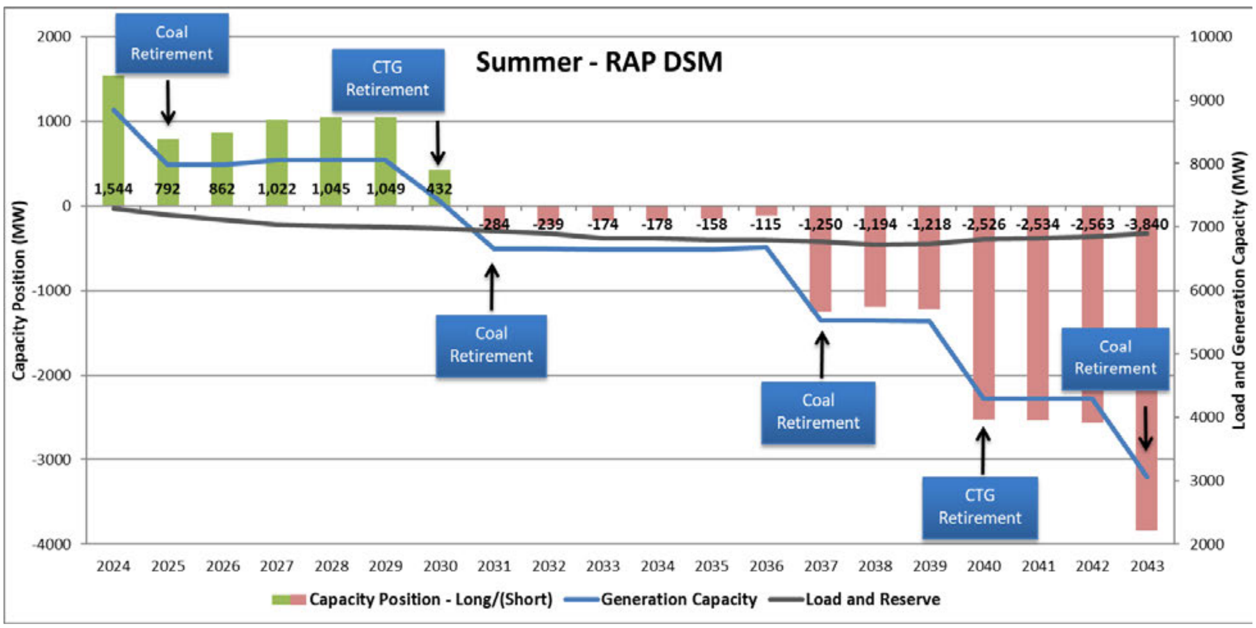
9.2 Capacity Position

To determine the timing and need for resources, Ameren Missouri first developed its baseline capacity position, including:

- Existing plant seasonal accreditation values (SAC) from the Midcontinent Independent System Operator (MISO)
- Peak demand forecast, as described in Chapter 3
- Seasonal planning reserve margin (PRM) requirements, based on MISO's Planning Year 2023-2024 Loss of Load Expectation (LOLE) Study Report (updated 5/1/2023) as shown in Chapter 2.

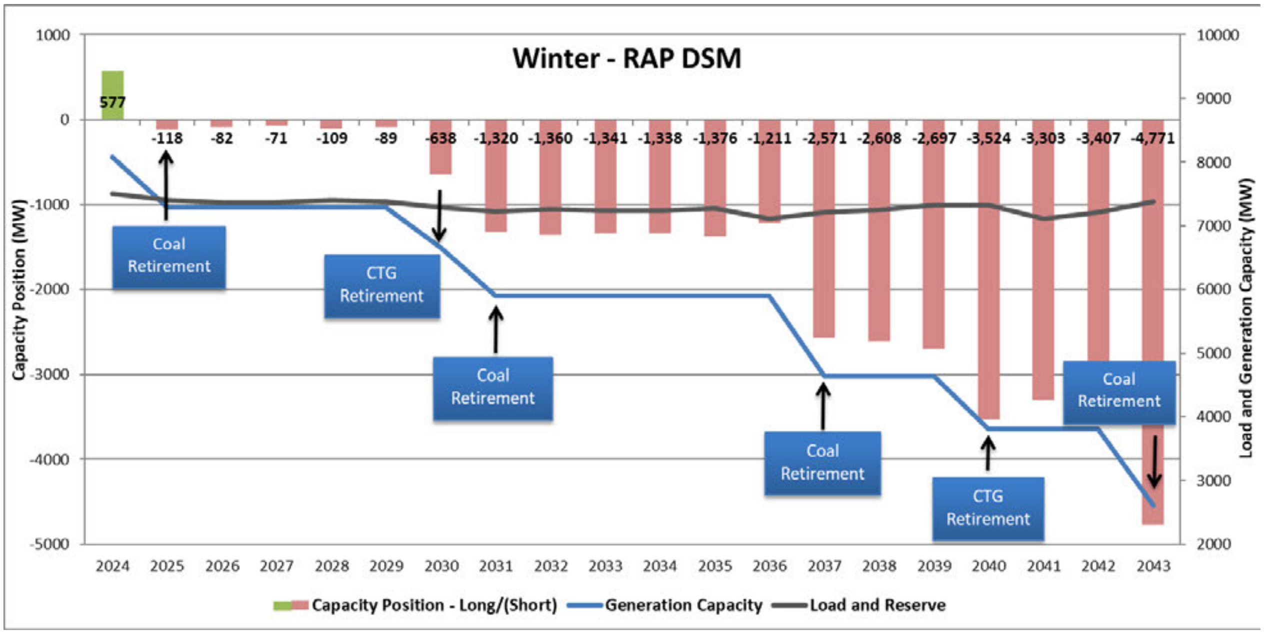
Figures 9.2 and 9.3 show Ameren Missouri's net capacity position with no new major generating resources for summer and winter.[3]

Figure 9.2 Summer Capacity Position – No New Supply-Side Resources (Baseline)



[3] Based on MISO Resource Adequacy view with normal weather. See Chapter 10 for discussion of the Operating View for capacity and consideration of extreme weather.

Figure 9.3 Winter Baseline Capacity Position – No New Supply-Side Resources



The charts show the system capacity, customer needs (including the MISO reserve requirement), and capacity above/below the MISO requirement (i.e., long/short position). The customer needs include peak load reductions due to RAP EE and DR. The system capacity includes the capacity benefit of the RES Compliance portfolio.[4] Retirement dates reflected in the base capacity position for existing coal-fired units are those established in Ameren Missouri's most recent depreciation study filed with the Missouri Public Service Commission (MPSC) and are considered to be the base retirement dates.

Retirements and Modifications

Ameren Missouri is considering retirement of its four older gas- and oil-fired CTG units – Fairgrounds, Mexico, Moberly, and Moreau – with a total summer net capacity of 217 MW, over the next 20 years. Additionally, Ameren Missouri will be retiring its IL CTGs – with a total summer net capacity of 1,952 MW – due to the Climate and Equitable Jobs Act (CEJA), passed in Illinois in 2021. Chapter 4 - Table 4.4 provides a summary of the planned CTG retirements. The CTG retirements were included in all alternative resource plans. Ameren Missouri also has assumed the restoration of oil backup capability at its Peno Creek and Kinmundy Energy Centers for a total of 87 MW of winter capability increase.

Coal energy center retirements were also included in the capacity planning process. Three different Sioux retirement options were considered: 1) retirement by December 31,

[4] Boomtown Renewable Energy Center is also included since the CCN application is approved.

2030, as reflected in the preferred plan adopted by the Company in 2022, 2) retirement by December 31, 2028 and 2) retirement by December 31, 2032. Four different retirement options for Labadie were considered: 1) current retirement dates, with two units retired by December 31, 2036 and two units retired by December 31, 2042, 2) two units retired by December 31, 2036 and two units retired by December 31, 2039, 3) all four units retired by December 31, 2036, 4) all four units retired by December 31, 2031. Rush Island Energy Center was assumed to be retired by December 31, 2024.

DSM Portfolios

EE and DR programs as described in detail in Chapter 8 are included in the DSM portfolios. DSM programs not only reduce the peak demand but also reduce reserve requirements associated with those demand reductions. The following combinations of DSM portfolios were evaluated: 1) RAP EE and DR, 2) MAP EE and DR, 3) RAP with RAP Load Flexibility (LF) DR, 4) MAP with MAP LF DR, 5) RAP 80% EE[5] and RAP DR, and 6) No DSM after MEEIA Cycle 3. The No DSM portfolio reflects completion of Ameren Missouri's current program cycle with no further EE or DR during the planning horizon. Note that the recent MPSC approval of Ameren Missouri's request for a one-year extension of MEEIA programs occurred after the IRP analysis was underway, which means that the No Further DSM portfolio starts one year before that extension ends.[6] Table 9.1 summarizes the cumulative demand and energy savings passed on to integration analysis.

Table 9.1 DSM Savings Summary

DSM Program	Summer Peak Reduction MW @Gen			Winter Peak Reduction MW @Gen			Energy Savings MWh @Transmission		
	2025	2035	2043	2025	2035	2043	2025	2035	2043
EE RAP	202	1010	1248	110	647	906	609,777	3,245,499	4,336,386
EE MAP	286	1436	1801	147	839	1192	819,087	4,247,043	5,730,736
EE RAP 80%	162	808	999	88	518	725	487,822	2,596,399	3,469,109
DR RAP	205	298	320	6	14	19	-	-	-
DR MAP	302	486	514	9	22	30	-	-	-
DR RAP Load Flexibility	205	298	320	156	233	226	-	-	-
DR MAP Load Flexibility	302	486	514	229	383	363	-	-	-

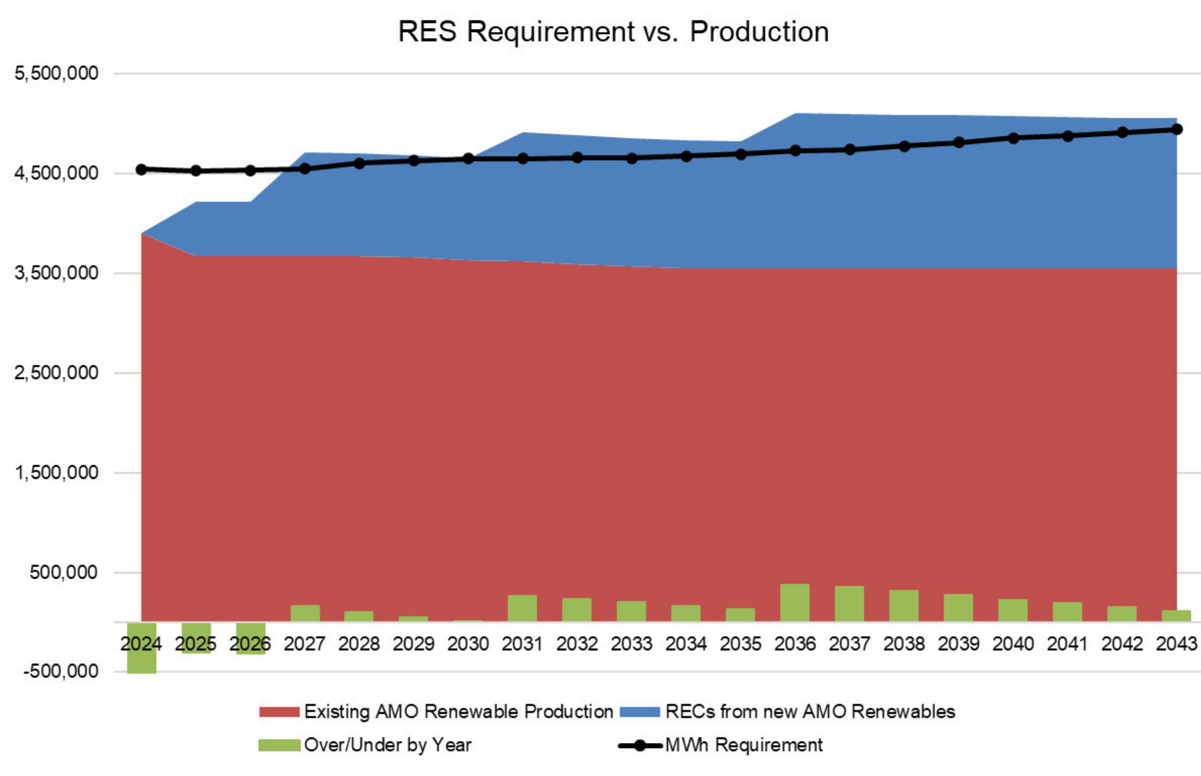
[5] An additional energy efficiency portfolio that achieves 80% of RAP level energy and demand savings.
[6] The extension of MEEIA Cycle 3 should not have a material impact on the analysis.

Renewable Portfolios[7]

Compliance with Missouri's RES was updated to reflect current assumptions, including baseline revenue requirements and an updated 10-year forward-looking model which calculates the impact of the statutory 1% rate impact limitation.

Ameren Missouri performed its RES compliance analysis with the *10 Year MO RES Compliance Model 2023 IRP* (Model). The Model is designed to calculate the retail rate impact, as required by the Commission's RES rules.[8] This Model determines the quantity of renewable energy needed to meet both the overall RES portfolio standard and the 2% solar portfolio standard "carve-out" absent any rate impact constraints. The Model then determines the amount of renewable energy, both solar and non-solar that can be built without exceeding an average 1% revenue requirement increase over a ten-year period. Ameren Missouri's renewable energy credit (REC) position is presented in Figure 9.4.[9]

Figure 9.4 Ameren Missouri's RES REC Positions



[7] File No. EO-2023-0099 1.C; File No. EO-2023-0099 1.E; File No. EO-2023-0099 1.H
[8] 20 CSR 4240-20.100(5)
[9] Assumes RAP EE and DR DSM Portfolio. Consistent with the Company's 2023-2025 RES Compliance Plan, the chart reflects Keokuk, High Prairie, Atchison, and Huck Finn at P-90 production levels.

Figure 9.4 shows that Ameren Missouri expects to meet the overall REC requirement through 2043 primarily with owned renewable generation. Year-to-year compliance may also include banked RECs and purchased RECs. Near term shortfalls will be reduced by the addition of the Huck Finn Solar Project in late 2024.

Table 9.2 shows the amounts of wind and solar resources added for various renewable portfolios, including RES compliance under different load cases. The RES compliance portfolio established by the previously described Model is used for alternative resource plans and reflects wind resource additions that take advantage of Production Tax Credits, allowing full compliance with the RES while remaining under the one percent rate cap limitation. Appendix A shows the amounts of wind and solar resources needed in Term 1 (2024-2033) and Term 2 (2034-2043).

When developing the RES compliance investment needs, consideration was given to the potential difference between RAP DSM investment vs MAP DSM investment vs no further DSM. As MAP DSM results in more energy savings, the RES Compliance requirements are slightly lower than the requirements when RAP DSM is assumed, which also has lower requirements than with No Further DSM.

In addition to the RES Compliance portfolios, we also included "Renewable Expansion." "For Capacity Need" and “Renewable Expansion Plus” portfolios to evaluate the performance of additional solar and wind resources. The Renewable Expansion portfolio includes a total of 2,000 MW new wind and 2,700 MW solar while the Renewable Expansion Plus portfolio includes a total of 4,900 MW wind and 4,600 MW solar resources.[10] The For Capacity Need portfolio has the same amount of additions as the Renewable Expansion portfolio by the end of the planning horizon. However, new wind and solar resources are added only when there is a capacity need above the Company's build threshold.[11]

Table 9.2 shows the timing of new resources for renewables included in the alternative resource plans.

[10] File No. EO-2023-0099 1.E

[11] As determined using the MISO Resource Adequacy view of capacity under normal weather load conditions.

Table 9.2 Renewable Portfolios (Nameplate Capacity)

Renewable Additions		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
RES Compliance - RAP DSM	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	-	350	-	175	-	-	-	100	-	-	-	-	100	-	-	-	-	-	-	-	725
RES Compliance - MAP DSM	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	-	350	-	175	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	625
RES Compliance - no Further DSM		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	350	-	300	-	-	-	100	-	-	-	-	150	-	-	-	-	-	-	-	900
Renewable Expansion	Wind	-	-	-	-	200	400	400	-	200	200	200	200	200	-	-	-	-	-	-	-	2,000
	Solar	-	500	50	650	200	-	-	400	200	200	200	200	100	-	-	-	-	-	-	-	2,700
Renewables for Capacity Need	Wind	-	-	-	-	-	-	200	-	-	-	-	-	-	1,500	100	100	-	-	-	100	2,000
	Solar	-	350	-	175	-	-	-	100	-	-	-	-	100	-	-	1,775	-	-	-	200	2,700
Renewable Expansion Plus	Wind	-	-	-	-	200	400	400	-	450	450	450	450	450	450	450	450	300	-	-	-	4,900
	Solar	-	500	50	650	200	-	-	400	350	350	350	350	350	350	350	350	-	-	-	-	4,600

Batteries were also included with all of the renewable portfolios. The Renewable Expansion Plus portfolio had a total of 3,500 MW, and all other renewable portfolios had a total of 800 MW of battery additions. Ameren Missouri assumes some of these batteries would be placed at retiring energy centers; the rest can be stand alone or placed with wind or solar additions, which would not change the analysis results.

Table 9.3 Battery Additions (Nameplate Capacity)

Battery Additions	2028	2029	2030	2031	2032	2033	2034	2035	Total
Renewable Expansion Plus	-	200	300	-	-	3,000	-	-	3,500
All Other Renewable Portfolios	-	200	200	-	-	200	200	-	800

The Inflation Reduction Act (IRA) that was passed in 2022 extended and expanded tax credits for clean energy resources. Ameren Missouri assumed full PTC for solar and wind resources and full ITC for battery storage resources that go in service by 2032, and reduced the tax credits as prescribed in the IRA for resources that go in service in later years. No tax credits were assumed for projects completed after 2036.

Other Supply-side Resources

After including DSM resources and the renewable portfolios, if the capacity shortfall in a given year met or exceeded the build threshold, then supply-side resources selected from the following technologies are added to eliminate the shortfall: combined cycle (CC), CC with carbon capture (CCS), simple cycle (SC) with dual fuel capability, small modular nuclear reactor (SMR) and pumped hydro storage. The build threshold was determined to be 300 MW in the short-term and 200 MW in the long-term regardless of the type of supply-side resource under consideration. The accredited summer and winter capacities for each supply side type are shown in Table 9.4. Ameren Missouri has assumed reliance on short-term capacity purchases to cover shortfalls that are less than the build threshold and has assumed that any long capacity position would be sold. The earliest in-service dates for each supply-side resource are also shown in Table 9.4. The in-service date constraints represent the expectations for construction lead time as well as the commercial availability of each technology.

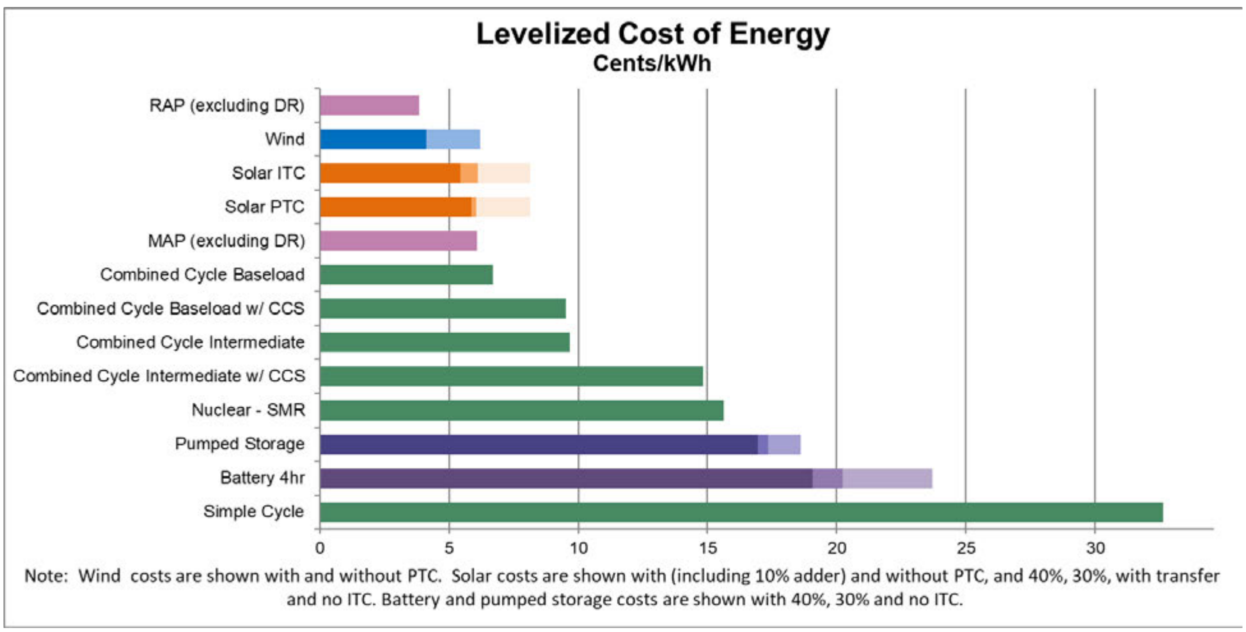
Table 9.4 Summer and Winter Capacity for Supply-Side Types[12]

Supply Side Type	Capacity (MW)	Accredited Capacity (MW) Summer/Winter	Earliest Year In-Service
CC	1,200	1,092	2028
CC with CCS	1,200	1,033	2035
SC	1,150	1,045	2027
SMR	864	821	2035
Pumped Hydro	600	564/594	2035

The remaining net capacity position was represented in the financial model as capacity purchases and sales priced at the market-based seasonal capacity costs as discussed in Chapter 2. The capacity purchases and sales were also adjusted for the various peak demand forecasts and DSM impacts.

Figure 9.5 summarizes the levelized cost of energy (LCOE) for all potential future resources evaluated in the alternative resource plans.

Figure 9.5 Levelized Cost of Energy – All Resources[13]



[12] While the Company does not believe that combined cycle gas can be implemented by 2028, the earliest start date was set to allow for analysis of a plan with no further DSM beyond MEEIA Cycle 3, which results in a need for additional capacity and energy during that timeframe.
[13] 20 CSR 4240-22.010(2)(A)

9.3 Planning Objectives

The fundamental objective of Missouri's electric resource planning process is to provide energy to customers in a safe, reliable and efficient way, at just and reasonable rates while being in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.[14] Ameren Missouri considers several factors, or planning objectives, that must be considered in meeting the fundamental objective. Planning objectives provide a guide to the decision-making process while ensuring the resource planning process is consistent with business planning and strategic initiatives.

Five planning objectives were used in the development of alternative resource plans: Portfolio Transition (formerly Environmental/Resource Diversity); Financial/Regulatory; Customer Satisfaction; Economic Development; and Cost. These planning objectives, which are the same as those discussed in Ameren Missouri's IRP filings since 2011, were selected by Ameren Missouri decision makers and are discussed below.[15]

Portfolio Transition

Ameren Missouri has relied for many years on a portfolio that consists, in large part, of large, efficient coal-fired generators some of which have already retired or will soon be retiring. Current and potential future environmental regulations may have a significant impact on Ameren Missouri's remaining coal-fired units and its selection of future generation resources. Ameren Missouri seeks to transition its generation portfolio to one that is cleaner and more diverse in a responsible fashion. To test various options for advancing this transition, alternative resource plans were developed to include varying levels of DSM portfolios, renewables in addition to those required for RES compliance, new gas-fired generation, new nuclear generation, storage resources and early coal retirements.

Financial/Regulatory

The continued financial health of Ameren Missouri is crucial as it will need access to large amounts of capital in order to comply with RES and environmental regulations, invest in new supply side resources, and fund continued EE programs while maintaining or improving safety, reliability, affordability, and customers' ability to control their energy use and costs. While making its investment decisions, it is important for Ameren Missouri to consider factors that may influence its access to low-cost sources of capital. This includes

[14] 20 CSR 4240-22.010(2)
[15] 20 CSR 4240-22.010(2)(C)

measures of cash flow, profitability, and creditworthiness as well as assessment of risks associated with investment management and cost recovery.[16]

Customer Satisfaction

While there are many factors that can influence customer satisfaction, there are several that can be significantly affected by resource decisions. Ameren Missouri has focused on levelized annual rates, inclusion of EE, reliability, availability of DER and DR programs, inclusion of new clean energy resources, and significant reductions in CO_2 emissions to assess relative customer satisfaction expectations.[17]

Economic Development

Ameren Missouri assesses the relative economic development potential of alternative resource plans in terms of job growth opportunities associated with its resource investment decisions. Plans were rated on a relative scale based on direct jobs (FTE-years) required for both construction and operation.[18] We have assumed that second and third level economic impacts would not significantly affect the relative economic development potential of alternative resource plans, and therefore have not included such impacts in our assessment.

Cost

Ameren Missouri is mindful of the impact that its future resource choices will have on its customers' rates and bills. Maintaining reasonable costs while meeting its other planning objectives is of utmost importance to Ameren Missouri. Cost alone does not and should not dictate resource choices at the expense of other important considerations, but it is a very important factor in making resource decisions. Therefore, minimization of the present value of revenue requirements (PVRR) was used as the primary selection criterion.[19]

9.4 Pre-Analysis

A pre-analysis was conducted prior to the development of alternative resource plans to determine two key elements for inclusion as the default option in alternative resource plans: Sioux retirement date and addition of selective catalytic reduction (SCR) systems at two units at Labadie Energy Center.

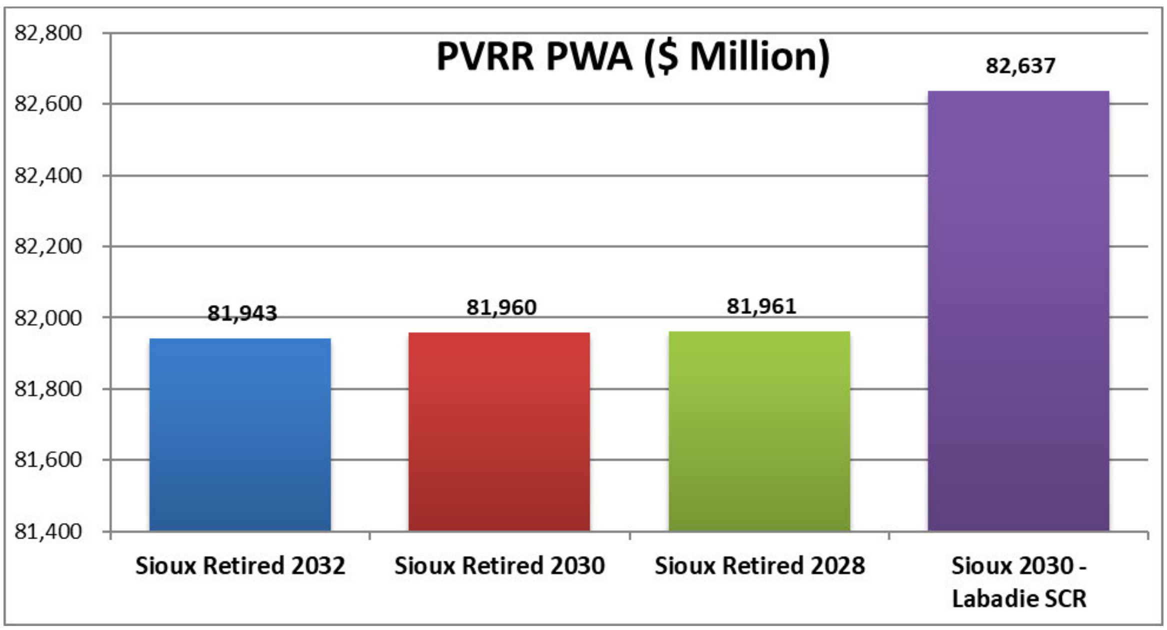
[16] 20 CSR 4240-22.060(2)(A)6
[17] 20 CSR 4240-22.060(2)(A)4
[18] 20 CSR 4240-22.060(2)(A)7
[19] 20 CSR 4240-22.060(2)(A)1; 20 CSR 4240-22.010(2)(B); 20 CSR 4240-22.060(2)(B)

Ameren Missouri analyzed two additional retirement dates for Sioux Energy Center – end of 2028 and 2032 – in addition to its prevailing retirement date of 2030 in light of the Good Neighbor Rule and the proposed additions to Clean Air Act under Section 111 (b) and (d).

Ameren Missouri also analyzed the addition of SCRs at Labadie Energy Center to determine whether the investment in the technology would result in lower cost to customers to comply with the Good Neighbor Rule as opposed to just reducing generation. Allowance limits were estimated for both with and without SCRs and for the different retirement dates to be used in the analysis.

Figure 9.6 summarizes the PVRR results of the pre-analysis, which was run on all nine price scenarios described in Chapter 2.

Figure 9.6 Pre-Analysis PVRR Results



Differences in PVRR from the Sioux 2030 retirement (no SCR) can be seen in table 9.5. The different retirement dates result in similar PVRRs, with 2032 retirement being lower by $17 Million than the 2030 retirement. The addition of SCRs, however, increases costs significantly; PVRR with SCRs is higher by $676 Million than the plan without SCRs.

The Sioux 2032 retirement and no SCR addition are passed to integration as the default options.[20] However, the 2028 and 2030 retirement dates and SCR addition were still included in the alternative resource plans, and the results of the pre-analysis were

[20] As explained in Chapter 10, the Company also considered risk associated with the US Environmental Protection Agency (EPA)'s proposed rule for CO_2 emissions.

validated by evaluating these options under the full range of scenarios and critical uncertain factors in the risk analysis.

Table 9.5 Pre-Analysis – Difference in PVRR

(Million $)	PVRR	Difference from Sioux 2030 Retirement	Difference from Sioux 2030 SCR
Sioux Retired 2028	81,961	1	
Sioux Retired 2032	81,943	-17	
Sioux 2030 - Labadie SCR	82,637		676

9.5 Determination of Alternative Resource Plans[21]

Twenty-three alternative resource plans were developed to incorporate different combinations of demand-side and supply side resource options, seek to fulfill Ameren Missouri's planning objectives, and answer key questions, including the following:

- Does inclusion of DSM programs reduce overall customer costs?
- What level of DSM – RAP, MAP, addition of load flexibility DR– results in lower costs?
- How would our plans and customer costs be affected if we could add less than RAP EE resources?
- How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?
- Is earlier retirement of Labadie Energy Center cost effective?
- Is earlier/later retirement of Sioux Energy Center cost effective?
- What is the impact of reducing NO_x emissions further with added mitigation technology?
- What are the benefits of including renewables beyond those needed for RES compliance?
- What is the impact of delaying deployment of renewables until there is a capacity deficit?
- What is the impact of pursuing only new renewables?
- What is the impact of pursuing only dispatchable supply-side resources?

[21] 20 CSR 4240-22.060(3)

- How do various supply-side resource options compare?

Table 9.6 provides a summary of the alternative resource plans.

Table 9.6 Alternative Resource Plans[22]

	Plan Name	DSM EE-DR	Renewables	New Supply-Side	Coal Retirements/ Modifications
A	Sioux Retired 2030	RAP-RAP	Renewable Expansion	SC 2028, CC 2031 CC 2040 and 2043	Sioux Dec-2030
B	Sioux Retired 2028	RAP-RAP	Renewable Expansion	SC 2028, CC 2029 CC 2040 and 2043	Sioux Dec-2028
C	RAP - Renewable Expansion	RAP-RAP	Renewable Expansion	SC 2028, CC 2033 CC 2040 and 2043	Base
D	Labadie SCR	RAP-RAP	Renewable Expansion	SC 2028, CC 2033 CC 2040 and 2043	Labadie SCR
E	MAP	MAP-MAP	Renewable Expansion	SC 2028, CC 2033 CC 2040 and 2043	Base
F	RAP-RES Compliance	RAP-RAP	RES Compliance	SC 2028, CC 2033 CC 2030, 2040 and 2043	Base
G	MAP-RES Compliance	MAP-MAP	RES Compliance	SC 2028, CC 2033 CC 2037, 2040 and 2043	Base
H	MAP LF-RES Compliance	MAP-MAPLF	RES Compliance	SC 2028, CC 2033 CC 2040 and 2043	Base
I	No Additional DSM	-	Renewable Expansion	SC 2028, CC 2033 CC 2028, 2040, 2043 and 2043	Base
J	No Additional DSM- RES Compliance	-	RES Compliance	SC 2028, CC 2033 CC 2028, 2037, 2040 and 2043	Base
K	Renewables for Capacity Need	RAP-RAP	For Capacity Need	SC 2028, CC 2033 CC 2040 and 2043	Base
L	Pumped Storage w/ MAP LF	RAP-MAPLF	Renewable Expansion	SC 2028, CC 2033 Pumped Storage 2040, CC 2043	Base
M	SC	RAP-RAP	Renewable Expansion	SC 2028, CC 2033 SC 2040, CC 2043	Base
N	SMR w/ RAP LF	RAP-RAPLF	Renewable Expansion	SC 2028, CC 2033 SMR 2040, CC 2043	Base

[22] 20 CSR 4240-22.010(2)(A); 20 CSR 4240-22.060(3); 20 CSR 4240-22.060(3)(A)1 through 8; 20 CSR 4240-22.060(3)(B); 20 CSR 4240-22.060(3)(C)1; 20 CSR 4240-22.060(3)(C)2; 20 CSR 4240-22.060(3)(C)3; File No. EO-2023-0099 1.E

	Plan Name	DSM EE-DR	Renewables	New Supply-Side	Coal Retirements/ Modifications
O	Labadie 2039	RAP-RAP	Renewable Expansion	SC 2028, CC 2033 CC 2040 and 2040	Labadie 2U Dec-2036 Labadie 2U Dec-2039
P	Labadie 2036	RAP-RAP	Renewable Expansion	SC 2028, CC 2033 CC 2037 and 2039	Labadie 4U Dec-2036
Q	Labadie 2031	RAP-RAP	Renewable Expansion	SC 2028, CC 2033 CC 2032 and 2032	Labadie 4U Dec-2031
R	RAP LF	RAP-RAPLF	Renewable Expansion	SC 2028, CC 2033 CC 2040 and 2043	Base
S	MAP LF	MAP-MAPLF	Renewable Expansion	SC 2028, CC 2033 CC 2040 and 2043	Base
T	All Renewables	RAP-RAP	Renewable Expansion Plus	SC 2028	Base
U	SC instead of First CC	RAP-RAP	Renewable Expansion	SC 2028 and 2033 CC 2040 and 2043	Base
V	CCS on 1st CC	RAP-RAP	Renewable Expansion	SC 2028, CC 2033 CC 2040 and 2043	Base
W	RAP 80%	RAP 80%-RAP	Renewable Expansion	SC 2028, CC 2033 CC 2038, 2043 and 2043	Base

All of the plans include an 800 MW SC addition at the end of 2027 for reliability needs. Any CC added on or after 2035 include CCS, and CCs that go into service prior to 2035 with the exception of CC added right after Sioux retirement do get retrofitted with a CCS in 2040. The CC that is placed into service upon Sioux retirement is assumed to have its CO_2 emissions eliminated beginning in 2040. This may be achieved through some combination of alternative fuels (e.g., hydrogen, renewable natural gas), carbon capture and sequestration, purchased offsets, or reduced operation. Because of the uncertainty regarding the eventual method used to mitigate carbon emissions, the higher variable and fixed operating and maintenance (O&M) costs for CC with CCS are included with no major capital expenditures for CCS. Plan V adds the capital cost of CCS as well to indicate the change in cost for including this capital expenditure. Ameren Missouri assumed that the incentives in the IRA will help green hydrogen and CCS projects become commercially available by 2040.[23]

Does inclusion of DSM programs reduce overall customer costs?

Plans C, E, R, S and W include RAP and MAP, RAP with LF, MAP with LF, and RAP 80% level of DSM programs, respectively. Therefore, these plans can be compared against

[23] File No. EO-2023-0099 1.C

plan I that has the same level of renewable portfolios but do not include DSM programs to assess the impact on cost and other performance measures due to inclusion of different levels of DSM. Additionally, the same comparison can be made between plans F, G and H that include RAP, MAP and MAP with MAP LF level of DSM programs against plan J with no additional DSM programs as these plans all have the RES Compliance only portfolio.

What level of DSM -RAP, MAP, and addition of load flexibility DR- results in lower costs?[24]

Plans with the same attributes except for the level of DSM resources have been evaluated as described above and provide a direct comparison of the relative cost of the various DSM portfolios.

How would our plans and customer costs be affected if we could only add less than RAP EE resources?

Plan C includes RAP level of EE while Plan W includes only 80% of RAP. Comparison of the two plans should reveal cost/benefits of not deploying energy efficiency resources at RAP levels as identified in the Market Potential Study.

How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?

Plans I and J also evaluate the impact if DSM cost recovery and incentive requirements are not met.

Is earlier/later retirement of Sioux Energy Center cost effective?[25]

Plans A, B and C evaluate the cost effectiveness of retiring the Sioux Energy Center by 2030, 2028 and 2032, respectively.

Is earlier retirement of Labadie Energy Center cost effective?[26]

Plans O, P and Q evaluate the cost effectiveness of earlier retirement of two or four units and can be compared against the base retirement dates as in Plan C.

[24] 20 CSR 4240-22.060(3)(A)3
[25] 20 CSR 4240-22.060(3)(A)7
[26] 20 CSR 4240-22.060(3)(A)7

What is the impact of reducing NO_x emissions further with added mitigation technology?

Plan D evaluates the cost effectiveness of adding two SCRs at Labadie Energy Center by 2027 NO_x season.

What are the benefits of including renewables beyond those needed for RES compliance?[27]

To assess the relative benefits of including additional renewable resources, several alternative resource plans were developed that exceed the level of renewable investment indicated by the RES compliance model. Plans C and F with RAP DSM, plans E and G with MAP DSM, and plans I and J with no additional DSM can be compared to assess the costs/benefits of additional renewables.

What is the impact of delaying deployment of renewables until there is a capacity need?

Plan K evaluates the costs effectiveness of deploying renewable resources beyond RES compliance only when there is a capacity need.

What is the impact of pursuing only new renewables?

Plan T is the 'all renewables' alternative resource plan. It is included with addition of RAP level DSM programs and the SC, and yet, does not meet the reliability requirements.[28]

What is the impact of pursuing only dispatchable supply-side resources?

Plan J evaluates the costs effectiveness of adding no additional DSM programs, renewable resources for only RES compliance and dispatchable supply-side resources.

How do various supply-side resource options compare?

The relative performance of the new supply-side resources can be determined by comparing Plans C, L, M and N, and by comparing Plan C against Plan U.

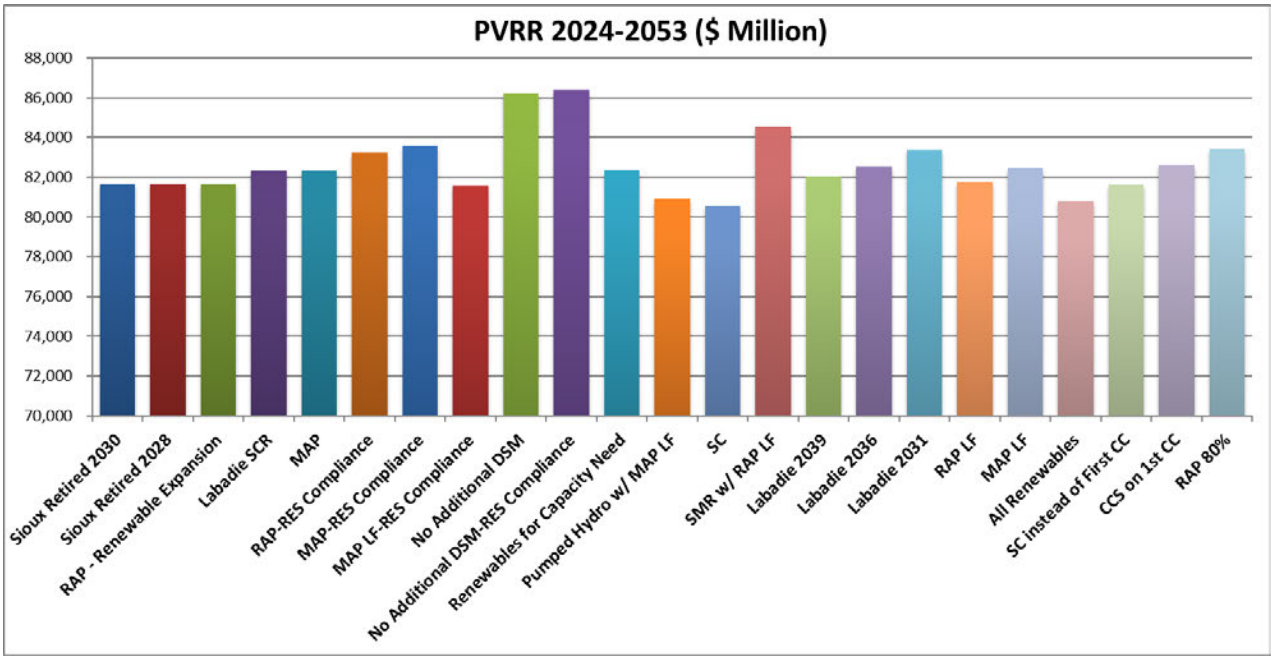
The type, size, and timing of resource additions/retirements for the alternative resource plans are provided in Appendix A and also in the electronic workpapers.[29]

Integration, sensitivity, and risk analyses for the evaluation of alternative resource plans were done assuming that rates would be adjusted annually for the 20-year planning

[27] 20 CSR 4240-22.060(3)(A)1
[28] 20 CSR 4240-22.060(3)(A)2
[29] None of the alternative resource plans analyzed include any load-building programs
20 CSR 4240-22.060(3)(B); 20 CSR 4240-22.080(2)(D); 20 CSR 4240-22.060(3)(D)

horizon and 10 additional years for end effects, and by treating both supply-side and demand-side resources on an equivalent basis. Integration analysis was performed on the most likely scenario of the probability tree (Scenario 5) as explained in Chapter 2. Integration analysis present value of revenue requirements (PVRR) results are shown below in Figure 9.7. Results for the remaining performance measures for integration analysis are provided in the workpapers.[30]

Figure 9.7 Integration PVRR Results[31]



It should be noted that all costs and benefits in all analyses were expressed in nominal dollars, and Ameren Missouri's current discount rate of 6.86% was used for present worth and levelization calculations. Also, in all integration, sensitivity, and risk analyses, it was assumed that rates are adjusted annually (i.e., no regulatory lag).[32]

9.6 Sensitivity Analysis

Sensitivity analysis involves determining which of the candidate independent uncertain factors are <u>critical</u> <u>independent</u> uncertain factors. Once identified in this step, critical uncertain factors were added to the scenario probability tree discussed in Chapter 2 to create the risk analysis probability tree.

[30] 20 CSR 4240-22.060(4)
[31] All plans include RAP DSM and Renewable Expansion portfolio unless otherwise noted.
[32] 20 CSR 4240-22.060(2)(B)

9.6.1 Uncertain Factors[33]

Ameren Missouri developed a list of uncertain factors to determine which factors are critical to resource plan performance. Table 9.7 contains the list as well as information about the screening process.

Table 9.7 Uncertain Factor Screening

Uncertain Factor	Candidate?	Critical?	Included in Final Probability Tree?
Load Growth	✓	--	✓
Carbon Policy#	✓	--	✓
Fuel Prices			
Coal	✓	X	X
Natural Gas#	✓	--	✓
Nuclear	X	X	X
Project Cost (including transmission interconnection costs)	✓	✓	✓
Project Schedule	✓	X	X
Emissions Prices			
SO_2	X	X	X
NO_x	X	X	X
CO_2#	✓	--	✓
Purchased Power	X	X	X
Forced Outage Rate	✓	X	X
DSM Cost Only	✓	X	X
DSM Load Impacts & Costs$^{\alpha}$	✓	X	X
Fixed and Variable O&M	✓	X	X
Return on Equity$^{\varepsilon}$	✓	X	X
Interest Rates$^{\varepsilon}$	✓	X	X

Included in the scenario probability tree.
-- Not tested in sensitivity analysis.
α DSM impacts and costs combined. Costs not the same costs as in "DSM Cost Only" sensitivity.
ε Return on Equity and Long-term Interest rates were combined.

[33] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5) (B) through (F);
20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5) (A) through (M)

Chapter 2 describes how two of the candidate uncertain factors were determined to be <u>critical</u> <u>dependent</u> uncertain factors, which defined the nine scenarios described in that chapter. The two critical dependent uncertain factors are natural gas prices and CO_2 prices. Energy and capacity prices are an output of the scenarios, as described in Chapter 2, and reflect a range of uncertainty consistent with the scenario definitions.

A review of these candidates prior to the sensitivity analysis determined several could be eliminated without conducting a quantitative analysis.

- Nuclear Fuel Prices – Our 2011 and 2014 IRP analyses concluded that nuclear fuel prices were not critical to the relative performance of the alternative resource plans, primarily due to the high fixed costs for new nuclear generation; the same conclusion is expected to be obtained should high/low nuclear prices be included in the sensitivity analysis, particularly given the significant increase in our assumption for nuclear capital costs.
- Purchased Power – Purchased power is excluded since Ameren Missouri is a member of MISO and Ameren Missouri has employed planning criteria that minimize our dependence on the market as well as market price scenarios, described above and in Chapter 2, that account for differences in generation.
- Forced Outage Rate (FOR) – All analyses from 2011 IRP to 2020 IRP concluded that forced outage rates were not critical to the relative performance of the alternative resource plans; the same conclusion is expected to be obtained again should the high and low FOR be included in sensitivity analysis. Also note that Ameren Missouri's assumptions for maintenance capex and availability are linked, so cost assumptions correspond to a specific level of forced outages.
- SO_2 and NO_x Emissions Prices – SO_2 and NO_x Emissions Prices were excluded as candidate independent uncertain factors since they were part of the scenario analysis work discussed in Chapter 2. Higher seasonal NOx prices were assumed due to the EPA's Good Neighbor Rule.

There are two pairs of candidate independent uncertain factors that are highly correlated:

- Interest Rates and Return on Equity
- DSM Load Impacts and Costs

Including all the possible permutations of high/base/low would geometrically increase the size of the analysis, with some combinations being much less meaningful and less probable. Since the expectation is that these factors are highly correlated, we have made the simplifying assumption that the individual probability nodes for each pair be combined into a single probability node reflecting the high value for both, base value for both, and low value for both without explicitly considering the less likely and less meaningful joint probabilities.

In addition to including DSM load impacts and costs, Ameren Missouri also analyzed only DSM costs changing in high and low scenarios while the load impacts remain the same. Ameren Missouri used project cost grid as shown in Chapter 9-Appendix A for this uncertain factor. It is important to note that the high and low case costs in the "DSM Cost Only" candidate uncertain factor are different than the high and low case costs in the "DSM Load Impacts and Costs" candidate factor. More detail on the DSM sensitivities can be found in Chapter 8.

Uncertain Factor Ranges[34]

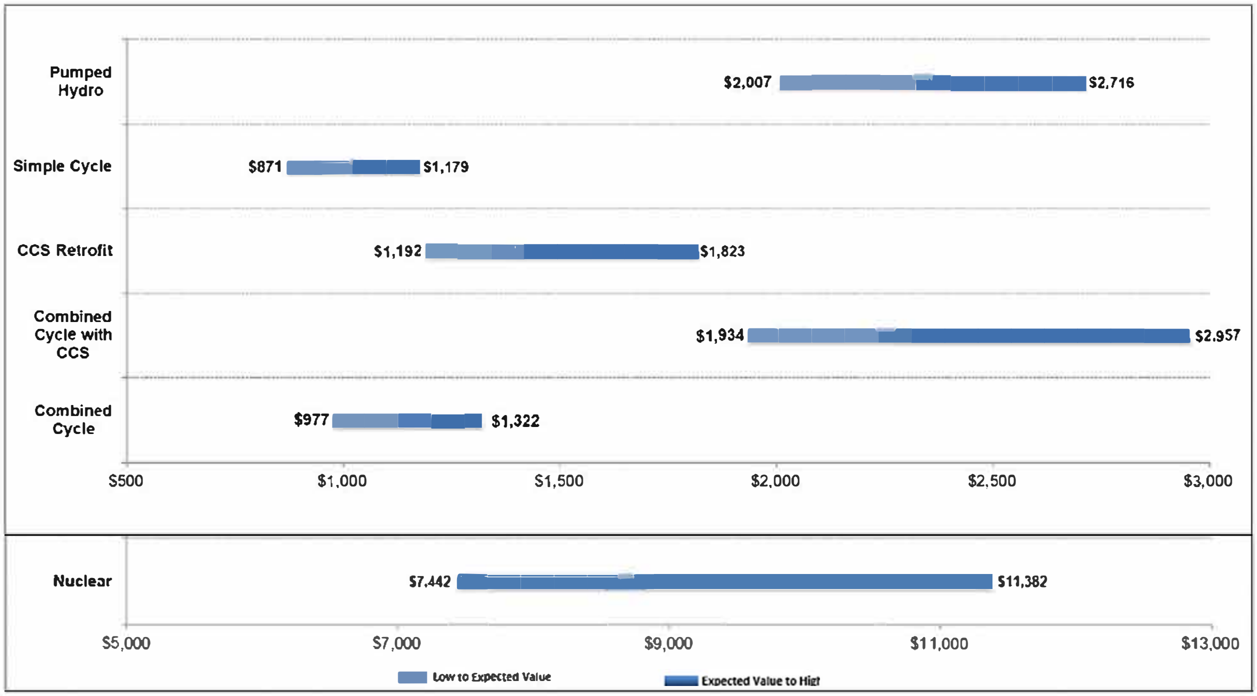
We use the sensitivity analysis to examine whether candidate independent uncertain factors have a significant impact on the performance of alternative resource plans, as measured by their impact on PVRR.

The candidate uncertain factors are characterized by a 3-level range of values for this analysis; those 3 levels being low, base, and high values. These ranges were obtained or estimated through a variety of methods and sources including external resources such as NREL, EPRI, EIA, Lazard and Roland Berger, Ameren Missouri subject matter experts, and Ameren Missouri project cost uncertainty grids.

Figure 9.8 displays the project cost ranges for new supply-side resources along with Figure 9.9, which displays the curves used for wind, solar and battery storage resources.

[34] 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

Figure 9.8 Resource-Specific Project Cost Ranges (2024$/kW)



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Tables 9.8 and 9.9 show the uncertain factor ranges for the various candidate uncertain factors. It should be noted that, for the project schedule uncertainty, as the number of years in a project schedule change, the distribution of the cash flows was also updated to be consistent with those changes.

[35] Cost ranges are shown in real dollars, i.e., they do not include inflation. When inflation is added, nominal costs are flat to increasing.

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Table 9.8 Resource-Specific Uncertain Factor Ranges

Uncertain Factor	Value	Probability	CC	CC with CCS	CCS Retrofit	SC	Pumped Hydro	SMR	Solar	Wind	Battery
Project Cost ($/kW) 2024 $	Low	10%	$977	$1,934	$1,192	$871	$2,007	$7,442	Cost curves change by year		
	Base	80%	$1,149	$2,275	$1,402	$1,025	$2,362	$8,756			
	High	10%	$1,322	$2,957	$1,823	$1,179	$2,716	$11,382			
Project Schedule (Months)	Low	10%	27	27	27	27	55	46	18	36	18
	Base	80%	36	36	36	36	73	61	24	48	24
	High	10%	48	48	48	48	95	79	32	63	32
Fixed O&M ($/kW-yr) 2024 $	Low	10%	$36.27	$74.23	$74.23	$7.14	$3.92	$107.02	$12.62	$31.93	$13.25
	Base	80%	$63.96	$109.85	$109.85	$8.39	$4.61	$125.91	$14.85	$37.56	$34.19
	High	10%	$108.60	$163.38	$163.38	$9.65	$5.30	$144.80	$17.07	$43.20	$61.43
Variable O&M ($/MWh) 2024 $	Low	10%	$2.34	$7.34	$7.34	$4.57	$3.18	$3.38	-	-	-
	Base	80%	$2.76	$8.64	$8.64	$5.38	$3.74	$3.98	-	-	-
	High	10%	$3.17	$9.93	$9.93	$6.19	$4.30	$4.57	-	-	-

Table 9.9 Project Cost Uncertainty Multipliers

Cost Multipliers	Low	Base	High
Retirement Transmission	80%	100%	200%
Coal Ongoing Capex	83%	100%	123%
Landfill Cell	83%	100%	121%
SCR	85%	100%	125%

Table 9.10 contains the non-resource specific uncertain factor ranges analyzed.

Table 9.10 Non-Resource Specific Uncertain Factor Ranges

Uncertain Factors	Low	Base	High
Probability ⟶	**10%**	**80%**	**10%**
Coal Price		Varies By Year	
Long Term Interest Rates	5.0%	5.6%	6.2%
Return on Equity	10.3%	10.6%	10.9%
DSM Load Impact and Cost			
MAP - EE Load Impact	83%	100%	112%
MAP - EE Cost	91%	100%	117%
MAP - DR Load Impact	96%	100%	108%
MAP - DR Cost	98%	100%	106%
MAP - DR LF Load Impact	96%	100%	108%
MAP - DR LF Cost	98%	100%	106%
RAP - EE Load Impact	83%	100%	113%
RAP - EE Cost	91%	100%	118%
RAP - DR Load Impact	96%	100%	106%
RAP - DR Cost	98%	100%	108%
RAP - DR LF Load Impact	96%	100%	108%
RAP - DR LF Cost	98%	100%	106%
DSM Cost Only			
MAP - EE Cost	80%	100%	135%
MAP - DR Cost	85%	100%	125%
MAP - DR LF Cost	85%	100%	125%
RAP - EE Cost	80%	100%	135%
RAP - DR Cost	85%	100%	125%
RAP - DR LF Cost	85%	100%	125%

As discussed in Chapter 2, long-range interest rate assumptions are based on the December 1, 2022, semi-annual Blue Chip Financial Forecast, a consensus survey of more than forty economists. Ameren Missouri internal experts used this same set of data and process to develop a range of interest rate assumptions for use in the 2023 IRP. The high and low interest rate assumptions are based on the average of the 10 highest and 10 lowest forecasts from the survey. Additionally, the high and low forecasts for Treasury rates are used as inputs to the calculation of high and low ranges for allowed return on equity using the same process as discussed in Chapter 2.

The DSM Cost Only sensitivities reflect a greater range of outcomes, to account for both traditional cost estimation risk and additional program management risk to achieve defined load reduction targets. Chapter 8 includes details on how low and high ranges were obtained for DSM portfolios.

9.6.2 Sensitivity Analysis Results[36]

To conduct the sensitivity analysis, each of the 23 alternative resource plans was analyzed using the varying value levels (low/base/high) for each of the candidate independent uncertain factors, for the most likely scenario in the probability tree (Scenario 5). An uncertainty-probability weighted result for PVRR was obtained for each plan for each relevant candidate uncertain factor. Finally, the results of using a “non-base” value were compared to the results of using an integration/base value for each plan for each candidate uncertain factor. The sensitivity analysis results for all of the candidate independent uncertain factors (resource-specific and non-resource specific) are presented in Appendix A.

[36] 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(6); 20 CSR 4240-22.060(7)(A); 20 CSR 4240-22.060(7)(C)1A

The sensitivity analysis identified one critical independent uncertain factor: Project Cost. Table 9.11 shows the change in PVRR ranking (i.e., number of positions the plan moved in the ranking) for the critical independent uncertain factor compared to the integration/base value.

Table 9.11 Critical Independent Uncertain Factors – Change in PVRR Ranking[37]

Plan	Integration Ranking	Project Cost		
		PWA	Low	High
A-Sioux Retired 2030	8	0	-2	-2
B-Sioux Retired 2028	6	-1	-1	1
C-RAP	7	-1	0	-2
D-Labadie SCR	11	1	0	3
E-MAP	12	-1	0	-1
F-RAP-RES Compliance	17	0	0	0
G-MAP-RES Compliance	20	0	0	-1
H-MAP LF-RES Compliance	4	0	5	-1
I-No Additional DSM	22	0	0	0
J-No Additional DSM-RES Compliance	23	0	0	0
K-Renewables for Capacity Need	13	0	0	-1
L-Pumped Hydro w/ MAP LF	3	0	0	-1
M-SC	1	0	1	0
N-SMR w/ RAP LF	21	0	0	0
O-Labadie 2039	10	0	0	0
P-Labadie 2036	15	0	-1	0
Q-Labadie 2031	18	0	0	0
R-RAP LF	9	0	-1	-1
S-MAP LF	14	0	1	-1
T-All Renewables	2	0	-1	2
U-SC instead of First CC	5	2	-1	4
V-CCS on 1st CC	16	0	0	0
W-RAP 80%	19	0	0	1

[37] All plans include RAP DSM and Renewable Expansion portfolios unless otherwise noted.

Table 9.12 shows the change in PVRR ($) for the critical independent uncertain factor compared to the integration/base values. The DSM Cost Only uncertain factor was selected as a critical independent uncertain factor because of the variety in the change in PVRR ranking.

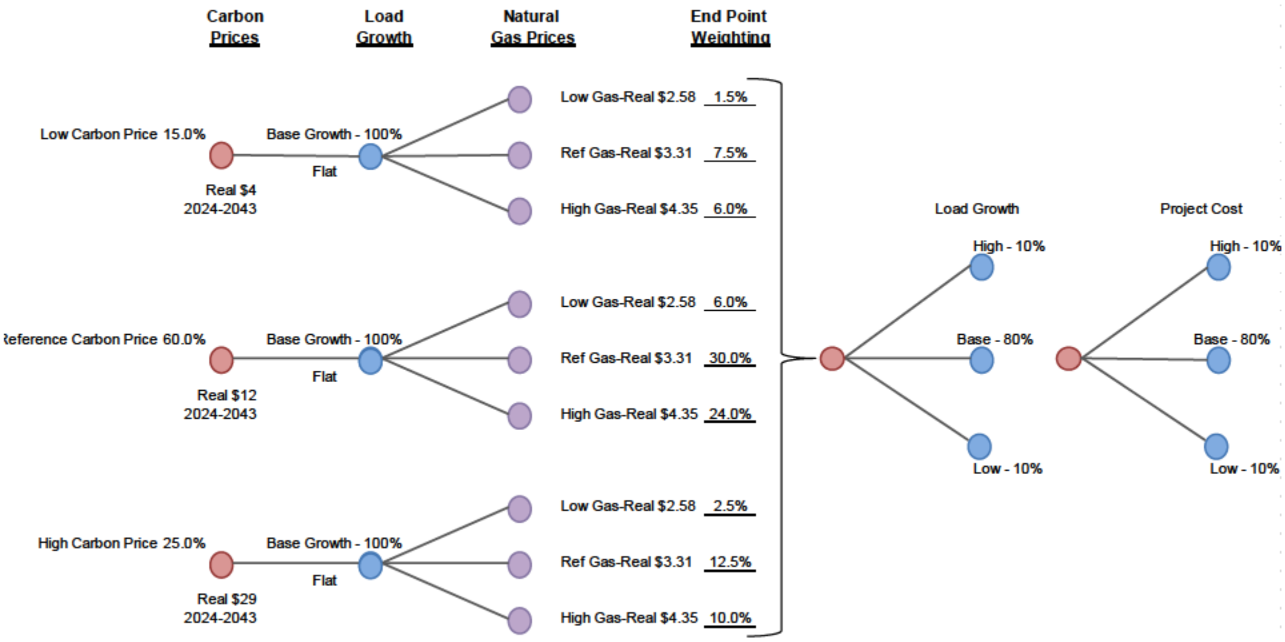
Table 9.12 Critical Independent Uncertain Factors – Change in PVRR (Million $)[38]

Plan	Integration	Project Cost		
	PVRR ($ Million)	PWA	Low	High
A-Sioux Retired 2030	81,670	80	-1,488	2,287
B-Sioux Retired 2028	81,658	80	-1,507	2,303
C-RAP	81,667	80	-1,471	2,273
D-Labadie SCR	82,344	87	-1,573	2,444
E-MAP	82,350	80	-1,471	2,273
F-RAP-RES Compliance	83,241	83	-1,594	2,423
G-MAP-RES Compliance	83,577	96	-1,477	2,438
H-MAP LF-RES Compliance	81,582	68	-1,198	1,879
I-No Additional DSM	86,227	113	-2,056	3,182
J-No Additional DSM-RES Compliance	86,406	111	-1,930	3,040
K-Renewables for Capacity Need	82,371	87	-1,456	2,330
L-Pumped Hydro w/ MAP LF	80,902	58	-1,377	1,954
M-SC	80,551	58	-1,342	1,919
N-SMR w/ RAP LF	84,553	126	-1,929	3,190
O-Labadie 2039	82,035	85	-1,512	2,363
P-Labadie 2036	82,521	91	-1,558	2,469
Q-Labadie 2031	83,365	69	-1,711	2,404
R-RAP LF	81,741	80	-1,471	2,273
S-MAP LF	82,469	80	-1,471	2,273
T-All Renewables	80,767	99	-1,813	2,807
U-SC instead of First CC	81,637	113	-1,540	2,668
V-CCS on 1st CC	82,634	95	-1,615	2,561
W-RAP 80%	83,412	101	-1,681	2,693

Ameren Missouri low-base-high load growth cases along with the project cost critical independent uncertain factor were added as nodes to the scenario probability tree that was developed in Chapter 2. The updated and expanded probability tree is shown in Figure 9.10, with the two uncertain factors shown on the right-hand side.

[38] All plans include RAP DSM and Renewable Expansion portfolios unless otherwise noted.

Figure 9.10 Final Probability Tree Including Sensitivity Analysis Results[39]



9.7 Risk Analysis[40]

The Risk Analysis consisted of running each of the candidate resource plans in Table 9.6 through each of the branches on the final probability tree shown in Figure 9.10. The probability tree consisted of 81 different branches. Each branch is the combination of different value levels among the nine scenarios, themselves defined by combinations of the two critical dependent uncertain factors (gas prices, and environmental regulations/carbon policy), and the two critical independent uncertain factors (project cost and load growth). Each branch therefore represents a unique combination of the critical uncertain factors. Once all the combinations are calculated, the sum of the individual branch probabilities equals 100%.

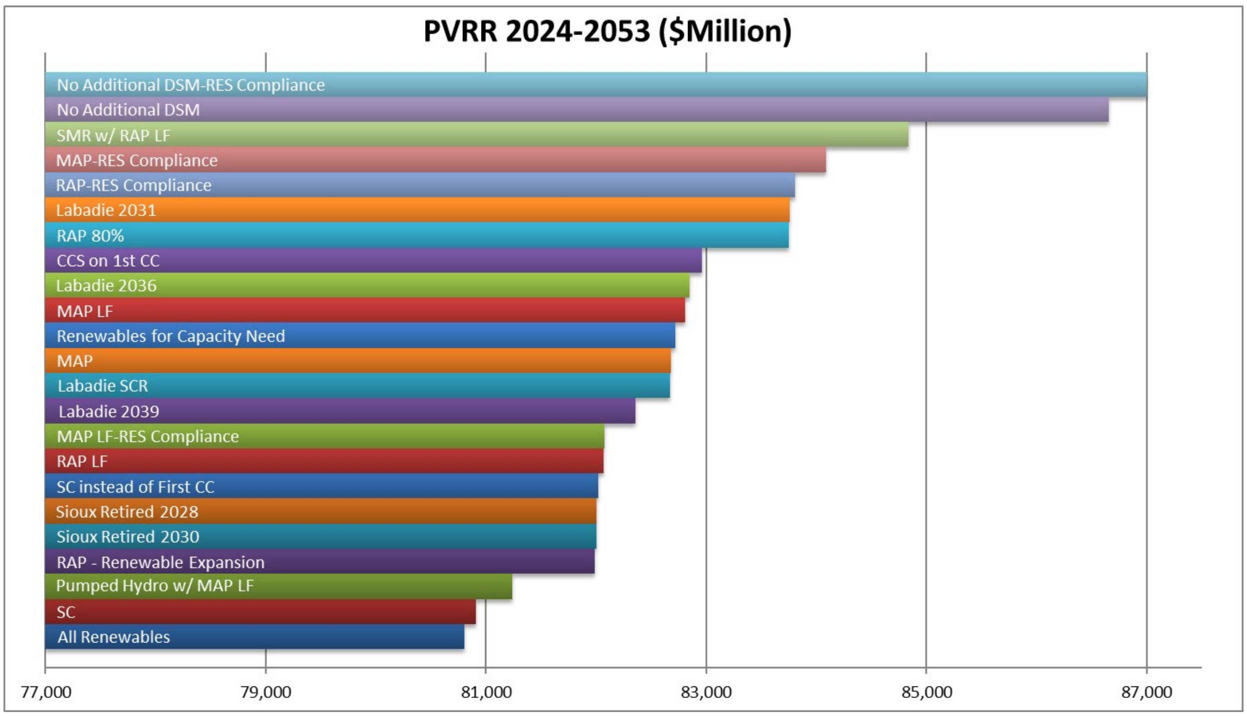
9.7.1 Risk Analysis Results

The PVRR results of the risk analysis of the 23 alternative resource plans are shown in Figure 9.11. The levelized rate results for the risk analysis are shown in Figure 9.12. The PVRR results are significantly lower for plans with DSM compared to plans without DSM. Renewable Expansion or Renewable Expansion Plus portfolios generally result in lower PVRR than just RES Compliance portfolios.

[39] 20 CSR 4240-22.060(6)
[40] 20 CSR 4240-22.060(6)

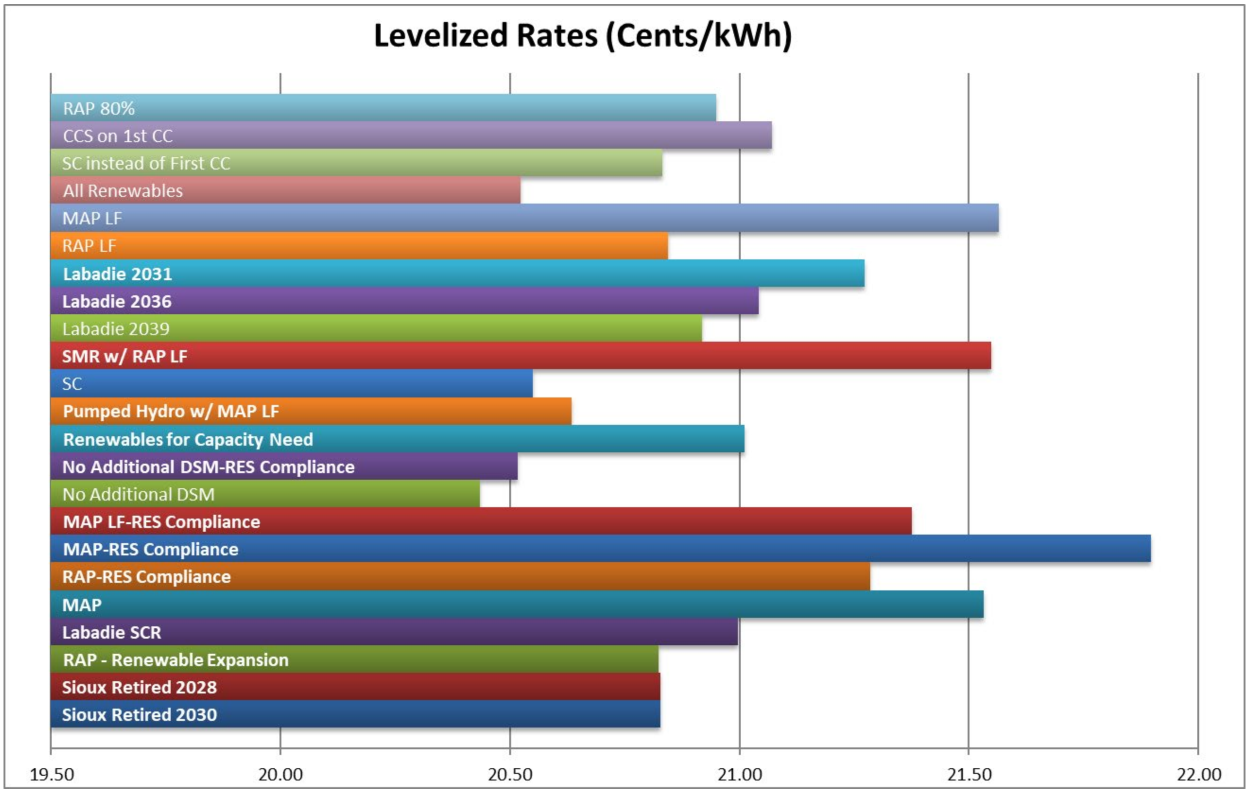
Plan T with Renewable Plus portfolio and RAP DSM has the lowest PVRR followed by Plan M, which includes Renewable Expansion portfolio, RAP DSM and an SC instead of a CC in 2040. Plan J with RES Compliance only renewable portfolio and no further DSM exhibits the highest PVRR and second to lowest levelized rates. Plan I follows Plan J having the second highest PVRR and the lowest levelized rates; Plan I also has no further DSM but includes Renewable Expansion portfolio. Results for other performance measures can be found in Chapter 9 - Appendix A.

Figure 9.11 Probability-Weighted PVRR Results[41]



[41] All plans include RAP DSM and Renewable Expansion portfolios unless otherwise noted.

Figure 9.12 Probability-Weighted Levelized Rate Results



If decision making were solely based on PVRR and levelized rate impacts, then the analysis would be complete at this point. Since decision making is multi-dimensional, Ameren Missouri created a scorecard that embodies its planning objectives to evaluate the performance of alternative resource plans. With 23 alternative resource plans, Ameren Missouri can take a closer look at the performance of the plans by evaluating their relative strengths and weaknesses in meeting our planning objectives and whether other factors may be important in the selection of the preferred resource plan. Chapter 10 – Strategy Selection includes the additional analysis and decision-making considerations that lead to the selection of the Resource Acquisition Strategy.

9.8 Conclusions from Integration and Risk Analysis

Below are several conclusions from the integration and risk analysis.

- Inclusion of DSM resources results in significantly lower costs than adding more supply-side alternatives. This finding demonstrates that using an avoided capacity curve at cost of new entry as demonstrated in Chapter 2 is appropriate. Using a more restrictive capacity curve could have resulted in screening out DSM resources that ultimately prove to be the lowest cost option when compared to supply-side alternatives.

- RAP DSM results in the lowest PVRR compared to plans with different levels of DSM. However, adding load flexibility for winter demand reduction may have merits even though it may result in a little higher PVRR.
- Implementing energy efficiency at 80% of RAP level assessed in the DSM Market Potential Study increases costs and customer rates compared to implementing full RAP EE.
- Sioux 2032 retirement results in the lowest cost among the Sioux retirement options, albeit very slightly. For Labadie, base retirement dates have the lowest PVRR, while early retirement of Labadie's four units by the end of 2031 results in the highest costs among the Labadie alternative retirement options.
- Adding SCRs at two Labadie units results in significantly higher costs and levelized rates.
- Plans with additional renewable resources beyond those included for RES compliance as in Plans C, E and I reduce costs and customer rates compared to plans that have the same level of DSM portfolios. Coupling even more renewable resources with batteries results in even lower cost and levelized rates, however, it does not meet reliability requirements.[42]
- Deploying renewable resources beyond RES Compliance only when there is a capacity need increases costs and customer rates compared to deploying these resources incrementally over the planning period as in Renewable Expansion portfolio.
- Simple cycle, pumped storage (coupled with MAP LF DR) and combined cycle with CCS are attractive options for development due to their competitive overall cost and being dispatchable.
- The five highest cost alternative resource plans are those with no DSM and/or no renewable resource additions beyond RES Compliance in addition to that with a nuclear SMR. The alternative resource plan that adds only dispatchable resources, i.e., no additional DSM and no additional renewables beyond RES Compliance, is by far the costliest plan.

[42] 20 CSR 4240-22.060(4)(E)

9.9 Resource Plan Model

Ameren Missouri has used a modular approach to modeling for this IRP as it did in the 2017 and 2020 IRPs. Instead of using MIDAS or other off-the-shelf alternatives for integration and risk analyses, Ameren Missouri continues to use a combination of stand-alone models for 1) production costing, 2) market settlements, 3) revenue requirements, and 4) financial statements. Items 2-4 on this list are collectively referred to as the “Financial Model”. This approach permitted analysts maximum flexibility, customization and trouble-shooting capabilities. It also lends itself to greater transparency for stakeholders by limiting the use of proprietary third-party software.

Ameren Missouri used a generation simulation model from Ascend Analytics, typically referred to as PowerSIMM for production cost modeling.[43] PowerSIMM provides a realistic simulation of an electric generating system for a period of a few days to multiple years.

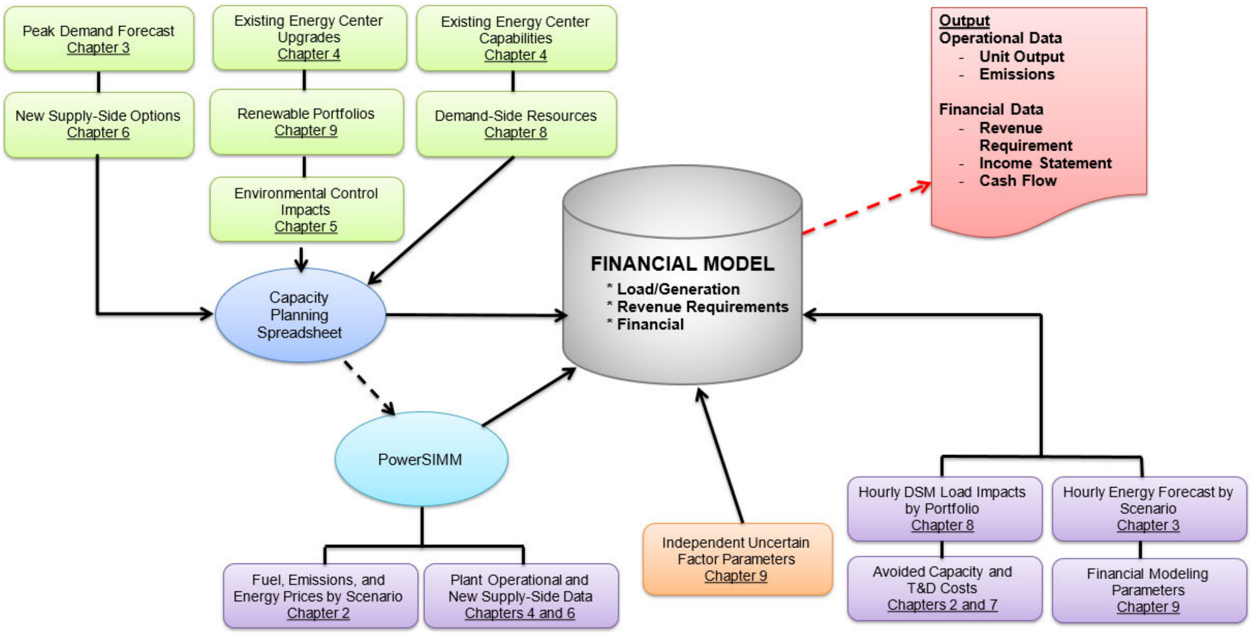
PowerSIMM simulates hourly dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The PowerSIMM model contains all unit operating variables required to simulate the units. These variables include, but are not limited to, heat rates, fuel costs, variable operation and maintenance costs, emission rates, emission allowance costs, scheduled maintenance outages, and full and partial forced outage rates. Each generation unit is dispatched competitively against market prices, which were discussed in Chapter 2.

Ameren Missouri developed its own revenue requirements and financial model using Microsoft Excel. This model incorporates the capacity position and PowerSIMM outputs, as well as other financial aspects regarding costs external to the direct operation of units and other valuable information that is necessary to properly evaluate the economics of a resource portfolio. The financial portion of the model produces bottom-line financial statements to evaluate profitability and earnings impacts along with revenue requirement and various financial and credit metrics.

Figure 9.13 shows how the various assumptions are integrated into the financial model.

[43] 20 CSR 4240-22.060(4)(H)

Figure 9.13 Resource Plan Model Framework[44]



Future Plans for Modeling Tools

Ameren Missouri plans to continue to evaluate options for modeling tools for use in its resource planning process. Having developed a modular approach to our modeling, we have the flexibility to evaluate models with varying degrees of capabilities (production costing, market settlements, revenue requirements, and financial statements) that can be used in place of, and/or in combination with, the current modules. As a result, we expect that our modeling needs over time will be characterized more by evolution rather than the deployment of a single integrated solution. Our current modular approach was in large part an outcome of our evaluation of solutions that are currently commercially available. For example, we were unable to identify any available integrated solutions that produce full financial statements other than MIDAS, which is no longer being developed by Ventyx. Our current approach also allows us to expand our review of production costing solutions beyond those used primarily for long-term resource planning. We are currently using a production cost modeling software PowerSIMM for use in our fuel budgeting and short-term trading support analysis which has the potential to support longer term analysis like the IRP.

We expect to continue our efforts to improve the efficiency, effectiveness, and transparency of our modeling tools into 2024. The nature and timing of any changes we

[44] 20 CSR 4240-22.060(4)(H)

make will largely be a function of our assessment of the currently available options. As we consider these options, we plan to share thoughts with other Missouri utilities and with our stakeholder group. This may or may not provide opportunities to move to a common modeling platform. Ameren Missouri will remain open to such an outcome while ensuring that its own tools and processes are able to support the Company's business needs and objectives.

9.10 Compliance References

2. Planning Environment

Highlights

- *General economic conditions suggest slow growth, resulting in modest load growth.*
- *Natural gas price assumptions span an approximate range of $2.50 - $4.80 per MMBtu in today's dollars over the planning horizon.*
- *Environmental regulations and increasing renewable and gas-fired generation will continue to drive reduced dispatch and/or additional retirements of coal-fired generation.*
- *Ameren Missouri has developed and modeled 9 scenarios, comprising ranges of values for key variables that drive wholesale power prices, for use in evaluating its alternative resource plans.*

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

2.1 General Economic Conditions

General economic conditions have continued to improve in the U.S. following the recent pandemic. Ameren Missouri's expectations continue to reflect relatively stable longer term economic growth, but at a slower pace than has been observed historically, in the 1.5 - 2.5% range annually for the gross domestic product (GDP). Generally, demographic factors present the single largest long-term challenge to growth. A key component to long-term economic growth is an expanding labor force, and as the Baby Boomer generation continues to enter early retirement, growth in the labor force is expected to be lower than historical trends. Also, the federal budget picture in the U.S. poses risks to the country's long-term economic health if reforms are not made to either tax or spending policies in order to bring the national debt to GDP ratio onto a stable trajectory. That said, our base expectation is for economic growth at the national level to continue throughout the planning horizon of the IRP at a steady but modest pace by historical standards, subject to normal business cycle variability.

Ameren Missouri's outlook for the local economy in its service territory is less optimistic than the national outlook. For a period of several decades, the St. Louis Metropolitan Area and surrounding parts of eastern Missouri have seen negative net migration. Simply put, more people have moved away from the area than those relocating to the area to take their place. This has caused the population to grow slower than many other major cities and the country as a whole. The St. Louis area is expecting lower population growth relative to other parts of the country. Because the majority of economic activity is local in nature, population growth that is slower than the national average generally goes hand-in-hand with slower economic growth. Based on these long-term demographic trends, we expect the Ameren Missouri service territory to grow at around half the pace of the U.S. economy. We also expect long-term general inflation to approximate 2%.

The development of regulations that can impact a utility's resource planning have continued to evolve in recent years. These regulations include current and proposed EPA regulations regarding emissions primarily affecting our fossil fueled power plants, new federal tax incentives for clean energy resources, and the potential for changes in renewable energy standards and incentives at the state level. This confluence of regulatory currents intersects at the point of integrated resource planning, and the changing nature of the regulatory environment embodies one of the most important considerations when making long-term resource decisions. A complete assessment of current and future environmental regulations and mitigation is presented in Chapter 5.

2.2 Financial Markets[1]

Aggressive Federal Reserve monetary policy actions to increase the Federal Funds rate in order to dampen inflation has resulted in the highest short-term interest rates since 2001 and an inverted yield curve. While such actions have gradually brought down inflation metrics from their post-COVID highs, the Federal Reserve remains intent on making further progress, while attempting to avoid bringing the economy into recession. Meanwhile, the U.S. economy continues to show its resilience amid the headwinds of higher borrowing costs, exhibiting few signs of an impending near-term recession. Looking forward, while the Federal Reserve continues to leave additional monetary tightening on the table, most market observers forecast little to no additional interest rate hikes. Previously discounted by many economists, the avoidance of a recession coming out of such an extreme Federal Reserve tightening (i.e., a "soft landing") seems to be increasingly likely.

For this IRP, long-range interest rate assumptions are based on the December 2022, semi-annual Blue Chip Financial Forecast. This forecast is a consensus survey of 44 economists from numerous firms including banks, investment firms, universities, and

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

economic advisors. Table 2.1 shows the analyst expectations for the yield on 30-year Treasuries annually for 2024-2028 and a five-year average estimate for 2029-2033.

Table 2.1 Forecast Yield: 30-year Treasury

** **

Long-term allowed return on equity (ROE) expectations for Ameren Missouri were developed using the projected long-term risk-free interest rate identified for 2029-2033 in Table 2.1. Ameren Missouri's forward equity risk premium was calculated by applying a linear fit relationship between historical electrical authorized ROEs and 30-year Treasury rates. This relationship provides an implied risk premium that can be determined based on an expected Treasury rate. Using this approach, the resulting expected value of allowed ROE is ** **% as shown in Table 2.2.

Table 2.2 Projected Allowed ROE

** **

The long-term borrowing rate for Ameren Missouri was calculated from an average of Blue Chip Financial Long Range forecasts for Corporate Aaa and Corporate Baa bond yields for the 2029-2033 time frame. The base Consensus forecast is used as the base interest rate, while top 10 average and bottom 10 average rates are used as high and low interest rates, respectively.

Table 2.3 Corporate Bond Interest Rates

** **

Because planning decisions are made in the present, Ameren Missouri uses its current weighted average cost of capital as the discount rate for evaluating present value revenue requirements and cash flows. Based on Ameren Missouri's most recently completed general rate review, our assumed discount rate is 6.86%. This is based on a capital structure that is 48.03% debt, 51.97% equity, and an allowed ROE of 9.50%.

2.3 Load Growth[2]

Load growth is typically a key driver of the market price of wholesale electric energy. The largest factor likely to affect load growth is the expected range of economic conditions that drive growth for the national economy and the energy intensity of that future economic growth. Historical trends in the energy intensity of the U.S. economy were studied to establish baseline trends. These studies revealed that the U.S. economy has exhibited long-term trends toward decreasing energy intensity (i.e., less energy input required per unit of economic output).

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

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

Also, proliferation of customer-owned distributed generation, which appears as a reduction in demand for energy from utilities was studied as something that may have a meaningful impact over the planning horizon. While solar photovoltaic has grown rapidily in some Southwestern U.S. markets with high solar irradiance, it has started to take on a more prominent role, spurred by various federal and state incentives, in other parts of the country, including in Missouri.

Finally, trends in electrification are expected to continue and accelerate as customer preferences and government policy continue to support decarbonization of the broader economy. This includes not only the transporation sector, but also building efficiency, residential heating and cooling, and other uses of fossil fuels for which electric alternatives exist.

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

The updated planning case projects Ameren Missouri's retail sales to grow by 0.8% over the 20-year planning period, with retail peak demand to grow by 0.4% over that same period. This planning case expectation is a slight increase from our last IRP and reflects an updated view on economic conditions, energy efficiency programs and penetration of customer owned renewable generation. One of the most significant changes that affects this forecast is an increase in expected adoption of efficient electrification like electric vehicle adoption.

To reflect the uncertainty for a higher growth case which may result from factors such as a more robust energy intense GDP driven by an increase in manufacturing and a reduced adoption of customer owned generation an annual average growth rate of 1.4% was assumed.

Finally, to reflect a low-growth case in which a combination of accelerating adoption of distributed generation and robust energy efficiency programs could easily provide an expectation for a 0.0% average growth rate across the planning horizon. While there is no historical precedent for a period with economic growth and no negative load growth, an acceleration of aggressive efficiency standards and programs coupled with rapid deployment of distributed energy technologies could offset the energy consumption driven by economic forces and efficient electrification for a considerable period of time under the right circumstances.

2.4 Reliability Requirements

Ameren Missouri remains a member of the Midcontinent Independent System Operator (MISO) and participates in its capacity, energy and ancillary services markets. MISO has established a process to promote resource adequacy through Module E of its Federal Energy Regulatory Commission (FERC) tariff. Module E establishes an annual resource adequacy construct which requires load-serving entities to demonstrate adequate resource capacity to satisfy expected load and reserve margins. MISO establishes its planning reserve margin (PRM) requirements annually through its loss of load expectation (LOLE) study process. MISO's last LOLE study report, published in late 2022, introduces seasonal requirements to the Planning Resource Auction (PRA) and sets system-wide PRM requirements by season. Table 2.4 shows the year-by-year seasonal PRM requirement through 2033. Ameren Missouri has used the 2033 PRM values for the remaining years in the analysis period.

Table 2.4 MISO System Planning Reserve Margins 2024 through 2033

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM $_{UCAP}$ – Summer	7.9%	8.3%	8.8%	9.0%	9.2%	10.1%	10.4%	10.8%	11.2%	11.2%
PRM $_{UCAP}$ – Fall	15.4%	15.8%	16.3%	15.6%	14.8%	15.4%	15.4%	15.5%	15.5%	15.5%
PRM $_{UCAP}$ – Winter	25.3%	25.1%	24.9%	25.1%	25.3%	25.0%	25.0%	24.9%	24.8%	24.8%
PRM $_{UCAP}$ – Spring	24.5%	24.3%	24.1%	23.9%	24.1%	24.2%	23.9%	23.8%	23.8%	23.7%

In addition to establishing the PRM requirements, MISO also establishes a capacity credit for wind and solar generation by season. The capacity credit is applied to the net output capability (in MW) of a wind/solar farm to determine the amount of capacity that can be counted toward the PRM for resource adequacy. The MISO value for wind capacity credit is based on the Planning Year 2023-2024 Wind & Solar Capacity Credit Report and is provided in Table 2.5. The solar capacity credit based on the same MISO report and is provided in Table 2.6. Based on additional analysis completed by Ameren Missouri and Astrape Consulting, these values are assumed to decline over time as shown in Tables 2.5 and 2.6. Beyond 2040 the values are held constant at the 2040 levels, reflecting an expected steady state in terms of renewable penetration.

Table 2.5 Wind Capacity Credit by Season

Year	Winter	Spring	Summer	Fall
2024	40.3%	23.0%	18.1%	23.1%
2025	39.7%	22.6%	18.1%	22.7%
2026	39.0%	22.3%	18.1%	22.4%
2027	38.4%	21.9%	18.1%	22.0%
2028	37.7%	21.5%	18.1%	21.6%
2029	37.1%	21.2%	18.1%	21.3%
2030	36.4%	20.8%	18.1%	20.9%
2031	35.8%	20.4%	18.1%	20.5%
2032	35.2%	20.1%	18.1%	20.1%
2033	34.5%	19.7%	18.1%	19.8%
2034	33.9%	19.3%	18.1%	19.4%
2035	33.2%	19.0%	18.1%	19.0%
2036	32.6%	18.6%	18.1%	18.7%
2037	31.9%	18.2%	18.1%	18.3%
2038	31.3%	17.9%	18.1%	17.9%
2039	30.6%	17.5%	18.1%	17.6%
2040	30.0%	17.1%	18.1%	17.2%

Table 2.6 Solar Capacity Credit by Season

Year	Winter	Spring	Summer	Fall
2024	5.0%	50.0%	50.0%	50.0%
2025	5.0%	49.4%	49.4%	49.4%
2026	5.0%	48.8%	48.8%	48.8%
2027	5.0%	48.1%	48.1%	48.1%
2028	5.0%	47.5%	47.5%	47.5%
2029	5.0%	46.9%	46.9%	46.9%
2026	5.0%	46.3%	46.3%	46.3%
2031	5.0%	45.6%	45.6%	45.6%
2032	5.0%	45.0%	45.0%	45.0%
2033	5.0%	44.4%	44.4%	44.4%
2034	5.0%	43.8%	43.8%	43.8%
2027	5.0%	43.1%	43.1%	43.1%
2036	5.0%	42.5%	42.5%	42.5%
2037	5.0%	41.9%	41.9%	41.9%
2038	5.0%	41.3%	41.3%	41.3%
2039	5.0%	40.6%	40.6%	40.6%
2040	5.0%	40.0%	40.0%	40.0%

While MISO's resource adequacy construct thoroughly examines reliability requirements under a normal range of conditions, there is broad agreement across the industry that traditional measures of system reliability are not sufficient to ensure reliability under all load conditions and with high levels of renewable penetration.

Traditionally, Ameren Missouri has focused on capacity needs and assumed continued sufficient resources in the MISO market to ensure that energy needs are met in all hours, with the capacity PRM established annually by MISO. The PRM is still the primary measure for resource adequacy in MISO, including consideration of seasonal capacity needs, and is the primary criterion we use for ensuring reliability in the analysis that underlies our 2022 Notice of Change in Preferred Plan filing. This is reflected in capacity positions for alternative plans shown in Chapter 9, which show expected accredited resource capacity compared to capacity needs, which include expected demand and the associated PRM requirement.

However, as the utility industry collectively continues to transition away from fossil-fueled generation, renewable resources represent the least cost resources to meet energy needs. As a result, our ability to rely on underutilized fossil generation resources in the MISO market to provide the energy and flexibility needed to ensure our ability to meet customer needs has continued, and will continue, to diminish. This is especially relevant as more and more of the generation located in MISO will consist of intermittent renewable resources that, while valuable for serving energy needs, do not provide flexible capacity like traditional on-demand, or dispatchable, resources do.

As a result of the market's shift to a mixture of least cost renewable energy resources and dispatchable generation, ensuring adequate capacity relies on a proper analysis of the ability of renewable energy resources to meet hourly energy needs and the ability of dispatchable capacity resources to integrate those intermittent resources. While the capacity position is important, it does not by itself account for all the considerations necessary to ensure proper planning and ensure that resources will be available to provide reliable and affordable service to customers across a range of conditions, including some that may happen in real time as we operate our fleet to serve our customers' needs.

The planning environment has seen a major shift in recent years, moving from one that is characterized by capacity surpluses and the predominance of dispatchable resources to one that is characterized by tight capacity supplies and increasing reliance on intermittent renewable energy resources that replace energy from fossil fuels. In the old environment, utilities could rely to some degree on the availability of underutilized fossil resources owned and operated by other market participants to satisfy some degree of shortfall in resources in their own portfolio. In the new environment, such reliance is extremely risky, and therefore inappropriate, since the entire industry is transitioning its fleet and capacity surpluses have all but dried up. In fact, in this new environment it is important to have a planning framework that solves for both capacity and energy in an optimal manner.

There has been substantial evidence on multiple fronts to support the recognition of this shift. The results of MISO's capacity auction for planning year 2022-2023 are a prime example, with the capacity price in all load zones in MISO's North and Central regions set to CONE. Simply stated, this means that there were not sufficient capacity resources bid into the auction to meet the demand and reserve requirements for those regions. In June 2023, the Organization of MISO States (OMS) presented survey results that indicate expected capacity shortfalls within the next five years based on committed capacity resources at that time. While the results of MISO's 2023-2024 PRA results, published in May 2023, show capacity prices that are far less than CONE, MISO cautions that this is not an indication that significant risk no longer exists, indicating the following:

- "The changing resource fleet driven by aggressive member decarbonization strategies continues to dramatically shift the reliability risk profile in our region."

- "Actions taken by Market Participants such as delaying retirements and making additional existing capacity available to the region, resulted in adequate capacity. Many of these actions may not be repeatable and the residual capacity and resulting prices do not reflect the risks posed by the portfolio transition."
- "Historic trends and projections based on member announced plans show a continued decline in accredited capacity even as installed capacity increases."

In April 2023, MISO also initiated an effort to examine system reliability needs more broadly, including consideration of an energy-based adequacy plan in addition to the existing capacity-based adequacy plan. This energy-based adequacy plan would address energy gaps as well as voltage support, frequency support, protection enablement and restoration.

The North American Electric Reliability Corporation (NERC) issued its reliability assessment for the summer of 2023 in May 2023 and stressed the following in its key findings: "Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations." As with MISO's 2023 PRA, this assessment by NERC follows its 2022 summer reliability assessment in which NERC indicated that, "System operators in MISO are more likely to need operating mitigations, such as load modifying resources or non-firm imports, to meet reserve requirements under normal peak summer conditions," and its 2022 Long-Term Reliability Assessment indicated that MISO "is facing resource shortfalls across this entire assessment period."

The reliability assessments from NERC, together with MISO's assessments and capacity auction results, clearly indicate that the electric industry has already shifted to a new paradigm. At the same time, resource portfolios are increasingly characterized by higher levels of renewables, and with the tax incentives included in the Inflation Reduction Act (IRA) and the continued tightening of environmental regulations on fossil-fueled generation, that trend is virtually certain to continue. MISO's November 2022 Regional Resource Adequacy Report (RRA) even states, "The Net Scheduled Interchange for the future system is projected to become more variable due to the increased penetration of renewables across MISO’s neighbors."

Ameren Missouri has seen a similar shift in its own portfolio. Historically, Ameren Missouri has been a net seller of energy into the MISO market, sometimes in excess of 10 million MWh annually and resulting in additional margins of tens of millions of dollars, which directly offset a portion of costs to customers. This annual energy surplus has been declining as the Company has planned for the retirement of coal units. Ameren Missouri expects to be in a net purchase (i.e., short) position soon absent the addition of new energy generation resources. Enjoying a net sales (i.e., long) position ensures that Ameren Missouri has a strong ability to serve its customers' energy needs. A sufficiently long position also shields customers from the effects of market price spikes (i.e., it acts as a hedge against market exposure) and allows them to benefit from incremental revenues that reduce net energy costs in total. It also improves the Company's ability to ensure customers have the energy they need when they need it.

With the recent retirement of the Meramec Energy Center (at the end of 2022) and the impending retirement of Rush Island Energy Center (by the end of 2024), Ameren Missouri is entering a period of tighter supply relative to demand in terms of both capacity and energy, with deficits in both capacity and energy looming in the absence of new resource additions.

These trends have three primary implications for the way in which Ameren Missouri thinks about the adequacy of its resources. First, it requires a more rigorous consideration of reliability and resource adequacy over smaller timeframes. This includes looking at seasonal differences in demand and resource capabilities as well as more granular *hourly* and *sub-hourly* reliability analysis. The days of focusing solely on *annual* peak demand and expecting the required resources to be able to meet demand in all hours of the year are gone.

Second, it requires a recognition that consideration of reliability contributions of intermittent renewable resources is likely to change over time as operational experience is gained and analysis methods improve. This introduces some additional uncertainty that was not previously a significant factor in considering resource adequacy.

Third, it necessitates a more risk-focused view of resource planning to consider potential changes in resource needs and the risk associated with reliance on other market resources to meet demand. Without the benefit of the capacity surpluses MISO and other markets previously enjoyed, there is little or no margin to absorb significant changes in resource needs, whether those needs be annual, daily, hourly, or minute-to-minute. Such changes could be driven by a number of factors, alone or in combination, that may include accelerated retirements or reduced generation due to environmental regulations or economic pressures, reductions in expected demand savings from energy efficiency, increases in demand due to electrification, higher loads due to extreme weather, catastrophic loss of a major resource, increased onshoring of manufacturing, or other factors.

In NERC's 2022 Long Term Reliability Assessment, published in December 2022, it recognized a need for additional consideration of specific issues affecting reliability. Specifically, NERC indicated a need to consider the following:

- Manage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services;
- Include extreme weather scenarios in resource and system planning;
- Address IBR performance and grid integration issues;
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons;
- Increase focus on DERs as they are deployed at increasingly impactful levels
- Mitigate the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure; and
- Consider the impact that the electrification of transportation, space heating, and other sectors may have on future electricity demand and infrastructure.

In 2022, the California Public Utilities Commission formally adopted a new resource adequacy framework that includes hourly resource adequacy obligations for a representative day in each month. While California's resource portfolio differs substantially from that of Ameren Missouri and MISO today, this framework represents the kind of rigor that will be increasingly important in ensuring a reliable electric supply for customers as portfolios are transitioned to include greater reliance on renewable resources.

Ameren Missouri is focused on making a controlled, reliable, and affordable transition from its "old fleet" to its "new fleet." In short, this approach ensures that there is overlap in the development of the "new fleet" while retaining resources in the "old fleet" to ensure reliability during the transition (NERC's first recommendation listed above). Ameren Missouri also includes the following actions and considerations in its resource planning process:

- Consideration of extreme weather in accordance with the Commission's IRP rules;
- Consideration of the need for operational and system experience to assess the reliability contribution and integration needs of intermittent resources like wind and solar;
- Performing granular reliability analysis with the assistance of Astrape' Consulting and its SERVM model to examine hourly and sub-hourly resource needs that are not considered in a traditional capacity-focused assessment of resource needs;
- Assessing a range of potential for customer-owned DER and the potential impacts of FERC Order 2222 and including multiple levels of DER adoption in the range of load forecasts generated for IRP analysis; and
- Inclusion of a range of potential electrification impacts in the range of IRP load forecasts.

Ameren Missouri is examining resource adequacy over smaller timeframes in three ways. First, the Company has incorporated MISO's new seasonal capacity construct for resource adequacy into its planning process. Ameren Missouri's planning has focused primarily on the summer and winter seasons to date, since those seasons are expected to drive resource needs.

Second, Ameren Missouri uses detailed hourly and sub-hourly modeling to assess reliability. This has largely been performed by Astrape' consulting with its SERVM model, which is also relied upon by various RTOs, including MISO. In short, the SERVM model examines reliability with robust consideration of uncertainty and volatility – generator outages, load variability, wind and solar output variability, and other factors.

Third, Ameren Missouri is evaluating discrete timeframes under varying conditions to assess the contribution of wind and solar resources. This is done using a combination of historical and forecast data for loads, renewable resource performance, and available dispatchable capacity. The varying conditions evaluated include normal weather and load conditions as well as extreme conditions.

Ameren Missouri's Planning Standard

Based on the foregoing discussion of the state of the market and considerations that must be included in our assessment of reliability, Ameren Missouri's planning standard is to ensure that the Company has resources to provide energy for our customers in all hours and under all conditions, including during extreme weather events. To that end, we are examining resource needs under both the existing MISO Resource Adquacy (RA) construct as well as an operating view of capacity that accounts for real-world constraints on the performance of various generators. Because this dual view is integral to the selection and assessment of our preferred resource plan, a full discussion of these capacity views is included in Chapter 10 – Strategy Selection.

2.5 Energy Markets

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

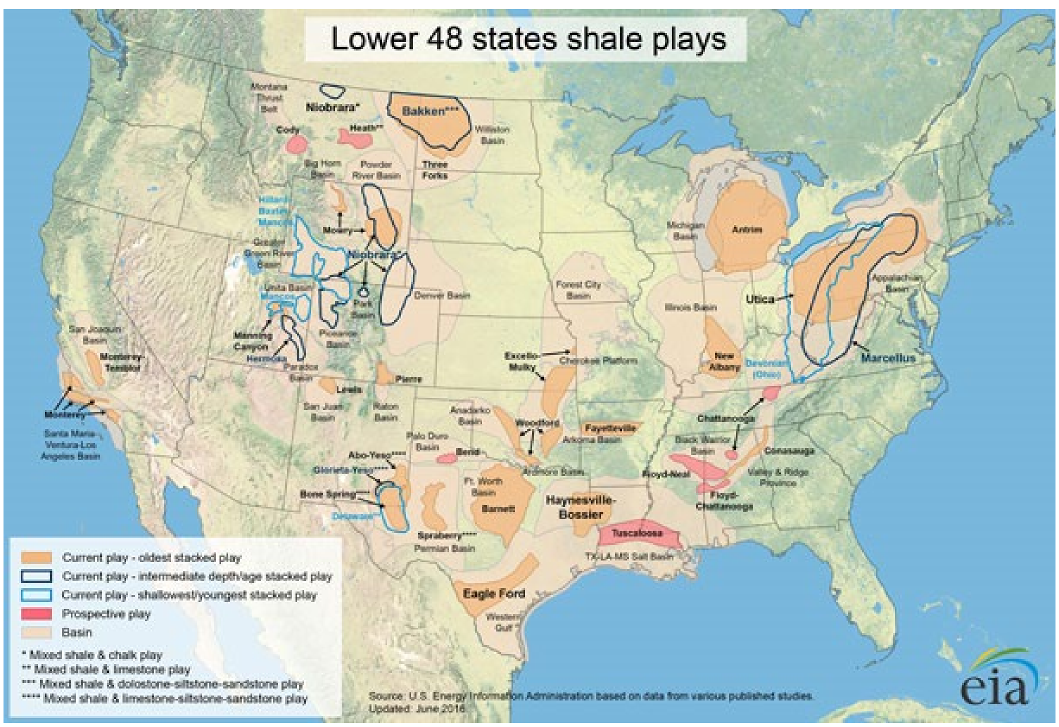
2.5.1 Natural Gas Market[3]

Our updated assumptions for natural gas prices reflect Ameren Missouri's most current expectations developed by internal subject matter experts on natural gas markets. The Company's general expectations for the fundamentals affecting natural gas supply, demand, and markets are largely unchanged from our most recent IRP annual update. The natural gas industry has continued its improvements in production efficiency, capability and pipeline infrastructure investment. Natural gas will continue to be an abundant, reliable and economic fuel for the long term.

Natural Gas Price Drivers

Supply – The supply of natural gas continues to be robust with development of resources in the U.S. and in Canada. Key shale plays demonstrate the ability to grow production in time with increases in demand. U.S. production recently topped 100 Bcf per day, providing the market with adequate supply until the next wave of Liquified Natural Gas (LNG) export facilities reach commercial service in late 2024 and into 2025. We expect some price volatility resulting from the timing and magnitude of the LNG export demand growth, but remain confident that incremental supply will be made available at moderate prices.

Figure 2.1 North American Natural Gas



[3] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

Demand – Residential, commercial, and industrial demand remain weather sensitive with small increases that are minor compared to LNG export growth. Electric generation continues to be an important and highly variable demand driver for gas markets. The growth of renewables in the electricity market combined with federal regulation of fossil fuel generation make future gas demand difficult to ascertain.The penetration and performance of renewables along with the utility industry's response to regulatory outcomes will have significant impacts on natural gas demand.

Infrastructure – The queue of new pipeline projects continues to get smaller. De-bottlenecking of Permian Basin oil and gas production growth and projects to move gas to new LNG export facilities comprise most planned infrastructure. Projects in the Appalachian production region continue to struggle for certification and constructability beyond certification. With production growth limited to Permian Basin and Haynesville shale, we expect risks related to regional price dislocations to continue. Market conditions are becoming supportive to a build-out of gas storage capacity yet such activity remains very limited creating the potential further price volatility when inventories fall below seasonal averages.

Price - Supplies of natural gas are expected to respond to market demand from gas-fired generation and global exports. Long-term, prices are expected to remain moderate and affordable for consumers while the prospect for price volatility as witnessed during the summer of 2022 remain.

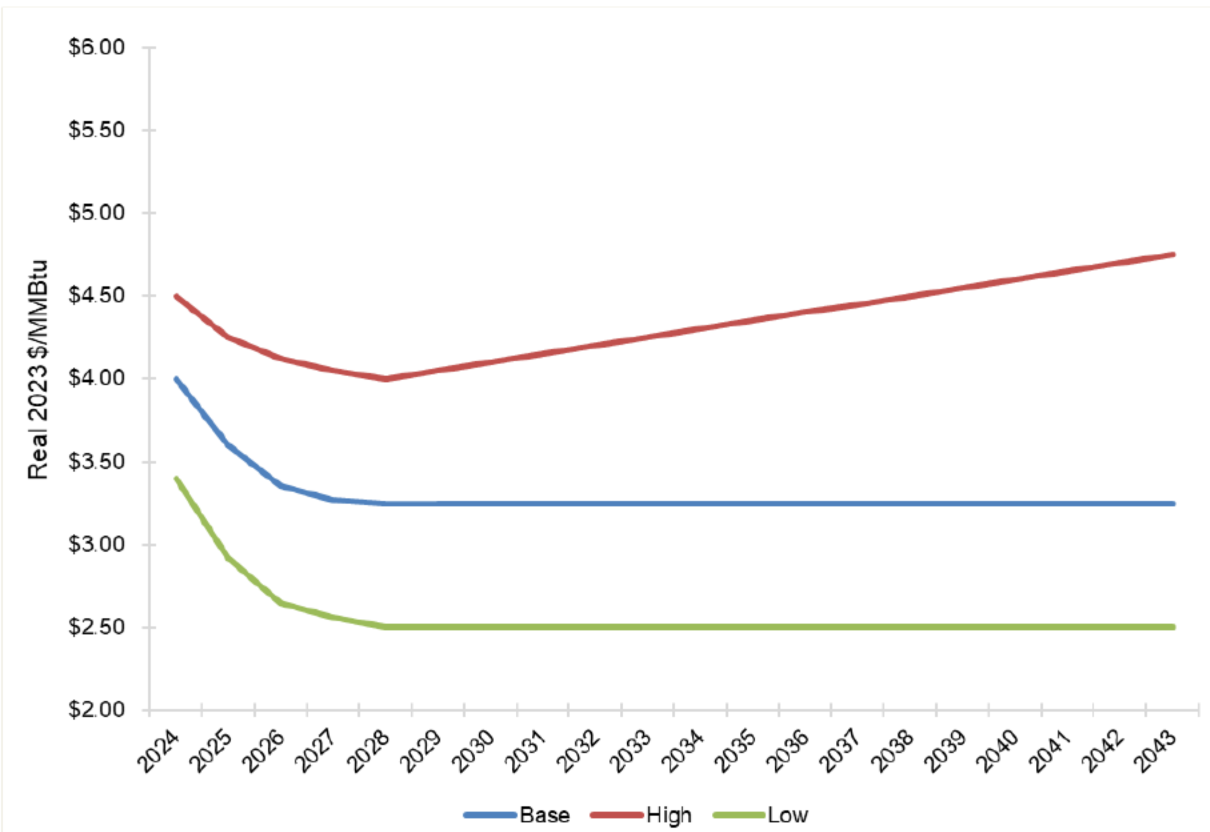
Natural Gas Price Assumptions

To develop our range of assumptions for natural gas prices, Ameren Missouri consulted its internal natural gas market experts. Several external expert sources of natural gas price projections have been reviewed in the development of our natural gas price assumptions.These sources include: U.S. Energy Information Administration (EIA), Platts Long-Range Forecasts, and the NYMEX Henry Hub market prices. These services, along with internal market knowledge of the natural gas industry, have helped to frame the long-term assumptions used in this IRP and identify the drivers of the market. Based upon our assessment of the market fundamentals at this time and our long-term market expectations, the Company has developed assumptions for future prices for natural gas that are represented by the price levels shown in Table 2.7 and Figure 2.2. These assumptions were also reviewed by Charles River Associates (CRA) as discussed in more detail in Appendix A.

Table 2.7 Natural Gas Price Assumptions ($/MMBtu)

	Real Gas 2023 $									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High	$4.50	$4.25	$4.12	$4.05	$4.00	$4.05	$4.10	$4.15	$4.20	$4.25
Base	$4.00	$3.60	$3.36	$3.27	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25
Low	$3.40	$2.92	$2.64	$2.56	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
High	$4.30	$4.35	$4.40	$4.45	$4.50	$4.55	$4.60	$4.65	$4.70	$4.75
Base	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25
Low	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50

Figure 2.2 Natural Gas Price Assumptions



2.5.2 Coal Market[4]

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

According to the U.S. Energy Information Administration, 2022 U.S. coal production was approximately 595 million tons. Over the next 20 years, U.S. coal supply and demand is expected to decline. In the next 5 to 8 years, U.S. coal supply is estimated to range from 300 to 450 million tons per year. However, there are some forecasts that include new and increased CO_2 taxes as well as new environmental regulations which project even lower U.S. coal demand. All U.S. thermal coal demand will likely be negatively impacted by coal plant retirements and ongoing competition with alternative energy sources. PRB coal production is anticipated to be the least impacted U.S. coal basin. Long-term supply of PRB coal is expected to be a maximum of 150 million tons in 2040. PRB exports are projected to stay flat and will have minimal impact on demand.

Coal Price Drivers

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

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

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

Ameren Missouri's current plan to meet emission compliance for SO_2 standards is to utilize installed environmental controls and burn predominately PRB coal. The supply for

[4] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

this product is anticipated to be available in the long-term forecasts, however, factors beyond Ameren Missouri's control may impact availability.

Coal Price Assumptions

In the development of the coal price forecasts for use in the 2023 IRP, low, base and high price forecasts were utilized for PRB coal delivered to the existing coal-fueled Ameren Missouri Energy Centers. This process included an assessment of current and future expectations of PRB coal prices (FOB at the mine) and rail transportation costs (including diesel fuel surcharges) for delivery to each of the coal-fueled Energy Centers. Next, coal price projections along with market-based forward curves were utilized to produce PRB low, base and high forecasts are shown in Table 2.8.

Table 2.8 Delivered Coal Prices ($/Ton)

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2.5.3 Nuclear Fuel Market[5]

Nuclear Fuel Price Drivers

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

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

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

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

Nuclear Fuel Price Assumptions

Ameren Missouri uses the nuclear fuel cycle component price forecasts of Ux Consulting Company. UxC was used in this role previously for the 2008, 2011, 2014, 2017 and 2020

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

IRPs. The SurfnOnline model by Huxtable Consulting is used by Ameren Missouri for Callaway 1 and is also used with modified engineering specifications for the fuel type associated with the AP1000 nuclear power unit and an SMR 12-module site. Figure 2.3 shows the nuclear price forecast for the nuclear fleet.

Figure 2.3 Nuclear Fuel Price Forecasts (Nominal)

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2.5.4 Electric Energy Market

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

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

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

2.5.5 Power Capacity Market

The expected market capacity price forecasts used in the 2023 IRP were developed by CRA using their proprietary model for capacity price forecasts. **

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The seasonal capacity price forecasts developed by CRA were used for the integration and risk analysis as discussed in Chapter 9.

Forward looking cost curves for energy and capacity are also used in the screening and cost-effectiveness analysis of demand side resource programs, as discussed in greater detail in Chapter 8. In contrast, the purpose of a screening or cost-effectiveness analysis is to identify the value of demand side resources relative to a planning environment without those same demand side resources. To this end, a separate capacity price curve was also developed to be used in future demand-side resource cost effectiveness analyses. This curve reflects the cost of new entry (CONE) value published by MISO. This method and cost curve may be used for future screening or cost effectiveness analysis purposes, instead of explicit capacity modeling, in order to ensure the inclusion of cost equivalent measures in the portfolios. The integration and risk analysis then serves as the holistic analytical test for cost effectiveness when compared to supply-side resource alternatives.

Figure 2.4a Capacity Position without Further DSM - Summer[6]

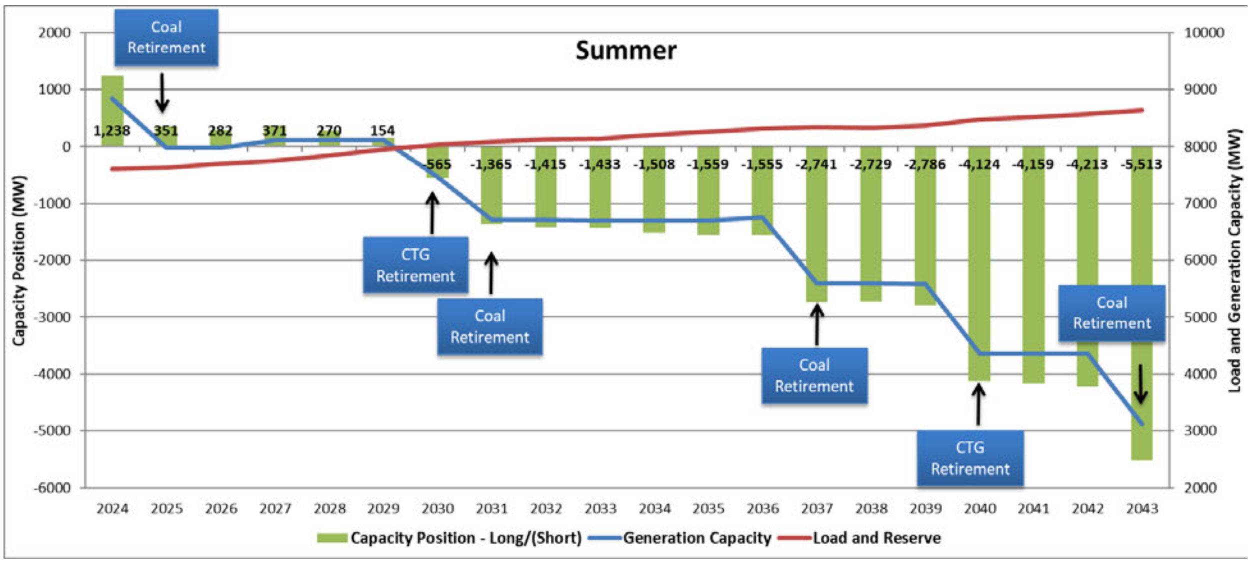
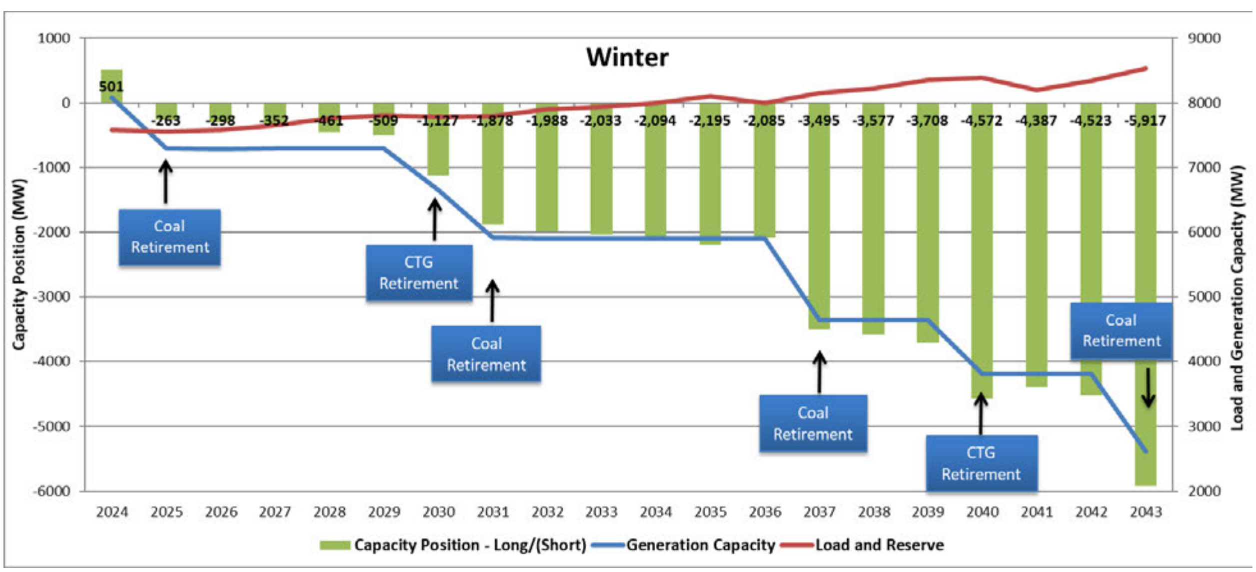


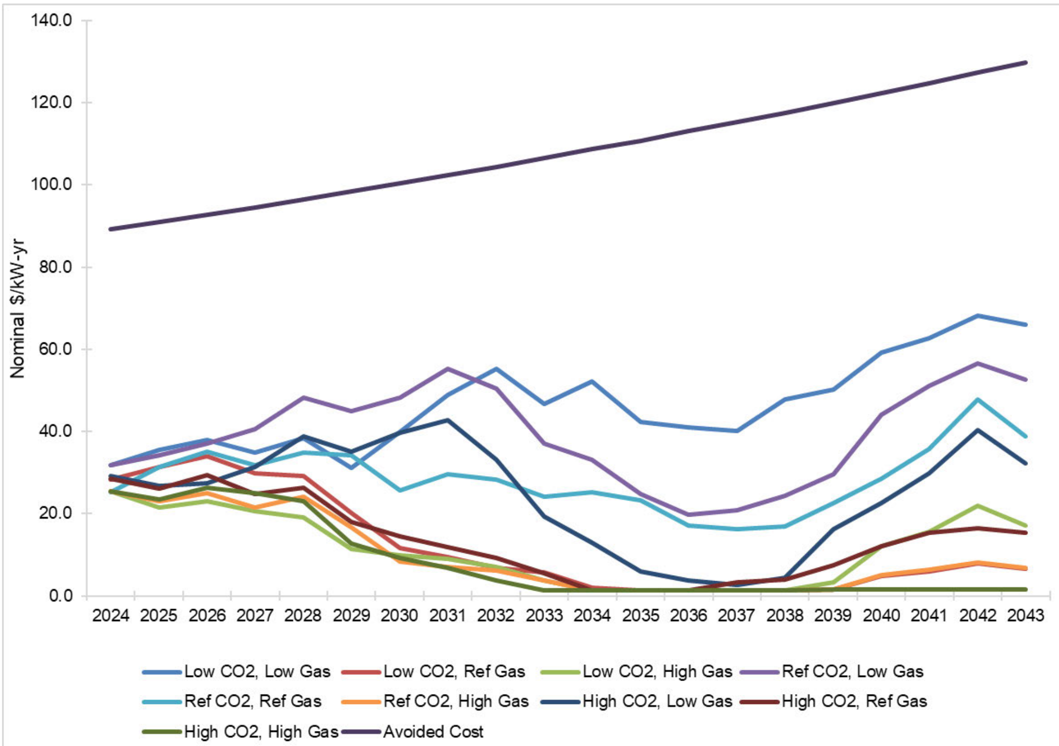
Figure 2.4b Capacity Position without Further DSM – Winter[6]



[6] Includes additional solar resources for RES Compliance.

Figure 2.5 shows the seasonal average capacity price curves developed by CRA and the avoided cost price curve developed for DSM screening purposes. Note that each CRA curve shown below is comprised of four separate seasonal curves. For additional details on the capacity prices developed by CRA, please see Appendix A.

Figure 2.5 Capacity Price Assumptions



2.5.6 Renewable Energy Standard

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

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

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

2.6 Environmental Regulations

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

A detailed discussion of enviromental regulations can be found in Chapter 5. In addition to the regulations discussed in Chapter 5, the potential continues for new and evolving laws and regulation to create a changing landscape for investment decisions over the planning horizon. Therefore, we must also consider potential actions with respect to climate policy and regulation of GHG emissions beyond the regulations that have been finalized by the EPA. To help frame the ongoing possibilities for carbon policy and regulation of GHG emissions, we examined a variety of sources and considered numerous policy pathways through which carbon prices could be implemented. Through this process an updated set of assumptions was developed to reflect environmental policy through the timing, magnitude and probability of an explicit price on carbon dioxide emissions.

Carbon Dioxide Emissions Prices[7]

Updated expectations for an explicit carbon price and timing were reviewed and revised for this IRP. The development of an assumed range of carbon prices included a review of several viewpoints on a carbon price including the 2022 EIA AEO, a variety of literature on the Social Cost of Carbon, Federal climate policy proposals, and various recent utility IRPs including those filed by Xcel, Entergy, CMS, AEP, and Pacificorp. Table 2.9 shows the values used in the current IRP analysis. These price assumptions were reviewed by CRA, a discussion of which is included in Appendix A.

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

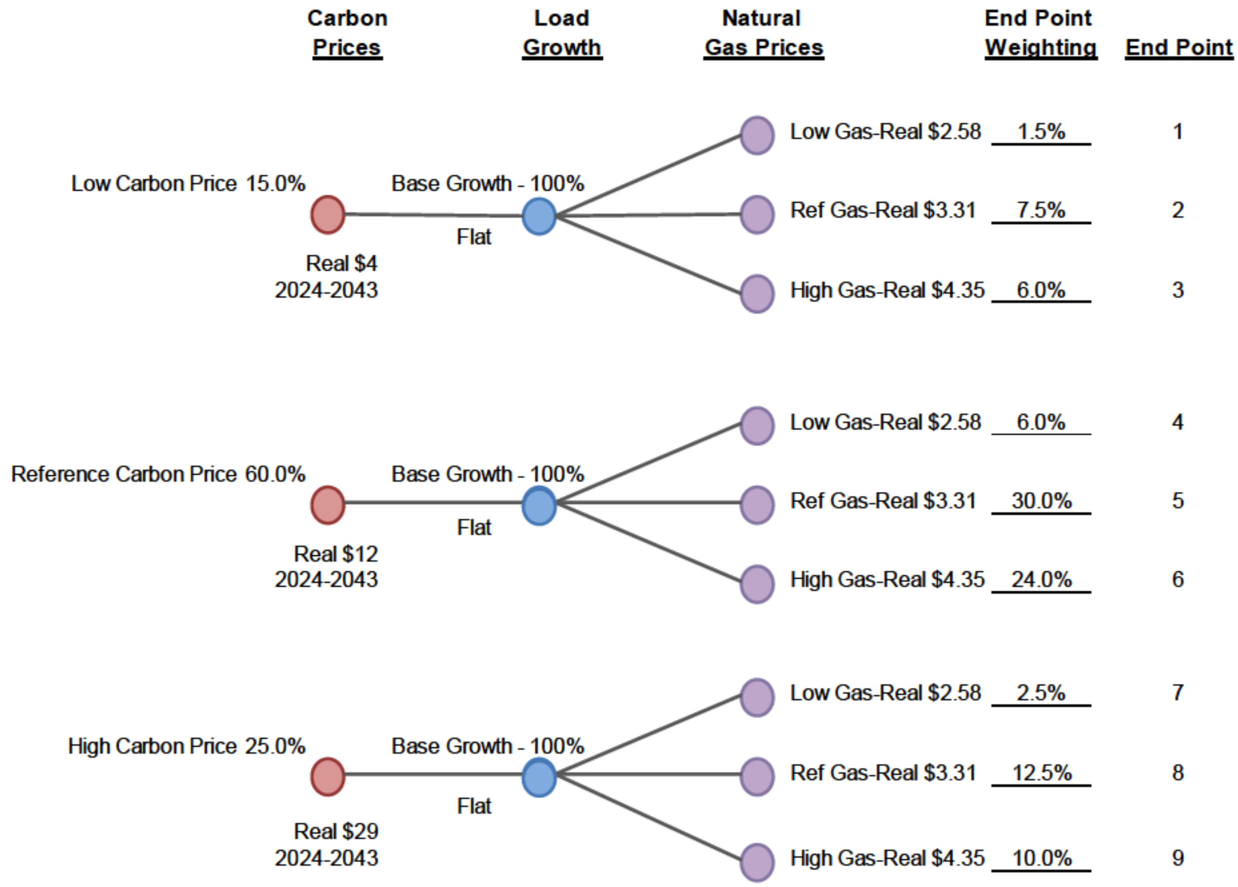
Table 2.9 Carbon Dioxide Emissions Price Assumptions

	Real 2023 $/metric ton			Nominal $/metric ton		
	Low Case	Mid Case	High Case	Low Case	Mid Case	High Case
2024	$1.29	$1.62	$2.05	$1.33	$1.67	$2.11
2025	$1.30	$1.65	$2.14	$1.37	$1.73	$2.25
2026	$1.30	$1.68	$2.23	$1.40	$1.80	$2.39
2027	$1.31	$1.71	$2.33	$1.43	$1.88	$2.55
2028	$2.60	$5.57	$10.40	$2.90	$6.22	$11.61
2029	$3.83	$9.28	$18.15	$4.36	$10.56	$20.66
2030	$5.02	$12.83	$25.60	$5.82	$14.90	$29.72
2031	$5.04	$13.20	$27.19	$5.96	$15.63	$32.20
2032	$5.05	$13.57	$28.89	$6.11	$16.39	$34.90
2033	$5.07	$13.95	$30.69	$6.25	$17.19	$37.82
2034	$5.10	$14.35	$32.61	$6.40	$18.03	$40.99
2035	$5.12	$14.76	$34.65	$6.56	$18.92	$44.42
2036	$5.14	$15.18	$36.83	$6.72	$19.84	$48.15
2037	$5.16	$15.61	$39.14	$6.88	$20.81	$52.20
2038	$5.18	$16.05	$41.60	$7.04	$21.83	$56.59
2039	$5.20	$16.50	$44.22	$7.21	$22.90	$61.36
2040	$5.22	$16.97	$47.01	$7.39	$24.02	$66.53
2041	$5.24	$17.46	$49.97	$7.57	$25.20	$72.14
2042	$5.26	$17.95	$53.13	$7.75	$26.43	$78.24
2043	$5.29	$18.46	$56.49	$7.94	$27.73	$84.85

2.7 Price Scenarios

Power prices are influenced primarily by electric demand, the mix of available generation resources, and natural gas prices. Using our assumptions for carbon prices and natural gas prices, we developed scenarios based on combinations of these assumptions. The development of scenario modeling is best represented by a probability tree diagram and the associated probability of each branch of the tree. Each branch of the tree is used to represent a combination of dependent input variables that can have an impact on plan selection. In order to focus on those combinations with the greatest influence on alternative resource plan performance, potential branches that would be characterized by a significantly low probability of occurrence are collapsed to provide a simplified yet still robust set of possible branches. This process provides for a wide range of potential future combinations with which we can analyze alternative resource plan performance and risk. Figure 2.6 shows the final scenario tree.

Figure 2.6 Final Scenario Tree



Electric Power Prices[8]

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

- Natural gas prices
- An explicit price on carbon dioxide emissions

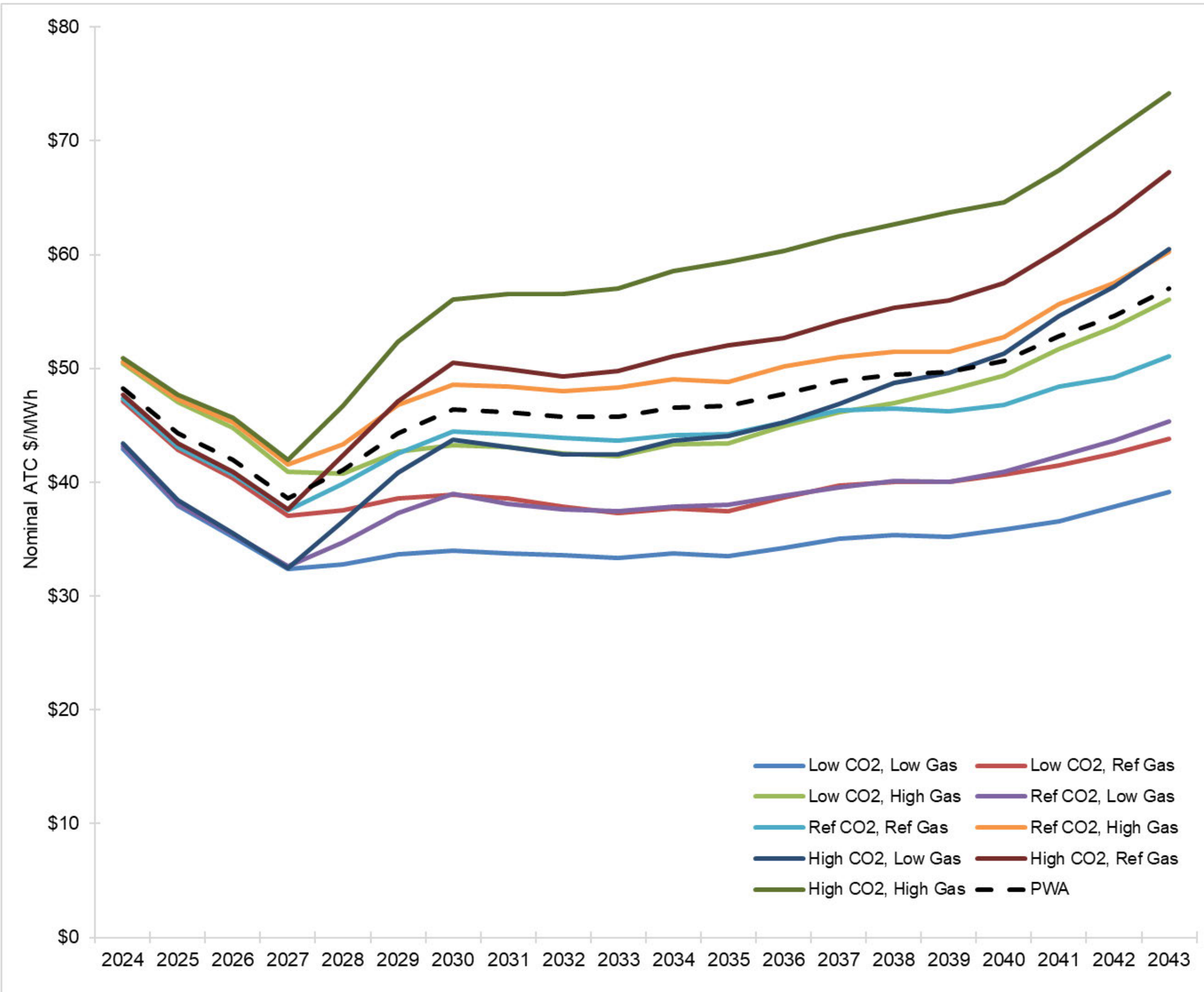
These inputs were varied within the model, and audited by CRA to ensure they were reasonable and comprehensive. This process produced values based on the probability

[8] 20 CSR 4240-22.060(5)(G); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

tree shown in Figure 2.6. The results of this modeling for each branch yield different power price futures, which are shown in Figure 2.7.

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

Figure 2.7 Scenario Power Prices



2.8 Compliance References

Ameren Missouri 2023 IRP

Table of contents

1. Introduction

Ameren Missouri retained Charles River Associates (CRA) to support Ameren Missouri for the 2023 Integrated Resource Plan (IRP) filing. CRA is a leading global consulting firm that offers economic, financial, and business management consulting expertise and applies advanced analytic techniques and in-depth industry knowledge to complex engagements for a broad range of clients.

The energy practice of CRA has staff located in Washington DC, Boston, London, and Toronto. CRA advises a range of clients on a range of issues including resource planning, asset valuation, auction design and implementation, policy development, and procurement and planning strategies. Recently CRA has supported numerous investor- and publicly-owned utilities to develop long-term generation, transmission and distribution plans that meet the evolving needs of customers, regulators, and other stakeholders.

In this report, we provide the results for three specific workstreams that were part of the scope of work developed for Ameren in late 2022. More specifically:

- Section 2 includes an assessment of the reasonableness of the load forecast, carbon price forecast, and natural gas price forecast assumptions used by Ameren Missouri in the upcoming IRP.
- Section 3 includes analysis regarding the need for ancillary services price development for this IRP and;
- Section 4 includes commentary on the energy and capacity prices results determined by CRA's modeling effort.

2. CRA Objectives and Framework for the IRP Input Audit

CRA performed a comprehensive review that examined all aspects of the IRP input analysis including the applied methodology, sources, and justification of the final projections. To accomplish this review, CRA formed a team of subject matter experts that have supported IRP analyses throughout North America and have been involved in the development of inputs for various IRPs.

Additional support and consultation was provided throughout each step of the process by members of Ameren's Corporate Analysis team to ensure accurate understanding of Ameren's process by the CRA team.

During the pre-work for this effort, Ameren shared with CRA three critical objectives for the IRP Input review effort:

- Provide clarity around the entire IRP input development process for internal and external stakeholders.
- Verify the reasonableness of the key inputs needed for modeling and determine whether the current process produces an adequate range of each variable that captures most expected outcomes.
- Identify appropriate and efficient resolutions for any identified gaps in the development of the key inputs.

In order to conduct a full examination of the multitude of inputs used in the IRP process, CRA reviewed all aspects of these inputs, including cross-verification against source materials and evaluation of internal methodologies and processes for developing Ameren-specific data (e.g., the company load forecast).

Specifically, CRA evaluated the reasonableness of Ameren's load, natural gas price, and carbon price assumptions, comparing the company's input development and results to:

1. Industry accepted data sources and forecast development approaches.
2. Acceptable historic performance of the data sources.

The review of peer companies and their forecast development approaches provide a reasonable basis for Ameren's forecasting methods. Widely accepted approaches that have been in place for multiple IRPs indicate their robustness and reasonableness. Similarly, acceptable historic performance of the data sources enhances confidence in the assumptions and the eventual results of the portfolio development.

2.1. IRP Input Audit Findings Summary

CRA's review spanned a three-week period, and involved interviews with Ameren staff, review of documentation provided by the Company, and review of industry best practices and other utility assumptions. The recommendations can be summarized as follows:

IRP input development process:

- Overall, CRA recommends the development of a documented process for the IRP input to ensure consistency between IRPs. Changes driven by staff turnover, methodology updates and other can be mitigated by a well- documented process.

Natural Gas Price:

- Continue the consideration of the Henry Hub pricing point as the basis for the development of natural gas base/high/low outlooks. Henry Hub is commonly used by peers and represents a reasonable reflection of natural gas market dynamics in North America.
- Based on CRA's analysis, the proposed range of the Henry Hub prices appears to be reasonable. Given the recent market developments and the market expectation over the long run reflected in peer company projections, our analysis indicates a reasonable range of the expected curves. CRA recommends the continuation of the consideration of multiple third-party forecasts in the development of the Company's natural gas price assumptions to better reflect expected natural gas market fundamentals.
- Continue to incorporate internal subject matter experts' views on price curves obtained from publicly available sources, private services, and current market pricing. The natural gas market is continuously shifting; therefore, the incorporation of expert views can better align less recently developed forecasts with newer market developments.

Carbon Price

- Continue to incorporate a carbon price in the regional forecast to reflect recent industry trends. Based on CRA's review, it is appropriate for Ameren to evaluate the impact of a federal carbon price program or other explicit or implicit carbon price mechanisms on resource planning.
- It is still unclear how the newly passed Inflation Reduction act will affect the need for a future carbon pricing program. The IRA is mostly focused on accelerating the integration of clean energy technology, while the carbon price seeks to limit fossil generation. Therefore, it is difficult to correlate the impact of the two without further studies.

- CRA's review of peer companies and CRA's internal analysis confirms the reasonableness of Ameren's proposed high, base and low carbon price projections.

Load Forecast

- Align with peer companies that include ISO/RTO load forecasts in their IRP regional load forecasts. Various companies consider their native ISO/RTO load that could reflect regional load dynamics more precisely than EIA's AEO projections. For Ameren, it is reasonable to use as the market IRP input the load forecast developed for the Midcontinent Independent System Operator (MISO), since it provides an independent view that is more in alignment with the ISO/RTO planning processes than the EIA load projections.
- CRA recommends Ameren incorporate the high and low MISO load growth cases for regional load. These load forecasts have been developed by an independent party considering different demand side management, electrification, and distributed generation penetration.

2.2. Natural Gas Price Forecast Audit

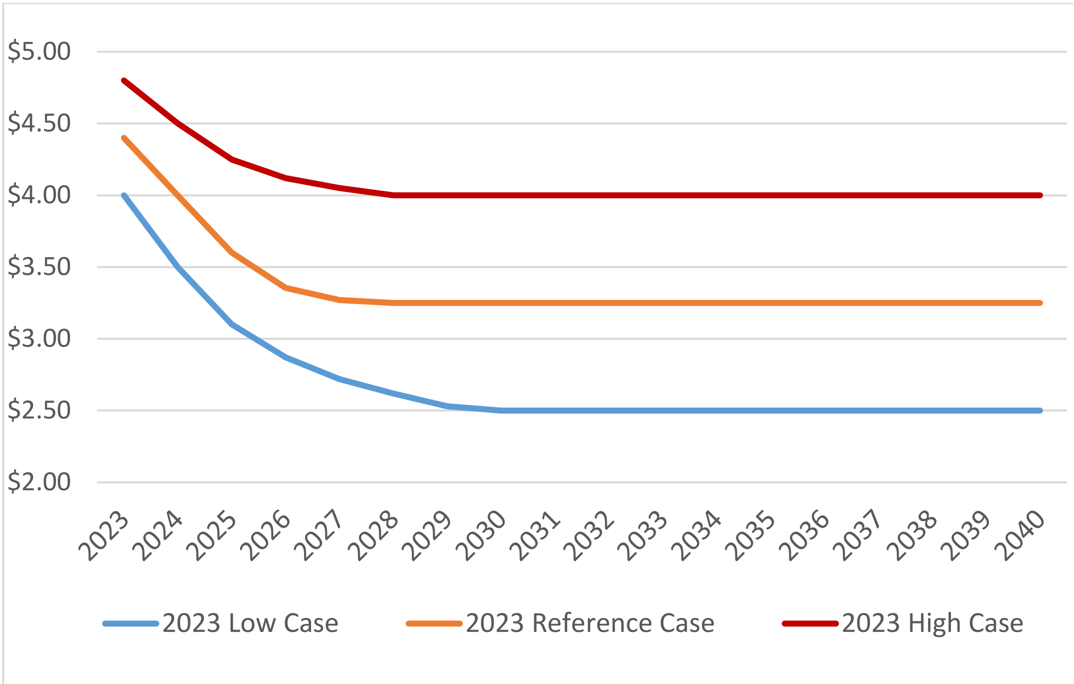
Natural gas prices continue to have a very strong influence on energy prices. The company employs a forecasting method for natural gas prices based on a hybrid approach that considers third party forecasts, the latest projections from the Energy Information Agency Annual Energy Outlook and Ameren's natural gas experts' views. For this IRP, Ameren used multiple views from the recent EIA AEO 2022 for Henry Hub, a current third-party forecast from Platts, and natural gas market intelligence collected by Ameren's gas market experts.

Specifically, Ameren's internal experts considered a range of drivers for the 2023 IRP including the following:

- Impacts to natural gas supply due to the Russian invasion of Ukraine
- Natural gas infrastructure challenges related to greenhouse gas and environmental/legal considerations
- Hydrocarbon production disruptions reflected in investments of new production

Based upon these inputs Ameren developed assumptions for three price curves – base, high and low – for future prices for natural gas that are represented by the price levels depicted below:

Exhibit 1 Henry Hub ($2023/Dth)



Following the audit methodology described in the introduction of this section, CRA reviewed widely accepted industry practices to compare the reasonableness of the forecasting approach utilized by Ameren.

First, CRA collected information related to the methods used for the development of the natural gas price projections from several peer companies' IRPs. Although applied in slightly different manners, CRA's research identified three generic approaches used by utilities to develop regional natural gas price forecasts:

The first method relies on a combination of multiple third-party consultants as well as current trading sources, such as NYMEX for the development of the different price outlooks with appropriate internal adjustment. This method was used by Entergy Arkansas, LLC which considered multiple independent, third party-consultants for its long-term forecast.[1] Vectren (Southern Indiana Gas and Electric Company) averaged forecasts from PIRA, Wood Mackenzie, Pace Global, ABB, and EVA.[2] Third party forecasts capture the most recent market dynamics, but their vintage can be an issue, since they may not have been developed during a timeframe that fully reflects current and expected market dynamics. This drawback is usually mitigated by adjustments on the forecast by internal natural gas market experts. Ameren's approach considers multiple sources while also considering current and expected market dynamics, thus avoiding the need for secondary adjustments to averages of third party forecasts.

The second method applies a standardized probability-weighed approach on external independent sources with very minimal internal expert view modifications. Evergy Metro, Inc.

[1] Entergy IRP, 2021 Integrated Resource Plan

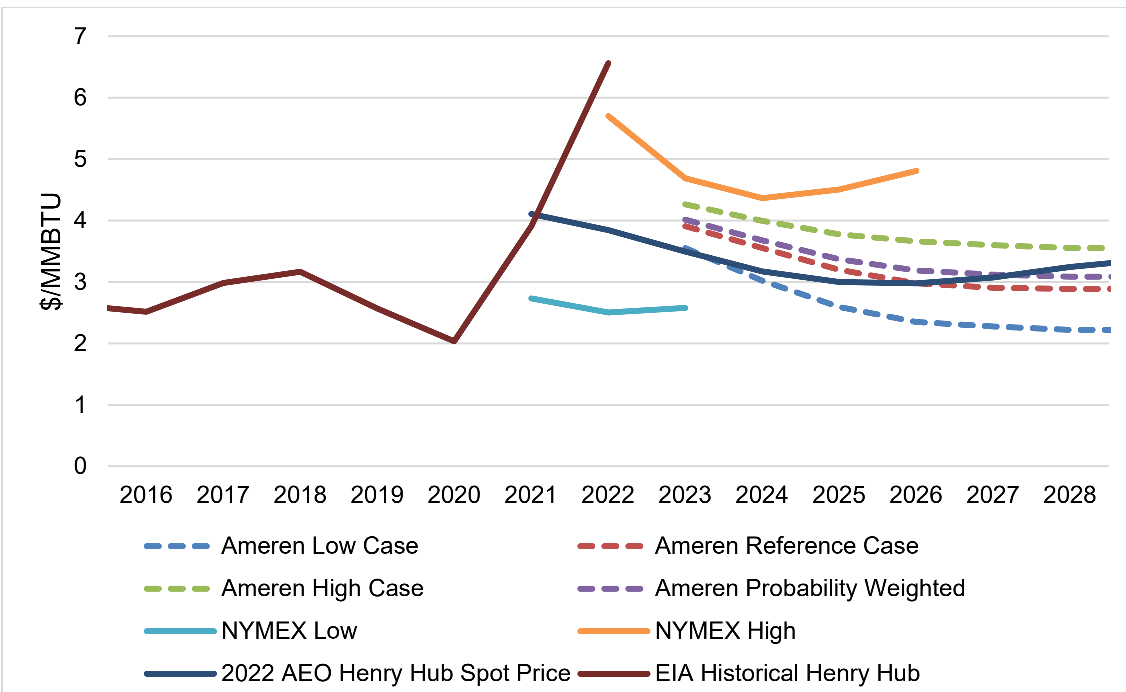
[2] Vectren 2019-2020 IRP

subscribed to this approach by combining external source forecasts in equal weight. These forecasts were from IHS Markit, Energy Information Administration, S&P Global Platts, Energy Ventures Analysis, and CME Futures. Similar to the previous approach, it can be challenging to align the results of different vintage forecasts. Also, the limited internal adjustment may exclude more recent market dynamics. The multiple third parties forecast approach limits the risk of “anchoring” the forecast on one view.

The third approach relies on a bottom-up forecast of North American gas production and prices using a fundamentals-driven natural gas model. The model develops natural gas price outlooks under different supply, demand, infrastructure investment levels. In the near term, this method considers current market forward strips and slowly incorporates the fundamental view beyond the near term. CRA has utilized this approach for various IRP efforts in North America. However, doing so can add cost and complexity to the consideration of price assumptions by internal experts.

Exhibit 2 compares Ameren’s preliminary forecast with the AEO EIA’s reference case and the recent NYMEX high and low prices taken from separate time frames. Overall, Ameren’s projections are aligned with the EIA AEO view over the near to mid-term. Since the 2022 AEO prices did not capture the most recent price spike, it is appropriate to reflect this recent market development in the near term by using recent forward strips and natural gas market expert’s input.

Exhibit 2 Ameren's Reference Natural Gas Forecast compared with the 2022 Forecast ($2022)[3]



In terms of the forecasting approach, CRA finds Ameren’s approach reasonable. The consideration of multiple sources along with internal market knowledge provides an appropriate view of the natural gas market prices projections. The method ensures

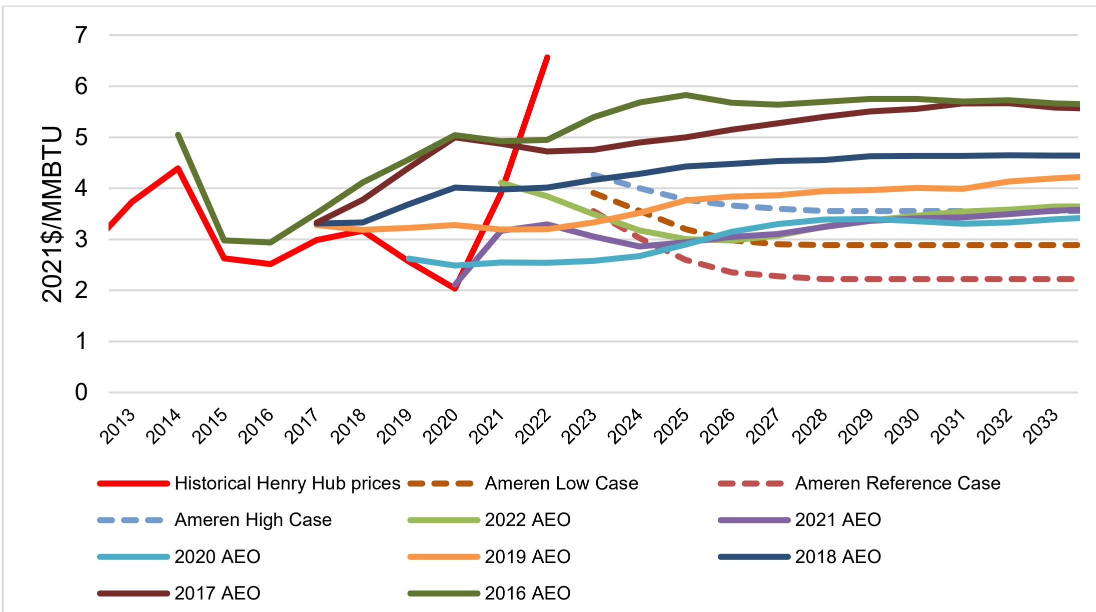
3 Low Case Based on Low Range April 2021 NYMEX trading, Reference Case based on average of Platt's and EIA AEO averages, High Case based on High Range July 2022 NYMEX trading

independency by the inclusion of third-party views and better reflection of current market dynamics provided from experts' views.

As mentioned above, Ameren uses EIA and various third-party forecasts for the development of its future gas price estimates. Since CRA has no access to the historical third-party data and is thus unable to compare their performance against actual results, the audit concentrated on the comparison of the AEO EIA reference case with actual historical prices.

Exhibit 3 provides the AEO EIA projections for the Henry Hub under different vintages and compares them with actual prices. Overall, the AEO reference case tends to over-estimate the price for gas, as identified by the separation between the actual prices and the different projections. As expected, the forecast error decreases when closer to the actual pricing. However, the forecast error always appears to be on the high side.

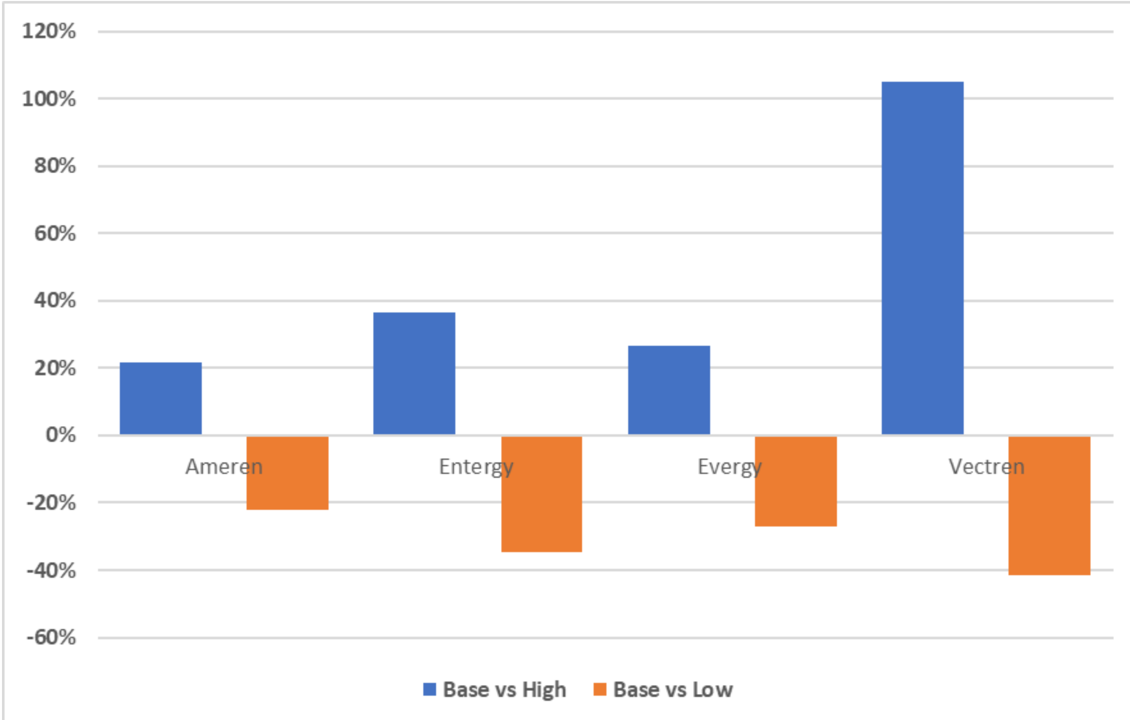
Exhibit 3 Comparisons of natural gas prices between AEO Annual forecasts and Ameren's 2023 IRP prices



Based on this assessment, it is reasonable for Ameren to establish its base and boundary price projections slightly below the AEO's reference case projection. The historical over-estimation compared to actuals provides a reasonable justification for this result.

Furthermore, to assess in more detail Ameren's base and boundary conditions, CRA reviewed peer company projections for low and high and their ranges compared to base. Although the information reviewed does not align with the timing of this IRP – and as result does not capture most of the latest market developments – it provides a reasonable benchmark on whether the base and boundary conditions proposed by Ameren are reasonable. The exhibit below compares in CAGR terms the difference between base and low and base and high cases for three Ameren peers that developed their IRPs during a recent timeframe.

Exhibit 4 Ameren and peers natural gas range average % difference for base vs high and base vs low



Note that Ameren's ranges are in line with Evergy's but shorter than Entergy and Vectren as Ameren's most recent price forecast includes a price spike related to the latest market developments in the natural gas market that may not have been fully incorporated into the Evergy and Vectren IRPs (due to the timing). All four IRPs stress the natural gas market on the high side more than the low end, which is appropriate given the planning risks of a prolonged high natural gas market price environment.

In conclusion, CRA finds Ameren's base, high and low projections for the natural gas prices reasonable. More specifically:

- Continue the consideration of the Henry Hub pricing point as the basis for the development of natural gas base/high/low outlooks. Henry Hub is commonly used by peers and represents a reasonable reflection of natural gas market dynamics in North America.
- Based on CRA's analysis, the proposed range of the Henry Hub prices appears to be reasonable. Given the recent market developments and the market expectation over the long run reflected in peer company projections, our analysis indicates a reasonable range of the expected curves. CRA recommends the continuation of the consideration of multiple third-party forecasts in its natural gas projections to better reflect expected natural gas market fundamentals.
- Continue to incorporate internal subject matter experts' views on price curves obtained from publicly available sources and current market pricing. The natural gas market is continuously shifting; therefore, the consideration of expert views is appropriate to reflect more recent changes affecting ranges of future prices.

2.3. Load Forecast Audit

Load estimation over the IRP time horizon is one of the IRP cornerstones. The long-term energy and demand forecast is usually separated into two processes. One determines the load forecast for the utility territory – usually used during the preferred portfolio determination. The second focuses on the estimation of the regional load forecast required to establish regional market scenarios that will be used to test the performance of various developed portfolios. In this effort CRA audited Ameren's regional load determination process and projected views.

Ameren develops three regional load growth scenarios that represent different economic projections and expert views on energy efficiency, distributed generation, and electrification. The Energy Information Administration's West North Central Case for the Eastern Interconnect is utilized as a basis of the forecast adjusted for the high and low cases according to input from Moody's Economic Outlook and impacts from the factors mentioned above.

To evaluate the reasonableness of Ameren's regional forecast process and projected views, CRA relied on reviewing the processes of Ameren's peers and assessing the reasonableness of Ameren's sources and historic performance.

There is limited information in produced IRPs on the development of the regional load forecast. The IRP documents include detailed information on the native load forecast development for each company but spend limited time on the effort for the development of the regional load used for the fundamental analysis. Since utilities have a limited impact to the regional load trends, they usually rely on commonly accepted publicly available sources with a historically consistent forecasting methodology.

CRA reviewed various IRPs to identify different approaches for the forecast of regional load The most common methods are the following:

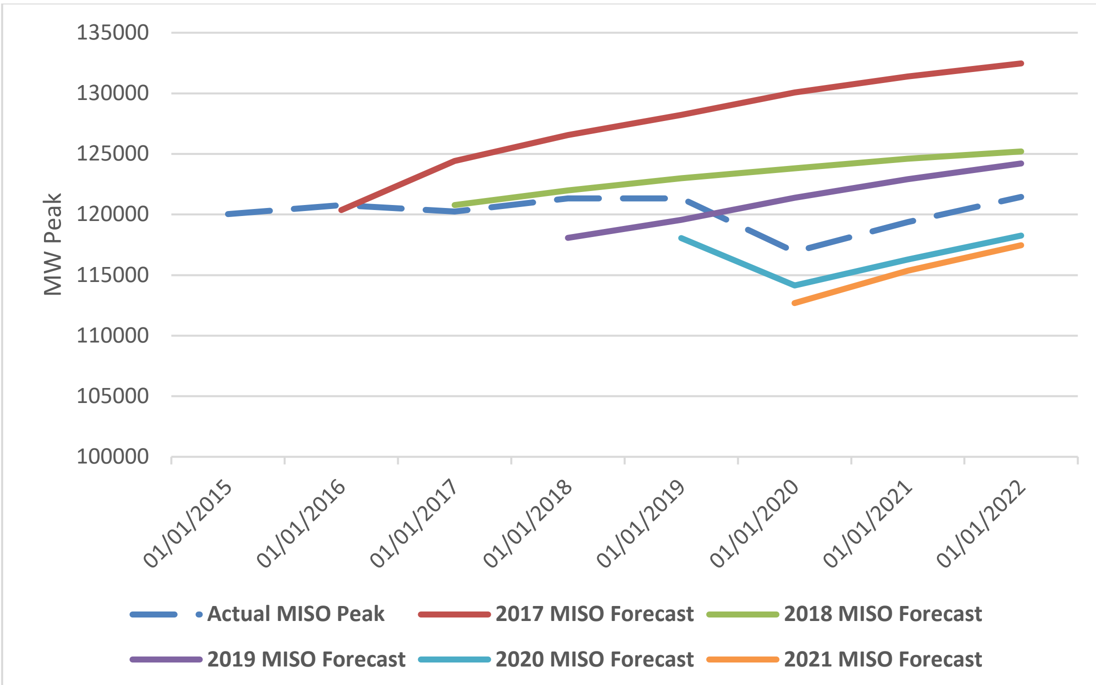
- Utility developed regional load; For example, Indiana Michigan Power incorporates AEP's (parent company) load forecast for the base and alternative scenarios. The IRP documentation provides no additional details on how these forecasts were developed.
- RTO/ISO produced load; PJM, MISO and other ISO/RTOs develop regional forecasts for energy and demand on an annual basis. The forecast incorporates input from load serving entities within their jurisdiction. For example, Vectren utilizes the demand forecast provided by the MISO market in the System Forecasting for Energy Planning Section of MISO's website. The alternative load forecast scenarios are a variation of the base MISO load forecast that incorporates analysis from Vectren staff. CRA's regional load forecast approach relies on this method that has been used for various client engagements within organized markets.
- AEO EIA load forecasts; Various utilities including Ameren rely on the annual regional load forecast updates provided by EIA. These forecasts are heavily influenced by economic factors such as Gross Domestic Product and provide a reasonable source for the regional IRP load forecast development.

The RTO/ISO forecasts are developed by an independent entity under rigorous scrutiny by stakeholders. Although EIA AEO's forecasts are reasonable, the RTO/ISO projections provide a "closer view" to a specific region in the US. The ISO/RTO forecasts also incorporate input from stakeholders – usually utilities – that reflects more accurate trends than a nationwide forecast.

For the historic performance evaluation, CRA's review relied on two comparisons. The first compared MISO's historical load projections with actuals, and the second compared EIA's projections with actuals.

First, CRA compared the forecast developed by Purdue University for the MISO process. We collected the load forecast for five MISO Energy and Peak Demand Forecast reports and compared them the actual peaks realized by the ISO. The exhibit below depicts this comparison. Notably, the projections both overestimate and underestimate the actual regional forecast but remain in a tight band, especially in the near term.

Exhibit 5 MISO Forecast compared to actual Summer Peak



Second, CRA compared EIA's AEO projections for the reference case for the past 8 years with the actual demand for the states within the West North Central Region. The table below compares the expected annual average growth from each AEO and the total load year over year consumption growth for of the states that comprise the region.

	EIA AEO West North Central average expected growth – Reference Case	**Year over Year Actual load growth consumption**
2014	0.54%	1.2%
2015	0.55%	-2.1%
2016	0.49%	0.1%
2017	0.56%	0.1%
2018	0.48%	4.3%
2019	0.48%	-1.8%
2020	0.54%	-2.3%

2021	0.66%	3.5%
Average	0.54%	0.38%

Overall, the West North Central estimates by EIA capture the year over year expected base growth for the region. However, they appear to slightly overestimate the expected load growth for the region.

In conclusion, CRA finds reasonable the consideration of EIA AEO's West North Central case as the basis for the regional load forecast used in Ameren's IRP. However, CRA recommends adopting the MISO load forecast for the following reasons:

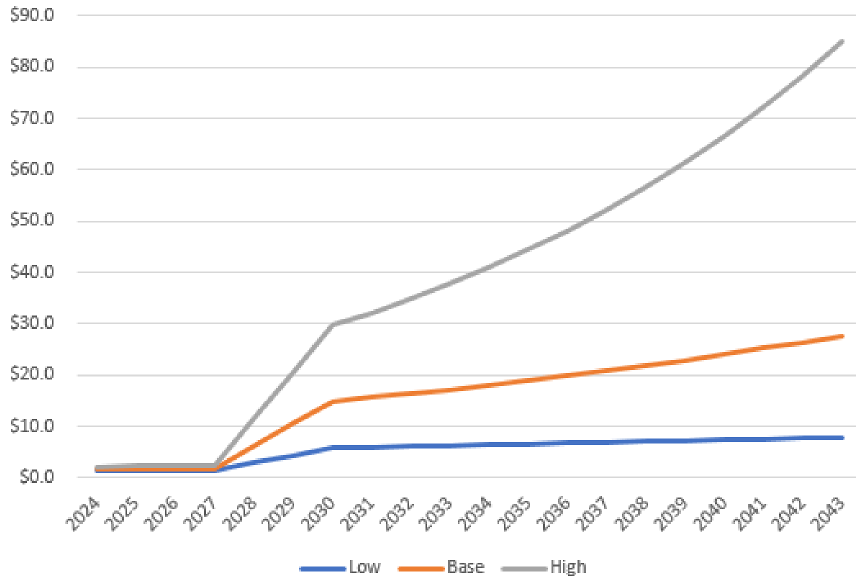
- The ISO load forecast reflects a view of energy consumption that more closely matches regional performance and expectations than EIA's forecasts, since it is developed by the ISO after incorporating input and feedback provided by member utilities.
- The MISO load forecast appears to be more commonly used by utilities in MISO. A more widely accepted approach can be better understood by regulators and stakeholders and ensures better consistency of assumptions.

2.4. Carbon Price Forecast Audit

Although several legislative and executive actions related to Greenhouse Gas Emissions (GHG) have been attempted over the last decade, there is currently no federal carbon pricing program and no binding power sector GHG emission limits at the federal level. However, given multi-faceted efforts by the Biden Administration and Congress to reduce GHG emissions, CRA concurs that Ameren's IRP modeling should include a carbon price to reflect the impact of such policy on planning.

Similar to the development of the natural gas price and regional load forecasts, Ameren developed a range of carbon price assumptions to reflect different potential policy regimes. Based on CRA's discussion with the Ameren staff, the three cases (base, high and low) were informed by detailed research with the objective to capture a wide spectrum of outcomes using input from databases and other utilities' projections. The exhibit below depicts Ameren's proposed base, low and high cases.

Exhibit 6 CO2 Price Forecast ($2022/MT) for Base, High and Low cases

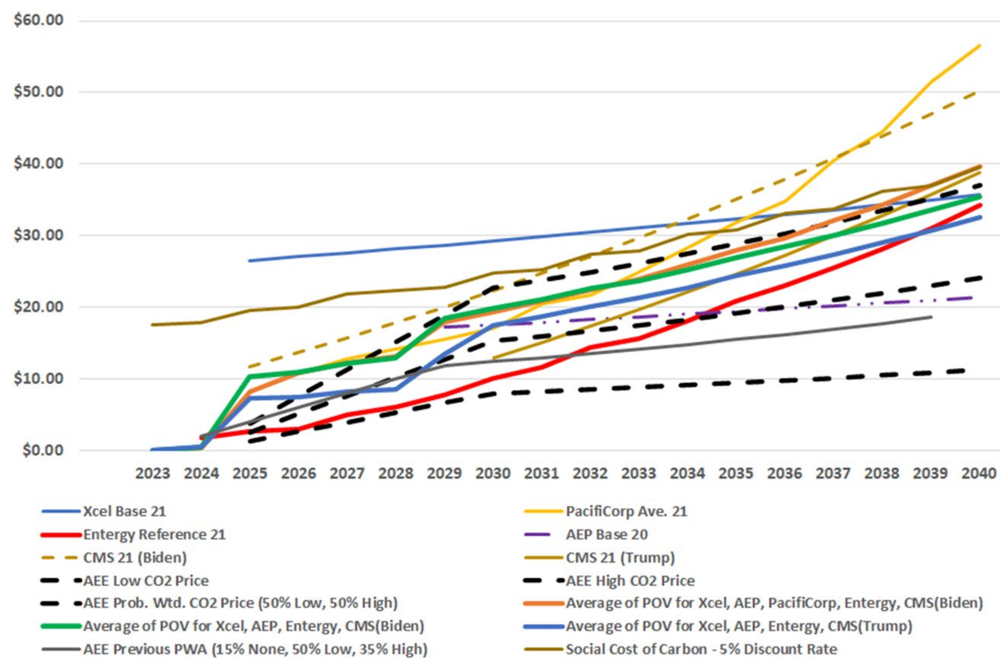


Ameren considered various drivers that affect the timing and level of carbon pricing such as the need for a potential program that considers carbon pricing through legislation (e.g., Carbon Tax, Cap-and-trade Program, Clean Energy Standard), RTO markets, and other mechanisms. Ameren also considered recent price forecasts developed by peer companies such as Xcel, AEP, Entergy and others.

Since there is no established federal program for carbon price, a comparison with peer company approaches is limited to the motivation for the application of carbon price (level and timing) and the sources considered to justify the developed price projections. Moreover, the choice for a specific level and timing was also driven by the considered scenario theme the IRP was seeking to capture. For example, a scenario that modeled a view of increased regulatory pressure on carbon and stricter GHG goals incorporated a higher price for federal carbon than a scenario that modeled a view with moderate to low regulatory intervention.

The exhibit below depicts the various price projections of available sources.

Exhibit 7 CO2 Price comparisons from various utility sources (2021 Nominal$/Metric Ton)



Comparing Ameren's projections to the rest of the sources, it appears that the company captures a reasonable spectrum of potential outcomes. The base case tracks most of the peer utility projections, while the high case reflects more aggressive carbon emission reduction studies (CMS). If a carbon price increases to the $80-90/ton range (in real 2021$) it could make certain alternative technologies required to achieve net zero emissions by the 2035-2040 timeframe (such as hydrogen, CCS, and nuclear) economically feasible. On the low end, Ameren's forecast considers a non-zero price for the carbon program that will commence around the same time as the base and high cases. It is appropriate to have an outcome where the carbon program will not have a significant impact to the planning decisions since there is a potential for futures in which state and/or federal legislators and/or regulators may not be as aggressive on carbon reduction.

Based on CRA's analysis and discussion with the Ameren staff, it was confirmed that the latest passage of the Inflation Reduction Act was not expected to alter the range of carbon price curves. Even though IRA is expected to have a positive effect on the development of renewables, it is difficult to determine whether a carbon program will still exist regardless of the IRA. However, a range of potential policy regimes that reflect some degree of explicit or implicit carbon pricing remains a possibility.

In conclusion:

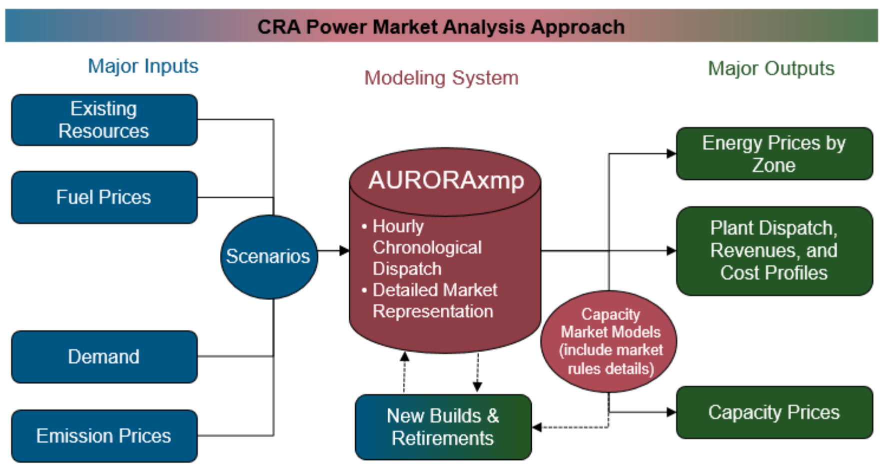
- Continue to incorporate a carbon price in the regional forecast to reflect recent industry trends. Based on CRA's review, it is appropriate for Ameren to evaluate the impact of carbon prices, whether explicit or implicit, on resource planning.
- CRA's review of peer companies and CRA's internal analysis confirms the reasonableness of Ameren's proposed high, base and low federal carbon price projections.

3. Planning Scenarios Price Development

CRA developed various MISO market scenarios that test plausible but materially different long-term views of fundamental external market conditions such as natural gas prices, carbon prices and energy consumption. These eleven scenarios were used to inform the creation of candidate portfolios of demand- and supply-side resources.

Each of these market scenarios is supported by a set of assumptions describing the fundamental inputs from the Ameren IRP Input process that was audited by CRA. The key categories of assumptions used to develop the 2023 IRP market scenarios include: load, natural gas prices and CO_2 prices. All eleven scenarios in the 2023 IRP were modeled using AURORA to evaluate the evolution of generation capacity and prices across MISO under these different sets of fundamental conditions. This process is illustrated in Figure 1.

Figure 1: 2021 IRP Modeling Framework



3.1. Price Scenarios Development

The primary tool used for the development of the North American long-term energy market pricing forecasts is the Aurora energy market simulation model. The Aurora model iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions, and other.

The AURORA model is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada, and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities, and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the AURORA model.

CRA evaluated eleven market scenarios that describe plausible futures that may develop over time and result in a materially different set of market conditions under which Ameren will need to serve customer needs. Each scenario is developed by a combination of three critical variables: load, natural gas prices and carbon prices. The cases are labeled as follows:

Case	Load	NG	CO2
1	Base	Base	Base
2	Base	Base	Low
3	Base	Base	High
4	Base	Low	Base
5	Base	Low	Low
6	Base	Low	High
7	Base	High	Base
8	Base	High	Low
9	Base	High	High
10	High	Base	Base
11	Low	Base	Base

3.2. Scenario Assumptions

For the development of the eleven cases, CRA used three different projections each for regional load, natural gas prices and carbon prices.

MISO Load Growth

Load growth is a critical driver of wholesale energy and capacity prices. CRA utilized the latest MISO estimates developed for the April 2021 MISO Futures report.

Under the Base Case, demand for energy in MISO is expected to grow by 0.7% per year over the 20-year forecast period (2023-2042) and 2.1% per year for the High case where load growth reflects increased economic growth, deployment of electric vehicles, and greater building electrification. For the Low case, the annual growth is -0.3% per year driven by lower economic growth and adoption of distributed technologies.

Peak summer demand is expected to grow at a rate of 0.7% per year for the Base case, and 2.2% for the High case. The Low case reflects a 0.4% decline in energy consumption per year over the study period. The details of the analysis and the assumptions underlying the load forecast are discussed in Section 2 above.

Exhibit 8 MISO Energy Load Projections for Base, High and Low cases

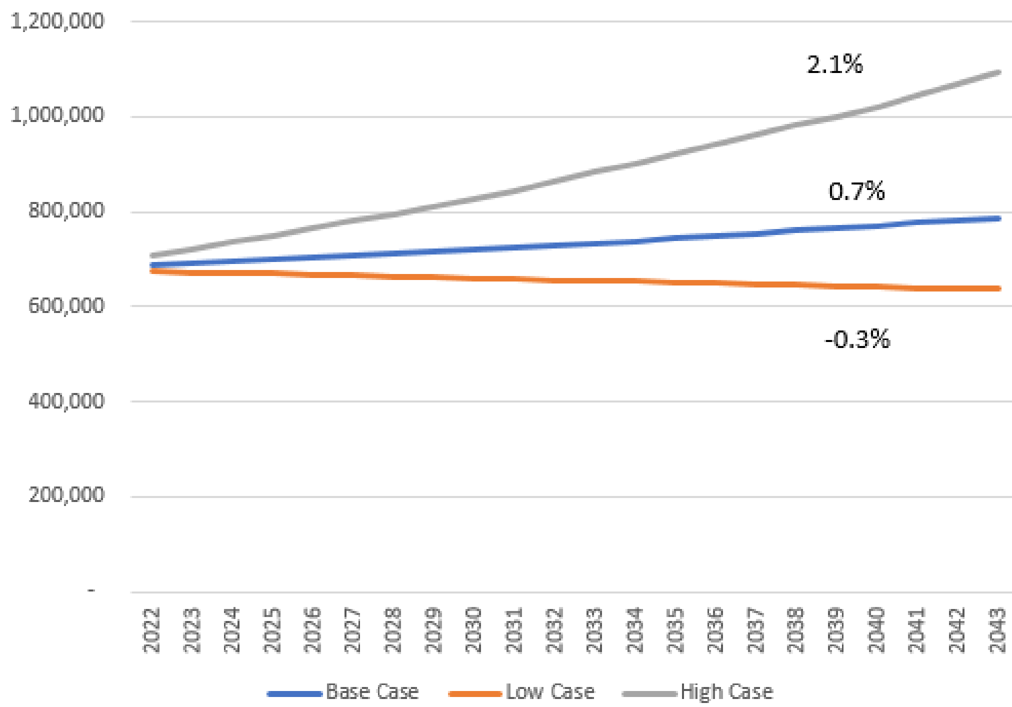
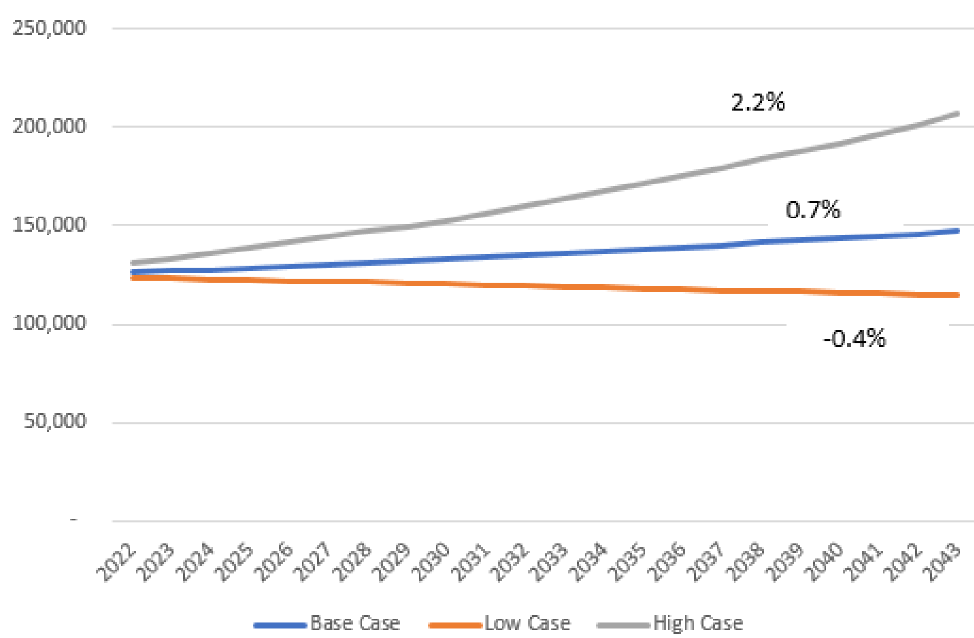


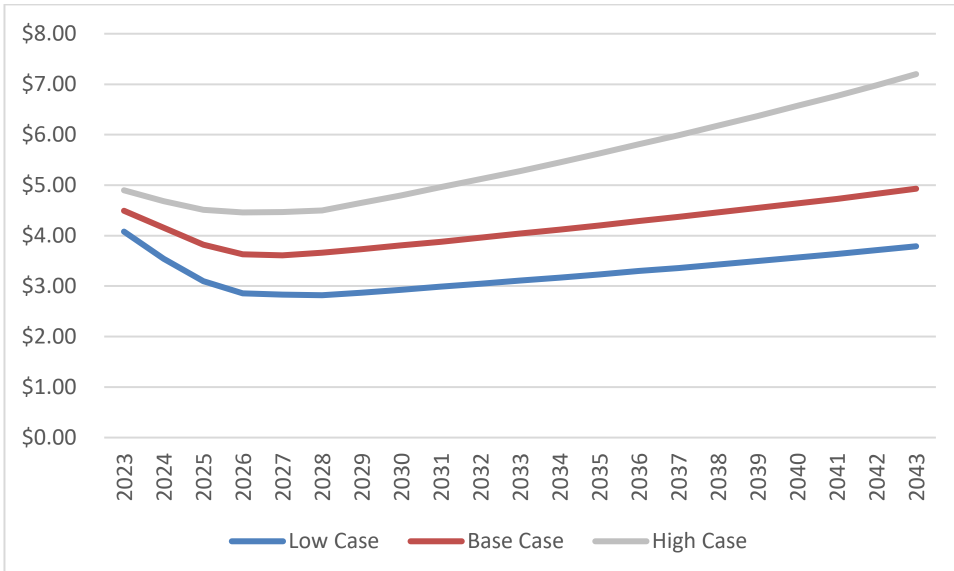
Exhibit 9 MISO Summer Peak load for Base, High and Low cases



Natural Gas Prices

Exhibit 10 illustrates the annual Henry Hub natural gas price forecast that was used for the MISO market modeling in the different cases. This pricing point was selected for the report because it reflects the most liquid pricing point for natural gas in North America. In all three cases, prices decline in the early years to reflect normalization of the market after the various supply and demand shocks related to the pandemic and geopolitical turbulence. In the base and low case, the prices remain flat in real terms – with the low case at lower levels than the base case. The high case depicts an outcome where natural gas prices do not decline as much reflecting reduced gas supply relative to demand over time.

Exhibit 10 Henry Hub Prices for Base High Low (nom $ / MMBtu)

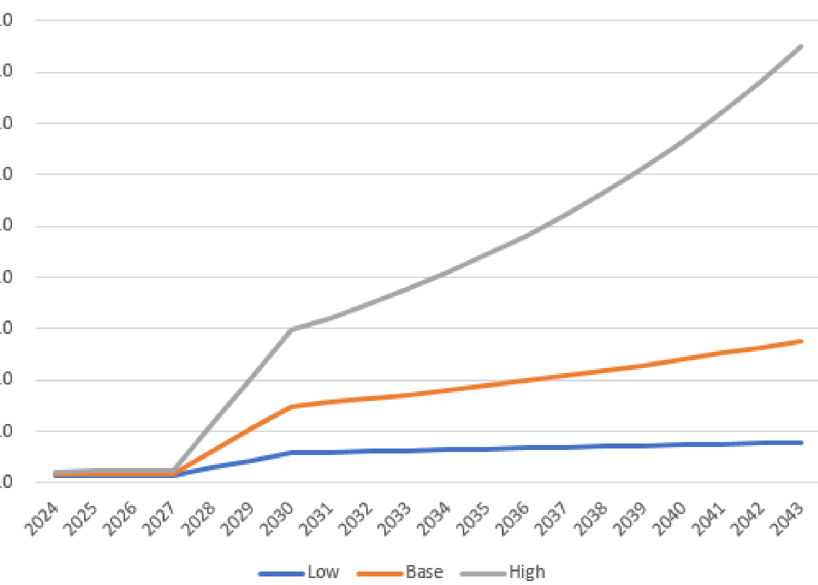


CO_2 Prices

Under the base case policymakers enact measures that put moderate pressure on the economy to reduce greenhouse gas emissions in the form of a carbon price starting in 2028. However, there is the potential that future emissions reduction policy could be more restrictive than expected and that the level of policy pressure could be materially higher, as represented in the high CO_2 price forecast used in the High Case. Under the low case scenario, policymakers enact minimal restrictions or economic disincentives on CO_2, and prices are assumed to be the lowest of the three outcomes throughout the forecast period.

The CO_2 price increases the dispatch cost of all fossil-fired units in MISO based on the modeled emissions of the unit that, in turn, is a function of each unit's heat rate and carbon content of the fuel it consumes.

Exhibit 11 CO2 Price Forecast ($2022/MT) for Base, High and Low cases



3.3. Capacity Expansion Results

CRA used the AURORA LTCE model to forecast the least-cost combination of resource additions and retirements in MISO using the assumptions for each pricing scenario. Exhibits 12 and 13 below illustrate the 2042 capacity and generation mix (respectively) across all eleven market scenarios compared with the MISO resource mix in 2023.

Exhibit 12 Comparison of Nameplate Capacity by Technology in MISO between 2023 and 2042 for all 11 cases

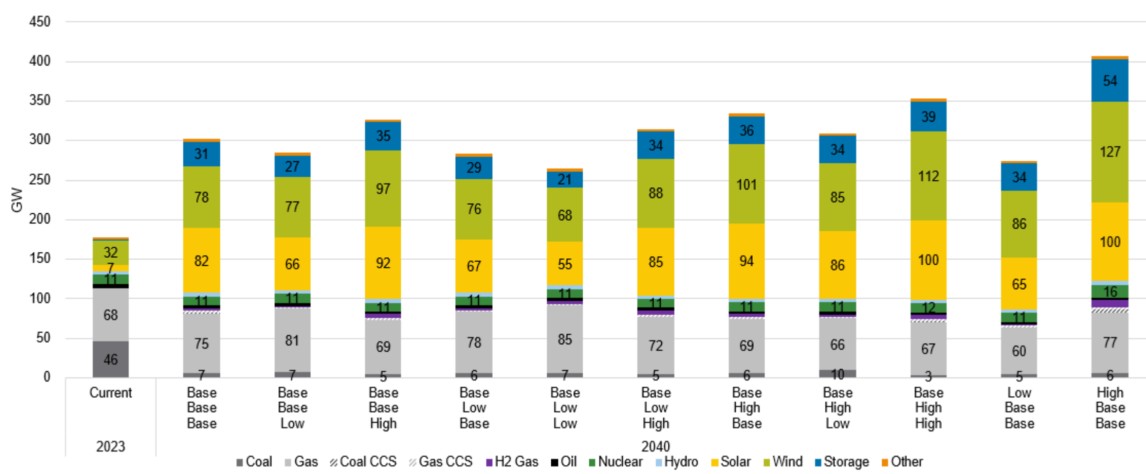
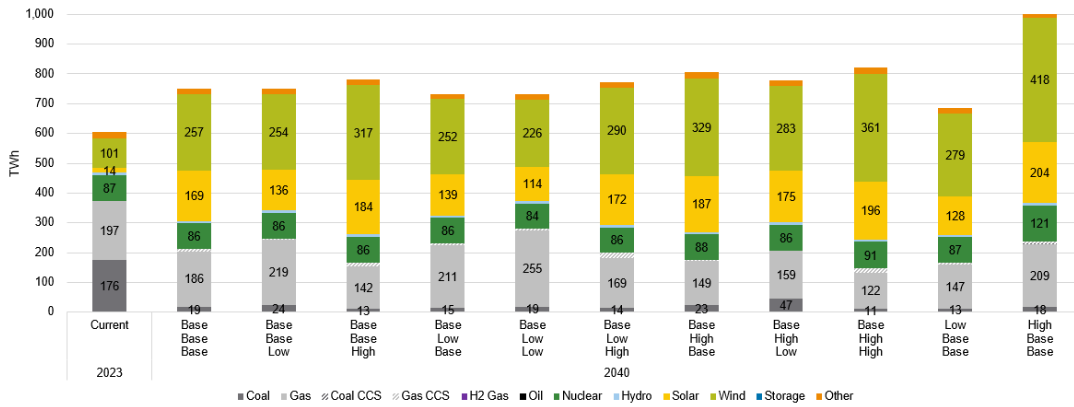


Exhibit 13 Comparison of Generation by Technology in MISO in 2042 with 2023 in Zone 5



The results that differentiated each case are:

Capacity and Generation

Future renewable entry was heavily influenced by the natural gas and carbon price inputs. Lower input prices tend to result in worse economics for renewable resources due to their nature as low-variable-cost price takers, while natural gas and coal resources are more likely to maintain their relative economics. In specific cases, the reverse occurs, where higher natural gas and carbon prices result in accommodative economic conditions for renewables, while certain less efficient natural gas and coal resources retire. Other fundamental drivers are the Inflation Reduction Act that incentivizes solar, wind, and storage entry through the realization of Production Tax Credits and Investment Tax Credits.

Overall, renewable entry directly affects the total amount of fossil-fuel capacity in the system since low variable cost resources drive traditional fossil fuel resources up the merit order making them uneconomic more frequently. Between coal and gas resources, higher gas prices tend to benefit coal generation that under those conditions remains in the market longer. Furthermore, high carbon price negatively affects the economics of coal resources, accelerating their retirement.

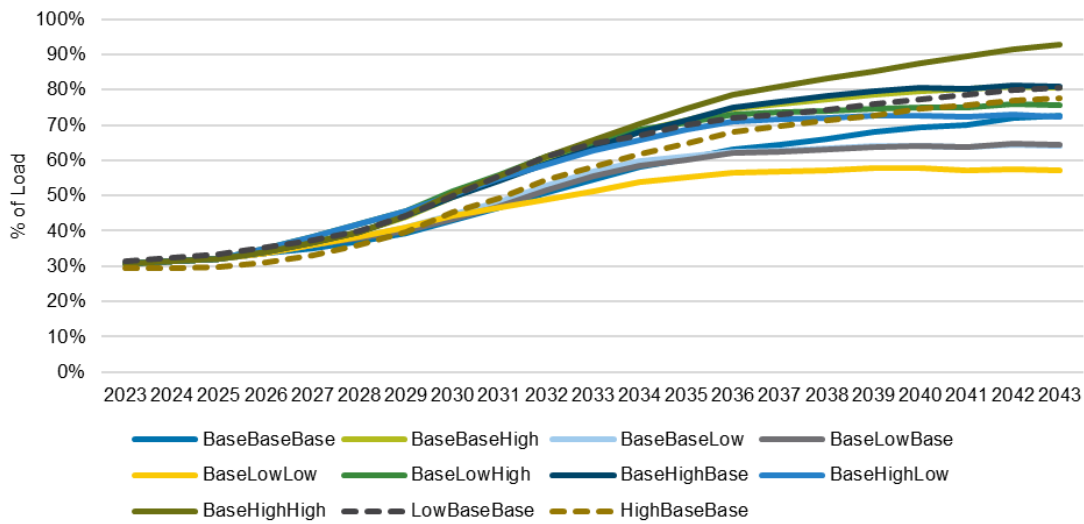
Within CRA's analytical framework, the level of natural gas and CO2 prices directly affect different levels of renewables penetration. Based on each case's assumed combination of natural gas and CO_2 prices, gas and coal resources react in a different manner. For example, in the high gas and low carbon price case, economics favor coal plants over natural gas, while in all high gas prices cases the model adds higher levels of renewables, which gradually replace existing fossil-fuel capacity.

CRA also considered other programs exogenous to the MISO market construct in this effort. For example, within Ameren's territory, CEJA's emission constraints accelerated retirements of several coal plants.

Clean Generation (% of Load) and Emissions

Clean generation as a % of load increases and emissions decline in all eleven cases. The BaseHighHigh case realizes the highest amount of clean generation as high carbon prices penalize fossil generation while high natural gas prices improve the economics of new renewable entry. On the opposite side of the spectrum, the BaseLowLow case maintains the highest amount of coal resources – due to the less punitive carbon prices – and the lowest amount of renewables – due to unfavorable economics from the assumed low gas prices.

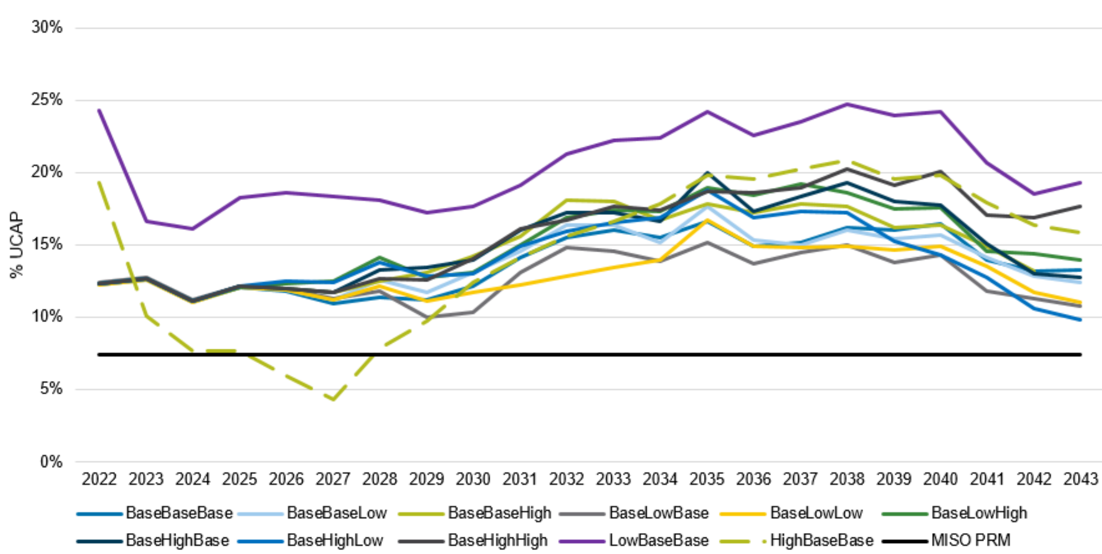
Exhibit 14 Clean Generation as % of MISO Load



Reserve Margins

Reserve margins alter based on produced capacity results for each case. In general, reserve margins are maintained above the MISO PRM (specifically 7.4% for summer and 25.5% for winter). The HighBaseBase Case is the only one that experiences a low RM in the short term due to the aggressive load growth and the slow replacement of exiting high peak credit capacity with renewables with lower accredited capacity value.

Exhibit 15 MISO Summer Reserve Margin for all cases

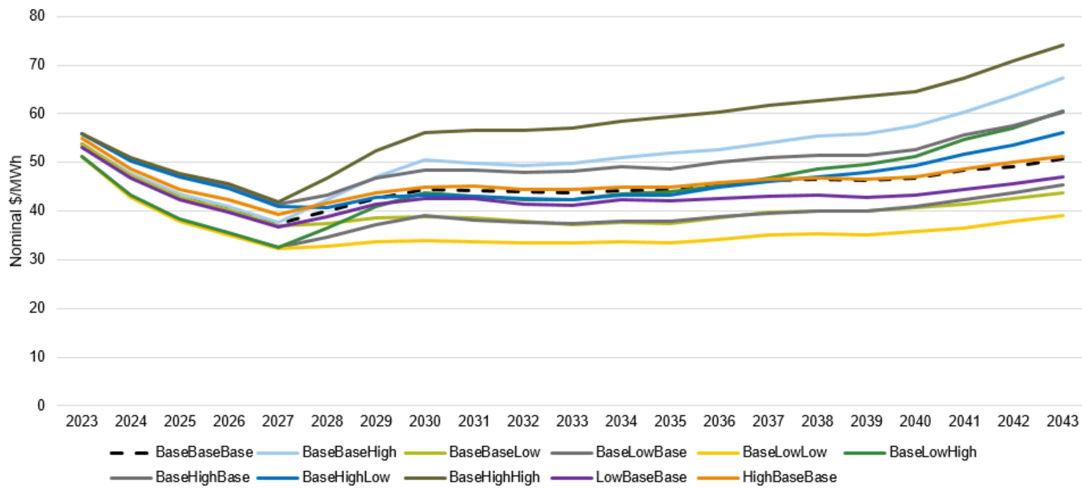


3.4. Energy Market Price Results

The key market outputs from the scenario modeling process are the power prices illustrated below in Exhibit 16. Shown are all eleven market scenarios modeled as input to the 2023

Ameren IRP. The exhibit illustrates the wide but plausible range of energy prices that emerge from the scenario modeling that were used to develop and select the preferred plan.

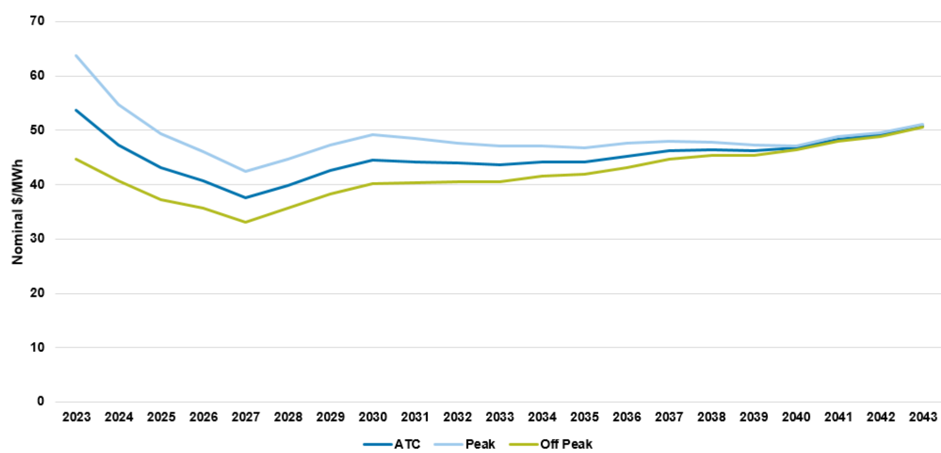
Exhibit 16 Annual Around the Clock MISO Zone 5 Electricity Price ($nom/MWh)



Power prices (nominal$) range from an upper boundary of $70/MWh in the BaseHighHigh case to the lower one represented by prices around mid-$30s/MWh in the BaseLowLow case.

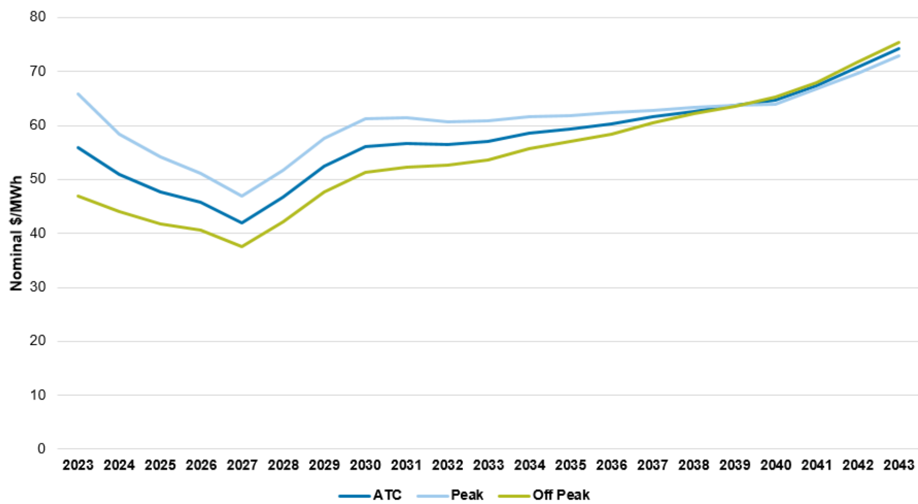
- The cases also experience a peak/off-peak price convergence, as illustrated in Exhibit 17, which shows the MISO Z5 price outlook for the BaseBaseBase case. With high levels of renewables and storage added to the system, the prices in the BaseBaseBase case completely converge by 2040.

Exhibit 17 Base Base Base Zone 5 Energy Prices ($/MWh)



- For the BaseHighHigh case depicted in Exhibit 18, the off-peak is higher than the peak price in the late 2030s. With higher NG price and CO2 price, hours where fossil resources are marginal begin to have greater impacts on pricing – especially in the off-peak hours where no solar is available. This phenomenon is already taking place in places like California, where the region has experienced a significant entry of solar and storage resources lately.

Exhibit 18 Base High High MISO Zone 5 Energy Prices ($/MWh)



- On the load varying cases (HBB and LBB), prices have not diverged from the BaseBaseBase case significantly. In general, lower load depresses prices while higher load enables greater prices spikes, assuming everything else remains constant. However, once the system rebalances with enough supply and the marginal resources remain similar, the impact on prices becomes more subtle over time.

As briefly described above, on- and off-peak prices converge over time. In other words, on peak prices generally remain flat-to-declining over time, while the off-peak prices increase at a much faster rate. Exhibit 19, Exhibit 20 and Exhibit 21 below provide additional details around how the energy prices, system demand and generation evolve over time. In summary, the following factors contribute to the pricing convergence indicated above:

- On the supply side, renewable generation and storage penetration increase over time. The increase in output by these resources, decrease system net loads[4] across all seasons, with the spring and fall seasons experiencing the largest decline. In terms of generation, on average the output from these resources is the highest during the traditional peak periods, e.g. 8 am to 5 pm, although output from wind and storage still increase considerably during the rest hours.
- On the demand side, the system net load generally declines due to the increase of renewable generation. Net load flattens and on average – over time - exhibits lower demand requirements during daytime across all seasons. Particularly during spring, the system net demand is projected to drop significantly. Also, with lower net system demand during these periods, the system can rely on more efficient units and hence realize lower system LMPs.
- The combination of increasing zero- or low-operating-cost supply and declining net system requirements over time during the day places significant downward pressure on prices, leading to flat to declining on-peak LMPs in CRA's projection.
- During off-peak periods, system net loads decline over time, but coupled with aggressive fossil fuel retirements, system LMPs continue to be set by more

[4] Net load is defined as gross load net of renewables and storage output

expensive resources in the system. With increasing natural gas and CO2 prices, LMPs during the off-peak period increase at a faster rate over time.

Exhibit 19 Average Hourly Price by Season in 2030 and 2040

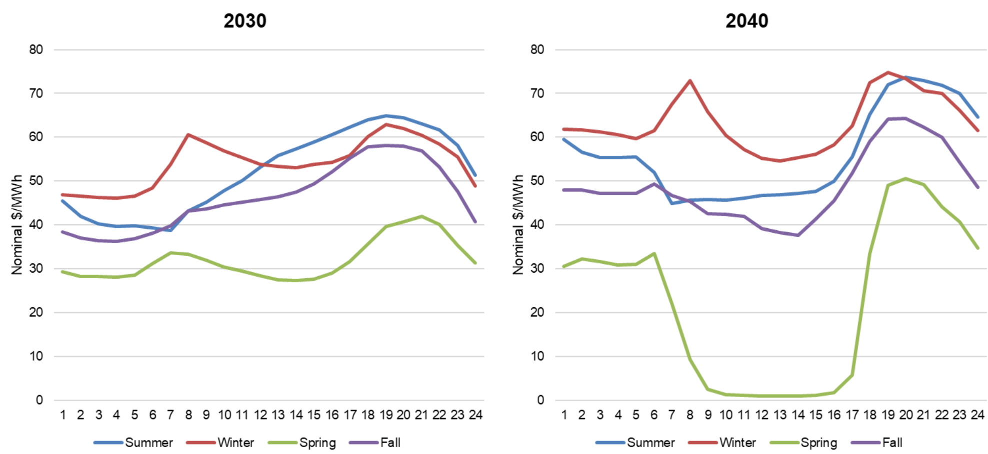
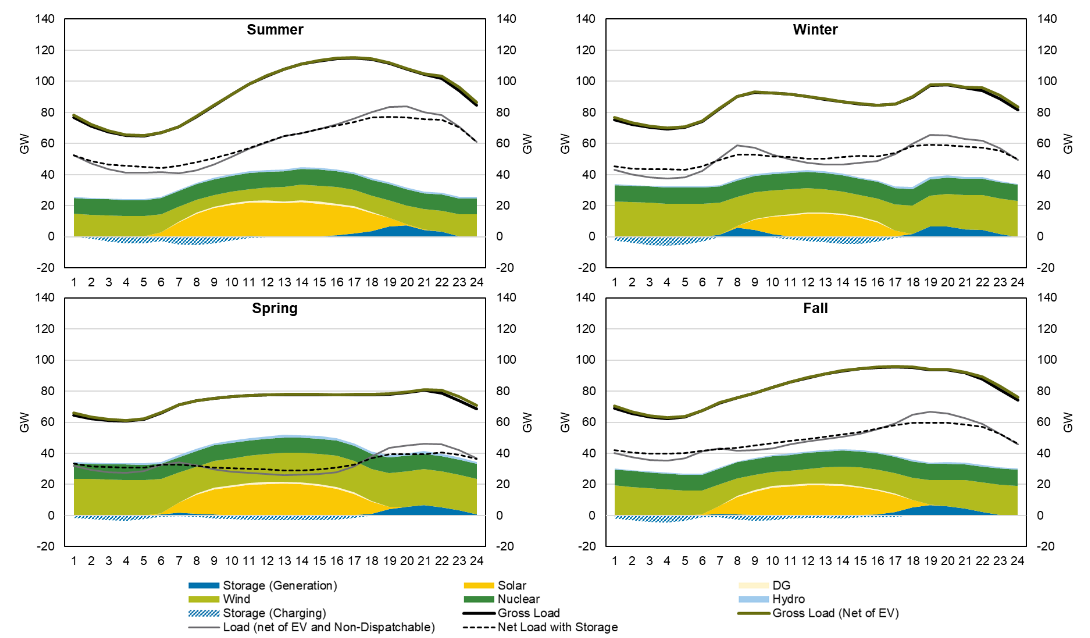
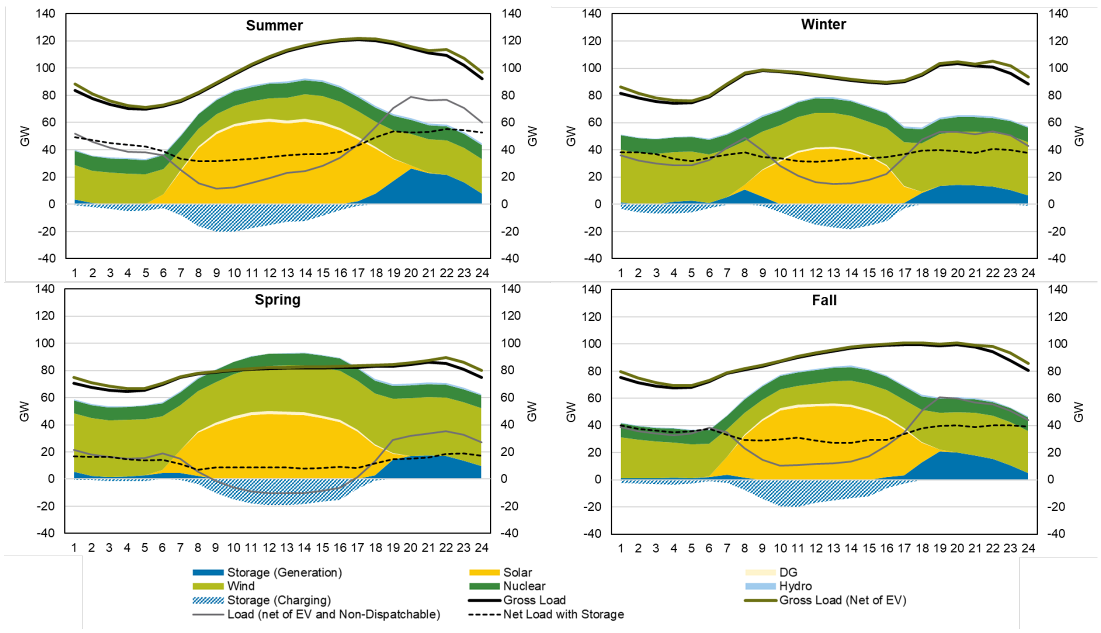


Exhibit 20:2030 Average Hourly Load and Generation Profiles[5]



[5] Net Load with Storage = Gross Load (Net of EV) – Solar – Wind – Nuclear – Hydro – Storage

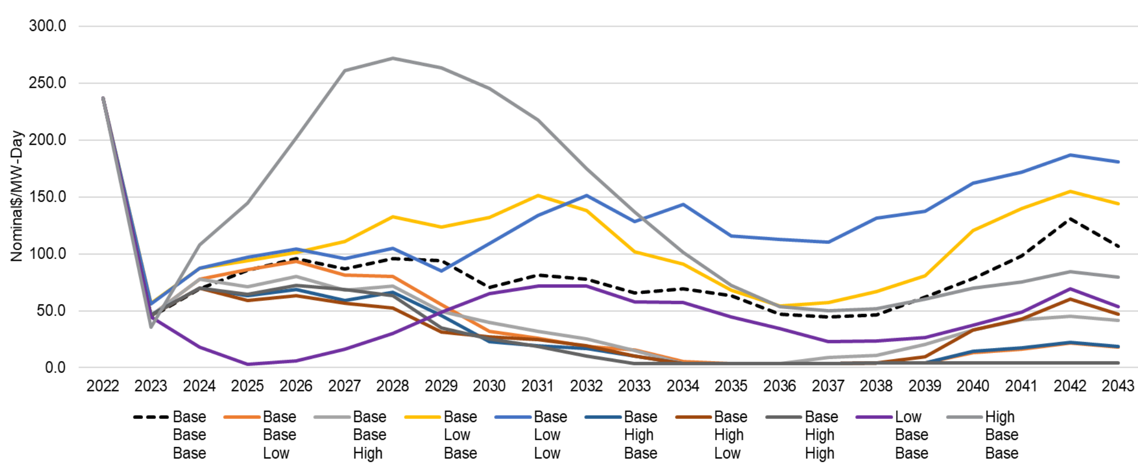
Exhibit 21: 2040 Average Hourly Load and Generation Profiles



3.5. MISO Capacity Market Price Results

In addition to the energy market, MISO also operates a capacity market that procures capacity on a seasonal basis. The capacity market is based on an administratively set demand requirement and supply offers from market participants that are willing to sell capacity. The exhibit below depicts CRA's MISO's capacity market projections for nine modeled cases. Note that the cases are described by how the three different variables are modified. For example, BaseBaseBase signifies a case that incorporates Base Load, Base Gas and Base Carbon price projections.

Exhibit 22 MISO North Seasonal Capacity Price Outlook - Annual Average in Nominal $/MW-Day



For the BaseBaseBase (BBB) case, following the recent price spike in the 2022-23 auction, CRA expects tight supply market conditions over the next couple years with the market reacting to the higher prices by delaying retirements, imports might recover, and PRM reduces to 7.4%. In the near-term, new entry remains limited and continued fossil retirements are planned. Into the late 2020s and early 2030s, IRA-related new entry and replacement capacity continue to expand and CRA expects capacity prices to trend down. Over the long term, prices remain in the $60-100/MW-day range, reflecting an average balance necessary to maintain existing resources and procure new resources.

Winter prices are on par with fall for the most part over the near-term, even though prices in the winter do not clear at CONE. In the 2020-21 and 2021-22 winter assessment reports published by MISO, winter reserve margins were projected to stay in the 40% range a year or two prior to 2022. However, there is likely a case for higher-than-normal outages going forward especially given the winter storms that happened in 2021 and 2022.

- BBL, similar to above, is projected to remain high over the near term, where continued fossil retirements drive system tightness. Over time, due to a lack of carbon pressure, capacity requirements from high carbon emitting resources are relatively relieved. Prices trend to a lower level, as aging facilities are timely replaced by new intermittent resources.
- The near-term prices in the BBH scenario are expected to remain elevated following the recent price spike and the ongoing planned retirements. The high CO2 prices provide enough incentive for new renewables and storage capacity to enter the market and to fully displace existing units. The price downward from the current high through mid-2030s until the eventual fossil retirements require more capacity. However, on average the price level is not significant compared to today's level.
- In the BLB case, the combination of low NG and base carbon pressure results in early coal retirements. Moderate energy prices in this case do not provide enough economic benefits for renewables replacements. As a result, capacity prices in this case remain elevated throughout the forecast period.
- The BLL case is similar to the BLB case because low natural gas prices continue to pressure existing coal facilities towards early retirement. Throughout the forecast period, lower renewables entry compared to the BBB case and generally more stringent environmental regulations create unfavorable conditions for new gas entry. Under this environment, the combination of accelerated coal retirements, higher capacity requirements, and lower renewables entry contribute to persistently high capacity prices with new gas entry gradually replacing part of the fossil fleet.
- BHB, BHL, and BHH cases are projected to have similar capacity requirements, as strong energy market performance provides adequate pricing signals to aggressively replace existing fossil fuel capacity with new entry resources – especially new renewables and storage - timely and efficiently.
- Across all scenarios, BBB's capacity prices are in the middle, whereas BBL and BBH are on the lower end due to stronger prospects for new builds. BLB and BLL are on the higher end because of deteriorating coal resource economics, accelerated retirements, and overall weaker prospects for new replacements.

In addition to the main nine cases, CRA also performed two additional sensitivities that evaluate the high and low load forecast projections. The LowBaseBase (LBB) case evaluates the impacts of lower load forecast compared to the Base case, while the HighBaseBase (HBB) case evaluates the impacts of higher load than the Base.

- Compared to the BBB Case, the LBB case capacity prices are lower, primarily driven by flat-to-declining peak load over time. The lower load not only makes the emissions goal more achievable, but also leads to less pressure in terms of having to meet additional peak requirements with resources that have lower peak values.

- In contrast with the LBB case, the prices in the HBB are higher than the BBB. With winter peak load growing by 3 GW per year over the next 20 years, significant risks center around the winter season. While capacity prices likely remain high over the near term, winter remains the period at risk throughout the study period.

4. MISO Ancillary Services Analysis

MISO has operated an Ancillary Services (AS) Market for regulation and contingency Reserves since 2009. Currently, MISO procures ancillary services in the Day Ahead and Real Time markets, which are simultaneously co-optimized with its energy market. MISO's contingency reserve consists of two separate products for Spinning Reserves and Supplemental (Non-spinning) Reserves.

Spinning Reserves can be provided by either generation resources or demand-side resources and must be synchronized to the grid and able to dispatch energy within ten minutes of receiving an instruction to do so. There is a fixed requirement of around 1000 MW for Spinning Reserves. Supplemental Reserves are also provided by qualified generation and demand side resources, but these resources do not need to be synchronized to the grid but must be able to start up and adjust output within ten minutes of receiving a dispatch signal from the MISO. There is a fixed requirement of around 1000 MW for Supplemental Reserves. [6]

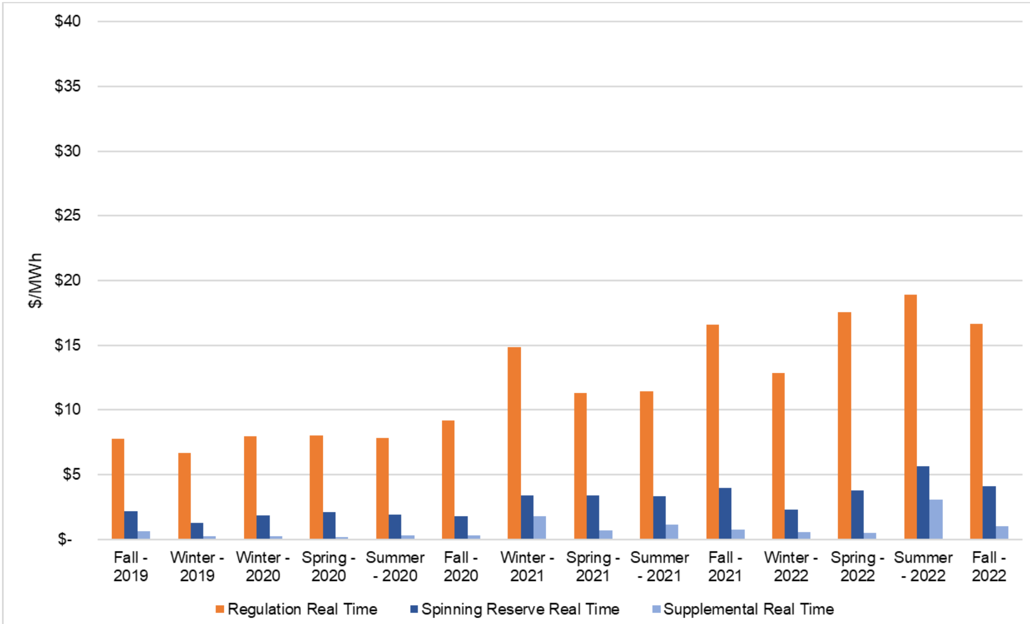
Regulation reserves generation-based resources and stored energy resources. These resources must be able to adjust their output in response to automatic signals within five minutes of receiving a signal to do so. MISO has only a single product for Regulation Reserves applied across all zones with a requirement that varies between 300 MW and 500 MW, depending on system conditions. This requirement is not based explicitly on NERC standards, but rather on operational experience.

Lastly, MISO has recently implemented a 30 min short term reserve product that seeks to procure online or offline resources that can provide incremental energy within 30 minutes. The product separately addresses market-wide, sub-regional and local short-term needs. The market wide short term 30-minute requirement is set at 1.5 times the largest generator contingency.

Price for ancillary services have remained between $7-20/MWh on average for regulation and $1-8/MWh on average of the operating reserves.

6 https://www.ercot.com/files/docs/2019/09/18/4._MISO_Energy_and_Ancillary_Service_Co-optimization_091819.pdf

Exhibit 23 Average Regulation, Spinning and Supplemental Reserve Prices($nom/MWh) (2019-22)



Notably, due to the nature of these markets, hourly prices can reflect short but very lucrative in value time periods, when the system is under duress. As depicted in the table below, summer and winter seasons tend to experience higher maximum prices than fall and spring, when historically the system has experienced less periods of reserve shortages.

Exhibit 24 Ancillary Prices Historical Descriptive Analytics

Regulation Prices				
	Average Price $/MWh	Max Price $/MWh	Min Price $/MWh	StdDev of Price $/MWh
Fall	$12.40	$373.17	$1.62	$10.09
Spring	$12.39	$214.64	$1.39	$5.97
Summer	$12.76	$941.76	$1.63	$7.35
Winter	$11.23	$492.09	$1.32	$5.99

Spinning Prices				
	Average Price $/MWh	Max Price $/MWh	Min Price $/MWh	StdDev of Price $/MWh
Fall	$2.96	$324.22	$0.00	$7.71
Spring	$3.25	$205.85	$0.04	$4.73
Summer	$3.75	$851.51	$0.00	$6.40
Winter	$2.46	$434.63	$0.00	$4.71

Supplemental Prices				
	Average Price $/MWh	Max Price $/MWh	Min Price $/MWh	StdDev of Price $/MWh
Fall	$0.50	$275.15	$0.00	$5.70
Spring	$0.37	$188.47	$0.03	$3.18
Summer	$1.20	$801.29	$0.00	$4.99
Winter	$0.79	$434.63	$0.00	$3.48

4.1. Ancillary Services Market Value Estimate

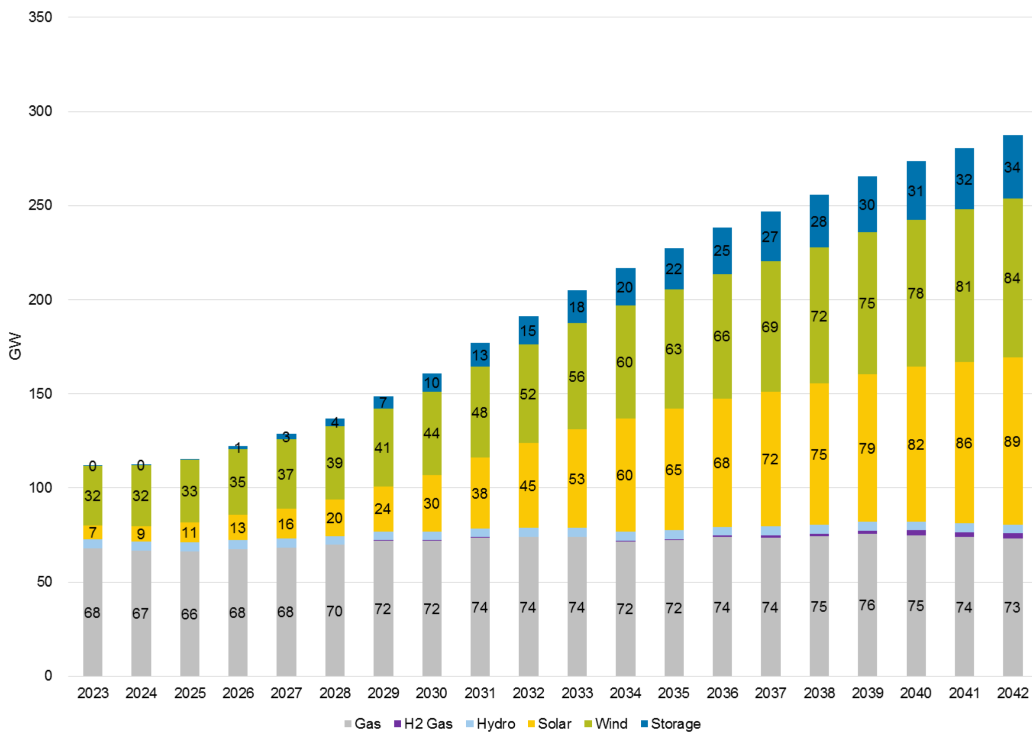
As mentioned above, the AS markets are quite shallow (roughly 300-500 MW for regulation and around 2 GW for combined operating reserves) at consistent historical levels for prices and total revenues. Although the requirements for such services have remained static in the past, the expected changes in MISO's resource mix with the significant influx of intermittent resources and energy storage and the eventual exit of traditional dispatchable resources will likely affect the structure of the ancillary services market and as a result its pricing and potential value. In addition, expected changes on the demand side – enhancements on load dispatchability – combined with more frequent occurrences of high impactful stressed system events will also have an impact on the need for ancillary services in the future.

Various studies[7] have examined how the wholesale energy and ancillary services markets will be affected by the influx of energy storage and renewable generation together with more frequent system stressed conditions. The studies identified the need for ISOs and market participants to think about the changing system in a holistic manner (energy, capacity and ancillary services). For example, one of the findings was an interesting interaction between the ancillary and energy markets. Baseload resources (including coal and natural gas combined cycle) that participate in both the energy and reserve markets shift capacity towards generating, when the renewable production does not match the expected output thereby reducing their reserves. Because these plants are cheaper to operate than peaking capacity, this behavior reduces the market price below peaking resource marginal costs, thereby requiring more uplift which is inefficient for the market. Various ISOs have tried to mitigate this inefficiency by establishing ramping products that compensate resources on a competitive basis for such instances. Although early, similar market reforms will be more common in the future.

Since the effect on the Ancillary Services requirements from the system and market participation changes is difficult to estimate without a more detailed study, CRA focused on the ancillary services supply over time to determine how the AS market may behave. The expected build of the BaseBaseBase case provides a reasonable outlook on the amount of the resources that mostly affect the ancillary services construct – both on the demand and supply side.

[7] Penn State Study

Exhibit 25 BaseBaseBase Capacity Mix over the study period (GW)



As depicted in the graph, more than 30 GW of new storage is expected to enter the market over the study period. Although AS markets currently provide a premium to wholesale energy markets in many hours, as more storage is brought into the region, which is very effective at providing these services, it is expected that the A/S market value will be negatively affected. However, as mentioned above, the demand for A/S is expected to increase due to the proliferation of renewables and more frequent system disturbances. MISO and CAISO have established ramping products with the expectation that the demand for these services will increase over time.

Therefore, for this analysis, it is reasonable to assume that total margin compensation of flexible, dispatchable resources, whether that be from sales of energy or sales of ancillary services, is expected to be similar to total margin compensation total margin compensation were these resources to dispatch only for energy.

Chapter 10 - Appendix D

Other Implementation Analysis

10D.1 Gas Price Volatility Analysis

Introduction

To assess potential impacts of gas price volatility during extreme weather events, Ameren Missouri has analyzed the potential costs to customers that may result from an extreme winter weather event similar to those seen in the past couple of years.[1] The evaluation includes two key aspects:

- An evaluation of the feasibility and cost of fully firm gas supply contracts for existing and planned gas plants.
- An evaluation of rate and bill impacts to customers, taking into account any reduction in the risk of gas price volatility due to existing futures contracts.

The Company assessed these two key aspects separately for existing and planned simple cycle natural gas combustion turbine generators (CTG) and planned combined cycle natural gas combustion turbine generators (NGCC or CC)

Feasibility and Cost of Firm Gas Supply Contracts - CTG

For CTGs, Ameren Missouri concludes that 'fully firm gas supply contracts' is not a feasible option. Assuming that each pipeline has, or could develop, enough Firm Transportation (FT) capacity to supply our CTG fleet, there are other pipeline tariff restrictions that conflict with Midcontinent Independent System Operator (MISO) utilization of our CTG fleet during extreme winter weather events. During extreme winter weather events, we typically see the pipelines take the following actions:

1. Curtail all schedules utilizing Interruptible Transport (IT).
2. Require all shippers to adhere to tariff provisions requiring ratable flows.

The ratability provision generally requires Ameren Missouri's CTGs to be made unavailable. Even on critical winter days, MISO does not commit our CTG fleet for a full 24-hour operation. Generally, MISO would prefer to commit the CTG fleet for winter morning and evening peaks. Since this gas flow would conflict with the pipeline's ratability requirements, the CTGs become unavailable. As a result, they are immune to natural gas price volatility because they simply would not operate.

[1] Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022.

One exception is for any existing or planned CTGs that are capable of firing on dual fuels. During critical winter weather events, any CTGs capable of firing on fuel-oil will remain available to MISO. Since the fuel-oil will have been previously bought and stored in tanks onsite, the units should not be exposed to any fuel-oil price volatility during the weather event in this case, either. However, such units could benefit from any related increase in the market price arising from volatile natural gas prices. This value has not been included in the customer rate impact calculations.

Feasibility and Cost of Firm Gas Supply Contracts - NGCC

The NGCC project differs from the CTG fleet, in that it would have 'fully firm gas supply contracts'. The fuel arrangements for the CC would be to have pipeline FT contracts back to a major supply basin. Assuming Ameren Missouri's preferred location for a new NGCC project is at Sioux Energy Center, this means Ameren Missouri would contract for FT on Spire STL, and for FT on Rockies Express (REX) back to a supply basin.

With this firm pipeline transport investment, Ameren Missouri would also seek to source firm natural gas supply. A logical approach would be to buy monthly baseload gas for an amount equivalent to the expected capacity factor for the NGCC units. In a winter month, it is prudent to assume that the CC would have a modeled 70% capacity factor. With the CC assumed to be a 1,200 MW unit, the site could potentially consume 185,000 MMBtu/day – based on reasonable heat rate expectations.

If baseload gas purchases match expected capacity factors, then Ameren Missouri would have bought 70% of the 185,000 daily max requirements at the stable monthly gas price, thus avoiding the daily price volatility of the extreme weather event. However, Ameren Missouri would be exposed to the volatile daily gas price for 30% of that daily 185,000 volume, or 55,500 MMBtu per day. Looking to Winter storms Uri and Elliott, each storm had an approximate 5-day impact. 55,500 MMBtu/day times 5 days equals, 277,500 MMBtu with volatile price exposure.

Volatility of gas prices: During Winter storm Uri and Elliott, the highest reported daily gas price for REX zone 4 was $65/MMBtu. This was escalated from what was normally a $3 gas price pre-storm.

Customer Rate Impact - NGCC

For purposes of calculating potential rate impact, Ameren Missouri has assumed that any differences in net fuel cost are recovered through the Company's fuel adjustment clause (FAC), including application of the existing 95/5 sharing mechanism by which customers incur 95% of any changes in net fuel cost. For purposes of determining market revenue for generation, Ameren Missouri has assumed normal operation of the NGCC unit in the MISO market, including application of the make-whole provisions of the MISO Energy and Ancillary market. It was also assumed that the Company has the opportunity to buy gas on a daily basis. This means that the Company would not buy daily gas for first two days of the weather event. Note that if the NGCC unit does not clear on Day 1 and 2, then the Company would have the opportunity to arbitrage the $3 baseload gas that was bought in advance by selling it into the $65 daily gas market. This potential sales revenue has not been included.

Based on the assumptions described above, the analysis shows that incremental fuel costs borne by customers would be approximately $9.4 million, and incremental market revenues of $18.9 million would be credited to customers. The net impact to customers would thus be a net benefit of $9.5 million.

10D.2 Battery Storage at Retired Coal Generation Sites

Introduction

Ameren Missouri completed a preliminary review of the Meramec and Rush Island Energy Centers to determine the amount of battery storage each site could support based on available acreage, and to estimate the potential costs associated with said installation. Separately, the Company also completed preliminary modeling for a 200 MW lithium-ion storage facility, which reflects the likely size of a battery energy storage system (BESS) that could be placed at either Meramec or Rush Island prior to 2030 based on system resource and reliability needs. The modeling estimates expected rate base, revenue requirement, tax credit value, and levelized cost of storage for two lithium-ion battery chemistries under four different Inflation Reduction Act tax incentive scenarios:

1. No Investment Tax Credit
2. Investment Tax Credit
3. Investment Tax Credit with Energy Community Adder
4. Investment Tax Credit with Energy Community Adder and Loan Program Office Loan Benefit

At this time, Ameren Missouri expects that a BESS located at either Meramec or Rush Island would qualify for the investment tax credit with the energy community adder (scenario 3). Please note that current modeling does not include expected market revenues for the BESS installations and is not reflective of the full costs to complete a BESS installation (such as demolition costs for existing structures, interconnection upgrades, and internal and external project development costs). Such revenues and more complete cost estimates will be incorporated into future modeling iterations.

The opportunity to utilize retired coal power plant sites for battery energy storage systems (BESS) was examined. The goal of this preliminary analysis was to determine the amount of battery storage each site can support based on available acreage, and estimate the potential costs associated with said installation. This assessment was a very preliminary review, and therefore, the data and conclusions included in this discussion should not be used for decision-making purposes. Further detailed studies are required before proceeding with specific BESS projects. This document serves as a brief overview of our findings.

Assumptions

In the assessment, several foundational assumptions were made. It was presumed that all existing buildings, water treatment facilities, storage spaces, and generators currently existing at the sites would be demolished. New power lines and step-up transformers would be needed in addition to the new battery systems. With respect to the physical layout at each site, we made use of satellite maps to avoid existing ash ponds and other obstacles. Although a formal civil review has not been performed to determine the precise boundaries of these ash ponds and other potential obstructions, we stayed within the white boundaries indicated by the satellite maps.

As this is a high-level evaluation of these sites, there are many aspects that were not considered and would need further investigation prior to project approval and initiation. These items include, but are not limited to permitting, flood plain mitigation, internal costs, market data, interconnection upgrades, MISO filings, detailed engineering studies, raw material pricing, supply chain impacts, and other risks associated with BESS projects. Therefore, the layouts and pricing are only for preliminary evaluation purposes as Ameren continues to explore locations for BESS projects.

Pricing

Pricing information was developed in a 2023 Roland Berger study performed in collaboration with Ameren, which evaluated industry-wide BESS project costs covering several battery technologies. In addition, pricing information was provided by Florida Power & Light (FPL) for their Manatee battery storage site, which went online in 2021. It is worth noting that FPL utilized nickel manganese cobalt (NMC) batteries, but lithium iron phosphate (LFP) batteries are the most likely candidate for future battery storage projects. The FPL Manatee project data offered insights into real-world pricing, inverter size, battery capacity, and other relevant details. Leveraging this, we crafted our own battery layout blocks to create a standardized footprint and pricing based on our own substation design standards. The data from FPL aligned closely with figures from a budgetary quote by an equipment supplier, NREL data, and the Roland Berger data in terms of $/kWh and MWh/acre. We settled on the most recent LFP cost estimate developed by Roland Berger of $279/kWh, as illustrated below in Table 10D.1.

Site Layout

For the layout configuration, we adopted the same container size as employed by FPL. However, our assumed container spacing adheres to the standards set by Ameren

Missouri Substation Design. We aimed for a 4-hour battery system and consequently designed 81.6MW/326.4MWh blocks to be mapped onto satellite imagery at each specific location. This configuration results in a density of 61.8MWh/acre (calculated from 326.4MWh divided by 5.28 acres per block). This density surpasses FPL's specification of 48MWh/acre. This increase is attributed to advances in equipment sizing and enhancements in battery containerization but may not be achievable in a real-world project due to other siting considerations as mentioned above. While assumed placement avoided ash ponds, we did assume placement of equipment over the locations of existing structures, as these would be slated for demolition.

Site-Specific Considerations

At the Meramec and Rush Island sites, there would be required interconnection upgrades. Actual interconnection requirements would be determined upon completion of a MISO interconnection study. For Rush Island, we limited the addition of battery systems during the layout phase even though there is still usable acreage, as the available land is of such great size that it would not be reasonable to fill the available land with additional batteries. Neither site was evaluated for flood exposure, which could greatly impact the design or available space.

Results and Conclusion

Table 10.D1 below summarizes the results of the assessment, including detailing the maximum sizing and associated costs developed. This assessment provides an overview of the possibilities of repurposing the Meramec and Rush Island Energy Centers for battery energy storage. The data and conclusions included below should not be used for decision-making purposes, and further detailed studies are required before proceeding with specific BESS projects.

Table 10D.1 Forecasted Potential Solar Resources (2025$)

Point of Interconnection	**Meramec**	**Rush Island**
Interconnection Voltage	138 kV	345 kV
Acreage Available (avoiding coal ash)	86 acres	127 acres
Design MWh	979 MW - 3,917 MWh	1,142 MW - 4,570 MWh
Design Cost (Million $) ($279/kWh)	$1,093	$1,275