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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EA-2023-0286

SURREBUTTAL TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
December, 2023

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I. TABLE OF CONTENTS

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matt 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 Director of Corporate Analysis. In that capacity, I provide services to Ameren Corporation's operating subsidiaries, including Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company").

Q. Are you the same Matt 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 responding to the rebuttal testimony of certain Staff witnesses regarding the Company's analysis of the need for and economics of the solar projects ("Projects") for which the Company is seeking certificates of convenience and necessity ("CCN") in this case. Specifically, I will respond to various criticisms of the Company's analysis as described in the rebuttal testimonies of Staff Witnesses Michael Stahlman, Shawn Lange, Brad Fortson, J Luebbert, and Sarah Lange as well as the alternative view of resource planning decision making set forth in the rebuttal testimony of these witnesses.

Q. Please summarize your surrebuttal testimony.

A. The Missouri Public Service Commission ("Commission") has established a rigorous and time-tested framework for utility Integrated Resource Planning ("IRP") in the state of Missouri. Ameren Missouri has used and relied on this IRP framework for its resource decisions, with the Commission regularly finding that the Company's IRP process substantially complies with the requirements of the Commission's IRP rules. Staff seeks not only to undermine this framework, but to supplant it with a process of its own design that has largely if not entirely been manufactured as an apparent means to oppose the Projects, a process that takes Missouri backward to the times before IRP, when resource decisions were myopically focused on "what's next?" I will demonstrate in my surrebuttal testimony how this is so and why it is inappropriate, including important context regarding the history of utility planning and IRP. I will demonstrate that the Company's IRP process provides an appropriate basis for its resource requests, including the requests regarding the Projects. I will also demonstrate why Staff is wrong about the Company's case for the need for the Projects and the consistency in the conclusions of the Company's analysis supporting that need. As part of that, I will refute numerous errors and misconceptions contained in the testimony of the Staff witnesses mentioned above. Among these are Staff's (demonstrably inaccurate) assertions that:

- The Company has not updated its analysis to account for higher project costs (it has).[1]
- The Company has not updated its analysis to account for tax credit provisions of the IRA (it has).[2]
- The Company has limited its consideration of renewable resources only to the timeframe in which tax credits are available (it hasn't).[3]
- The Company has included in its IRP analysis, alternative resources plans ("ARP"), and preferred resource plan ("PRP"), resources that are not needed to ensure reliable and affordable service to customers (it hasn't).[3]
- The Company has not updated its analysis to account for changes in resource accreditation (it has).[4]
- The Midcontinent Independent System Operator ("MISO") market functions as a limitless resource to meet utility resource needs (it doesn't).[5]
- Explicitly modeling a carbon cap regime would yield materially different conclusions than using a price on carbon (it wouldn't).[6]
- The very same model and kind of modeling performed by MISO for granular reliability analysis is inappropriate for evaluating reliability contributions of new resources on Ameren Missouri's system (it's not).[7]

[1] J Luebbert Rebuttal Testimony, p. 15.
[2] J Luebbert Rebuttal Testimony, pp.14-15.
[3] J Luebbert Rebuttal Testimony, p. 9.
[4] J Luebbert Rebuttal Testimony, p. 17.
[5] Shawn Lange Rebuttal Testimony, p. 7.
[6] Shawn Lange Rebuttal Testimony, pp. 10-13. J Luebbert Rebuttal Testimony, pp. 17-18.
[7] Sarah Lange Rebuttal Testimony, pp. 67-69.

- The Company can rely on peaking gas units that were designed and permitted for limited operation to meet frequent and long-duration energy needs (it can't).[8]
- Assumed long-term convergence of on-peak and off-peak pricing is an indication of a model error rather than a logical conclusion of the operation of storage resources in MISO (it's not).[9]
- The Company inappropriately relies on MISO's analyses (through and with the cooperation of its member transmission owners) to address needs for voltage support, VAR support, frequency support and other system reliability and resiliency needs (it *is* appropriate).[10]

In addition, Staff raises several red herrings regarding potential "duck curve" issues,[11] the Company's consideration of the potential retirement of its Rush Island Energy Center ("RIEC"),[12] a nonsensical theory purporting to demonstrate the inappropriateness of the use of net present value revenue requirements ("NPVRR") for utility economic analysis of resource additions,[13] and the supposed need for highly granular, one-sided economic analysis of the Projects in isolation as though they are merchant facilities.[14]

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[8] Shawn Lange Rebuttal Testimony, p. 5.
[9] Michael Stahlman Rebuttal Testimony pp. 13-14.
[10] Shawn Lange Rebuttal Testimony, pp. 22-23.
[11] Michael Stahlman Rebuttal Testimony, pp.11-13.
[12] Brad Fortson Rebuttal Testimony, pp. 15-18.
[13] Sarah Lange Rebuttal Testimony, pp. 23-24.
[14] While Ms. Lange Rebuttal Testimony does not explicitly say so, her "ratepayer value" theme throughout much of her rebuttal testimony in effect equates to a decision-making approach that a merchant generator would take, that is, no merchant would build new generation unless from the merchant's perspective it was expected that the generation would always "pay for itself," i.e., generate profits. As Company witness Wills discusses in his surrebuttal testimony, this has never been the test for resources needed to discharge a public utility's obligation to serve -- ratepayers value reliable service -- they don't expect to get that service for free.

III. HISTORY, PURPOSE, AND ROLE OF IRP

Q. How is the history of utility resource planning important to this case?

A. To be brief, the history of utility resource planning is important because it contains the lessons learned over decades that culminated in the use of IRP for utility resource decision making, including the resource planning framework established by the Commission's IRP rules for investor-owned utilities in Missouri. Among those key lessons are the need to perform analysis at a level that allows for the consideration of many options, the need to examine a sufficiently long timeline (typically 15-20 years) to consider long-term implications of multiple resource decisions made over time, and to consider ranges of assumptions for key variables that could influence resource decisions over the planning horizon.

Q. Please provide a brief history of utility resource planning.

A. Before the nuclear build-out of the 1970s and early 1980s, resource planning was relatively simple. Sales growth was high, often 6-7% per year, driven by electrification and the steady proliferation of air conditioning and other significant end uses. Not only was high sales growth a reliable basis for the addition of new resources, typically coal, oil, and gas-fired power plants, but it allowed new costs to be spread over an ever-increasing sales base. This was in addition to the ever-increasing economies of scale being achieved in the development, construction, and operation of new power plants.

There was little or no impetus to plan beyond the next expected need, and needs were met with an evolving fleet of primarily dispatchable resources, which could provide energy on demand. Fleets were comprised of generators that were designated as "baseload" (i.e., designed to run throughout the day and throughout the year), "intermediate" (i.e., designed to run during long portions of days and seasons, but not continuously), and "peaking" (i.e., designed to run occasionally during peak load conditions and to backup baseload and intermediate resources during outages).

When nuclear generation became a favored option, in part because of its expected low cost of generation, nuclear power plants became a favored resource for meeting new demand. Burgeoning regulation of nuclear generation and increasing costs of construction following the accident at the Three Mile Island facility, along with sales growth that began to diminish, led to calls for policies that would focus on containing the cost of utility service. This included passage of the Public Utility Regulatory Policies Act ("PURPA") and, most relevant to this case, the establishment of IRP processes.

In establishing IRP processes, state commissions included several key features – 1) the consideration of demand-side resources (e.g., energy efficiency and demand response) in addition to new generation supply, 2) robust risk analysis, and 3) various forms of decision analysis and contingency analysis. Missouri first established IRP rules in 1992. Subsequently, we saw the proliferation of reregulation in the 1990s, the establishment of regional transmission organizations ("RTO") and organized power markets in the early 2000s, and the expansion of policies supporting clean energy development and the beginning of the transition away from heavy reliance on fossil fuels, particularly coal, while use of natural gas surged as a result of the fracking revolution.

Today, the utility industry in the United States and across the globe is transitioning to a new kind of fleet in which there is a much clearer distinction between energy resources and capacity resources and a requirement to consider the need for and role of both types of resources. Trends in environmental and climate policy are increasingly both driving and recognizing this transition. Markets are evolving to account for this shift in resource mix, and analyses of reliability are necessarily becoming increasingly more important and complex.

In 2011, the Commission revised its IRP rules, including the recognition of the role of organized RTO markets and the significant expansion of rules related to consideration of transmission and distribution needs and costs to recognize shifts in grid technology and the role of distributed energy resources ("DER"). The adoption of revised rules followed a robust stakeholder process that spanned several years and included input from numerous stakeholders, including Staff, Office of the Public Counsel ("OPC"), Missouri Department of Natural Resources ("MDNR"), all investor-owned electric utilities in Missouri, and parties representing industrial customers, environmental advocacy interests, and others. Those rules continue to serve as the framework for robust utility resource planning analysis and decision making today.

Q. What is the purpose of the Commission's IRP rules?

A. The fundamental objective of the Commission's IRP rules is to "provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies."[15] The Commission's IRP rules establish minimum requirements for utility resource planning and provisions to ensure that a utility pursues the implementation of its PRP, and revises its PRP when necessary, to ensure that its business plans and requests before the Commission are consistent with its PRP.

[15] Commission's IRP rules at 20 CSR 4240-22.010(2).

Q. What provisions of the Commission's IRP rules establish requirements to ensure that a utility pursues the implementation of its PRP?

A. Key provisions include the following requirements:

- As part of the utility's resource acquisition strategy, "develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the preferred resource plan over the implementation period."[16]
- As part of the utility's implementation plan, include a "process for monitoring the critical uncertain factors on a continuous basis…"[17] and as part of annual updates, report on the "[s]tatus of the identified critical uncertain factors."[18]
- As part of its triennial IRP filing, include a "[l]etter of transmittal expressing commitment to the approved preferred resource plan and resource acquisition strategy and signed by an officer of the utility having the authority to bind and commit the utility to the resource acquisition strategy;"[19]
- Report as part of annual updates, the "[u]tility's progress in implementing the resource acquisition strategy."[20]
- Notify the Commission in writing, "[i]f, between triennial compliance filings, the utility's business plan or acquisition strategy becomes materially

[16] 20 CSR 4240-22.070(6); 20 CSR 4240-22.070(7)
[17] 20 CSR 4240-22.070(6)(G)
[18] 20 CSR 4240-22.080(3)(A)2
[19] 20 CSR 4240-22.080(2)(A)
[20] 20 CSR 4240-22.080(3)(A)3

inconsistent with the preferred resource plan, or if the utility determines that the preferred resource plan or acquisition strategy is no longer appropriate…"[21] This provision further includes specific requirements for analysis and explanation of the effects of any changes to the PRP.

- "In all future cases before the commission which involve a requested action that is affected by electric utility resources, preferred resource plan, or resource acquisition strategy, the utility must certify that the requested action is substantially consistent with the preferred resource plan specified in the most recent triennial compliance filing or annual update report. If the requested action is not substantially consistent with the preferred resource plan, the utility shall provide a detailed explanation."[22]

Q. Has the Company complied with these provisions as they relate to the Company's current PRP and the requested action in this case?

A. Yes. The Company has complied with each and every one of these requirements, including in its 2022 Notice of Change in Preferred plan, on which it has continued to rely for its resource-related requests to the Commission, including the requests for approval of CCNs for the Projects.

Q. Staff witness Fortson notes that the Company recently filed a new triennial IRP. Does that filing indicate a material change in the Company's need for the Projects?

A. No. Ameren Missouri's 2023 IRP was filed on September 26, 2023, and it includes a resource acquisition strategy that still calls for the addition of significant levels

[21] 20 CSR 4240-22.080(12)
[22] 20 CSR 4240-22.080(18)

of renewable energy resources through the end of this decade and into the next decade, just as its PRP adopted in June 2022 did. While Staff witnesses argue that the new IRP is essentially "too new" to serve as an analytical basis upon which to support the need for the Projects, it does continue to provide a very strong indication of the consistency of the Company's expected need for renewable energy resources and the economic and risk benefits of adding renewable energy resources, including solar resources such as the Projects. I will address this consistency as part of my discussion reiterating the need for the Projects later in my surrebuttal testimony.

Q. Why is the resource planning framework embodied in the Commission's IRP rules the appropriate basis for utility resource decisions?

A. Because it is exactly the framework the Commission has chosen to rely upon to ensure proper resource decision making on the part of the utilities it regulates. The Commission last revised its IRP rules in 2011 following an extensive rulemaking process that took nearly two years, including nearly a year-long workshop process facilitated by Staff.[23] In the Commission's Order of Rulemaking adopting the revised IRP rules, it explicitly addressed concerns regarding the Commission's role in utility resource planning, stating, "[t]he Commission certainly is not interested in managing the utility companies, and these rules do not attempt to do so. Rather, the rules are designed to ensure that electric utilities implement an effective and thorough integrated resource planning process to ensure that their ratepayers continue to receive safe and reliable service at just and reasonable rates."[24] The Commission's investment of time and attention in the adoption of revised IRP rules in 2011 and its comments included in its Order of Rulemaking clearly

[23] See File No. EX-2010-0254.
[24] Order of Rulemaking in File No. EX-2010-0254, p. 1377.

indicate the Commission's intent and expectation that the IRP process embodied in its IRP rules serve as _the_ framework to be used for utility resource decision making. The specific provisions I cited previously further indicate the Commission's intent and expectation that utilities implement the resource decisions that result from the utilities' planning processes in compliance with the Commission's IRP rules.

Q. Does that mean there is no place or need for additional analysis or evaluation when the utility seeks to implement the resources in its PRP?

A. Not at all. However, such analysis should be limited to that which is necessary to support the specific _manner_ by which the utility seeks to implement a resource in its PRP rather than a complete rework of the analysis used to develop the utility's PRP. That is, it should be focused on how best to acquire a particular resource in the utility's PRP rather than a complete, and unnecessary, reassessment of that PRP. In this instance, the Company is seeking to implement solar resources included in its PRP, and it has engaged in a competitive RFP process to identify the best projects to fulfill that need. Company witness Scott Wibbenmeyer addresses the RFP process used by the Company to select the Projects in his direct testimony while also correcting a Staff claim regarding the scorecards developed as part of the RFP process in his surrebuttal testimony.

Q. Staff witness Sarah Lange proposes a list of economic modeling steps that Ameren Missouri should take.[25] Are you and/or other Company witnesses addressing each of these items specifically?

A. Yes. While the Company contends that its IRP process, in accordance with the Commission's IRP rules, is the proper framework for evaluating and supporting

[25] Sarah Lange Rebuttal Testimony, p.18, l. 20 through p.19, l. 9.

resource decisions, as I have described above, the Company has responded on each of the points listed under economic modeling in the proposed steps included in Witness Sarah Lange's rebuttal testimony. A summary of the Company's response and references to the applicable Company witness(es) is included in Schedule MM-S1.

Q. Setting aside the Commission's clear preference for its IRP framework to serve as the basis for utility resource decisions, can you explain why the framework embodied in the IRP rules is an appropriate basis for utility resource planning and decision making?

A. Yes. The framework established by the Commission's IRP rules represents a well-reasoned approach to integrated resource planning by addressing numerous requirements for good planning and by focusing on a few key elements in particular. First, it establishes a long planning horizon (at least 20 years)[26] over which to evaluate multiple resource decisions that may have to be made rather than simply focusing on the next resource need. This ensures that resource plans better address long-term needs in an integrated fashion and in a way that allows for consideration of broader portfolio-level solutions for meeting customers' needs. It also ensures that actions taken to address near-term needs consider long-term risks, such as the continued risks associated with climate, environmental, and energy policy.

Second, it establishes an appropriate balance between the level of analysis used and the breadth of options and inputs considered. By focusing on generic resources,[27] we can gain insights into the relative tradeoffs of a host of different options for which project or site-specific information may not be, and usually isn't, practically available. While it might

[26] 20 CSR 4240-22.020(43).
[27] I.e., solar, wind, natural gas peaking, natural gas combined cycle, hydro, etc.

be nice to have very specific project information for every resource option to be evaluated, this is frequently, if not always, impossible when evaluating a wide range of resource options that may include different types of gas generation, nuclear, wind, solar, hydro, storage, and other resource options. The same is true for demand-side resources, which are evaluated through the IRP process at a less granular level than that which is employed through detailed program implementation. The alternative would be to evaluate very specific project parameters for one resource type against generic project parameters for another resource type, resulting in a mismatch of the level of granular detail and introducing unnecessary potential biases into the comparison of different resource types.

Third, it ensures consideration of a range of potential values for key variables that can influence the relative economics of different resource and portfolio options. Ameren Missouri's IRP process reflects a robust consideration of risk. This includes consideration and analysis of a broad range of values for key variables like natural gas prices, carbon prices, project costs, and the cost and load impacts of demand-side programs. Market prices for energy and capacity in the MISO market are developed based on the ranges for natural gas and carbon prices to produce integrated market prices scenarios in which the inputs (natural gas and carbon prices) and the outputs (market energy and capacity prices) are correlated. In using ranges of values for these key variables, we are able to test alternative plans or portfolios under a wide range of conditions to ensure that our PRP performs well under a range of potential futures.[28]

While there are many other considerations reflected in both the Company's IRP process and the Commission's IRP rules, the three aspects of IRP I discuss here broadly

[28] For a more in-depth discussion of Ameren Missouri's consideration of risk, see my direct testimony in this case.

define an appropriately balanced framework for good, long-term resource planning that provides the opportunity for gaining important insights while avoiding the kind of "analysis paralysis" that can plague a process that is hyper-focused on the minute details of a particular project or group of projects.

IV. STAFF'S CRITICISMS OF THE IRP PROCESS AND THE COMPANY'S IRP

Q. Is Staff advocating an alternative approach to the IRP rules as a basis for utility resource decisions?

A. Yes. In short, Staff asserts that the Company's IRP process should not be used as a basis for making and implementing utility resource decisions.[29] Instead, Staff proposes that utilities cast aside their PRP when seeking to implement new resources in favor of highly detailed analyses that focus solely on the utility's next need for resources, with a specific need that is somehow isolated from resource needs in total over time, and the "best" resource for meeting that specific, imminent need, using market-based cost/benefit criteria of the kind used to justify merchant generator projects coupled with detailed assumptions regarding ratemaking and cost recovery that assesses economics not on the basis of costs, but rather on the basis of what costs will and will not be recovered through rates under a given set of assumptions.[30] Company witnesses Mitchell Lansford and Steve Wills explicitly address the details and shortcomings of Staff's analysis framework in their surrebuttal testimonies, including significant errors in Staff's analysis presented in the rebuttal testimony of Staff Witness Sarah Lange.

[29] J Luebbert Rebuttal, Testimony, p. 28.
[30] Shawn Lange Rebuttal, Testimony pages 3-15; Sarah Lange Rebuttal, Testimony pp. 53-62.

Q. How does Staff characterize the Company's IRP process?

A. Staff witnesses imply that the IRP process is essentially an academic exercise, subject to the biases of the utility and unreliable as a basis for resource-related requests before the Commission.[31] They emphasize that neither Staff nor the Commission endorse or "approve" the utility's PRP and assert that the utility is not bound by its filed PRP, indicating that the utility reserves the right to alter its PRP.[32] They dismiss the continuity of planning embodied in the Commission's IRP rules, arguing that the Company's prior PRP, adopted in June 2022, and the associated supporting analysis is too old and that the Company's new PRP, adopted in September 2023 and presented in its recent triennial IRP filing and affirming the need for renewable resources, and the associated supporting analysis is too new to serve as a proper basis for the Company's resource decisions.[33] Along the way they make various criticisms of Ameren Missouri's IRP process, all but one of which are new criticisms never before asserted by Staff in any IRP proceeding, despite numerous opportunities to do so, and all of which are invalid, ignore the steps the Company has taken to address the one criticism Staff has previously asserted[34] and ignore the updates the Company has made to the analysis presented as part of the Company's direct testimony in this case. Witness Luebbert even asserts that if the Commission relies on the IRP processes that a utility follows to approve the utility's resource-related requests, even if the utility's process is found to be in substantial

[31] Brad Fortson Rebuttal Testimony, pp. 10-11; J Luebbert Rebuttal, p. 10-11, p. 28.
[32] Brad Fortson Rebuttal Testimony, p. 3.
[33] Brad Fortson Rebuttal Testimony, pp. 9-10 and 19-20.
[34] Brad Fortson Rebuttal Testimony, pp.7-8.

compliance with the Commission's IRP rules, that would amount to a "self-approving capital plan" on the part of the utility.[35]

Q. What are the general criticisms Staff witnesses assert regarding the IRP process and the Company's IRP analysis?

A. Staff witnesses assert a number of criticisms that can be categorized as follows:

1. Outdated assumptions – Staff takes aim at a number of assumptions included in the Company's IRP planning and erroneously asserts that the Company has not properly updated its analysis for its direct case. Staff's claims include:
    a. Projects costs for solar and wind have increased significantly beyond those included in the Company's analysis.[36]
    b. Assumptions for tax credits do not properly reflect provisions of the IRA.[37]
    c. Assumptions for MISO capacity accreditation have changed but have not been appropriately considered.[38]
2. Biased or erroneous pricing assumptions – Staff makes a number of baseless assertions, with no supporting analysis, to attempt to cast doubt on the pricing assumptions used by the Company in its IRP analysis. Staff's claims include:

[35] J Luebbert Rebuttal Testimony, p. 28.
[36] J Luebbert Rebuttal Testimony, pp.15-16.
[37] J Luebbert Rebuttal Testimony, pp. 12-15.
[38] J Luebbert Rebuttal Testimony, p.17.

a. Using carbon prices rather than emission limits unfairly advantages renewables.[39]

b. Energy prices don't account for the impacts of the Projects.[40]

c. Capacity prices don't account for the impacts of the Projects.[41]

3. Biased analysis of alternative resource plans – Staff attempts to impugn the integrity of the Company's comparison of alternative resource plans through surface-level observations and innuendo rather than a reasoned critique and in doing so contradicts its own filed comments on the Company's IRPs. Staff's claims include:

a. The high share of plans with significant and similar renewable buildouts do not provide for a fair comparison of other resources.[42]

b. Plans are allowed to include resources that are not needed.[43]

c. Plans not required to "optimize" specific timing and amount of particular resources to be added.[43]

4. The IRP process is an inappropriate basis for specifying resources needed to meet customer needs – Staff alleges that the IRP process is not sufficient for specifying the types of resources needed by utilities to meet their customer needs due to several perceived shortcomings, as follows:

a. Assumptions are under the control of utility management.[43]

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[39] Shawn Lange rebuttal, pages 10-13.
[40] Michael Stahlman Rebuttal Testimony, p. 9.
[41] Michael Stahlman Rebuttal Testimony, p. 10.
[42] Brad Fortson Rebuttal Testimony, pages 10-12.
[43] J Luebbert Rebuttal Testimony, pp. 9-10.

b. Utility management can define multiple objectives to be achieved by the alternative resource plans they compare and the PRP they select.[44]

c. At a given time, the utility's PRP may be "too old" or "too new."[45]

d. IRP analysis relies on generic resource assumptions rather than project-specific assumptions.[46]

e. Utility management is not "bound" by the PRP and can change its PRP at any time.

Q. Are the criticisms regarding purported outdated assumptions (item 1 in the list above) accurate and valid?

A. No. In fact, they are completely wrong. As described in my direct testimony, I in fact did update key assumptions in the NPVRR analysis from the Company's 2022 Notice of Change in Preferred Plan for the comparison of two key plans – the Renewable Transition Plan, which is identical to the Company's PRP at the time of the filing of the application in this case, and the Renewables for Capacity Need Plan, which adds renewables only for a pure capacity need and regardless of the feasibility of doing so over a very short period of time late in the planning horizon. The key assumptions that were updated in my direct testimony for that analysis are project costs for renewable resources and the inclusion of tax credit provisions of the IRA, which includes not only the extension of qualification of tax credits for projects initiated through 2032, but also the use of production tax credits (PTC) for solar projects. These assumption updates are explicitly

[44] J Luebbert Rebuttal Testimony, p. 7.
[45] Brad Fortson Rebuttal Testimony, pp. 9-10 and 19-20.
[46] Brad Fortson Rebuttal, Testimony pp. 9-10.

referenced on page 55 of my direct testimony, further described on page 65 of my direct testimony, and included in my direct testimony Schedule MM-D16, which lists all assumption changes reflected in the analysis included in my direct testimony. In addition to the updates for renewable project costs and IRA tax provisions, my direct testimony reflects my updates to the analysis of the Company's capacity position for the latest updates from MISO at that time, which were the values used for MISO's 2023/2024 planning resource auction (i.e., "capacity auction"), as well as for the Company's 2023 IRP load forecast and expected load impacts from demand-side programs used in the Company's 2023 IRP analysis and based on the Company's demand-side resources market potential study completed in early 2023.[47] Again, these assumption updates are explicitly described in my direct testimony and summarized in Schedule MM-D16.

Q. Are the project cost assumptions for solar resources used in the NPVRR comparison of plans in your direct testimony consistent with the costs for the Projects?

A. Yes. The chart and table below reflect the assumptions used for the NPVRR comparisons between alternative resource plans I presented in my direct testimony and the current estimated base costs for the Projects. As the chart and table show, the estimated base case costs of the Projects are in line with the generic resource assumptions used for the NPVRR comparison of alternative resource plans. Note that while the generic project cost assumptions are higher than those reflected in the Company's June 2022 Notice of

[47] Each of these 2023 IRP assumptions, reflected in my direct testimony analyses, are the same assumptions used in our filed 2023 triennial IRP.

Change in Preferred Plan analysis, the increase in NPVRR resulting from this change is more than offset by the inclusion of tax credits under the IRA.[48]

Figure 1. Solar Capital Cost Assumptions ($/kW-AC Nominal)[49]**

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[48] The NPVRR advantage for the Renewable Transition Plan (i.e., PRP) relative to the Renewables for Capacity Need Plan increased from $632 million as indicated in Schedule MM-D2, page 27, Table 7, to $1.2 billion as shown in Table 2 of my surrebuttal testimony with the inclusion of the 2023 IRP assumptions for renewable project costs and IRA tax credits. These NPVRR differences do not include quantification of the renewable transition risks identified by Roland Berger and discussed in Schedule MM-D2.

[49] The 2023 IRP and Direct Testimony line are the same because, as noted, I in fact did update resource cost assumptions in my direct testimony using the resource cost assumptions that also now underlie the 2023 IRP. Please also note that the square (plotting the Vandalia Project) is sitting right on top of the triangle (plotting the Bowling Green Project) on the curve because the Projects' costs are quite close to each other.

Figure 2. Wind Capital Cost Assumptions ($/kW Nominal)**

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Table 3. Solar Capital Cost Assumptions ($/kW-AC Nominal)[50]**

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[50] Table 1 is a reproduction of Staff witness Hari Poudel's Table 4 from Mr. Poudel's rebuttal testimony but using actual base case Project cost estimates (without AFUDC, as noted in footnote 54) and using the 2023 IRP project cost assumptions (which I used in my direct testimony in this case, and which also are used in the 2023 IRP).

[51] Values reflect most recent base case cost estimates. For Cass County, Vandalia, and Bowling Green, the base case cost estimates remain the same as they were when this case was filed. For Split Rail, the base case has changed due to greater project maturity (Split Rail was less mature than the other three when this case was filed), leading to an update to the Split Rail Project cost estimates as reflected in the Company's Supplemental Data Request Response to Data Request No. 42. Please also note that AFUDC costs are excluded from the Project base case estimates since the IRP costs do not include AFUDC, which allows an apples-to-apples comparison between the IRP values and the Project cost estimates.

Q. You have explained that the IRP estimates are for generic resources and that the IRP does not model specific projects. How then are you able to provide a $/kW-AC estimate in the third column of Table 1 that is tied to a specific Project?

A. We know the in-service date for each Project, and we know the IRP solar cost estimate for a generic solar facility that would go into service in a given year. For example, the Cass County Project is slated to go into service in 2024 and the generic solar project cost estimate in the IRP for a 2024 project is $1,984/kW-AC. Thus, we can properly compare the Cass County Project base case estimate of $1,900/kW-AC to the IRP estimate for a 2024 project of $1,984/kW-AC, and so on, for each of the other three Projects.

Q. Staff witnesses indicated in rebuttal testimony that Ameren Missouri is expecting costs for solar projects to decline.[52] How does that compare to the increasing costs shown in Figure 1?

A. Staff appears to be referencing expected declines in project costs in real terms, that is, *without including inflation*. The costs shown in the charts and table above reflect nominal costs including inflation, which the Company has assumed to be 2 percent annually after 2023, in line with long-term history and targets used by the Federal Reserve. While discussing project costs in real terms, without inflation, is sometimes useful to depict expected cost trends vs. a baseline, nominal costs with inflation reflect the true expected costs of projects and the reality that inflation is expected to occur. Consequently, contrary to Staff's claim the Company does not expect solar project costs to decline in the future. Instead, the Company expects them to escalate.

[52] J Luebbert Rebuttal Testimony, p. 35; Hari Poudel Rebuttal Testimony, p. 8.

Q. You mentioned that the analysis presented in your direct testimony reflects PTCs for solar projects and the timeline for tax credit qualification provided for by the IRA. Do Staff witnesses recognize the use of these assumptions in the NPVRR analysis?

A. Inexplicably, no. As I mentioned previously, the updates of both renewable project cost assumptions and inclusion of the updated tax credit provisions of the IRA were explicitly noted in my direct testimony and highlighted in Schedule MM-D16.

Q. How do you respond to Staff's allegation that the Company has not updated its analysis to reflect the latest values used by MISO for resource adequacy, such as the capacity credits for renewable resources?

A. This too is simply not true. The Company updated its analysis of capacity need to reflect the values used by MISO for its 2023-2024 PRA, and I explicitly noted this in my direct testimony, including in Schedule MM-D16.[53]

Q. Do these assumption updates support the conclusion by Staff that the Company has biased its analysis toward the early deployment of renewable resources?

A. No. In fact, it renders such conclusions completely invalid. The Company has appropriately considered updates to renewable resource costs and tax credits for renewable resources pursuant to the IRA. The analysis in my direct testimony reflecting these updated assumptions showed that pursuing the renewable transition starting now and continuing through the mid-2030s results in NPVRR that is $1.2 billion <u>*lower*</u> than if the Company waited to add renewable resources for only a pure capacity need. As mentioned

[53] Matt Michels Direct Testimony, p. 48.

in my direct testimony, this advantage would be much higher if it included quantification of certain risks previously analyzed by Roland Berger and discussed in its report on renewable transition risk included in the Company's 2022 Notice of Change in PRP.[54]

Q. How do you respond to Staff's allegations regarding the Company's energy and capacity market pricing assumptions?

A. First, it is important to note that the price assumptions with which Staff's witnesses take issue are the prices that were developed for the Company's 2023 IRP. These same price assumptions were used in the individual project models for the Projects that I presented in my direct testimony. That said, the criticisms Staff makes are invalid and unsupported by any actual analysis, whereas the Company's price assumptions were developed through the use of detailed modeling by expert consultants, Charles River Associates ("CRA"), and documented in the Company's 2023 IRP.[55]

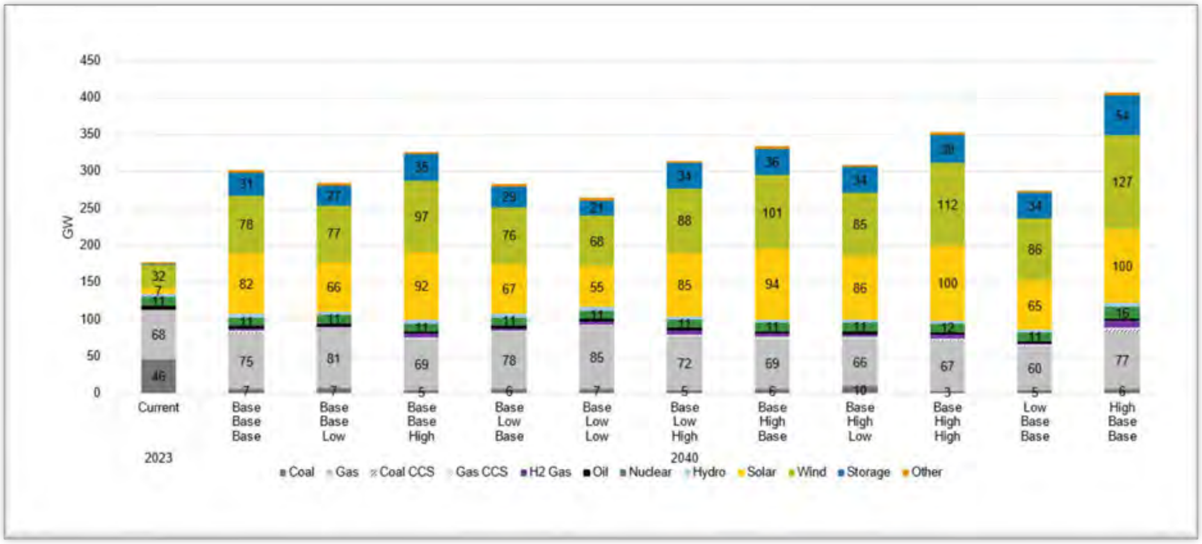
Staff claims that the Company has not accounted for the specific impacts of the Projects on locational marginal prices ("LMP") and on the market price of capacity in MISO and that such impacts may materially impact the Company's IRP analysis and the economics of the Projects. Staff's view reflects a fundamental misunderstanding of the price modeling performed by CRA and the Company's emphasis on the importance of using a range of assumptions for risk analysis for IRP. CRA's modeling reflects a range of assumptions developed by the Company for natural gas prices and carbon prices, both of which have consistently been identified as critical uncertain factors under the Commission's IRP rules and by the Company's IRP process. CRA performed capacity

[54] See Schedule MM-D2 for the Company's 2022 Notice of Change in Preferred Resource Plan, including the report on renewable transition risks from Roland Berger.
[55] As discussed below, the Staff had the full CRA report and workpapers on August 4, 2023.

expansion modeling for the US Eastern Interconnect for all combinations of natural gas and carbon prices and for sensitivities reflecting assumptions for high load and low load. The capacity expansion models produce broad portfolios for the Eastern Interconnect under each set of assumptions and included different levels of coal, natural gas, wind, solar, nuclear and other generation over the planning horizon. It should be noted that the Projects are representative of this market-wide expansion and are, generically, a subset of the renewable resource additions modeled by CRA. These varying portfolios are then used to determine the corresponding market prices for energy and capacity. The quantities of each resource type included in these portfolios varies significantly. The table in Figure 3 below, reproduced from CRA's report,[56] shows that total solar generation in 2040 varies from 55 GW to 100 GW across the different scenarios. The explicit inclusion or exclusion of the Projects, totaling 550 MW (less than 1 GW), clearly could not result in changes in power prices that are significant compared to the differences reflected in the range of scenarios analyzed by CRA. This is true for both energy prices (LMPs) and capacity prices.

Figure 3. Comparison of CRA Modeled Nameplate Capacity by Technology in MISO (2040)

[56] CRA's report was included in the Company's 2023 IRP filing as Chapter 2 – Appendix A and is attached as Schedule MM-S2. It was also provided to the Staff (together with CRA's underlying workpapers) in response to Data Request 0094, submitted to Staff on August 4, 2023.



Q. With respect to pricing assumptions, you also mentioned Staff's criticism of the Company's carbon price assumptions. Please describe Staff's criticism in more detail and provide your response.

A. Staff's criticism is essentially that the inclusion of carbon prices creates an economic advantage for the addition of renewable resources compared to fossil fueled resources and that using emission cap regimes would not. This is simply not true. Cap-and-trade mechanisms necessarily result in a market price for emissions allowances that is then included in the dispatch costs of emitting resources and therefore is reflected in the market price of energy. This is true for existing such regulatory mechanisms used in the regulation of other air emissions like sulfur dioxide ("SO_2") and nitrous oxides ("NO_X").[57] Similarly, clean energy standards, like those that were under consideration at the federal level as part of the Build Back Better Act (the forerunner of the IRA), often include alternative

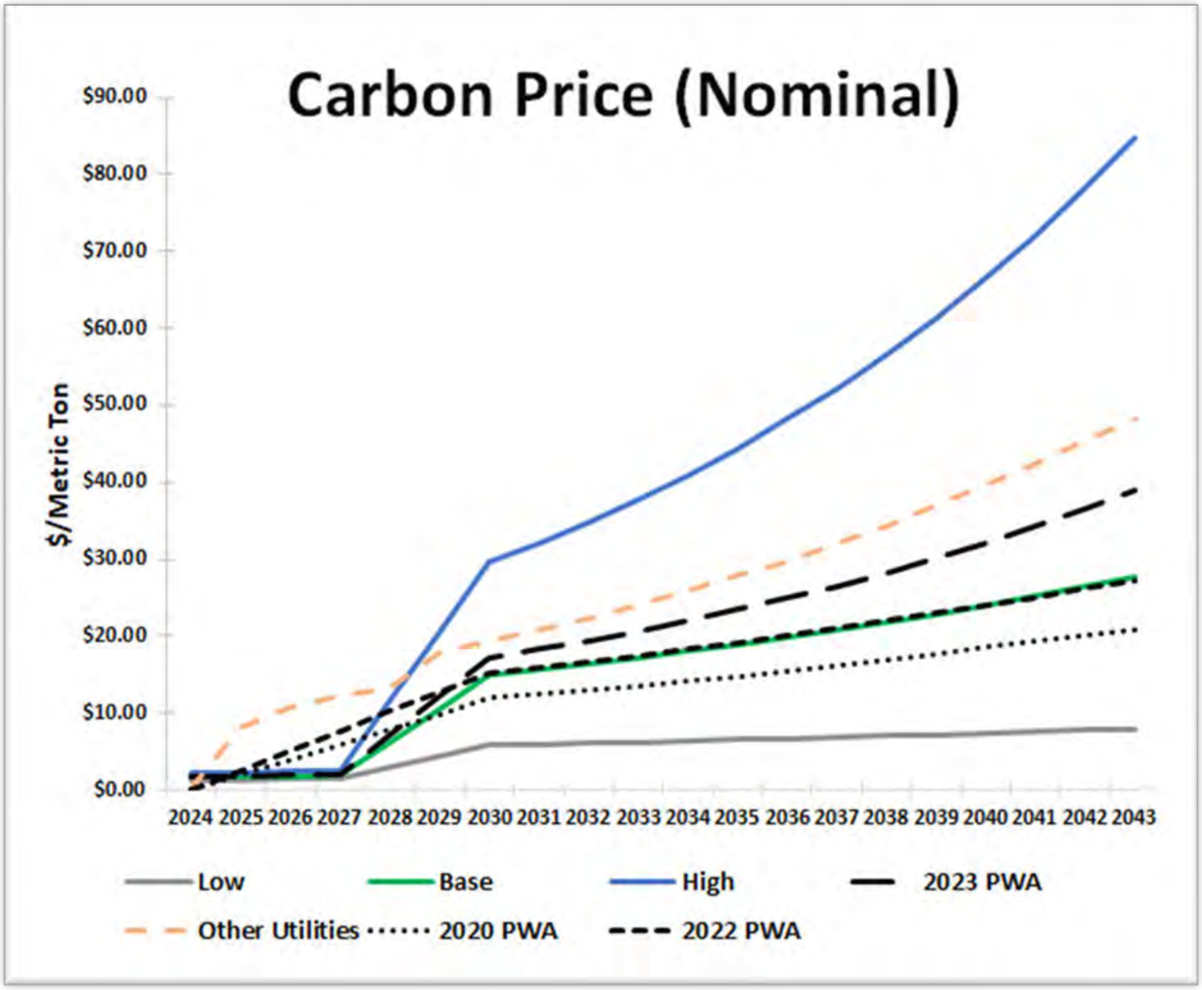
[57] Allowances are used in the regulation of such emissions under the Cross State Air Pollution Rule ("CSAPR") and were used in predecessor rules such as the Clean Air Interstate Rule ("CAIR") and Clean Air Transport Rule ("CATR").

compliance payments ("ACP") that impose an economic disadvantage on fossil fueled resources relative to cleaner resources such as wind and solar.

For the reasons described above, Ameren Missouri and a number of other prominent utility companies use a range of carbon price assumptions to reflect the range of potential policies that may be implemented over the planning horizon to address risks associated with climate change. The chart below shows the carbon price assumptions used by Ameren Missouri in its 2020, 2022 and 2023 IRP analyses compared to those recently used by other utility companies.[58] Note that while Ameren Missouri's 2023 PWA carbon prices are slightly higher than those used for the Company's 2020 and 2022 IRP analyses, they remain slightly below the average of peer utilities, and the range used by the Company provides for significant potential variation, which is central to the Company's IRP risk analysis.

[58] Prices are shown for probability weighted average ("PWA") for the 2020 IRP, 2022 PRP, and 2023 IRP. Base, low and high carbon prices are shown for the 2023 IRP. The average for other utilities includes the base or expected level price assumptions used by AEP, Xcel, CMS, Entergy, and Pacificorp.

Figure 4. Carbon Price Assumptions



The Company has used assumptions for carbon prices to represent ranges of potential climate policy over the planning horizon in its IRP analyses dating back to at least 2014. Prior to 2014, the Company experimented with approaches that accounted for more explicit forms of climate policy, finding that such explicit assumptions could quickly become outdated as policy proposals changed. It is important to note that when modeling explicit emission limits, it is typical for dispatch models to solve for meeting such limits through a process that establishes a price on emissions of the subject pollutant and iterates to find the price that results in compliance with the emission limit. As a result, a price on emissions is established *regardless* of whether the modeling begins with such a price or calculates it to meet an emission limit, further demonstrating that Staff's claim that using a carbon price unfairly disadvantages fossil-fueled resources is simply wrong.

Finally, it is important to recognize that the focus of potential climate policy has continued to broaden to sectors beyond power over the last decade, and in the last few years in particular, as emissions from transportation, industry and heating draw more attention. It is also important to recognize that many policy makers have become more focused on time-oriented goals for achieving economy-wide decarbonization, such as policies seeking to achieve net zero carbon emissions by 2050. Taken together, this approach to climate policy often reflects a desire to ensure consistency in application across sectors, something that can best be achieved through policies that place an explicit price on carbon emissions. This too has factored into decisions by Ameren Missouri and others to focus on ranges of prices on carbon emissions to represent the effects of potential climate policy.

Q. Has Staff previously expressed concerns with the Company's use of carbon pricing in its IRP analysis?

A. No. Staff explicitly reviewed the Company's approach to risk analysis and its use of carbon pricing as part of its review of the Company's IRP filings in 2014, 2017 and 2020 – Staff expressed no concerns with the Company's approach.[59] It seems unlikely that Staff would have harbored such a concern for nearly ten years without ever raising it.

[59] Staff reports on the Company's 2014, 2017, and 2020 IRP filings are attached as Schedules MM-S3, MM-S4, and MM-S5, respectively. Please note that while these reports have "C" or "HC" references, they are no longer confidential or highly confidential, although they were at the time of their original filing.

Q. Staff witness Stahlman asserts that the prices produced by CRA's modeling are in error because on-peak and off-peak prices converge late in the planning horizon and that this cannot happen because it harms the price arbitrage economics of energy storage.[60] Is this a valid criticism?

A. No. In fact, prices converge in part *because* of the arbitrage economics of energy storage. It is true that battery storage (and possibly other energy storage) resources are expected to be added to the grid in part to take advantage of power price differentials between peak and off-peak periods. As such resources are added, it will necessarily affect the prices during periods in which battery storage resources are charged (raising the price) and discharged (reducing the price). This effect is included in the analysis performed by CRA. It is also important to keep in mind that energy arbitrage is not the only value stream expected to be realized by energy storage resources. Such resources also have value that can be monetized by providing services such as capacity, ramping, and frequency regulation. So, the price convergence observed by Staff in the results of CRA's modeling is evidence of the proper working of CRA's modeling, not evidence of a modeling error.

Q. Turning to Staff's criticisms that the Company's analysis of alternative resource plans is biased, how do you respond?

A. As with Staff's criticisms regarding the Company's analysis assumptions, this criticism is completely unfounded. Staff witness Fortson notes the composition of the alternative resource plans evaluated by the Company in its 2020 IRP and leaps to the conclusion that this is evidence of bias by stating that, "Only three out of the 28 ARPs would have provided a comparison to a portfolio with a moderately different renewable

[60] Michael Stahlman Rebuttal Testimony, pp.13-14.

resource planning strategy" and that "It is difficult to imagine much insight can be gained" from comparisons of these plans.[61] But the plain truth is it doesn't take analysis of more plans to draw key insights and conclusions regarding the contribution of renewable resources to affordable energy services for customers. The Company explicitly describes its selection of alternative resource plans in Chapter 9 of its 2020 IRP filing, focusing on the key questions that analysis of alternative resource plans must answer. The set of alternative plans is designed to explicitly answer those questions. To a great degree, the results of prior analyses and expectations regarding the results of the analysis of alternative resource plans are factored into the design of the set of alternative resource plans to be analyzed. For example, Ameren Missouri has modeled potential nuclear generation in each IRP. Since the results have consistently shown that nuclear is more costly than natural gas combined cycle and given the nature and consistency of assumptions for each, the Company has used natural gas combined cycle as a primary generation resource for its analysis but continued to evaluate at least one plan with nuclear generation to continue to demonstrate its relatively greater cost. However, if the analysis demonstrated that the anticipated conclusions were inaccurate, the Company would alter its set of alternative resource plans to account for such results. To do otherwise would introduce unnecessary and time-consuming inefficiency into the analysis process, in which the risk analysis often includes analysis of 80 or more combinations of assumptions for each alternative resource plan.[62]

[61] Brad Fortson Rebuttal Testimony, p. 11.
[62] See pages 10-15 of Ameren Missouri's 2020 IRP Chapter 9 – Integrated Resource Plan and Risk Analysis, attached as Schedule MM-S6. Please note that while this report has "C" or "HC" references, it is no longer confidential or highly confidential, although they were at the time of its original filing.

Q. Has Ameren Missouri used this approach for prior IRPs?

A. Yes, including in its 2014 and 2017 IRPs in addition to its 2020 IRP. The Company continued to use this approach in the preparation of its 2023 IRP.[63]

Q. **Has Staff expressed a concern with the Company's approach to developing alternative resource plans in those prior IRPs?**

A. No. In its comments on the Company's 2014, 2017 and 2020 IRPs, Staff did not indicate any concern with the Company's approach to developing alternative resource plans. It should be noted that one of the two expert witnesses noted in Staff's report regarding the Company's 2020 integrated resource analysis, including its selection of alternative resource plans, was Staff witness Fortson.

Q. Staff also claims that the Company's analysis of alternative resource plans is biased because, in Staff's view, plans are permitted to include more resources than are needed.[64] Is this a valid criticism?

A. No. The resources added in alternative resource plans are needed, and the resources included in the Company's PRP are needed, as I explained in detail in my direct testimony and as I reiterate later in my surrebuttal testimony. While it is true that a number of alternative resource plans result in the Company attaining a position as a net seller of energy in a number of years, the total resources added over the planning horizon have been quantified to ensure that the Company has sufficient energy to meet its customers' energy needs and meet them under a range of circumstances that reflect real risks, including risks to the implementation of renewable resources themselves and risks to the Company's

[63] See 2014 IRP Chapter 9, attached as Schedule MM-S7, 2017 IRP Chapter 9, attached as Schedule MM-S8, and 2023 IRP Chapter 9, attached as Schedule MM-S9.
[64] J Luebbert Rebuttal Testimony, p. 9.

ability to rely on energy from its aging fleet of fossil fueled resources. While I do address the question of need more thoroughly later in my surrebuttal testimony, the key takeaway regarding Staff's claims of biased alternative resource plans is that there is no bias that results from the absence of a strict constraint on the annual amount of energy produced by the Company's anticipated fleet of resources in its PRP relative to its forecasted load under normal conditions.

The same is true regarding the addition of demand-side resources, which exhibit some of the same characteristics that renewable resources do. Specifically, both energy efficiency and renewable resources are, because of their nature, added in smaller increments than conventional generation resources like gas and nuclear, involve unique opportunities that may not be available later and mitigate risks associated with emissions from other generation sources. The state of Missouri does not seek to constrain energy efficiency resources based on a simple or strict analysis of expected annual energy balance under normal load conditions, nor should it do so with respect to renewable resources.

Q. Staff also asserts that the Company's analysis of alternative resource plans is insufficient for justifying the addition of renewable resources because it does not "optimize" the specific amounts and timing of renewable resource additions.[65] How do you respond?

A. This notion simply ignores reality. The Company's PRP seeks to add thousands of megawatts of renewable resources over the 20-year planning horizon. As has been explained in great detail in the direct testimonies of Company witnesses Ajay Arora and Scott Wibbenmeyer, as well as my own, there are numerous risks associated with the

[65] J Luebbert Rebuttal Testimony, p. 3.

implementation of such a renewable transition – risks that the Commission itself recognized in its recent order approving the Company's CCN application for the Boomtown Solar project, as detailed further in the surrebuttal testimony of witness Wills. These include risks associated with project development, contract negotiation, site permitting, procurement, construction, and regulatory approvals. Projects come in many sizes, but their sizes are often determined by the specific characteristics of the sites themselves, not by the precise amount of resource additions in a utility's PRP. The suggestion that the sizes of as-yet-unknown projects can be accurately predicted or that the year-to-year or project-to-project effects of such risks as those cited by the Company can be predicted and/or managed to a degree that analysis of a ten percent change in the amount of renewable resources added in a given year of a multi-decade transition provides any useful insight is not worth a moment's consideration. The truth is, there will be adjustments during the transition. Projects will have different and specific characteristics, including total output. As the Company executes on its PRP, it will do so to meet the overall need for resources of its customers and make adjustments as needed. Right now, the Company's best path for meeting those needs is to execute on the necessary resources identified in its PRP.

Q. The final set of Staff's criticisms of the IRP process that you cite are directed at what Staff perceives as the inappropriateness of relying on the IRP process for resource decisions at all. What are Staff's specific criticisms and what is your response?

A. As I stated previously, Staff's argument boils down to a few key thoughts, as follows:

a. Assumptions are under the control of utility management.

b. Utility management can define multiple objectives to be achieved by the alternative resource plans they compare and the PRP they select.

c. At a given time, the utility's PRP may be "too old" or "too new."

d. IRP analyses rely on generic resource assumptions rather than project-specific assumptions.

e. Utility management is not "bound" by the PRP and can change its PRP at any time.

I will discuss these individually in the testimony that follows, but in short, Staff's criticisms of the IRP process as a basis for resource decisions constitute a direct assault on the framework the Commission itself has established through its IRP rules. I discussed the Commission's rules as an appropriate framework, as *the* appropriate framework, for resource decisions by investor-owned utilities in Missouri earlier in my surrebuttal testimony. The framework is appropriate for such decisions, and Ameren Missouri has consistently been found to be in substantial compliance with the rules that define that framework. Furthermore, with a few narrow, limited exceptions, Staff has found the Company's IRP process to be in compliance with the Commission's rules.[66] Moreover, Staff itself has previously cited our reliance on our PRP in making actual resource implementation decisions, leveling no criticism against the Company for doing so. *See, e.g.*, Staff Rebuttal Report, pp. 7-8, File No. EA-2019-0181 (involving the Company's Atchison wind CCN case).

[66] See Staff reports on the Company's 2014, 2017 and 2020 IRP filings in Schedules MM-S3, MM-S4, and MM-S5.

In the process of disparaging the IRP framework, Staff understates or outright ignores its own opportunities to participate in and influence the IRP process, leaving the impression that utilities just do what they want with no oversight or accountability. Staff also attempts to discount the very continuity of IRP planning and analysis on which they rely in attempting to disparage the Company's process and PRP. Finally, Staff attempts to undermine the importance of IRP to utility resource decisions by suggesting that utility resource plans are non-binding and carry no weight, in spite of the numerous provisions of the IRP rules I discussed previously that suggest utility plans carry significant weight for both the utility and the Commission. If the IRP process and its importance were indeed as Staff attempts to characterize them in its rebuttal testimony, one would have to wonder about the need for IRP at all.

Q. As you just noted, you previously discussed the importance of IRP and the numerous provisions of the Commission's IRP rules that emphasize its importance. Do you have anything to add in that regard?

A. Yes. Just one thing, that is, Staff's own words about the importance resource planning generally, and of utilities actually implementing their PRPs. Specifically, when commenting on the proposed rules that became the Commission's current IRP rules (in 2011), Staff advised the Commission that "[i]t would be enlightening, and disturbing, to know that the utility's requested action [i.e., to implement its PRP] did not follow the utility's preferred resource plan. That would suggest that the preferred resource plan was not relevant and meaningful to the utility."[67] Staff went on to support the mandate in the rules that utilities be required to notify the Commission if the PRP changed materially: "As

[67] Staff's Comments to the Missouri Public Service Commission Proposed Rules Electric Utility Resource Planning File No. EX-2010-0254, p. 22.

written, the proposed rules contemplate a full snapshot every three years in the triennial compliance filing, a much smaller and narrowly focused snapshot every year in the annual update report, and an ongoing and notification of material changes filed whenever and as often as they occur. Together, they serve to keep the resource acquisition strategy and preferred resource plan *up to date and meaningful"* (emphasis added; footnote omitted).[68] Throwing the PRP in the trash and requiring (as Staff advocates for in this case) myriad new analyses and metrics perhaps suitable for merchant generators hardly gives meaning to a utility's PRP.

Q. You also discussed the use of generic assumptions in the Company's IRP analysis rather than project-specific assumptions. Do you have anything further to add on that point?

A. No, although it is worth reiterating that, in its direct testimony, the Company updated its generic assumptions for solar and other resources and, the specific parameters of the Projects are in line with those assumptions.

Q. How do you respond to Staff's criticism regarding the ability of utility management to use multiple self-defined objectives to craft and assess alternative resource plans?

A. This criticism is both inapt and untimely. Ameren Missouri has used the same planning objectives to inform and assess alternative resource plans since its 2011 IRP.[69] Staff challenged the weights applied by the Company for scoring in its comments

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[68] *Id.*, pp. 25-26. *See also* p. 21: "If the preferred resource plan is to be relevant and meaningful, it must be kept current."

[69] See Chapter 10 – Strategy selection for each of Ameren Missouri's 2014, 2017 and 2020 triennial IRP filings attached as Schedules MM-S10, MM-S11, and MM-S12, respectively. Please note that while Schedule MM-S12 has "C" or "HC" references, it is no longer confidential or highly confidential, although they were at the time of its original filing.

on the Company's 2011 IRP, but the Commission found those weights to be appropriate and in compliance with the provision of the Commission's IRP rules requiring that the minimization of NPVRR be the primary selection criterion.[70] Since that time, Staff has reviewed and commented on three Ameren Missouri triennial IRP filings and has expressed no concern with the use of the Company's planning objectives.[71] The Company's IRP planning objectives include cost, customer satisfaction, resource diversity, financial and regulatory risk, and economic development. Cost is measured by NPVRR and carries a weight of 30 percent for plan scoring. Economic development carries a weight of 10 percent, and the other three planning objectives each carry a weight of 20 percent. The Company continues to use these planning objectives based on their consistency with ensuring that the overall public interest is served and that minimizing costs to customers, which the Company's PRP does, is the primary criterion for assessing plan performance and selecting its PRP.

Q. Is Staff's assertion of bias in the Company's specification of its IRP assumptions valid?

A. Not at all. While it is true that the Company is, and should be, solely responsible for the assumptions it uses for its IRP analysis, it is also true that the IRP framework defined by the Commission's IRP rules provides ample opportunity for review and input on the part of Staff and other IRP stakeholders. First, the IRP rules provide for suggestions for so-called Special Contemporary Issues ("SCI") from Staff and other IRP

[70] File No. EO-2011-0271. In fact, Staff criticized the Company for not placing *more* weight on a plan's relative NPVRR yet now, when opposing the Projects, claims NPVRR matters not. [cite to staff report]
[71] See Staff 's reports on the Company's 2014, 2017 and 2020 IRP filings in Schedules MM-S3, MM-S4, and MM-S5.

stakeholders for both triennial IRP filings and annual updates.[72] This process allows Staff and other parties to recommend any issues or analysis, including assumptions or even specific plans, that the utility include in its next IRP filing. Because SCI suggestions are made in September of each year, and because Ameren Missouri has historically made its IRP filings by October 1st, this affords stakeholders the opportunity to suggest issues or items for analysis a full year in advance of the Company's IRP filings.[73]

Second, the IRP rules provide for stakeholder meetings and the provision of drafts of IRP documentation and the presentation to stakeholders of the assumptions the utility will use for its IRP analysis and the approach it will take to perform risk analysis of alternative resource plans prior to completing such analysis for its triennial IRP filings.[74] The assumptions presented to stakeholders include:

- Load forecasts, including base, high and low scenarios.
- Assumptions for supply side resource alternatives, including wind, solar, gas, and nuclear generation and battery storage and pumped storage resources. These include both cost and performance parameters.
- Assumptions for environmental compliance and mitigation for the utility's existing resource fleet.
- Cost and performance assumptions for the utility's existing fleet of resources.
- Prices for natural gas, emissions, market energy, and capacity.

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[72] 20 CSR 4240-22.080(4).
[73] Ameren Missouri has filed its triennial IRPs by October 1st since 2011 and its annual updates by October 1st since 2021 pursuant to a series of waivers approved by the Commission and supported by Staff.
[74] 20 CSR 4240-22.080(5).

- Assumptions for demand-side resource portfolios based on the utility's most recent market potential study.
- Assessments of transmission and distribution system requirements, and assumptions for transmission system investments associated with new generation additions and the retirement of existing generation.

The IRP rules provide stakeholders with 30 days to submit any comments, including potential alleged deficiencies or concerns with the assumptions presented or draft documentation provided to stakeholders. Ameren Missouri has routinely indicated that it would accept input beyond the 30-day period specified in the IRP rules.

Third, Ameren Missouri has made a practice of hosting a stakeholder meeting following the filing of its triennial IRPs and/or notifications to the Commission of a change in its PRP. The Company did so following both the filing of its 2020 IRP and its 2022 Notice of Change in Preferred Resource Plan. The Company has also indicated its openness to questions or discussions regarding issues outside of formal stakeholder meetings.

Throughout these interactions, the Company has remained open to questions and input regarding the assumptions it uses and its approach to IRP analysis. Throughout those same interactions, I do not recall anyone from Staff suggesting that the Company was using biased assumptions to achieve a desired outcome. The allegations made by Staff witnesses in this case in that regard are both surprising and disappointing.

Q. Did Ameren Missouri provide its draft IRP documentation and present its analysis framework and assumptions for its 2023 IRP in advance of its 2023 triennial IRP filing?

A. Yes, indeed well in advance of its filing of this case. On April 27, 2023, the Company presented its assumptions for its 2023 IRP analysis, along with its planned approach and framework for analyzing and assessing alternative resource plans. The slide deck used for that presentation is attached as Schedule MM-S13. The presentation covered assumptions for load forecasts, existing generation, new generation, transmission and distribution, natural gas prices, carbon prices, market energy prices and capacity prices. The market prices for energy and capacity are those produced by CRA, which I have discussed previously. The presentation also includes the Company's plans for evaluating uncertainties beyond the pricing scenarios analyzed by CRA. These include uncertainties regarding load growth, project costs and schedules, financing costs, forced outage rates, fuel costs (coal and nuclear), fixed and variable O&M costs, emission prices, and costs and load impacts from demand side programs.

On June 8, 2023, the Company shared drafts of the Chapters corresponding to 20 CSR 4240-22.030 (Load Forecasting), 20 CSR 4240-22.040 (Supply Side Analysis), 20 CSR 4240-22.045 (Transmission and Distribution Analysis), and 20 CSR 4240-22.050 (Demand Side Analysis). The drafts are attached to my surrebuttal testimony and marked as follows:

- Schedule MM-S14 – 2023 IRP Draft Chapter 3 – Load Analysis and Forecasting
- Schedule MM-S15 – 2023 IRP Draft Chapter 3 – Appendix A

- Schedule MM-S16 – 2023 IRP Draft Chapter 4 – Existing Supply-Side Resources
- Schedule MM-S17 – 2023 IRP Draft Chapter 4 – Appendix A
- Schedule MM-S18 – 2023 IRP Draft Chapter 4 – Appendix B
- Schedule MM-S19 – 2023 IRP Draft Chapter 5 – Environmental Compliance
- Schedule MM-S20 – 2023 IRP Draft Chapter 6 – New Supply-Side Resources
- Schedule MM-S21 – 2023 IRP Draft Chapter 6 – Appendix A
- Schedule MM-S22 – 2023 IRP Draft Chapter 7 – Transmission and Distribution
- Schedule MM-S23 – 2023 IRP Draft Chapter 7 – Appendix A
- Schedule MM-S24 – 2023 IRP Draft Chapter 8 – Demand-Side Resources (Potential Study)

Note that the Company's DSM potential study was provided in lieu of a separate draft of Chapter 8 as it appeared in the Company's final filing pursuant to a waiver requested by the Company and granted by the Commission to do so.[75]

[75] See the Commission's order granting the variance in File No. EE-2023-0021.

Q. You mentioned previously that the IRP rules provide the opportunity for Staff and other stakeholders to comment on the Company's draft documentation and the assumptions and analysis framework presented by the Company as you've just described. Did Staff provide any such comments, either formally or otherwise, regarding the Company's draft documentation, assumptions and analysis framework provided by the Company in advance of its 2023 IRP filing?

A. No.

Q. You mentioned the SCI process, by which Staff and other stakeholders can recommend issues or analysis that they would like the utility to perform. Did Staff suggest any SCIs for the Company's 2020 IRP, 2021 IRP annual update, or 2022 IRP annual update?

A. Yes. For the Company's 2020 IRP, Staff suggested analysis of transmission investments needed to facilitate coal retirements, ranges of adoption of electric vehicles, and consideration of potential future technologies for energy storage, distributed energy resources, and demand side programs. The Company routinely includes all of these in its IRP analysis. Staff did not propose any SCIs for the Company's 2021 annual update. Staff proposed two SCIs for the Company's 2022 annual update – discussion of the Company's plans for use of securitization and plans for handling emergency events (specifically citing the COVID pandemic and the February 2021 winter storm Uri).[76]

Q. Did Staff recommend any SCIs for the Company's 2023 IRP?

A. Yes. In addition to the two issues Staff had proposed for the Company's 2022 annual update, Staff also recommended analysis of customer and shareholder risks

[76] Staff's proposed SCI for the Company's 2020 IRP and 2022 annual update are attached as Schedules MM-S25 and MM-S26, respectively.

associated with the Company's planned renewable expansion. Staff noted that the additional suggested SCI was consistent with the Commission's order regarding the Company's 2020 IRP, that order having indicated the need for such analysis.

Q. Did the Commission adopt Staff's proposed SCIs for the Company's 2023 IRP?

A. No.

Q. Staff witness Fortson discusses the Commission's agreement with Staff for the need for the analysis of customer and shareholder risks as indicated in the Commission's order regarding the Company's 2020 IRP. Is there a reason the Commission declined to include this for the Company's 2023 IRP?

A. The Commission did not specify a reason for declining to include this issue, and I won't speculate as to why. I will note that the Company's response to the proposed SCI indicated that the Company had already performed and submitted analysis addressing this issue on two occasions. The first was a filing made by the Company on December 15, 2021, pursuant to the directive provided by the Commission in its order regarding the Company's 2020 IRP.[77] The second was as part of the Company's June 2022 Notice of Change in Preferred Resource Plan.[78] I am not aware of any other information on which the Commission may have relied to decline to include this issue as an SCI for the Company's 2023 IRP.

[77] The Company's December 15, 2021, filing is attached as Schedule MM-S27.
[78] The analysis included with the Company's 2022 Notice of Change in Preferred Plan is included in Schedule MM-D2, attached to my direct testimony.

Q. The analyses of customer and shareholder risks to which you refer were the eventual result of a concern raised by Staff regarding the Company's 2020 IRP, as witness Fortson notes. Has Staff provided any feedback to the Company regarding this analysis?

A. Staff has provided no formal feedback, and its informal feedback has been limited to a simple acknowledgement that the Company has performed the analysis.

Q. Did the Company discuss its analysis with Staff and/or other IRP stakeholders?

A. Yes. On December 2, 2021, the Company met with members of Staff to discuss the Company's analysis of customer and shareholder risks and to seek input from Staff prior to finalizing the Company's analysis for filing.[79] Staff indicated no issues with the Company's analysis and provided no suggestions for modifications, but cordially acknowledged the Company's efforts to perform the required analysis. While the Company had technically satisfied the Commission's directive regarding this analysis with its December 2021 filing, the Company sought the assistance of expert consultant Roland Berger to bring additional rigor to the analysis of risk for inclusion with the Company's 2022 Notice of Change in Preferred Resource Plan.

On July 11, 2022, the Company presented to stakeholders its updated PRP as indicated in its June 2022 Notice of Change in Preferred Resource Plan, including the results and approach to the analysis of customer and shareholder risks performed with

[79] The slides used to facilitate the discussion with Staff on December 2, 2021, are attached as Schedule MM-S28. Please note that while Schedule MM-S28 was confidential at the time it was presented, it no longer is. Following the Staff discussion on December 2, the Company made the filing on December 15, 2021.

Roland Berger.[80] Staff provided no pushback regarding Roland Berger's analysis at that time or since. In fact, Staff provides no critique of this analysis, or the Company's prior analysis of this issue, in its testimony in this case, despite noting its original concern which led to the analysis.

Q. Did the Commission provide the opportunity for Staff and other stakeholders to suggest SCIs for the Company's 2024 IRP annual update?

A. Yes. Staff and other stakeholders were afforded the opportunity to suggest SCIs for the Company's 2024 IRP annual update by September 15, 2023.[81] The deadline for SCI suggestions was about four weeks prior to the due date for Staff's rebuttal testimony in this case and about four months after the filing of the Company's direct case.

Q. Did Staff suggest any SCIs for the Company's 2024 IRP annual update?

A. No. Office of Public Counsel and Sierra Club provided suggested SCIs, but Staff did not.

Q. In your opinion, has Staff had numerous opportunities to voice the kinds of concerns it expresses regarding the Company's IRP assumptions and analysis in its rebuttal testimony in this case prior to the filing of that testimony?

A. Yes.

Q. In your opinion, has Staff had numerous opportunities to suggest assumptions or analyses to be performed by the Company of the kind it claims it should be afforded the opportunity to suggest?

A. Yes.

[80] The slides used to facilitate the discussion with Staff and other stakeholders on July 11, 2022, are attached as Schedule MM-S29.
[81] File No. EO-2024-0042.

V. THE COMPANY'S 2023 IRP ANALYSIS CONFIRMS THE ECONOMIC BENEFITS OF THE COMPANY'S PLANNED RENEWABLE TRANSITION

Q. Staff witnesses assert that the Company's analysis as presented in its direct case is not useful because the assumptions used for the analysis included in the Company's 2022 Notice of Change in Preferred Resource Plan are outdated and out of line with the Company's latest assumptions. At the same time, Staff witnesses also assert that the analysis included in the Company's 2023 IRP cannot be used to support the Company's requests in this case because it was filed only weeks prior to the date on which Staff's rebuttal testimony in this case was due. Are either of these contradictory points valid?

A. No. I would first note that, in combination, Staff's concerns of the prior IRP being too old and the instant IRP being too new would, if adopted, create a CCN process and a standard for CCN approval that would literally make it impossible for a utility to make any filing of any kind to implement the Company's PRP except in incredibly narrow – and as yet unidentified by Staff – windows of time where an IRP's age was "just right" – old enough to have been reviewed by stakeholders but not so old as to be "out of date" yet. Because the Company follows the requirements of the IRP rules regarding updates to its PRP between IRP filings, it always has a PRP that is in effect and reflective of its business plan. The Company's request in this case is consistent with the PRP the Company was implementing at the time it filed its direct case, and it remains consistent with the PRP it adopted when it made its triennial 2023 IRP filing.

Beyond that, though, Staff omits very important facts in making these claims. The first is that the Company updated key assumptions for the analysis presented in its *direct case*, including in my direct testimony, as I have explained in detail previously in my surrebuttal testimony. These updates included project costs for wind and solar generation, tax credit provisions under the IRA, and assumptions related to the Company's capacity position, including load forecast, demand-side program load impact, and capacity accreditations and planning reserve margin requirements as used in MISO's 2023-2024 PRA.

The second is that Staff has had a substantial portion of the Company's 2023 IRP filing available to review since before the Company filed its application in this case, including those assumptions which are key to the relative economics of renewable resources, including the Projects. Staff notes the date of the recent filing of the Company's 2023 IRP, implying that it did not have an opportunity to review even a substantial portion of the Company's filing before then. Whether intentional or not, this is misleading. As I have described previously in my surrebuttal testimony, the Company presented the assumptions and analysis approach the Company used for its 2023 IRP analysis to Staff and other IRP stakeholders in April and provided drafts of the chapters covering the Company's IRP assumptions in June, four months prior to the filing of Staff's rebuttal testimony in this case and now a full six months ago. Those assumptions did not change for the actual 2023 IRP filing with the exception of a small change to load to reflect emerging economic development activity, which is common to all plans. Staff's rebuttal testimony in this case demonstrates its awareness of these assumptions and the opportunity it has had to review and digest them. Most notably, Staff did have sufficient time and opportunity to make a comparison of the solar project cost assumptions between the Company's 2023 IRP and its 2022 Notice of Change in Preferred Resource Plan, to provide an assessment of the Company's use of its 2023 IRP assumptions for carbon prices, and to criticize the power pricing analysis performed by CRA for the Company's 2023 IRP.[82]

Q. What portions of the Company's 2023 IRP filing were only available to Staff and other stakeholders as of the filing date?

A. The following chapters of the IRP were only available upon the filing of the Company's IRP on September 26, 2023:

- Chapter 1 – Executive Summary – This chapter provides an overview of the Company's PRP and key elements of the filing.[83]
- Chapter 2 – Planning Environment – This chapter provides a discussion of the market scenario variables and results of CRA's price modeling for energy and capacity.[84] It also provides discussion of MISO's resource adequacy framework, planning reserve margin requirements, and capacity accreditation values, as well as general planning environment considerations. While this chapter was only available upon filing, the key inputs and results of price modeling were presented to Staff and other stakeholders in April 2023, and the MISO variables were included and reflected in the capacity analysis provided in my direct testimony in this case, filed in mid-June.

[82] As noted, Staff was aware of the CRA analysis in April, 2023, and then had more than two months to actually analyze it (including all workpapers) prior to filing Staff's rebuttal.
[83] Ameren Missouri's 2023 IRP Chapter 1 is attached as Schedule MM-S30.
[84] Ameren Missouri's 2023 IRP Chapter 2 is attached as Schedule MM-S31.

- Chapter 8 – Demand-Side Resources – This chapter covers the Company's consideration of demand side programs in final form in addition to the Company's market potential study, which was provided as a draft in June.
- Chapter 9 – Integration and Risk Analysis – This chapter covers the results of the Company's analysis of alternative resource plans.[85]
- Chapter 10 – Strategy Selection – This chapter covers the Company's selection of its PRP based on the analysis results described in Chapter 9 and the company's resource planning objectives, including minimization of NPVRR.[86]
- Chapter 11 – Stakeholder Process – This chapter provides an overview of the Company's stakeholder process, including descriptions of its analysis of SCI and consideration of stakeholder comments on its draft documentation and assumptions, along with any references to the location(s) within the filing where SCI and comments are addressed.

In short, the key portions of the 2023 IRP filing only available at the time of filing are the analysis results and selection of the Company's PRP. All relevant inputs and assumptions of the 2023 IRP were available to Staff before this case was filed.

Q. How long has the Company used the model that produces the results of analysis of alternative resource plans?

A. The Company has used its current IRP model since the preparation of its 2014 IRP. The model is an Excel-based model developed by Ameren Missouri. It is described in Chapter 9 of each of the Company's triennial IRP filings and is provided in

[85] Ameren Missouri's 2023 IRP Chapter 9 is attached as Schedule MM-S9.
[86] Ameren Missouri's 2023 IRP Chapter 10 is attached as Schedule MM-S32.

the workpapers included with each of the Company's triennial IRP filings. It uses as part of its inputs the results of production costs models used to determine generation dispatch, production, emissions, and costs. While the production cost model was changed from the RTSim model to PowerSimm Planner for the Company's analysis supporting its 2022 Notice of Change in Preferred Plan and then for the Company's 2023 IRP, the scope and format of the data used by the IRP model has remained the same. It should be noted that the PowerSimm Planner model has also been used previously by the Company in support of its electric rate review filings in both 2021 and 2022. In both of those cases, the model results were reviewed by Staff for both the Company's direct case analysis and true-up analysis.

Q. During the time the Company has used its current IRP model, has Staff or any stakeholder identified any material issue with respect to the operation or accuracy of the IRP model's results?

A. No.

Q. Is it fair to say that the Company's IRP model will produce accurate results reflecting whatever assumptions are used to drive the modeling?

A. Yes.

Q. Do you have any reason to believe that the results produced by the Company's IRP model for its 2023 IRP are not accurate and reflective of the assumptions used by the Company for that analysis?

A. No.

Q. Does Ameren Missouri place significant importance on the consistency and continuity of its IRP resource planning?

A. Definitely. The Company places significant importance on the consistency and continuity of its planning because it ensures stability in its planning and ensures that changes to its plans, including its PRP, are appropriate and explainable.

Q. Do you believe Staff also places significant importance on that kind of consistency and continuity?

A. I do. The rebuttal testimony of Staff witness Fortson provides an indication of the importance Staff places on consistency and continuity by noting the consistent presence of combined cycle gas-fired generation in the Company's PRP across multiple IRP filings and suggesting that this provides a strong indication of the need for such generation.

Q. Witness Fortson notes that the amount of combined cycle gas generation has increased across successive triennial IRP filings made by the Company over the years. Should that be cause for concern?

A. No. To the contrary, the increase in the Company's need for resources over the course of multiple IRP filings is primarily a reflection of the level of existing generation retirements expected during the 20-year planning horizon, which is extended three years with each successive triennial IRP filing. For the Company's 2011 IRP, the planning horizon extended through 2030, and the only significant generation retirement through then was that of the Company's Meramec Energy Center. With successive IRP filings, the planning horizon extended further into the 2030s and now through 2043, by which time the Company expects to have retired all of its coal-fired generation along with its gas-fired generation in Illinois. While the Company fully believes that its plans for significantly expanding its fleet of renewable generation to transition its generation portfolio is the best and most affordable path for meeting its customers' future energy needs, it also believes that significant dispatchable generation resources will be needed to ensure reliability as it retires its aging fleet of coal-fired resources.

Q. How has the Company's consideration of renewable generation and inclusion in its PRP evolved over the years and through the Company's IRP filings?

A. Through its 2014 IRP, the Company saw promise in the potential large-scale expansion of renewable resources, but the economics weren't sufficient to make such a commitment. Ameren Missouri added renewable generation to its portfolio in limited ways, including a wind PPA, a landfill gas generation facility, and a relatively small solar generation facility, which provided renewable energy alongside the Company's existing hydroelectric generation resources and helped the Company meet its obligations under the Missouri Renewable Energy Standard ("RES"). Shortly thereafter, the economics of renewable generation improved, primarily driven by decreases in project costs. As a result, the Company added 700 MW of wind generation to its PRP in its 2017 IRP filing to meet increasing RES requirements in 2021. As the Company implemented its planned wind additions, the economics of solar generation continued to improve. During this time, we also saw increasing support for and efforts to promote the use of renewable energy as part of policies to reduce greenhouse gas emissions, starting with the promulgation of EPA's Clean Power Plan (CPP). While the CPP was ultimately withdrawn, the sentiment of the public and policymakers supporting renewable energy has continued, including the passage of the IRA in 2022. This environment of improving economics and policy trends led the

Company to include a large-scale expansion of renewable resources in its PRP for its 2020 IRP. The Company has continued to include this renewable resource expansion, albeit with slight modifications in timing, in its PRP through its 2022 Notice of Change in Preferred Resource Plan and now its 2023 IRP.

Q. Staff, as part of its criticism of how the Company goes about selecting resource plans, points to materials regarding the 2023 IRP filing that were provided by the Company to Staff in mid-September of this year.[87] What kind of information about the 2023 IRP was shared with Staff?

A. On September 14, 2023, the Company shared its 2023 IRP PRP and key results of its analysis that led to the PRP's selection, including its energy and capacity position and comparison of NPVRR results for key plans evaluated as part of the 2023 IRP process.

Q. Did the Company's 2023 IRP analysis indicate a need to significantly alter the Company's plans (at that time most recently reflected in its 2022 PRP) for renewable resource expansion?

A. No. While some of the details have changed from the 2022 PRP (although in most key respects the 2023 PRP is very similar to the 2022 PRP), the analysis results of alternative resource plans for the Company's 2023 IRP continue to support the implementation of the Company's planned addition of renewable resources over the planning horizon. The chart in Figure 1 below was included in the overview provided to Staff on September 14, 2023, and shows the NPVRR for selected alternative resource plans analyzed by the Company as part of its 2023 IRP. From left to right, the results correspond

[87] Brad Fortson Rebuttal Testimony, p. 20.

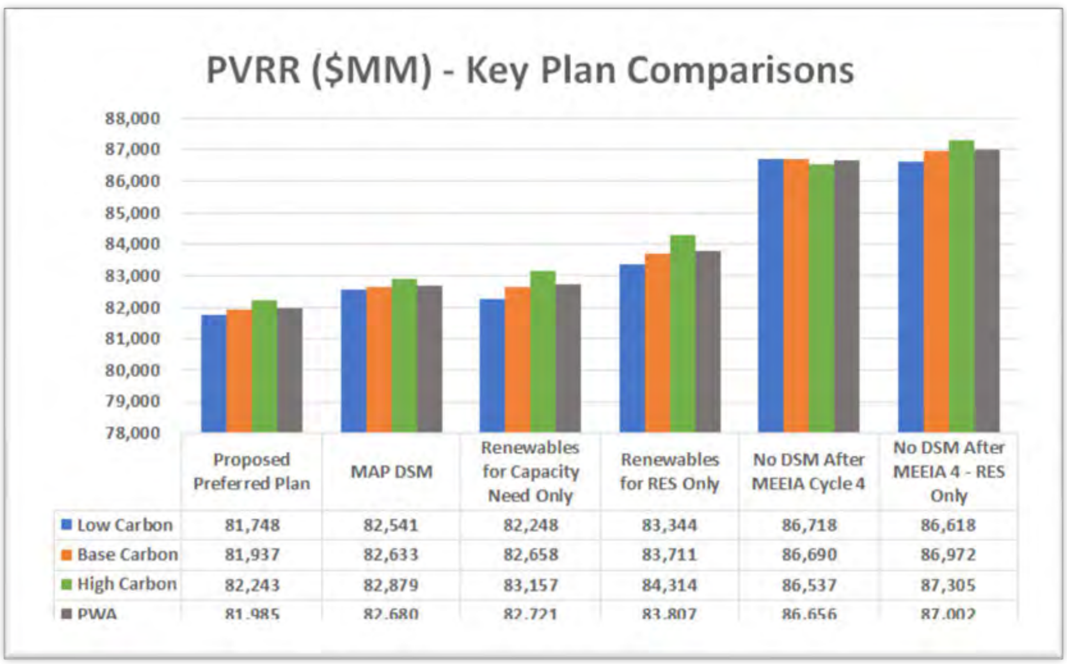
to 2023 IRP Alternative Resource Plans C, E, K, F, I and J.[88] The key takeaways relevant to the Company's request in this case come from comparison of Plan C, the Company's 2023 IRP PRP, to Plan K, the Renewables for Capacity Need Plan, and Plan F, the Renewables for RES Only Plan. The key differences between Plans C and F are the renewable additions – limited to 725 MW of solar resource additions over the planning horizon in Plan F compared to 4,700 MW of wind and solar additions for Plan C – and the addition of a further 1,200 MW of combined cycle gas generation in Plan F given the reduced level of renewable additions. This provides a direct comparison of the Company's planned addition of renewable resources to a plan in which gas-fired generation is added instead of non-RES renewable resources. The NPVRR for Plan C is lower than that for Plan F by approximately $1.6 billion to $2.1 billion, depending on the assumed carbon price, with a probability-weighted-average difference of approximately $1.8 billion.

The comparison of Plans C and K for the 2023 IRP is closely analogous to the comparison of similar plans included in my direct testimony. The only difference between Plans C and K is the timing of renewable additions, which in Plan K are limited to the amount of renewable resources needed to meet the Company's required planning reserve margin precisely when such capacity is needed, regardless of the infeasibility of doing so. The NPVRR for Plan C is lower than that for Plan K by approximately $500 million to $900 million, depending on the assumed carbon price, with a probability-weighted-average difference of approximately $700 million. Note that this comparison is conservative and does not include a quantification of certain risks that were analyzed by Roland Berger and included in the Company's 2022 Notice of Change in Preferred Resource Plan. As

[88] See 2023 IRP Chapter 9, Schedule MM-S9, Table 9.6 for detailed descriptions of each plan.

discussed in my direct testimony, risks regarding financing costs and land availability remain real risks that could significantly increase costs to customers if the Company's deployment of renewable resources is significantly delayed. Roland Berger had estimated the financing cost risk to be approximately $300 million alone, which would bring the expected difference in costs between Plans C and K to roughly $1 billion. Land availability risks were estimated to be between $200 million and $300 million.

Figure 5. NPVRR of Selected 2023 IRP Alternative Resource Plans[89]



[89] The "Proposed Preferred Plan" is Plan C, the "Renewables for Capacity Need Only" is Plan K, and the "Renewables for RES Only" is Plan F.

Q. Staff witness Fortson notes several changes in the Company's PRP from what it filed in 2022 to what it just filed with its 2023 IRP.[90] Do those changes suggest that the analysis provided by the Company in its direct testimony in this case is invalid for purposes of supporting the Company's request in this case regarding the Projects?

A. Not at all. In fact, the Company's 2023 IRP analysis results simply serve to *confirm* the direct case the Company has already made in support of the Projects. Witness Fortson lists changes to the PRP he says he is aware of, then speculates that there might be others (there aren't). The truth is that the Company's PRP in its 2023 IRP represents a modest evolution from that filed by the Company with the Commission in 2022. The total amounts of wind, solar and battery storage added in the PRP are unchanged. Only the timing has changed with some delays in both solar and wind additions compared to 2022 assumptions. 400 MW of battery storage was moved up to the late 2020s because of the addition of stand-alone ITC for storage resources through the IRA. The retirement of Sioux Energy Center and the effectively simultaneous addition of 1,200 MW of combined cycle gas generation has been delayed by just two years, from the end of 2030 to the end of 2032. The Company has also added 800 MW of simple cycle gas generation by the end of 2027 to ensure reliability during extreme conditions and to partner with renewable resources to ensure reliability. Beyond that, the level of clean dispatchable resources added near the end of the planning horizon, in 2040 and beyond, has increased to reflect expected reliability needs, including the needs that arise from the evolving resource adequacy framework in MISO.

[90] Brad Fortson Rebuttal Testimony, p. 18.

Q. Is the fact that the Company has updated its analysis as part of its 2023 IRP an indication that the analysis presented in the Company's direct case in support of the Projects is invalid? Put another way, does the 2023 IRP analysis and the Company's new PRP conflict with the analysis presented by the Company in its direct case?

A. No. The analysis included in the Company's 2023 IRP simply confirms the conclusions the Company has reached regarding the need for renewable resources, which has consistently existed in the Company's 2020 PRP, its 2022 PRP, its 2022 PRP (with key assumptions updated) presented in our direct case, and now in its 2023 PRP. While assumptions change and analysis results fluctuate, the Company's latest IRP analysis points unequivocally to the need for a significant expansion of renewable resources to meet customers' energy needs affordably and, with the help of existing and new dispatchable resources, reliably while mitigating risks attendant to the continued use of coal-fired generation to maintain reliability during the transition. None of these changes alter the basic fact that by next year we will have retired about 2,000 MW of what was once a 5,400 MW coal-fired fleet, and that the rest of it is expected to be retired within the planning horizon, including another nearly 900 MW in less than ten years. None of these changes indicate that renewables should not play a significant role in replacing some (eventually about 50%) of the energy those coal-fired resources formerly provided – certainly not that we don't need the 550 MW of solar at issue in this case – and none of those changes undermine the significant risk mitigation the Projects in this case and additional renewables provide against the risks facing our coal-fired generation fleet, and that are present in the MISO market. A key take-away from the 2022 PRP is confirmed by the 2023 PRP: the

Company's prior and current PRP produces an NPVRR that is hundreds of millions (or a billion dollars or more when the very real risks of transition are included) more cost-effective than the alternative, while also mitigating the kinds of risks discussed by Company witness Arora in his direct and surrebuttal testimonies, and about which the Commission's Boomtown order indicates the Commission is also concerned.

VI. THE COMPANY'S 2023 IRP ANALYSIS CONFIRMS THE NEED FOR RENEWABLE RESOURCES, INCLUDING THE PROJECTS

Q. What does Staff's rebuttal say about Ameren Missouri's need for renewable energy projects?

A. Staff asserts that the Company does not need to add renewable resources like the Projects in the near term because, in Staff's view, the Company has not adequately defined the term "energy need,"[91] the Company has not sufficiently demonstrated a need for the energy,[92] and the Company need not be concerned with energy needs as long as it has sufficient capacity to meet peak demand, the idea being that the Company can simply rely on the capacity resources it would own and operate to generate when needed, and/or continue to rely on the MISO, where (presumably according to Staff's view) there will always be sufficient energy resources to meet utilities' needs whether or not they add the resources necessary to meet those needs themselves.[93]

Q. Has the Company defined what an "energy need" is?

A. Yes, although not in the kind of neatly packaged formulaic definition that Staff indicates it would like, as Company witness Arora discusses in his surrebuttal

[91] Staff witness Sarah Lange Rebuttal Testimony, pp. 62-67.
[92] Staff witness Shawn Lange Rebuttal Testimony, p. 7.
[93] Staff witness Shawn Lange Rebuttal Testimony, pp. 7-8; Staff witness Michael Stahlman Rebuttal Testimony, pp. 7-8.

testimony. By and through the discussion that the Company has included in its IRP filings and related documentation, beginning with its 2020 IRP, an energy need is indicated when the Company expects to have insufficient generation to meet its load obligation and to mitigate risks to its ability to do so.

Q. Has the Company sufficiently demonstrated its energy need?

A. Yes. As I mentioned above, the Company discussed this need in its 2020 IRP.[94] It further discussed its need for energy in its testimony accompanying its request for a CCN for the Boomtown solar project,[95] and in my direct testimony in this case.

Q. Does the Company's 2023 IRP reflect an expectation that the energy need established by the Company in its direct case will be eliminated or materially diminished?

A. No. Staff witness Fortson calls changes to the Company's 2023 IRP PRP "substantial." As I discussed earlier, Staff takes the position the 2023 IRP is too new, although as also demonstrated earlier many key 2023 IRP assumptions were known to Staff months ago and in fact were used in my direct testimony analyses. It is clear to me that Staff at a minimum wants to create the impression that the 2023 PRP may materially change the existence of the Company's energy need, the implication being that the Company's direct case might be inadequate due to changes between then and now. But the facts are that the results of the Company's 2023 IRP analysis in fact do *not* indicate a reduced energy need relative to that demonstrated in my direct testimony in this case, nor do they in any way undermine the Project justifications presented by the Company in this case. If anything, the 2023 IRP indicates a greater need for energy. Regardless, the energy

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[94] Schedule MM-S12.
[95] File No. EA-2022-0245.

need established by a string of analyses going back several years, including by my direct testimony, remains. This is driven by assumptions and expectations for customer demand, including electrification and economic development, and expectations for generation production in light of proposed and potential future environmental and climate policy.

Q. So, it is simply not true that the 2023 IRP is too new, that if Staff took months to examine it a different picture for energy needs would emerge??

A. No, that is not true, as comparisons to our direct case energy positions and energy positions reflecting the 2023 IRP show. The charts in Figures 6, 8, and 10 below show the Company's annual energy position under three different sets of assumptions for resource additions and using probability-weighted-average ("PWA") load and carbon prices based on its 2023 IRP analysis. Figure 6 shows the annual energy position for Company's 2023 PRP with only renewables added for RES compliance (Plan F in Figure 5 above) – additional renewables, the 2033 combined cycle, and the 2040 and 2043 clean dispatchable generation additions are excluded. Figure 8 shows the annual energy position with only RES renewable additions and the 2033 combined cycle – still excluding additional renewable resources and the 2040 and 2043 clean dispatchable generation additions (Plan K). Figure 10 shows the energy position for the Company's PRP (Plan C) with no exclusions. Figures 7, 9, and 11 show the comparable energy positions that I presented in my direct testimony.[96]

[96] As outlined in my direct testimony and again in this surrebuttal testimony, these direct case charts were all based on updated key assumptions for the 2023 IRP, but since the 2023 PRP was not determined at that time, obviously did not fully reflect the entirety of the 2023 IRP. Please also note that my direct case energy position charts started with the year 2023 and ended with the year 2050. The updated charts run from 2024 through 2045. The 2023 IRP planning horizon actually ends in 2043.

Figure 6. Annual Energy Position for 2023 PRP with Only RES Renewables (MWh)

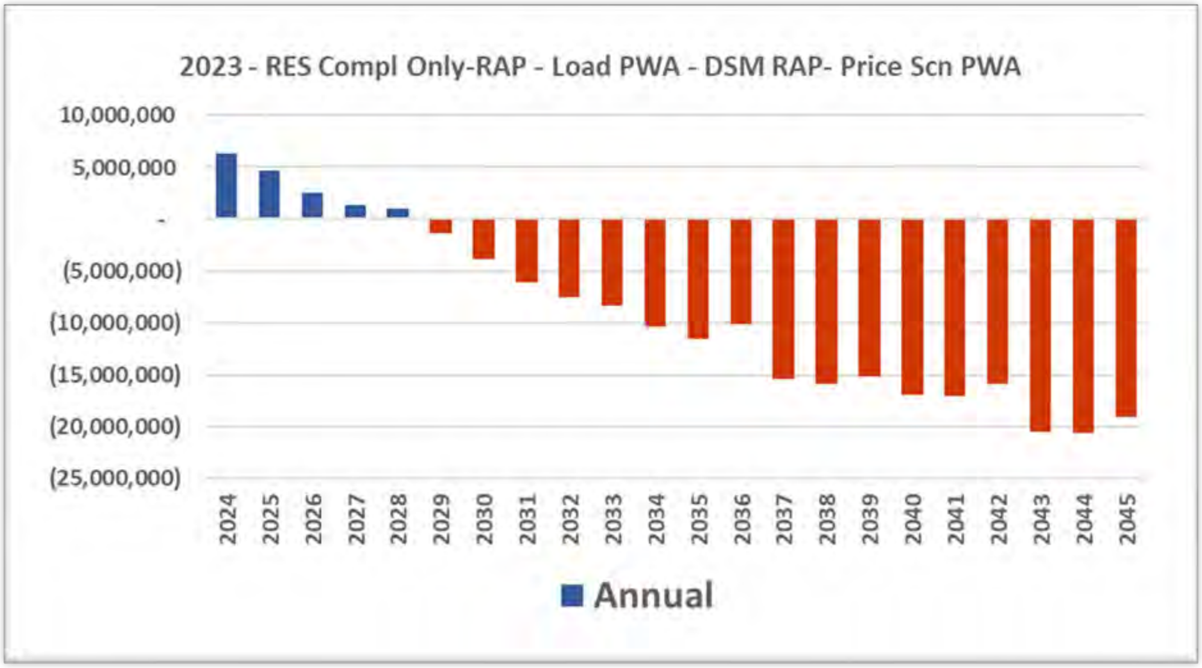
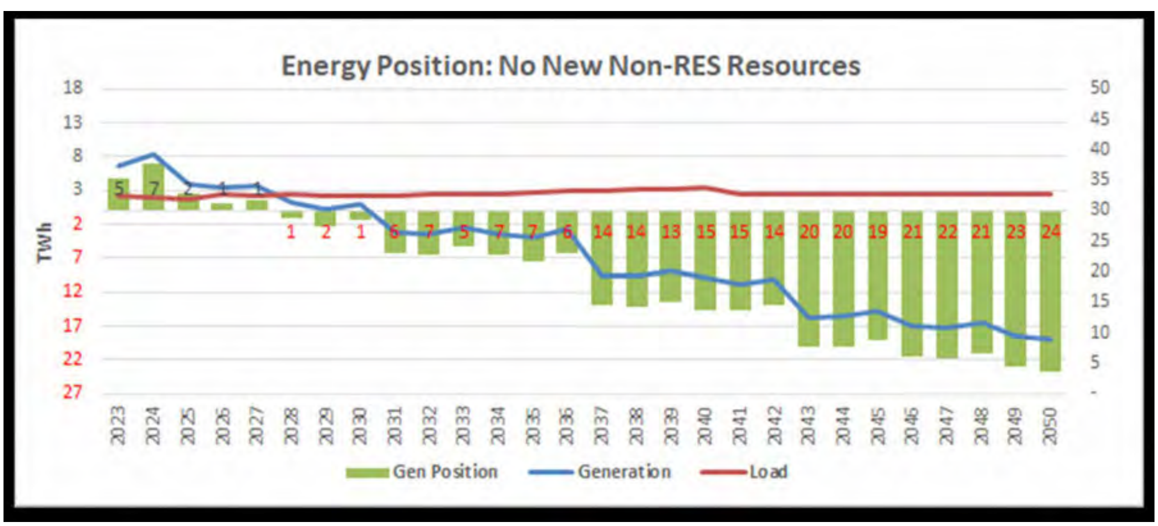


Figure 7. Annual Energy Position for 2022 PRP with Only RES Renewables (MWh)[97]



[97] Figure 7 here is a reproduction of Figure 5 in my direct testimony.

Figure 8. Annual Energy Position for 2023 PRP with Only RES Renewables and 2033 Combined Cycle

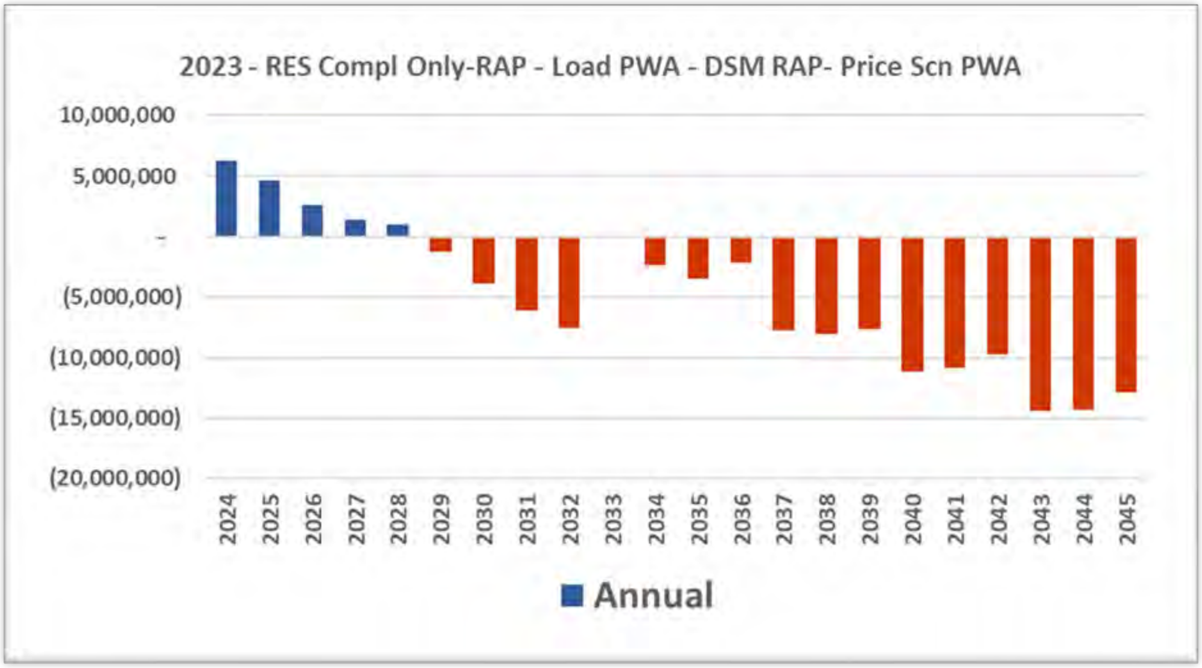
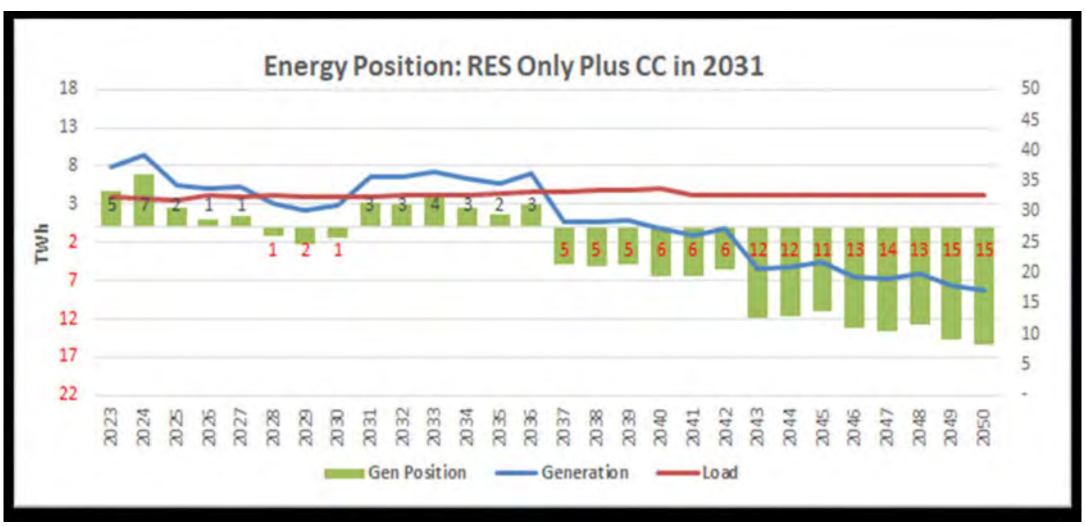


Figure 9. Annual Energy Position for 2022 PRP with Only RES Renewables and 2031 Combined Cycle[98]



[98] Figure 9 here is a reproduction of Figure 6 in my direct testimony.

Figure 10. Annual Energy Position for 2023 PRP

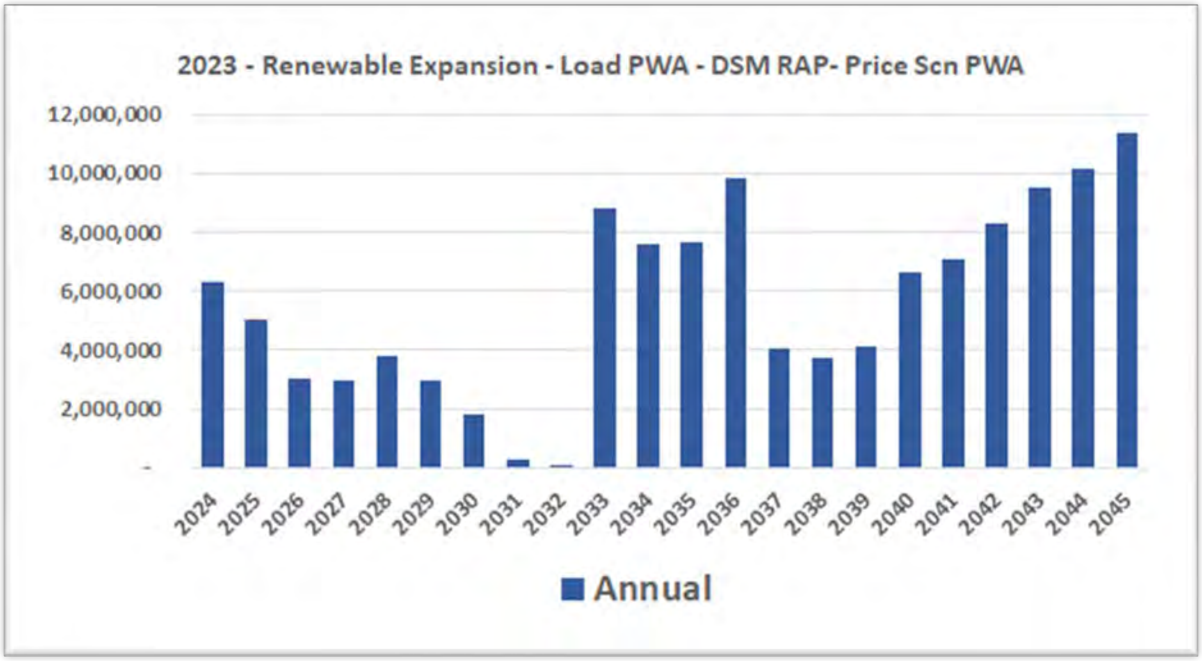
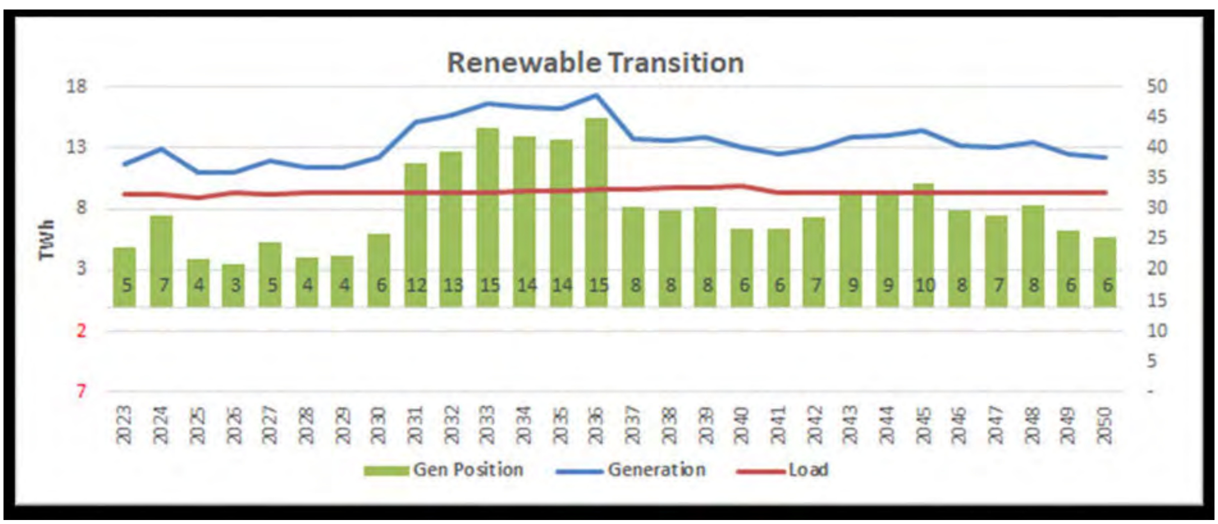


Figure 11. Annual Energy Position for 2022 PRP[99]



As Figure 6 shows, the Company has a need for energy resources starting in 2029 without non-RES renewables which starts at 1-2 GWh and grows to approximately 17 GWh in 2040. As shown in Figure 8, the addition of combined cycle gas generation

[99] Figure 11 here is a reproduction of Figure 7 from my direct testimony.

partially alleviates the need for energy resources, but still leaves a need of 4 GWh in 2030 and 11 GWh in 2040. Finally, Figure 10 shows the inclusion of all renewable and dispatchable additions in the Company's PRP results in satisfaction of the Company's need for energy resources and a buffer to mitigate risks on both the demand-side and the supply-side. While there are some differences in the exact timing and magnitude in a given year of the Company's energy position between the direct testimony charts and the charts using the full 2023 IRP, the basic facts remain the same: the Company has a significant need to replace energy that used to come from coal, and adding renewables greatly assists in meeting that need.

Q. Figure 10 shows a significant surplus of energy in 2040 and growing further in 2043. Do the resources added in those years obviate the need for some of the renewable additions the Company plans to make?

A. No. The Company expects to need what it refers to as "clean dispatchable resources" in that timeframe to replace the coal and gas-fired dispatchable resources being retired in 2039 and 2042. Because of uncertainty regarding resource technology development, Ameren Missouri has included gas-fired combined cycle generation with carbon capture and sequestration as a placeholder resource to meet that need. However, other resources may ultimately prove to better meet those needs by the time resource decisions must be made. For example, the Company also analyzed alternative resource plans that include the addition of simple cycle gas, which operates sparingly, and pumped hydro storage, which produces no net energy, instead of combined cycle gas in that timeframe. These plans were competitive with the PRP selected by the Company and indicate the need for flexibility regarding commitments to dispatchable resource technologies near the end of the 20-year planning horizon. The Company continues to follow developments regarding new nuclear and hydrogen-based technologies as well since such technologies may also prove useful for meeting future dispatchable resource needs.

Q. You mentioned a "buffer" of energy production to mitigate risks with respect to demand and supply. Have you analyzed the potential impacts of such risks?

A. Yes. Figures 12 and 14 below show the Company's energy position excluding non-RES renewables and clean dispatchable resources in 2040 and 2043 under two different scenarios that represent such potential risks based on the Company's 2023 IRP analysis. Figure 12 shows the energy position for this portfolio with PWA load and high carbon prices. Figure 13 shows the energy position for high load and high carbon prices. Both demonstrate the degree to which energy needs may increase or accelerate when compared to the energy position in Figure 8, which reflects PWA load and carbon prices. Figures 13 and 15 show the comparable energy positions for each as presented in my direct testimony.

Figure 12. Annual Energy Position for 2023 PRP with Only RES Renewables and 2033 Combined Cycle – High Carbon Price

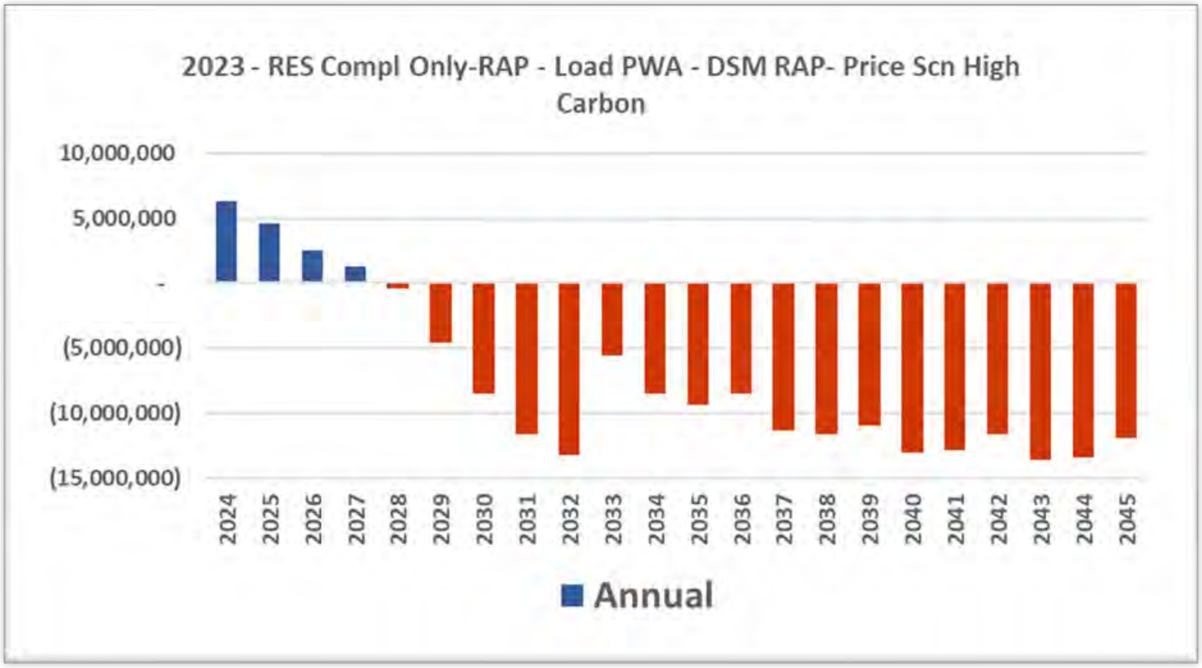
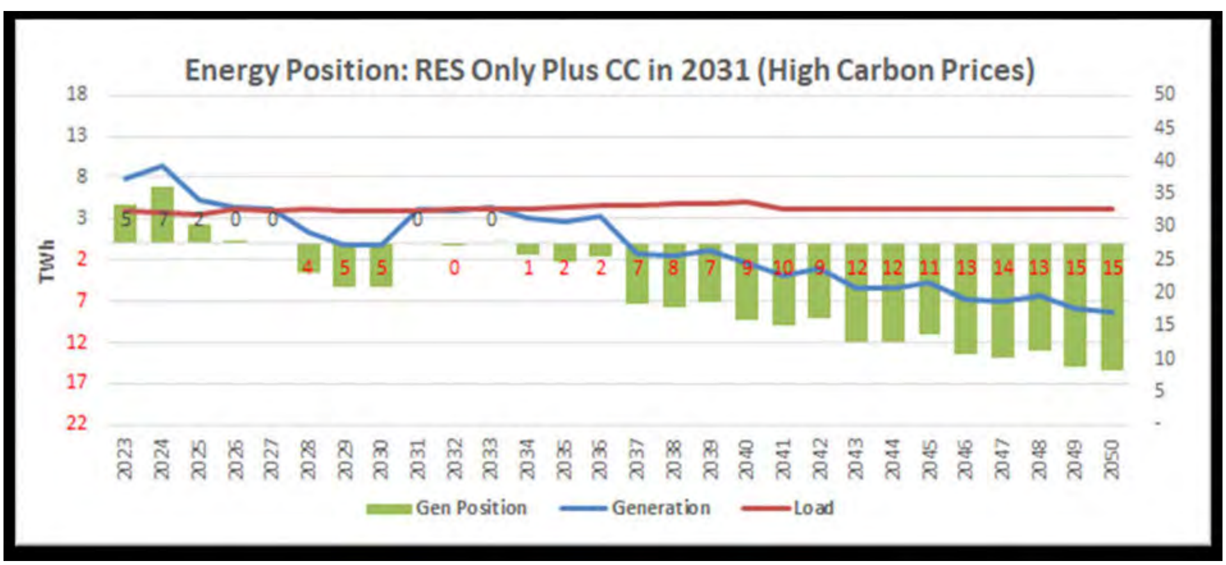


Figure 13. Annual Energy Position for 2022 PRP with Only RES Renewables and 2031 Combined Cycle – High Carbon Price[100]



100 Figure 13 is a reproduction of Figure 8 from my direct testimony.

Figure 14. Annual Energy Position for 2023 PRP with Only RES Renewables and 2033 Combined Cycle – High Load, High Carbon Price

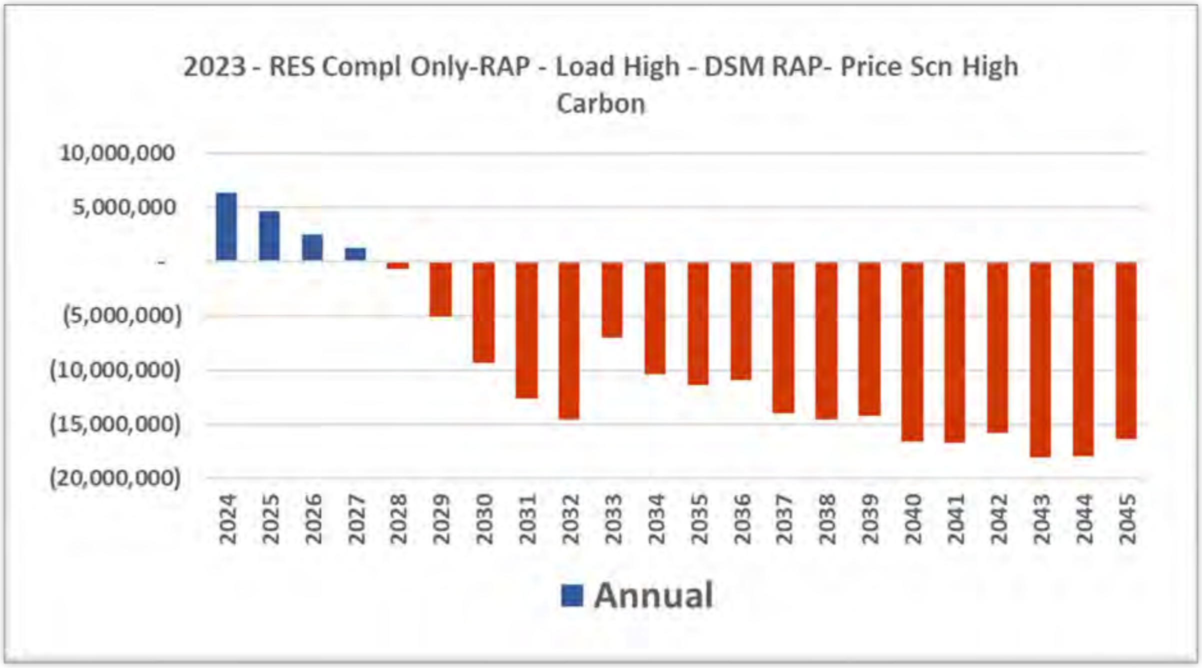
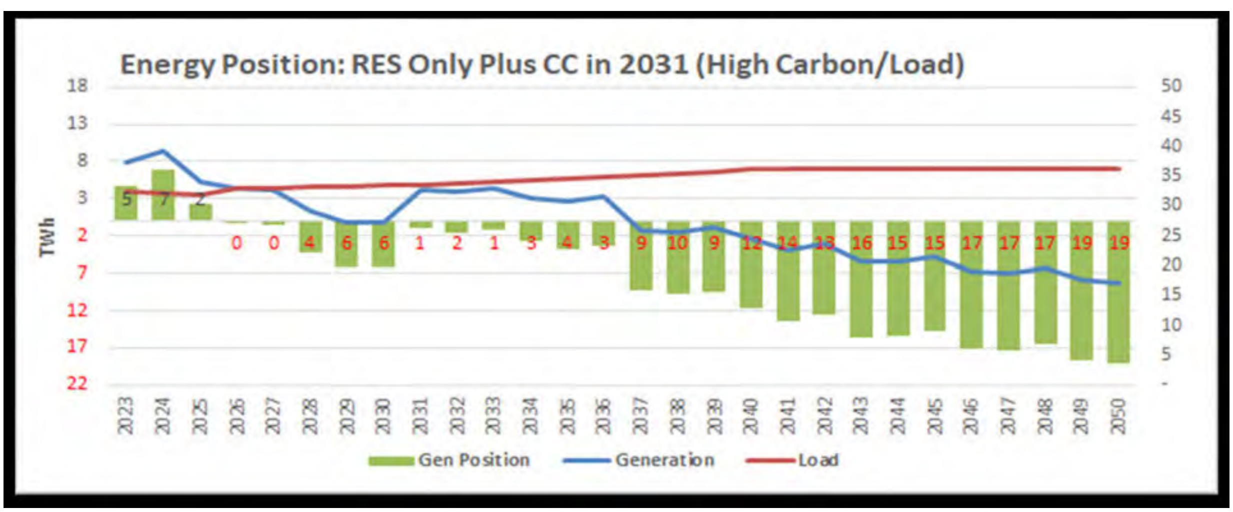


Figure 15. Annual Energy Position for 2023 PRP with Only RES Renewables and 2031 Combined Cycle – High Load, High Carbon Price[101]



[101] Figure 15 is a reproduction of Figure 9 from my direct testimony.

It is important to guard against such risks, particularly because load and carbon prices (or more broadly, environmental and climate policy) are influenced by numerous factors that are outside Ameren Missouri's control or influence. Load-related risks include higher or more rapid expansion of electrification and higher than expected economic expansion, including the addition of large loads for data centers and manufacturing. Environmental and climate policy can significantly impact generation from both existing and new fossil-fueled resources and may in some cases result in the need for significant reductions in generation at certain facilities and/or early retirement. Maintaining an energy buffer allows the Company to maintain flexibility as conditions change and to plan for such changes.

Starting with its 2020 IRP and continuing to today, the Company's PRP, with its inclusion of a steady buildout of renewable resources throughout the planning horizon, significantly mitigates these risks. Figures 16 and 18 below show the same risk scenarios illustrated in Figures 9 and 10 but include the non-RES resources in the Company's PRP based on its 2023 IRP analysis. The comparable energy positions charts from my direct testimony are shown in figures 17 and 19. As these charts show, the Company's need for energy can change significantly as a result of changing conditions and expectations. This highlights the need to ensure an energy buffer to mitigate the risks associated with such changing conditions that affect both demand and supply, as I have discussed previously in my surrebuttal testimony.

Figure 16. Annual Energy Position for 2023 PRP -High Carbon Price

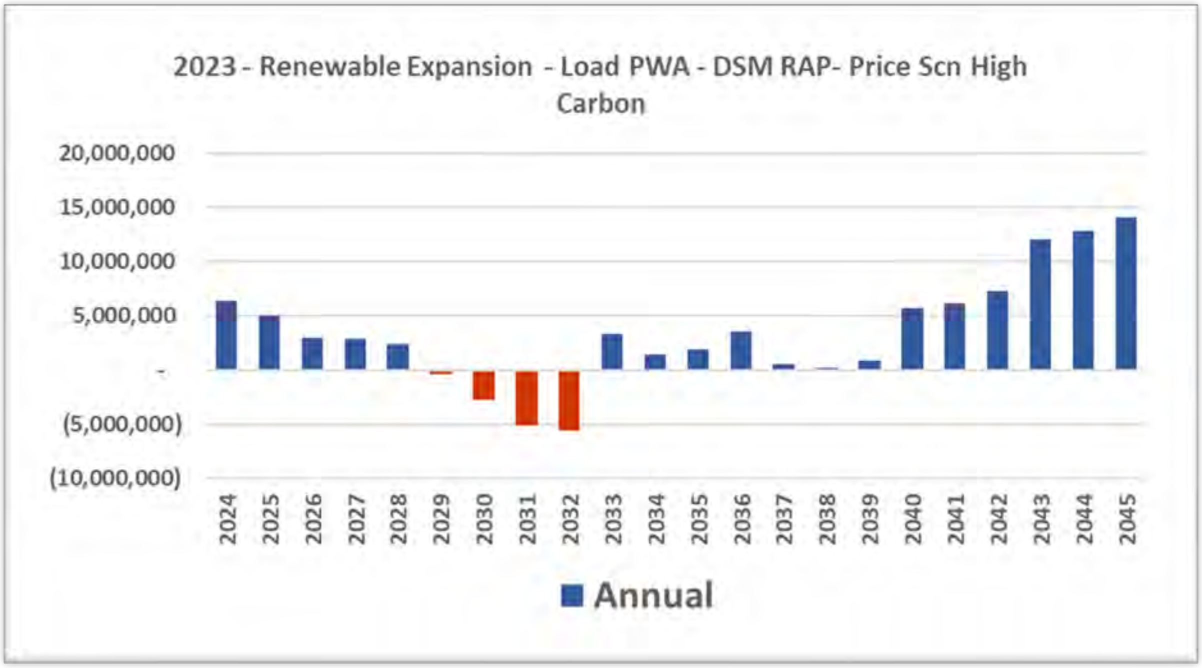
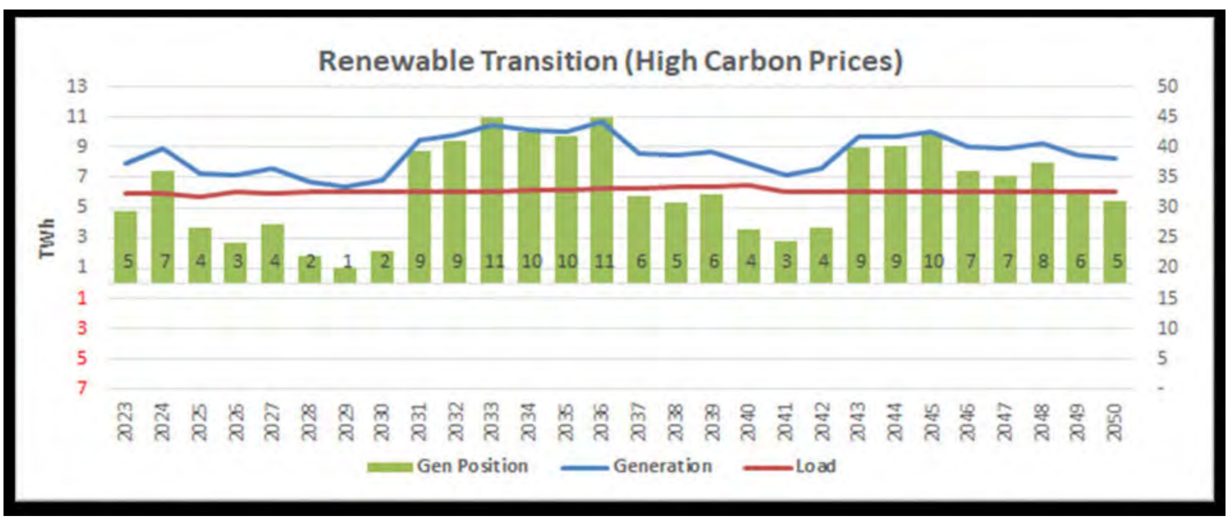


Figure 17. Annual Energy Position for 2022 PRP -High Carbon Price[102]



[102] Figure 17 is a reproduction of Figure 10 from my direct testimony.

Figure 18. Annual Energy Position for 2023 PRP – High Load, High Carbon Price

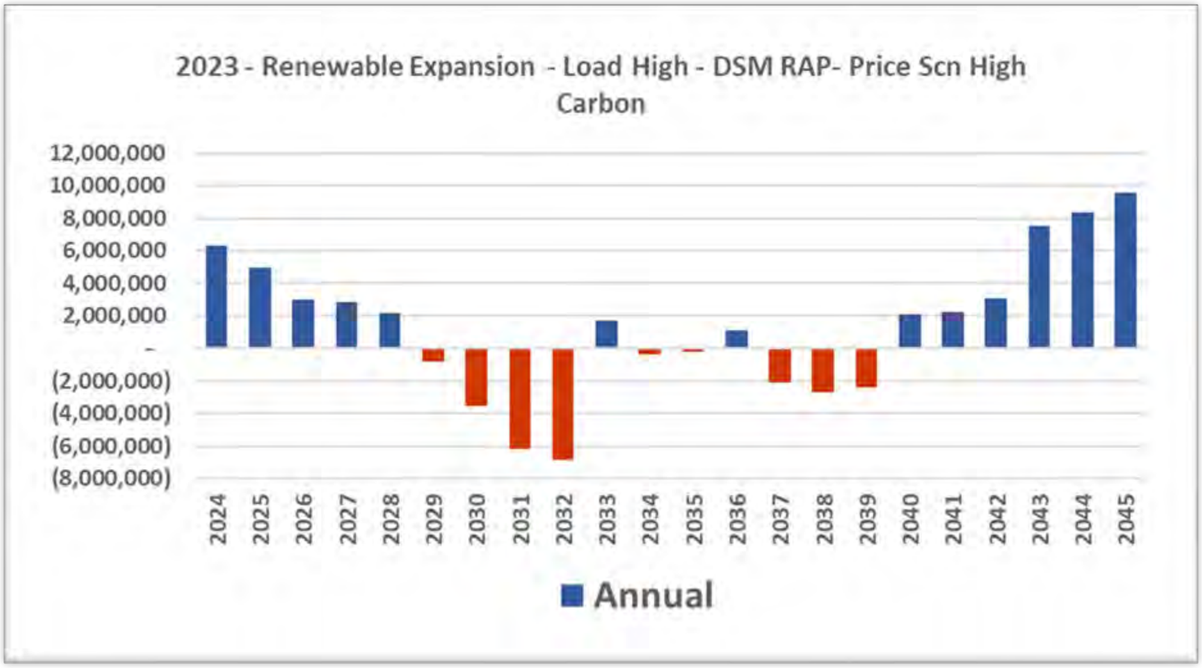
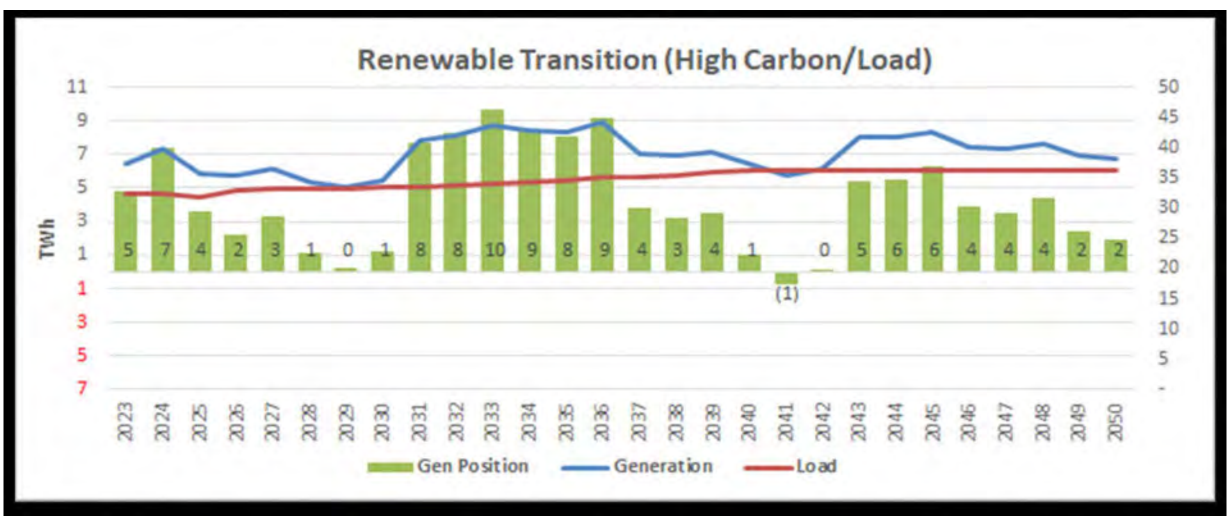


Figure 19. Annual Energy Position for 2022 PRP – High Load, High Carbon Price[103]



[103] Figure 19 is a reproduction of Figure 13 from my direct testimony.

Q. The energy positions in Charts 16-19 appear to show some stark differences in energy position under the 2023 IRP assumptions compared to the 2022 PRP assumptions. Can you explain why this is so?

A. It is driven primarily by the difference in the assumption for the high carbon price scenario. As shown in Figure 4, the carbon prices under the high carbon price scenario are significantly higher than those used in the 2022 PRP analysis. It should also be noted that the difference in timing of the addition of combined cycle gas generation and the retirement of Sioux Energy Center, from the end of 2030 to the end of 2032, contributes to differences in energy position during that relatively brief period.

Q. In your direct testimony, you also included charts in Figures 14-21 that show hourly energy positions for selected timeframes. Have you prepared updated versions of those charts?

A. No. Because those charts reflected updated load information included in the Company's 2023 IRP analysis and filing, they are still valid and useful in demonstrating the contribution that renewable resources make to meeting customer demand during key times of the year and in different years during the planning horizon.

Q. Staff witness Shawn Lange criticizes the charts in Figures 14-21 in your direct testimony for excluding energy from the Company's gas-fired peakers. How do you respond?

A. The charts in question are intended to show energy needs and production, and gas-fired peakers are used sparingly, not only because of economics (although economics are unquestionably a valid rationale as well, as discussed by witness Arora), but also by design because of additional operational costs associated with more frequent operation and due to permitting and environmental constraints. The value of these peaking resources is the capacity they provide to meet demand in a limited number of critical hours and to serve as backup to the resources that produce the bulk of the energy the Company generates.

Ameren Missouri's simple cycle gas units in Illinois are constrained by provisions of CEJA, which limits emissions from each fossil-fueled generator to the annual average emissions produced by each generator in 2018-2020 for any (rolling) 12-month period. Most of these units (17 of 24) are limited to less than 100 hours of operation during a 12-month period. Another three units are limited to less than 200 hours of operation during a 12-month period. As I mentioned previously, they still provide value as capacity to backup other resources and to meet demand during critical hours, but they cannot be relied upon to provide energy for significant portions of the day for weeks at a time. Solar resources like the Projects can, and that is what the charts in Figures 14-21 of my direct testimony illustrate.

Q. Staff witnesses downplay the Company's need for energy, labeling this energy need as "amorphous."[104] How do you respond?

A. The Company has been clear about its energy needs and how it plans to meet them starting with the filing of its 2020 IRP and continuing with its 2022 Notice of Change in Preferred Plan, its testimony in this case (i.e., based on its 2022 PRP but with key assumptions updated with 2023 IRP assumptions), and previous cases regarding requests for CCNs for solar resources, plus its 2023 IRP filing in September. The Commission itself recognized this need in its Report & Order in the Boomtown CCN case

[104] J Luebbert Rebuttal Testimony, p. 24.

(File No. EA-2022-0245) as described by witness Wills. In short, the Company is transitioning its portfolio from one that is heavily reliant on coal-fired resources to one that reflects a combination of established existing clean resources (nuclear and hydro), new clean renewable resources (mainly wind and solar) and existing and new dispatchable resources (natural gas and potentially developing technologies) and must do so in a way that ensures customers' energy needs will be met reliably and under a wide range of circumstances. This includes consideration of risks to both demand and supply as I've mentioned previously in my surrebuttal testimony and as I discussed in my direct testimony. It also includes consideration of extreme weather conditions of the kind we've experienced in just the last few years during both summer and winter seasons. We've evaluated our need for energy resources across the entire planning horizon, determined that renewable resources must play a key role from a customer affordability and risk management perspective, and crafted a plan – the Company's IRP PRP – that implements these resources in a way that mitigates the numerous and significant risks associated with the transition.

Q. Witness Shawn Lange insists that the Company must focus on "net-load" hours to define an energy need that justifies the addition of renewable resources like the Projects.[105] Is that valid?

A. No. His use of "net load" refers to load less production from renewable resources. It is nonsensical to use load <u>*less*</u> renewable resources to establish a <u>*need*</u> for energy from renewable resources. Doing so is circular; the Company's load is what it is, as is its generation. The Company has properly focused on the difference between load and

[105] Shawn Lange Rebuttal Testimony, pp. 6-7,

total generation from existing and other planned resources and accounting for specific characteristics and constraints of those resources to establish its need for energy and assess the ability of renewable resources, including the Projects, to help meet that need.

Q. Witness Shawn Lange also suggests that the Company's future energy shortfall can be met by MISO at a lower cost.[106] Is that a valid option?

A. No. It is a risky and irresponsible option.[107] While MISO coordinates the expansion and operation of the regional transmission system, coordinates the efficient dispatch of resources within MISO, and establishes resource adequacy processes and criteria for ensuring reliability, the responsibility for planning and implementing resources to ensure reliability rests squarely with the market participants responsible for serving customer load. MISO has no responsibility to ensure *resources* are available to meet the needs of utilities that don't effectively plan to meet the resource needs of their customers. Consequently, there is no process or framework in place for MISO to do so. MISO has gone from a market with surplus generation to one with imminent and ongoing shortfalls.

Q. Is Mr. Lange aware of the resource situation in MISO?

A. I can only assume so based on his inclusion of a chart from the 2022 survey of the Organization of MISO States ("OMS") on page 15 of his rebuttal testimony. The 2023 OMS survey continues to show near-term resource shortfalls in MISO. A presentation of the 2023 OMS Survey results is attached as Schedule MM-S33. On slide 2 of the presentation, OMS indicates that, "The North/Central subregion shows potential capacity deficits starting in summer of PY 2025/26."

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[106] Shawn Lange Rebuttal Testimony, p. 7.
[107] The Commission clearly recognizes this in its Boomtown order, as discussed by Company witness Wills in his surrebuttal testimony.

Q. Is this consistent with points you made in your direct testimony?

A. Yes. I discussed the 2022 OMS survey as well as various reliability assessments published by NERC on pages 15-18 of my direct testimony and included the various reports as schedules attached to my direct testimony. The 2023 OMS survey continues to recognize the need for resources in MISO as highlighted in those prior reports. In addition, NERC published its latest long-term reliability assessment on December 13, 2023. That report shows a continued expectation for potential reliability issues in MISO, noting in an accompanying infographic an expected capacity shortfall in MISO in 2028.[108]

Q. Witness Shawn Lange suggests that the Company's primary focus is to be a net seller of electricity,[109] and Witness Stahlman notes that not all utilities can be a net seller.[110] How do you respond?

A. This is a complete mischaracterization of the Company's objective for its PRP and the renewable resource additions in the PRP in particular. The Company does not seek to be a net seller of electricity for its own sake. This is a byproduct of the Company's thoughtful planning for meeting its customers' needs and mitigating potential risks to meeting those needs, as I have described previously in both my direct and surrebuttal testimonies. *Of course*, not all utilities can be net sellers of electricity, any more than all utilities could be net buyers, even though that fact doesn't stop Staff from suggesting that the Company rely on a completely unsupported ability to do so. Each utility must plan for its own resource needs and do so in light of the particular risks it identifies to meeting those needs. That is what Ameren Missouri has done. The Commission also clearly recognizes

[108] NERC's 2023 Long-term Reliability Assessment report is attached as Schedule MM-S36, and the accompanying infographic is attached as Schedule MM-S37.
[109] Shawn Lange Rebuttal Testimony, p.7.
[110] Michael Stahlman Rebuttal Testimony, p. 8.

this: "Like Ameren Missouri, MISO is no longer long on capacity, especially in peak summer months. The Company can no longer count on the MISO market as a source of low cost energy to meet its peak load."[111]

Q. Staff witness Shawn Lange discusses potential changes to the resource adequacy construct under consideration by MISO and the possibility that planning reserve margin requirements and capacity accreditations for renewable resources may be lower.[112] Has MISO produced any newer information on these parameters?

A. Yes. On December 5, 2023, MISO published its Loss of Load Expectation ("LOLE") Study Report for planning year 2024-2025.[113] That report shows new seasonal planning reserve margin ("PRM") requirements, all of which are higher than those used for planning year 2023-2024. The spring PRM increased from 24.5% to 26.7%, the summer PRM increased from 7.4% to 9.0%, the fall PRM increased from 13.5% to 14.2%, and the winter PRM increased from 25.5% to 27.4%. While the report did not indicate new values for capacity accreditation for wind and solar, MISO's LOLE Working Group did produce a presentation for a working group meeting in October that shows preliminary capacity accreditation values for wind and solar.[114] Notably, the preliminary value for solar capacity credit for winter was shown as 12.8%, up from the 5.0% value used for the 2023-2024 planning year and reflected in the Company's 2023 IRP and the analysis presented in my direct testimony.[115] While this is not a final value, it does indicate the potential for a significantly higher value for solar winter capacity credit than that previously used.

[111] File No. EA-2022-0245, *Report and Order,* p. 29.
[112] Shawn Lange Rebuttal testimony, pp.19-20.
[113] See Schedule MM-S34.
[114] See Schedule MM-S35.
[115] See slide 12 of the MISO LOLE presentation attached as Schedule MM-S35.

Q. Staff Witness Sarah Lange asserts that the reliability modeling performed for Ameren Missouri by Astrape Consulting is not useful or sufficient to demonstrate the reliability contribution of solar resources.[116] Do you agree?

A. Absolutely not. Astrape Consulting developed their SERVM model specifically to evaluate reliability needs and the reliability of resource portfolios. Astrape provides reliability analysis services to utilities and regional transmission organizations (RTOs) across the United States, including MISO. The resource adequacy work that MISO performs to analyze and establish resource adequacy criteria such as planning reserve margins and capacity accreditation values, the very same parameters cited by Staff Witness Shawn Lange,[117] is performed using Astrape's SERVM model, as described beginning on page 25 of MISO's latest LOLE Study Report.[118]

Q. Witness Sarah Lange claims that Astrape did not account for the contribution of the MISO market to Ameren Missouri's system reliability. Is that correct?

A. No. Astrape modeled the potential contribution of MISO resources outside of Ameren Missouri's portfolio as separate resources with a capability that varies by season and hour. This was first illustrated by the Company in its 2022 Notice of Change in Preferred Plan, which showed the variation in external market potential contribution for winter and summer, by hour.[119]

[116] Sarah Lange Rebuttal Testimony, pp. 67-69
[117] Shawn Lange Rebuttal Testimony, pp.16-21.
[118] See Schedule MM-S34.
[119] See Schedule MM-D2, page 14.

Q. Witness Sarah Lange claims that Astrape's modeling did not allow for resources to sell into the MISO market.[120] Is that important to the reliability modeling?

A. No. The reliability modeling performed by Astrape with SERVM only seeks to evaluate whether load can be met, not whether the Company's resources can sell additional energy into the MISO market. The Company's own production cost modeling, using PowerSimm, evaluates the potential for such sales into MISO.

Q. Witness Sarah Lange concludes that the modeling performed by Astrape using its SERVM model is insufficient for demonstrating the reliability contribution of solar resources, in part because the addition of any generation will result in an improvement of LOLE and that Ameren Missouri already plans to add combined cycle gas generation, which will more significantly contribute to a reduction of LOLE.[121] Is that accurate?

A. No. The reliability of any system is determined by the totality of the resources in that system. For Ameren Missouri, that includes all of its existing and planned generation as well as demand side programs that reduce demand and therefore the potential that generation will be insufficient to meet demand. Solar and wind resources contribute to reliability in a manner that is similar to energy efficiency, reducing net load which must be met with dispatchable resources.

Witness Sarah Lange provided an analogy involving Twinkies and Sundrop to attempt to illustrate that any increase in available resources will reduce the probability of running out of snacks and drinks, but it doesn't account for a situation in which the supply

[120] Sarah Lange Rebuttal Testimony, p. 68.
[121] Sarah Lange Rebuttal Testimony, pp. 67-69.

is so great that there is no incremental value to adding supply. If someone has access to 10 million Twinkies and 10 million bottles of soda, adding one more of either or both won't increase the value of the supply to a person who could only consume a million of each in their lifetime.

So too is it true with electric resources. The contribution of a resource to reliability depends on whether and to what extent that resource can supply energy when it is needed. The Astrape analysis showed that adding solar resources measurably improves LOLE, confirming that solar resources contribute to the reliability of Ameren Missouri and its customers.

Q. Witness Shawn Lange criticizes the Company's reliance on MISO analyses to ensure satisfaction of reliability criteria such voltage support, VAR support, and frequency support.[122] Is this a fair criticism?

A. No, for two main reasons. First, Ameren Missouri includes consideration of transmission system upgrades needed to support the reliable operation of the electric grid in light of its resource decisions. This includes consideration of both new resource additions and retirement of existing generators, as described in detail in Chapter 7 of the Company's IRP filings, including the Company's 2020 and 2023 IRP filings.[123] This work is performed in accordance with the Commission's IRP rules on transmission and distribution analysis and includes consideration of criteria such as those listed by Witness Shawn Lange. Second, those rules also provide for the Company's reliance on RTO analyses of the transmission system, specifically stating that a utility may use its RTO's transmission expansion plan to satisfy requirements of the rules if the utility actively

[122] Shawn Lange Rebuttal Testimony, pp. 22-23.
[123] See Schedule MM-S22 for an example.

participates in the development of the RTO's transmission expansion plan and reviews the plan to ensure that it is in the best interests of Missouri customers.[124] The Company has documented its reliance on MISO's transmission expansion plans in its IRP filings since the rules were last revised and this rule provision became effective.

Q. Staff Witness Stahlman raised the issue of the "duck curve," which is used to describe the potential extreme effects of solar resources on net loads during a 24-hour period.[125] Does Staff believe that a "duck curve" issue will be caused by the Projects?

A. No. Witness Stahlman so states on page 13 of his rebuttal testimony. Instead, Witness Stahlman indicates a concern regarding the addition of far greater levels of solar resources.

Q. Witness Stahlman suggests that if the level of solar additions reaches a point that incremental energy storage resources are necessary, that the costs for those storage resources should be included in the cost of the incremental solar resources.[125]Do you agree?

A. No. Storage resources are a separate resource, with grid capabilities that go beyond the simple temporary storage of solar energy. Ameren Missouri evaluates storage in the same way it evaluates other resources – as part of a portfolio of resources to meet customer needs and ensure affordable and reliable service in both the near term and the long term. Each resource contributes to the reliability of the whole portfolio, albeit in different ways. It would be no more appropriate to include the cost of storage resources in

[124] 20 CSR 4240-22.045(3)(B).
[125] Michael Stahlman Rebuttal Testimony, p. 13.

isolation than it would be to include the cost of new gas-fired generation with solar resources in isolation.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

sRequest	Company Response
Update inputs	The Company has already committed to provide updates to the Staff if there are changes to major project inputs. As discussed in my direct testimony, the Company also, as part of its direct case, used updated 2023 IRP assumptions for key inputs in this case, a fact either ignored or overlooked by Staff, as I explain in my surrebuttal testimony.
Account for expected production differences among projects (P50-P95)	The projects were modeled at customized production levels based on PVsyst modeling completed for each project. Please refer to Mr. Wibbenmeyer's surrebuttal testimony for more details on this modeling. Both base and low capacity factor scenarios were included in my direct testimony.
Account for PISA	The projects were modeled using perfect ratemaking, which includes no regulatory lag, and therefore necessarily cannot include PISA, which only exists to address regulatory lag. This is the appropriate modeling approach for a CCN application as discussed in detail in Mr. Wills' surrebuttal testimony.
Account for RESRAM as applicable, on the specific projects where Ameren Missouri anticipates it to be applicable,	Ameren Missouri does not expect the RESRAM to be applicable for the Projects. Further, if RESRAM were to be used for any reason, the same rationale for excluding it from the perfect ratemaking analysis would exist as discussed above with respect to PISA.
Include reasonable rate case timing scenarios/permutations	The projects were modeled using perfect ratemaking. This is the appropriate modeling approach for a CCN application as discussed in detail in Mr. Wills' surrebuttal testimony.
Model tax benefit treatment in some manner other than a single year offset to expense, such as an offset to rate base to be amortized over various intervals such as 10 years, 20 years, or the life of the facility	Mr. Wills' surrebuttal testimony discusses why the Company's approach to modeling tax benefits is in fact reasonable and a change is neither necessary nor appropriate.
Consistently model the treatment of real estate among the facilities, such as assuming appreciation at the rate of inflation and then modeled as sold at the	Real estate was modeled consistently for the projects. Ms. Lange's concern on this point references the Company's response to Staff Data Request 0042, which indicates small "real property purchases" for the Cass County and Split Rail that were not modeled in the same manner as real estate costs for the Vandalia and Bowling Green projects. These small real property purchases indicated

time terminal net salvage is applied.	for Split Rail and Cass County are for the transmission point of interconnect, and the plots will be transferred to the transmission company after they have concluded civil work. Therefore, it would be inappropriate to model these costs in the same manner as the real estate purchases shown for Vandalia and Bowling Green which have no transmission interconnection.
Account for voltage distinctions in the valuation of the LMPs as energy,	It is reasonable to account for line losses when considering the value of energy interconnected at different points on the Ameren Missouri system. The Company is amenable to including this value in future project modeling, but it is completely unnecessary to do so in this case. The impact of such a change would only lower the NPVRR of certain Solar Projects, making them even more cost-effective than the Company's direct testimony analysis suggests. Further, such a modeling change in the context of an IRP could not possibly impact the results in a meaningful way when the current PRP has an over $700 million advantage against the alternative.
Account for voltage distinctions in the avoidance of MISO charges based on load-ratio share or other characteristics,	It is reasonable to account for avoided MISO charges when considering the value of energy interconnected at different points on the Ameren Missouri system. The Company is amenable to including this value in future project modeling, but it is completely unnecessary to do so in this case. The impact of such a change would only lower the NPVRR of certain Solar Projects, making them even more cost-effective than the Company's direct testimony analysis suggests. Further, such a modeling change in the context of an IRP could not possibly impact the results in a meaningful way when the current PRP has an over $700 million advantage.
Reasonably estimate the extent to which capacity value may be monetized, addressing: i. MISO potential revision of ratings for solar, particularly in winter, ii. Reasonable projections of the market appetite for capacity,	i. In my surrebuttal testimony I discussed MISO's shifting capacity accreditation values for solar. As stated in that testimony, constant updates to this value are not useful and in this case if updated would only increase the winter capacity value of the projects. ii. It is reasonable to assume that the Company can monetize the full amount of the accredited value of the solar capacity. The Company has incentives to self-schedule such capacity in the MISO capacity auctions, which would ensure that it will clear, and thus be monetized at the auction clearing price.
Estimate the value of reduction in load LMP based on improved	As discussed in my surrebuttal testimony, these impacts are already incorporated through the energy price forecast developed by CRA. Further analysis is not necessary or useful.

modeling to substantiate claimed “energy need,”	
Estimate the lost value of marginal revenues on existing generation due to reduction in adjacent gen node LMPs based on improved modeling to substantiate claimed “energy need,”	As discussed in my surrebuttal testimony, these impacts are already incorporated through the energy price forecast developed by CRA. Further analysis is not necessary or useful.
REC sales or assumed values if and as applicable	The Company has clearly stated throughout testimony that the final "use" of each project is still being determined. For that reason, it remains inappropriate to quantify the value of project RECs at this time. We do not disagree with the Staff that the RECs will indeed be of value, but do not want to speculate on their exact value at this time. However, that value can only make the projects more cost effective than the Company's direct testimony analysis, with its conservative assumption of ascribing no incremental value to RECs, suggests.
Alternative energy pricing scenarios, such as prices resulting from environmental policies other than a carbon tax.	CRA developed nine different energy prices scenarios for the Company, and the projects have already been modeled under three of those scenarios, representing the highest, lowest, and middle price curves. As discussed in my surrebuttal testimony, carbon prices serve as a proxy for many possible types of environmental regulation and is regularly used throughout the industry for that reasons.

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

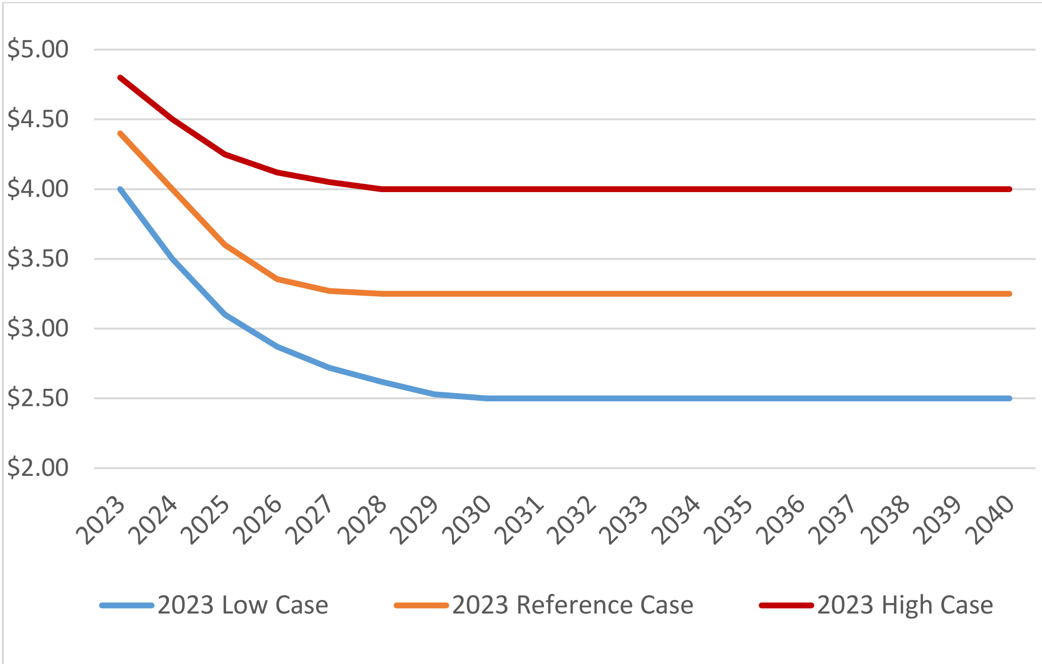
Natural gas prices continue to have a very strong influence on energy prices. The company employs a forecasting method for natural gas prices based on a hybrid approach that considers third party forecasts, the latest projections from the Energy Information Agency Annual Energy Outlook and Ameren's natural 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

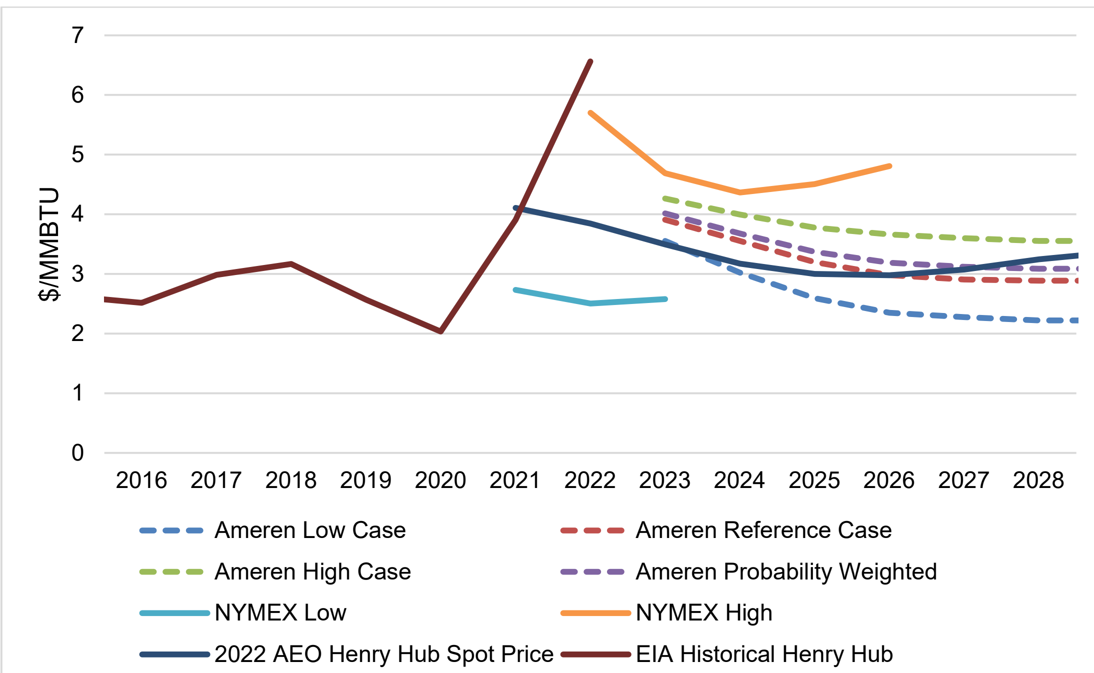
[2] Vectren 2019-2020 IRP

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

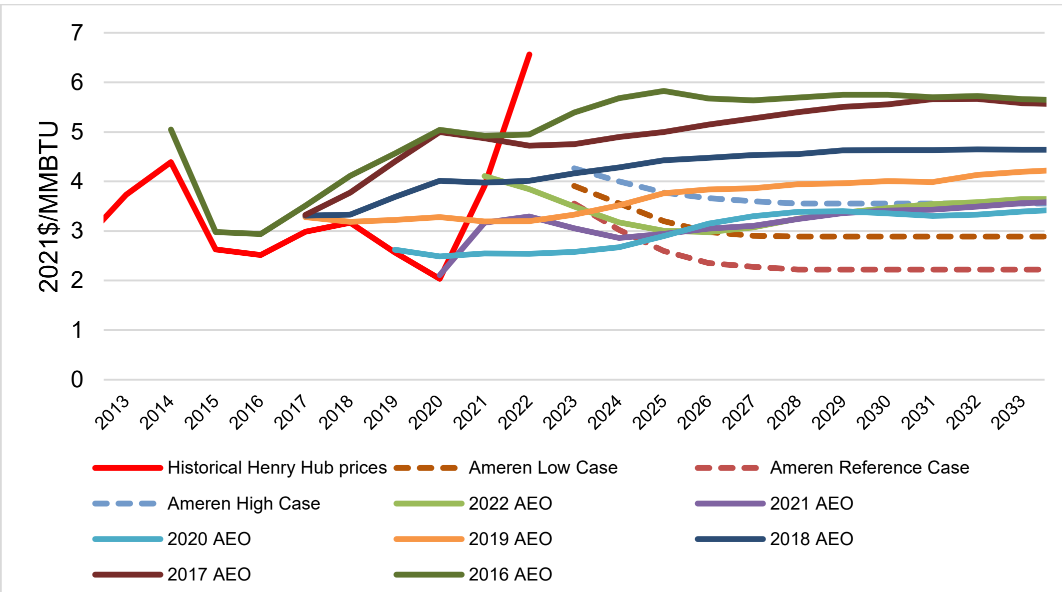
3 Low Case Based on Low Range April 2021 NYMEX trading, Reference Case based on average of Platt's and EIA AEO averages, High Case based on High Range July 2022 NYMEX trading

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

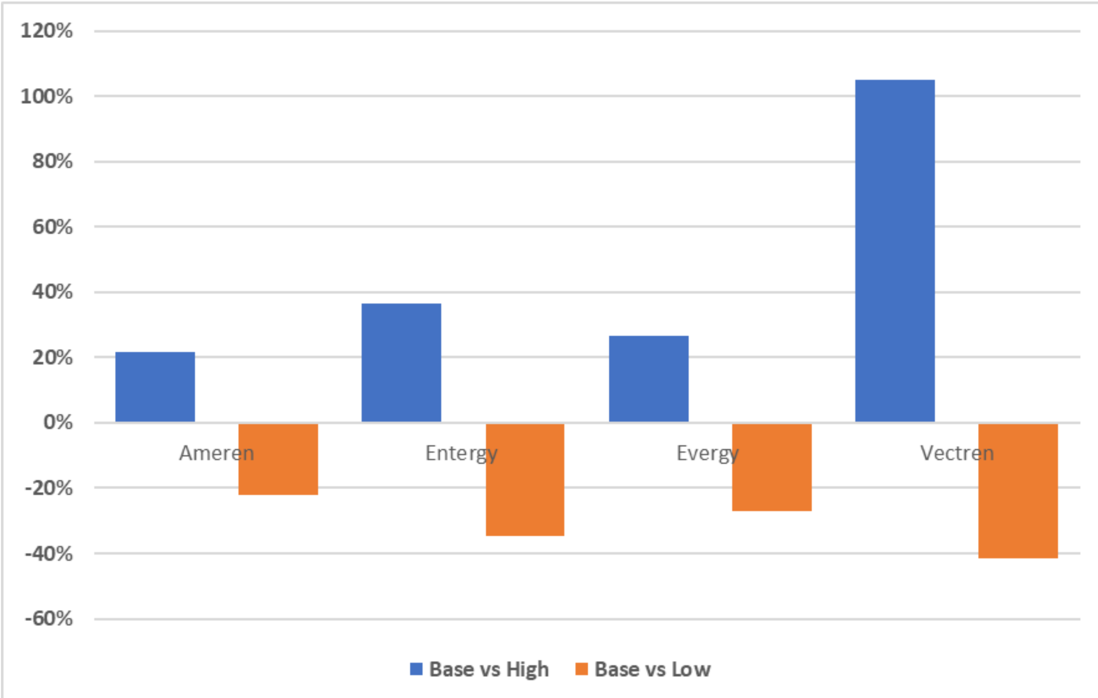


Based on this assessment, it is reasonable for Ameren to establish its base and boundary price projections slightly below the AEO's reference case projection. The historical over-estimation compared to actuals provides a reasonable justification for this result.

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

Schedule MM-S2



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:

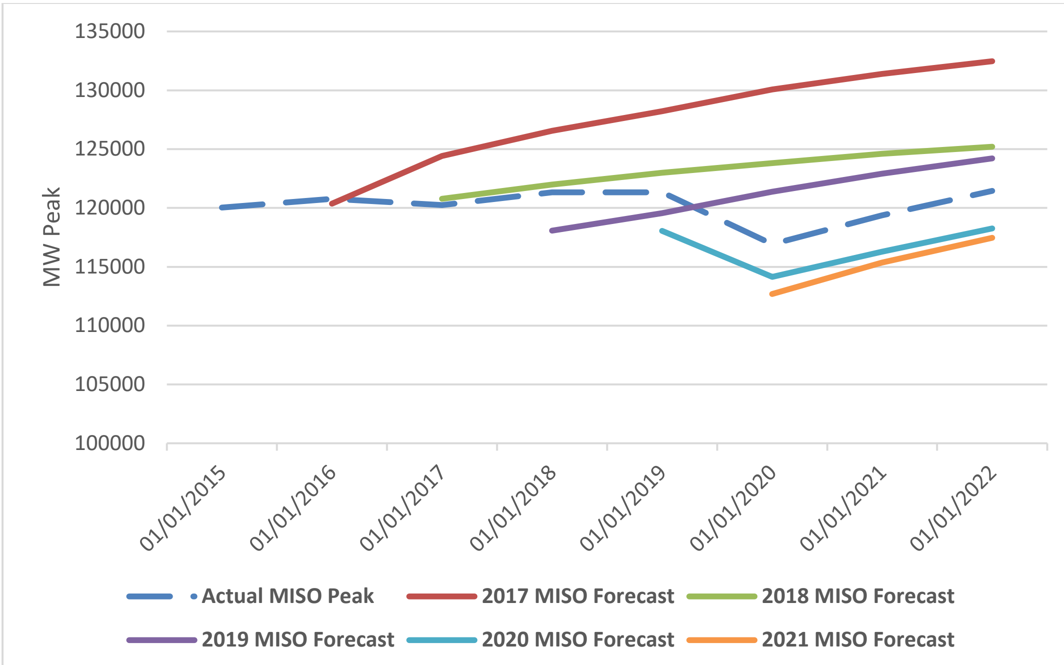
- Utility developed regional load; For example, Indiana Michigan Power incorporates AEP's (parent company) load forecast for the base and alternative scenarios. The IRP documentation provides no additional details on how these forecasts were developed.
- RTO/ISO produced load; PJM, MISO and other ISO/RTOs 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:

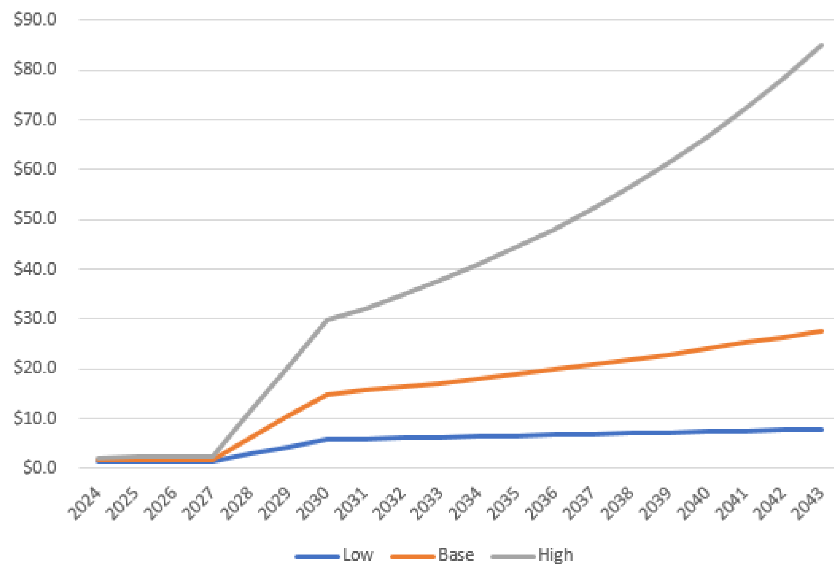
- The ISO load forecast reflects a view of energy consumption that more closely matches regional performance and expectations than EIA's forecasts, since it is developed by the ISO after incorporating input and feedback provided by member utilities.
- The MISO load forecast appears to be more commonly 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

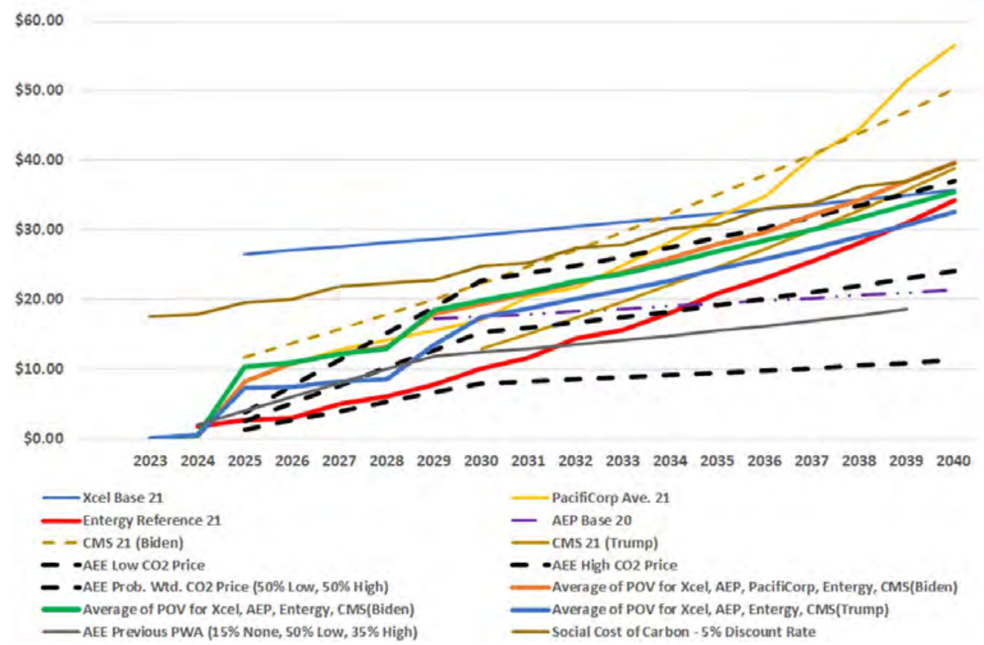


Ameren considered various drivers that affect the timing and level of carbon pricing such as the need for a potential program that considers carbon pricing through legislation (e.g., Carbon Tax, Cap-and-trade Program, Clean Energy Standard), RTO markets, and other mechanisms. Ameren also considered recent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

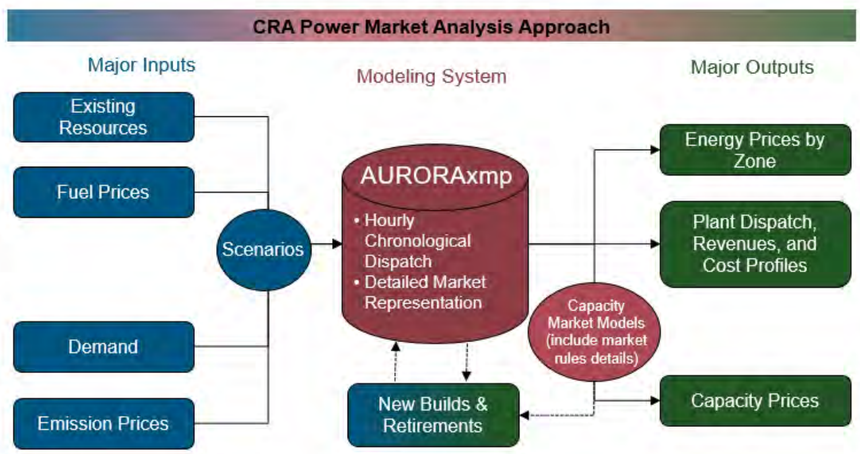
- Continue to incorporate a carbon price in the regional forecast to reflect recent industry trends. Based on CRA's review, it is appropriate for Ameren to evaluate the impact of carbon prices, whether explicit or implicit, on resource planning.
- CRA's review of peer companies and CRA's internal analysis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

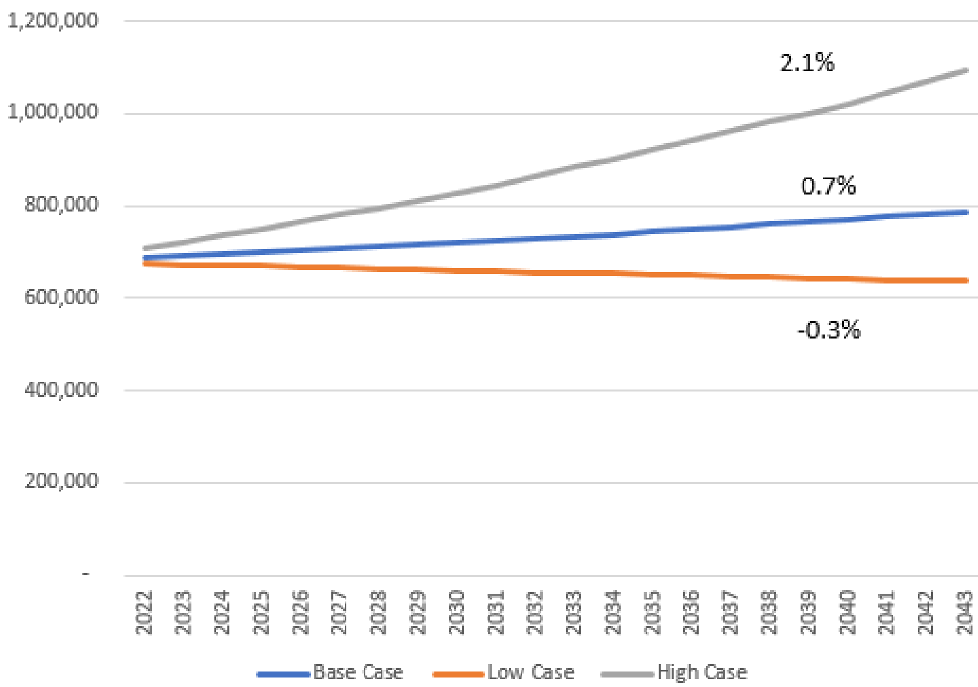
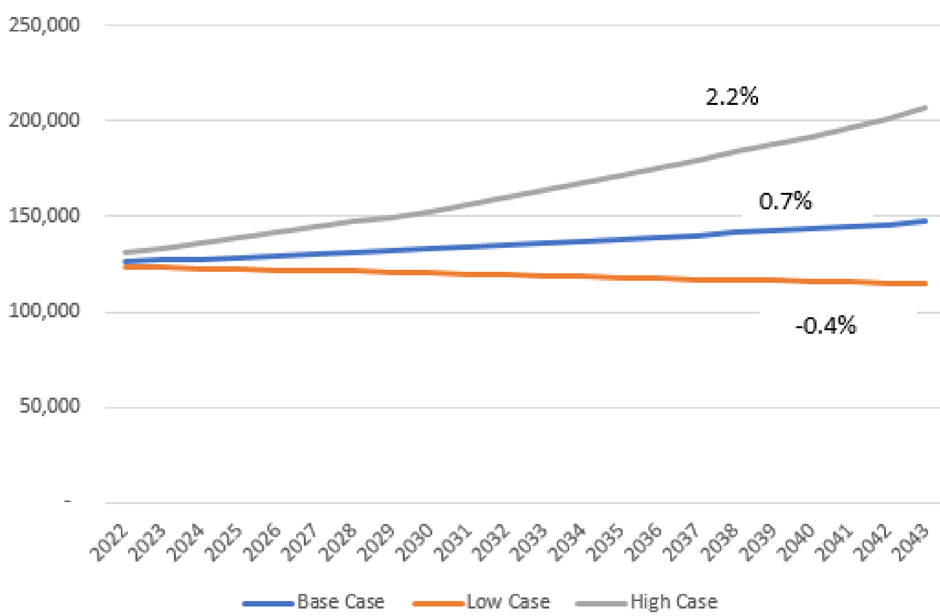


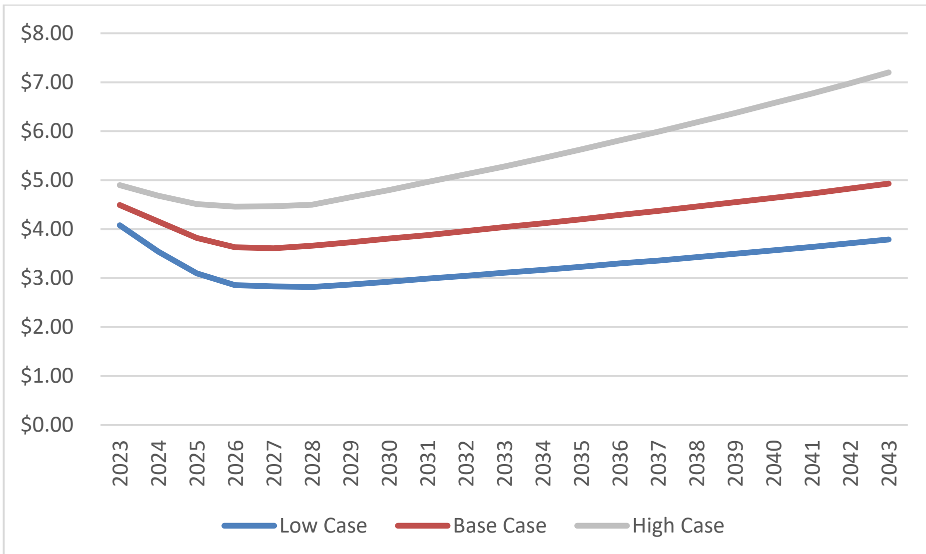
Exhibit 9 MISO Summer Peak load for Base, High and Low cases



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)

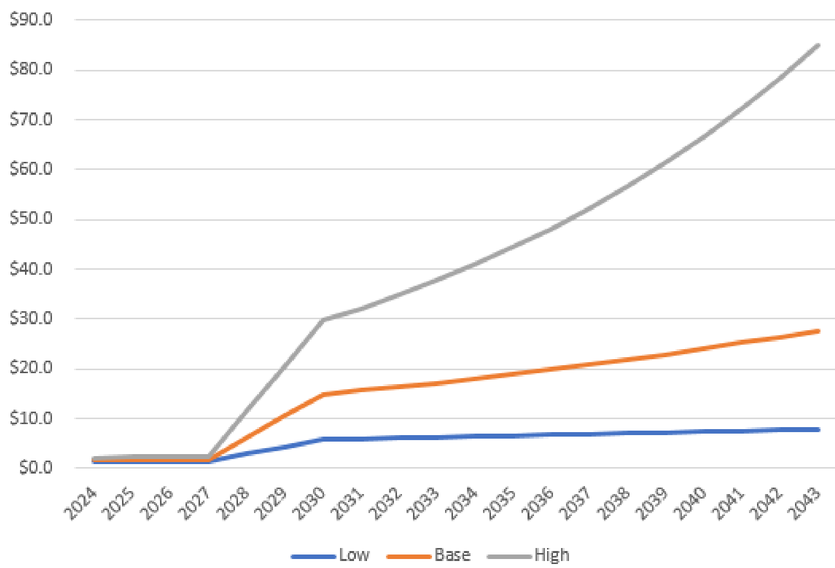


CO_2 Prices

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.

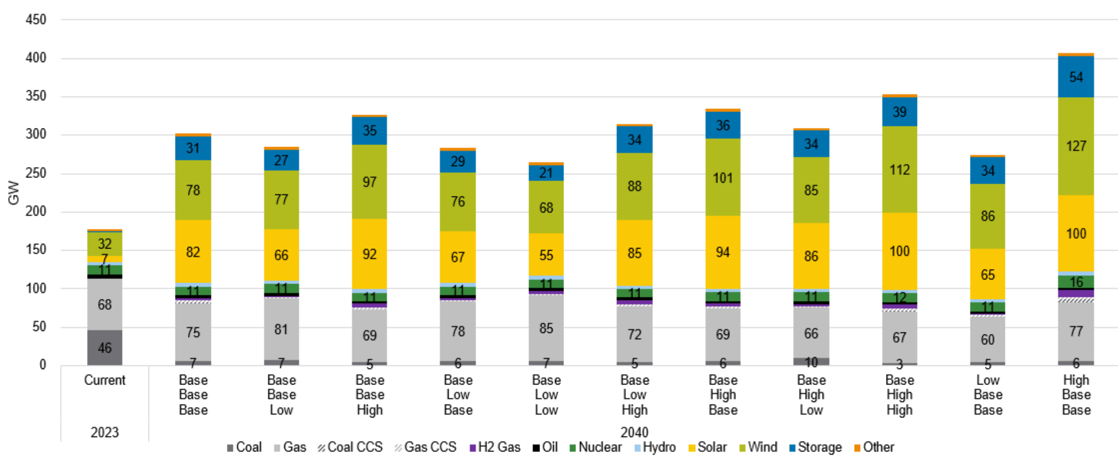
Exhibit 11 CO2 Price Forecast ($2022/MT) for Base, High and Low cases



3.3. Capacity Expansion Results

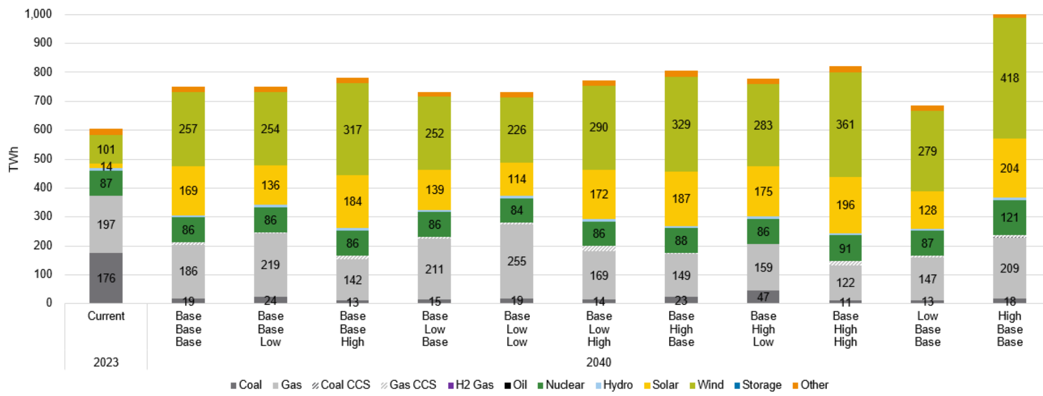
CRA used the AURORA LTCE model to forecast the least-cost combination of resource additions and retirements in MISO using the assumptions for each pricing scenario. Exhibits 12 and 13 below illustrate the 2042 capacity and generation mix (respectively) across all eleven market scenarios compared with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

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



Schedule MM-S2

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.

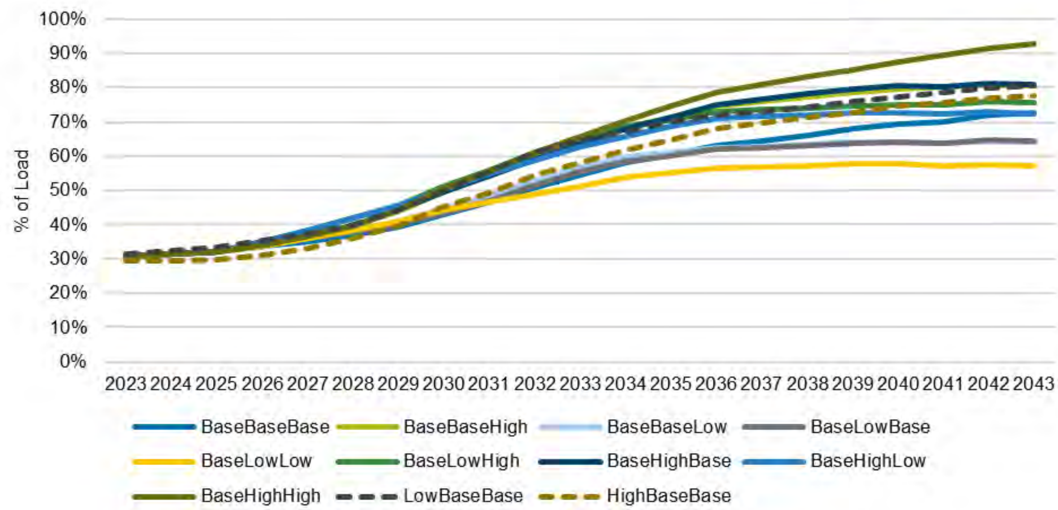
Within CRA's analytical framework, the level of natural gas and CO2 prices directly affect different levels of renewables penetration. Based on each case's assumed combination of natural gas and CO_2 prices, gas and coal resources react in a different manner. For example, in the high gas and low carbon 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.

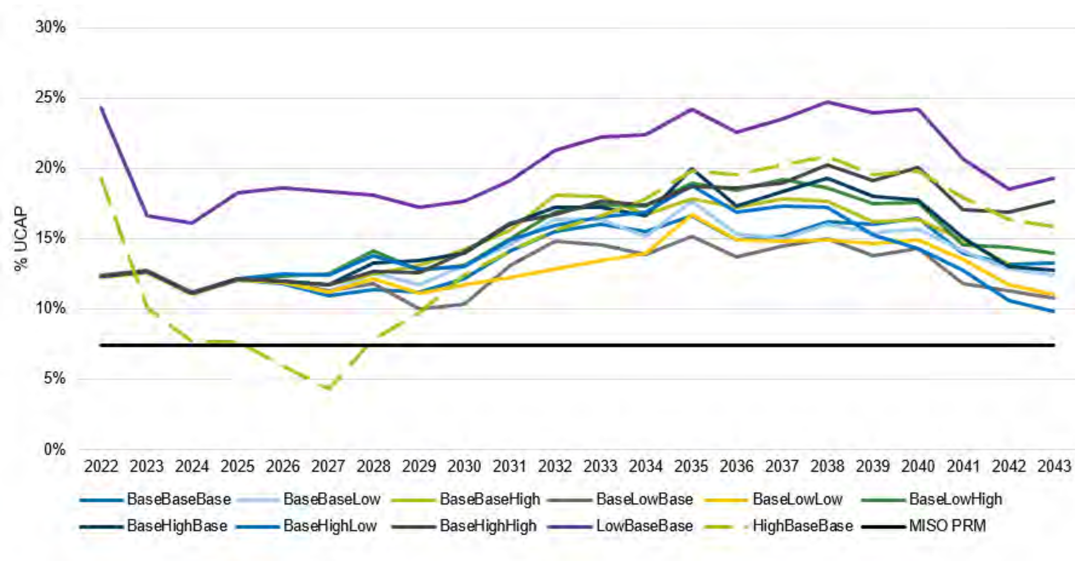
Exhibit 14 Clean Generation as % of MISO Load



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

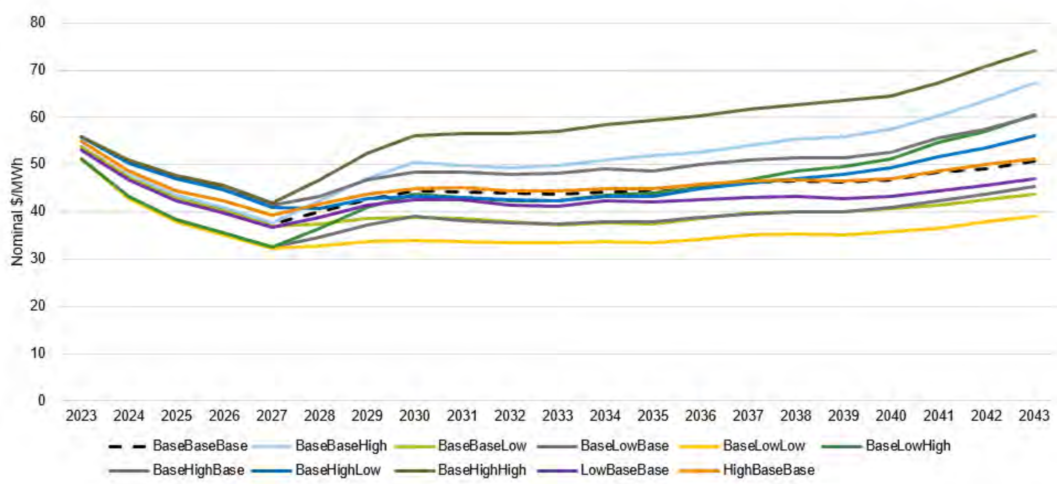


3.4. Energy Market Price Results

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.

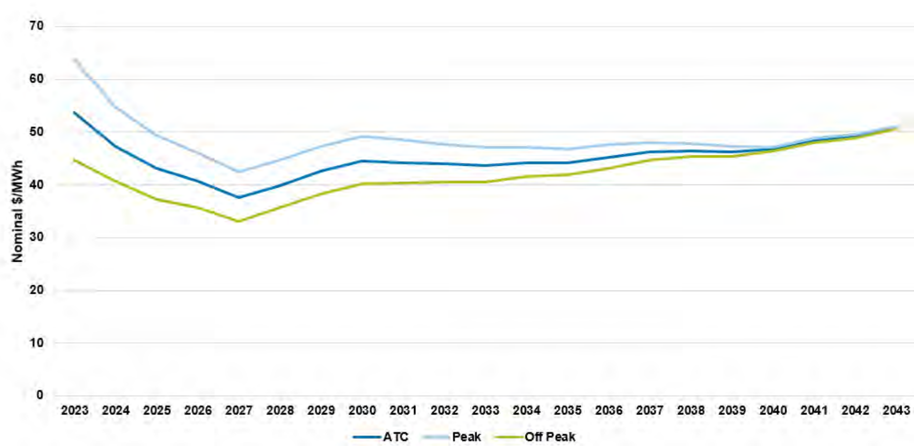
Exhibit 16 Annual Around the Clock MISO Zone 5 Electricity Price ($nom/MWh)



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.

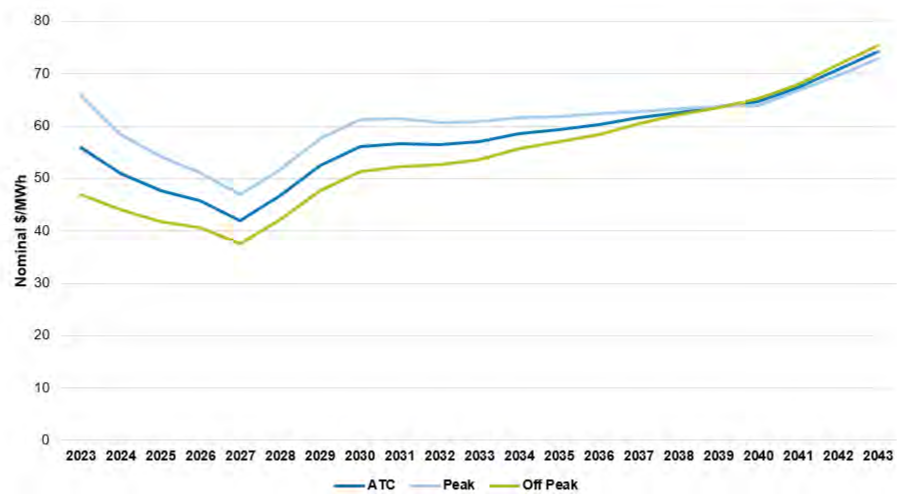
- The cases also experience a peak/off-peak price convergence, as illustrated in Exhibit 17, which shows the MISO Z5 price outlook for the BaseBaseBase case. With high levels of renewables and storage added to the system, the prices in the BaseBaseBase case completely converge by 2040.

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 CO_2 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

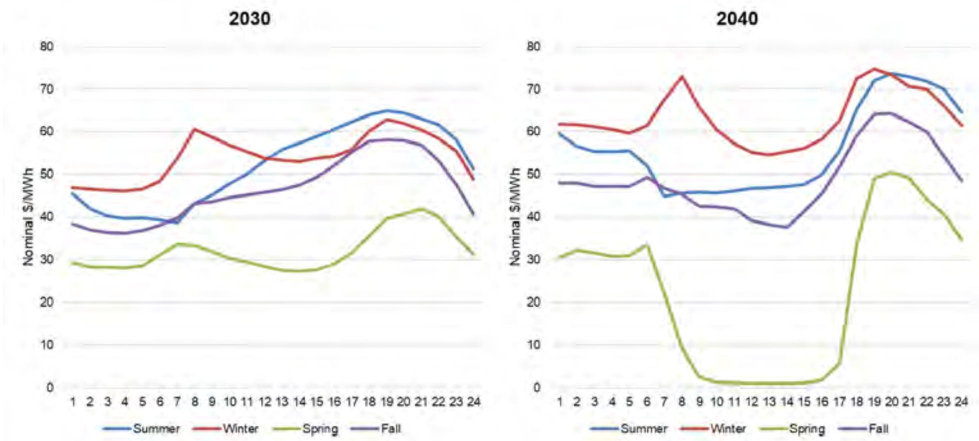
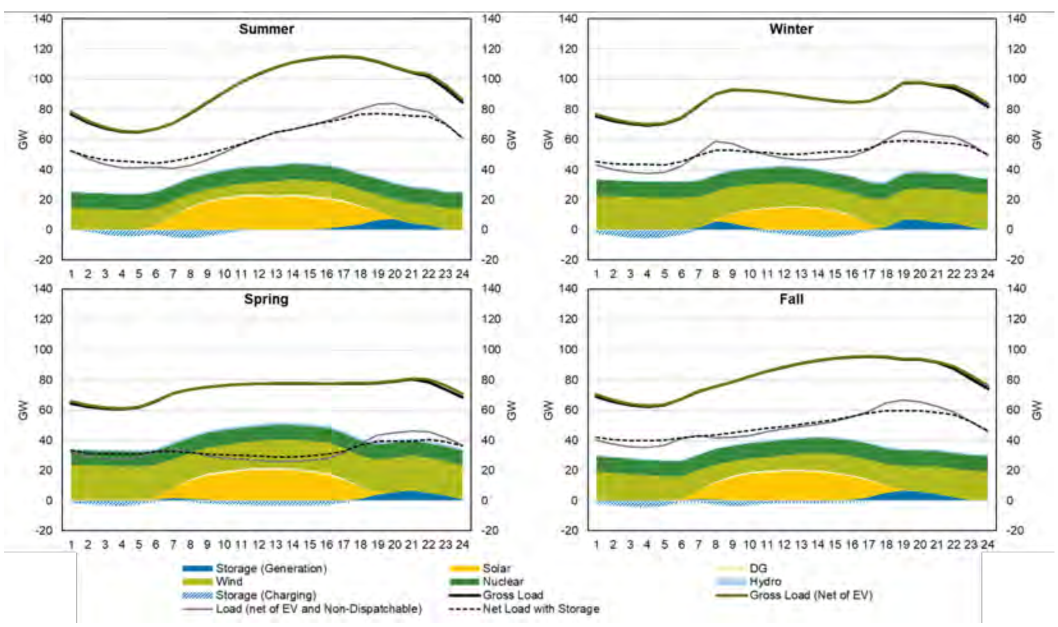


Exhibit 20:2030 Average Hourly Load and Generation Profiles[5]



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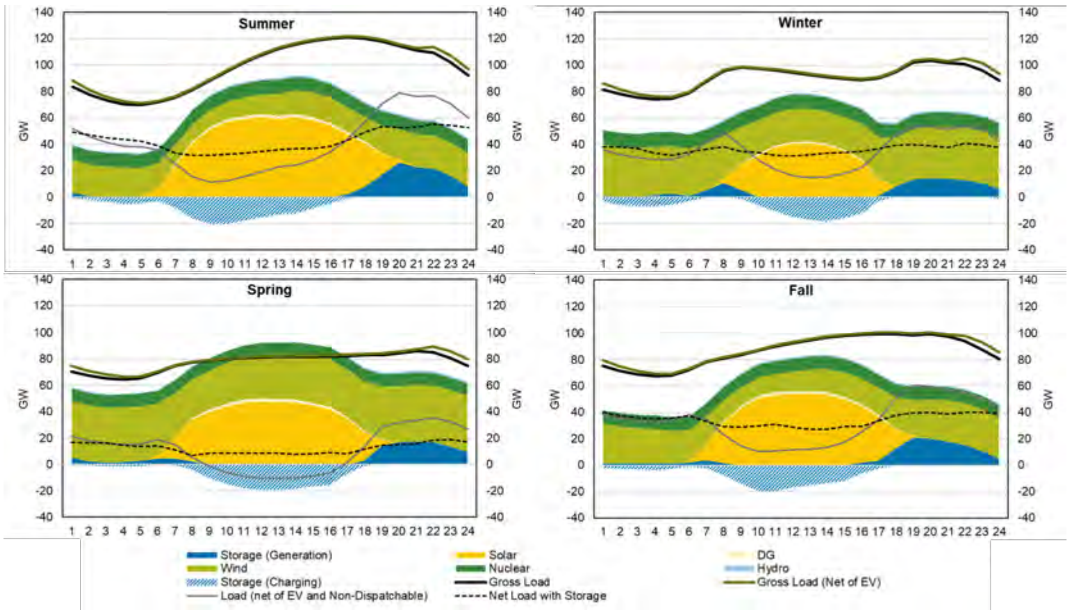
[5] Net Load with Storage = Gross Load (Net of EV) – Solar – Wind – Nuclear – Hydro – Storage

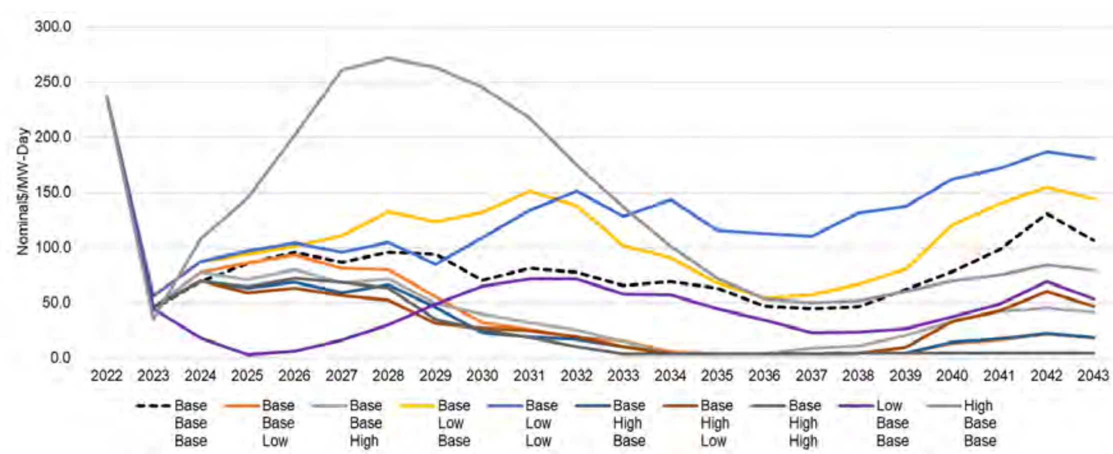
Exhibit 21: 2040 Average Hourly Load and Generation Profiles



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]

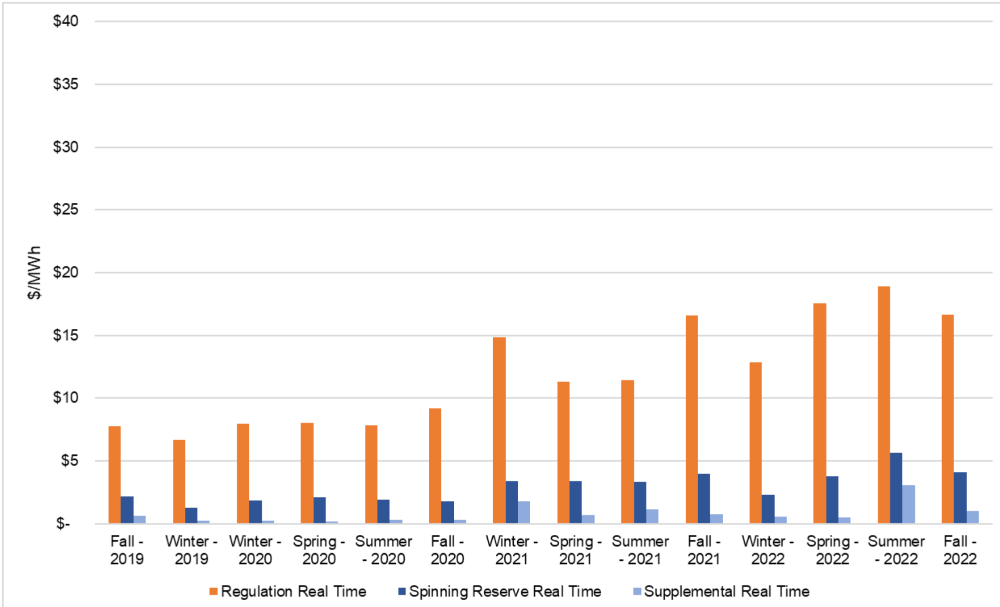
Regulation reserves generation-based resources and stored energy resources. These resources must be able to adjust their output in response to automatic signals within five minutes of receiving a signal to do so. MISO has only a single product for Regulation Reserves applied across all zones with a requirement 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

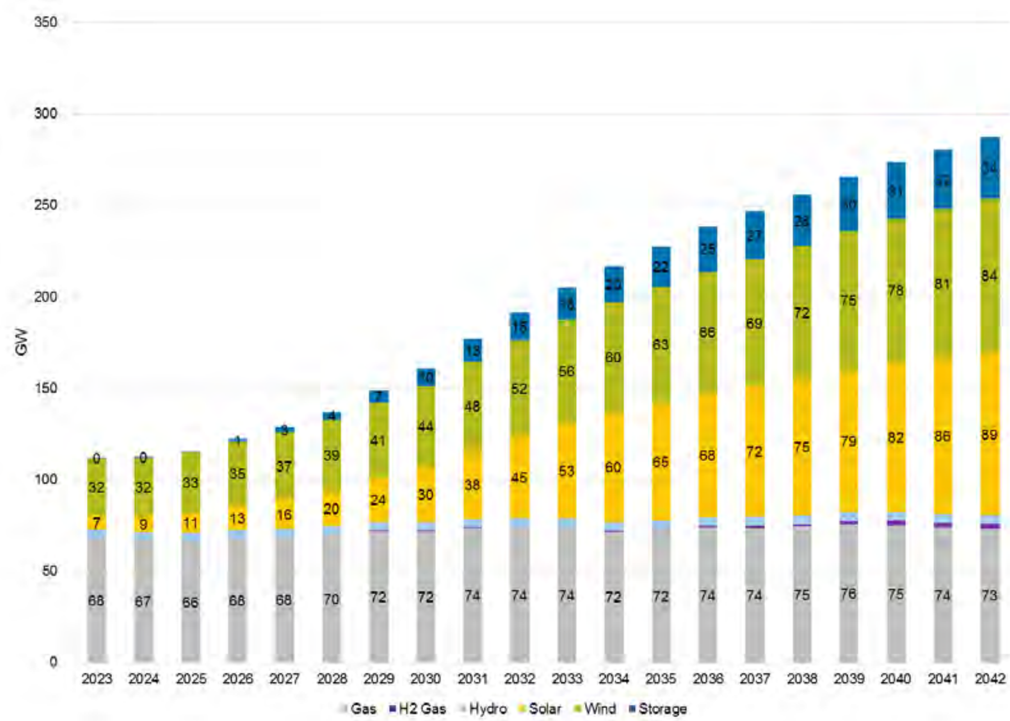
As mentioned above, the AS markets are quite shallow (roughly 300-500 MW for regulation and around 2 GW for combined operating reserves) at consistent historical levels for prices and total revenues. Although the requirements for such services have remained static in the past, the expected changes in 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.

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT ON

UNION ELECTRIC COMPANY
d/b/a AMEREN MISSOURI

ELECTRIC UTILITY RESOURCE PLANNING
COMPLIANCE FILING

FILE NO. EO-2015-0084

February 27, 2015

JEFFERSON CITY, MISSOURI

**** Denotes Highly Confidential Information ****

HC

Schedule MM-S3

Table of Contents

Executive Summary

On October 1, 2015, Union Electric Company, d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), filed its 2014 Integrated Resource Plan ("IRP") triennial compliance filing ("Filing") in File No. EO-2015-0084, as required by 4 CSR 240-22 Electric Utility Resource Planning. This is Ameren Missouri's first Chapter 22 triennial compliance filing under the Commission's revised Chapter 22 rules.[1] As more fully discussed throughout this report ("Report"), Staff identifies no deficiencies, but identifies the following concerns and suggested remedies:

A. The incremental annual energy savings expected from Ameren Missouri's realistic achievable potential ("RAP") portfolio for its MEEIA[2] Cycle 2[3] (2016 – 2018) may be vastly underestimated, since the kWh and kWh per $ savings are less than half the actual achieved levels of kWh and of kWh per $ during Ameren Missouri's pre-MEEIA programs (2009 – 2011) and MEEIA Cycle 1 programs to date (2013 – 2014).

B. The incremental and cumulative annual energy savings expected from Ameren Missouri's RAP portfolio during the long-term planning horizon may be vastly underestimated, since the Ameren Missouri savings are approximately one-half the incremental and cumulative annual energy savings of the IRP RAP portfolios[4] of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company.

To remedy these concerns, Ameren Missouri should work with parties to its 2014 IRP case and with parties to its MEEIA Cycle 2 case (File No. EO-2015-0055) during joint agreement[5] discussions and during technical conferences, respectively, to help parties understand Staff's concerns and, if necessary, to resolve those concerns.

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[1] Chapter 22 Electric Utility Resource Planning rules 4 CSR 240-22.010, .020, .030, .040, .050, .060, .070 and .080 were all revised effective May 31, 2011. Rule 4 CSR 240-22.045 Transmission and Distribution Analysis became a new rule effective May 31, 2011.

[2] MEEIA is the Missouri Energy Efficiency Investment Act of 2009, Section 393.1075, RSMo, Supp. 2013. The Commission's MEEIA rules include: 4 CSR 240-3.163, 4 CSR 240-3.164, 4 CSR 240-20.093 and 4 CSR 240-20.094.

[3] Ameren Missouri's MEEIA Cycle 2 application was filed in File No. EO-2015-0055 on December 22, 2014.

[4] Presented by Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company to their IRP stakeholder group on January 21, 2015 in a meeting required by 4 CSR 240-22.080(5)(A) for each utility's 2015 IRP to be filed on April 1, 2015.

[5] 4 CSR 240-22.080(9) If the staff, public counsel, or any intervenor finds deficiencies in or concerns with a triennial compliance filing, it shall work with the electric utility and the other parties to reach, within sixty (60) days of the date that the report or comments were submitted, a joint agreement on a plan to remedy the identified deficiencies and concerns. If full agreement cannot be reached, this should be reported to the commission through a joint filing as soon as possible but no later than sixty (60) days after the date on which the report or comments were submitted. The joint filing should set out in a brief narrative description those areas on which agreement cannot be reached. The resolution of any deficiencies and concerns shall also be noted in the joint filing.

Summary of Plan and Staff's Analysis

The policy objectives for electric utility resource planning are contained in:

4 CSR 240-22.010(2) The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. The fundamental objective requires that the utility shall—

(A) Consider and analyze demand-side resources, renewable energy, and supply-side resources on an equivalent basis, subject to compliance with all legal mandates that may affect the selection of utility electric energy resources, in the resource planning process;

(B) Use minimization of the present worth of long-run utility costs[6] as the primary selection criterion in choosing the preferred resource plan, subject to the constraints in subsection (2)(C); and

(C) Explicitly identify and, where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process, but which may constrain or limit the minimization of the present worth of expected utility costs. The utility shall describe and document the process and rationale used by decision-makers to assess the tradeoffs and determine the appropriate balance between minimization of expected utility costs and these other considerations in selecting the preferred resource plan and developing the resource acquisition strategy. These considerations shall include, but are not necessarily limited to, mitigation of:

1. Risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans;
2. Risks associated with new or more stringent legal mandates that may be imposed at some point within the planning horizon; and
3. Rate increases associated with alternative resource plans.

Staff provides this Report as required by Commission Rule 4 CSR 240-22.080(7):

(7) The staff shall conduct a limited review of each triennial compliance filing required by this rule and shall file a report not later than one hundred fifty (150) days after each utility's scheduled triennial compliance filing date. The report shall identify any deficiencies in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies and shall provide at least one (1) suggested remedy for each identified deficiency. Staff may also identify concerns with the utility's triennial compliance filing, may identify concerns related to the substantive reasonableness of the preferred resource plan or resource acquisition strategy, and shall provide at least one (1) suggested remedy for each identified concern.

[6] The term utilities costs is synonymous with revenue requirements.

As a result of its review, Staff finds that Ameren Missouri's analysis gave its decision-makers[7] a diverse and comprehensive set of nineteen (19) candidate resource plans, and risk analyses for each candidate resource plan, for use during the decision-makers' resource acquisition strategy selection process. For its risk analysis of each candidate resource plan, Ameren Missouri constructed a probability tree which contains four (4) critical dependent uncertain factors[8] (Eastern Interconnection's coal plant retirements, carbon prices, load growth and natural gas prices) and four (4) critical independent uncertain factors (DSM cost and load impact, long-term interest rates and return on equity, project capital cost, and coal prices). Ameren Missouri's final probability tree is included as Addendum A to this Report. The final probability tree has 1,215 branches with each branch representing a unique combination of the critical uncertain factors. Once the risk adjusted present value of revenue requirements ("PVRR") of all the combinations are calculated, the sum of the individual branch probabilities equals 100%.

The risk adjusted PVRR over 29 years[9] for the nineteen (19) candidate resource plans[10] varies from a low of $60.84 billion (for a plan with maximum achievable potential ("MAP") demand-side management ("DSM") resources (Plan G)) to a high of $66.97 billion (for a plan with no DSM and only new wind supply-side resources (Plan L)) for a PVRR range of $6.13 billion or approximately 9% for the nineteen candidate resource plans.

Ameren Missouri's decision makers used a decision scorecard to inform its resource acquisition strategy selection process.[11] Ameren Missouri's Preferred Plan Selection Scorecard

[7] Chapter 10, Appendix B, of Ameren Missouri's filing indicates that Ameren Missouri decision-makers present at the September 15, 2014 Ameren Missouri Board of Directors Meeting who adopted the 2014 IRP resource acquisition strategy included: Michael Moehn, President and Chief Executive Officer of Ameren Missouri; Dan F. Cole, President and Chief Executive Officer of Ameren Services; Greg L. Nelson, Senior Vice President General Counsel & Secretary; and Chuck D. Naslund, Executive Vice President Corporate Operations Oversight.
[8] Uncertain factor means any event, circumstance, situation, relationship, causal linkage, price, cost, value, response, or other relevant quantity which can materially affect the outcome of resource planning decisions, about which utility planners and decision-makers have incomplete or inadequate information at the time a decision must be made. Critical uncertain factor is any uncertain factor that is likely to materially affect the outcome of the resource planning decision.
[9] 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 horizon and 10 additional years for end effects, and by treating both supply-side and demand-side resources on an equivalent basis.
[10] Section 9.5 of the IRP describes each of the nineteen (19) alternative resource plans and the process used to determine the plans.
[11] The scorecard was used to comply with 4 CSR 240-22.010(2)(C); 4 CSR 240-22.010(2)(C)1 through 3; 4 CSR 240-22.070(1); and 4 CSR 240-22.070(1)(A) through (D).

("Scorecard") is included as Addendum B to this Report and reflects the following performance measures and assigned weights for each performance measure:

1. Environmental and resource diversity with a focus on transitioning to a cleaner and more fuel diverse portfolio (20%);
2. Financial and regulatory measures the expected financial performance and creditworthiness and potential risks (20%);
3. Customer satisfaction with a focus on rate impacts (average rates and maximum single-year rate increase) and customer preferences for cleaner energy sources and DSM (20%);
4. Economic development measured by potential for primary job growth (10%); and
5. Cost to customers as measured through PVRR (30%).[12]

The Scorecard for the top tier plans identified through scoring include combinations of RAP and MAP DSM portfolios as well as renewables, gas-fired resources and nuclear. Table 10.2 of the IRP contains the Alternative Resource Plan Scoring Results. The entire Scorecard is included as Addendum E to this Report.

[12] In its *Report and Order* issued on March 28, 2012, in Case No. EO-2011-0271, the Commission determined that compliance with 4 CSR 240-22.020(2)(B) "Use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan," means to give the PVRR performance measure the highest weights when complying with 4 CSR 240-22.070(1) "The utility shall select a preferred resource plan from among the alternative resource plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060. The utility shall describe and document the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by utility decision-makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk."

Table 10.2

Plan	Description	Overall Assessment
R	600MW CC in 2034, MAP, Balanced	4.10
I	600MW CC in 2034, RAP, Balanced	4.00
E	800MW Wind in 2034, 352MW SC in 2034, 600MW CC in 2034, RAP	3.80
G	600MW CC in 2034, MAP	3.80
A	600MW CC in 2034, RAP	3.60
C	704MW SC in 2034, RAP	3.60
S	600MW CC in 2034, MAP EE Only	3.60
H	169MW Nuke in 2034, 600MW CC in 2034, RAP, Balanced	3.40
F	1200MW CC in 2034,RAP EE Only	3.20
D	600MW Pumped Hydro in 2034, RAP	3.10
Q	169MW Nuke in 2034, MAP, Balanced	3.10
P	169MW Nuke in 2025, 600MW CC in 2025, 1200MW CC in 2034, RAP, Balanced, RI Ret 12/31/2024	3.00
B	450MW Nuke in 2034, 600MW CC in 2034, RAP	2.80
O	169MW Nuke in 2025, 1800MW CC in 2024, 1200MW CC in 2034, RAP, Balanced, LAB Ret 12/31/2023	2.50
N	600MW CC in 2025, 1200MW CC in 2034, MAP, RI Ret 12/31/2024	2.40
K	600MW CC in 2023, 600MW CC in 2031, 600MW CC in 2034, MEEIA1, Balanced	2.10
M	1800MW CC in 2024, 1200MW CC in 2034, MAP, LAB Ret 12/31/2023	2.10
J	169MW Nuke in 2031, 600MW CC in 2023, 1200MW CC in 2034, MEEIA1, Balanced	2.00
L	3300MW Wind in 2023, 3300MW Wind in 2027, 6600MW Wind in 2034, MEEIA1	1.60

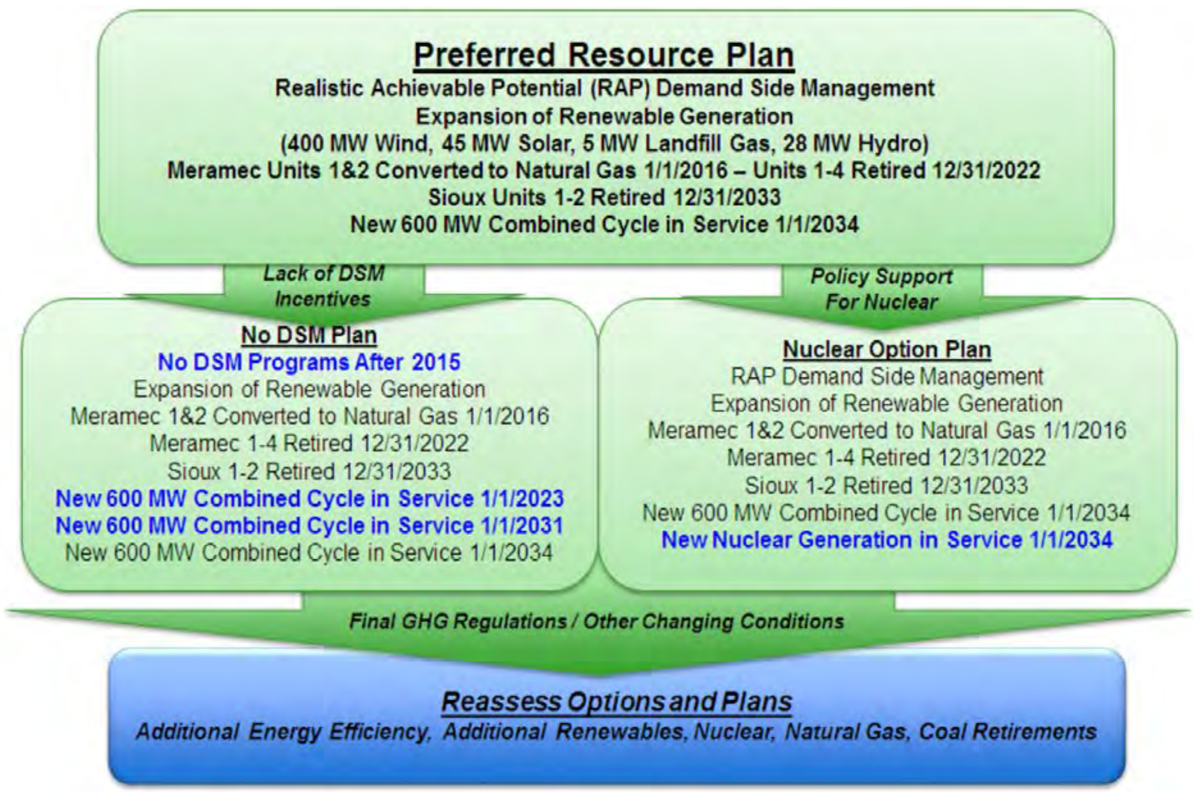
Ameren Missouri's adopted resource acquisition strategy includes its preferred resource plan (Plan A), which has a 29-year PVRR of $61.11 million and consists of realistic achievable potential ("RAP") energy efficiency and demand response programs, roughly 500 MW of new renewable generation, and a new 600 MW combined cycle energy center in 2034 along with conversion of Meramec Units 1 & 2 to natural gas-fired operation in 2016, retirement of all Meramec units by the end of 2022, and retirement of Sioux Energy Center at the end of 2033. Ameren Missouri's IRP discussion of its decision to choose a RAP plan even though similar MAP plans received higher overall scores on the Scorecard includes the following:

> **DSM Portfolio** – RAP and MAP DSM portfolios both performed well in the scoring and, importantly, both result in reduced total costs to customers. The decision between the two must involve a consideration of risk and reward from the perspective of both customers and Ameren Missouri. Based on our analysis of the year-by-year cost differences between RAP and MAP, and an understanding of the increased level of risk in achieving MAP relative to RAP, Ameren Missouri has chosen to include the RAP portfolio in its preferred resource plan.
>
> This is not to say that there couldn't be additional potential energy savings that can be realized. Indeed our uncertainty range for the RAP portfolio includes some significant amount of upside. However, we must consider the immediate cost impact to all customers of a large increase in DSM expenditures (the 2016-2018 budget would be nearly double for MAP) and the uncertainty of the relative

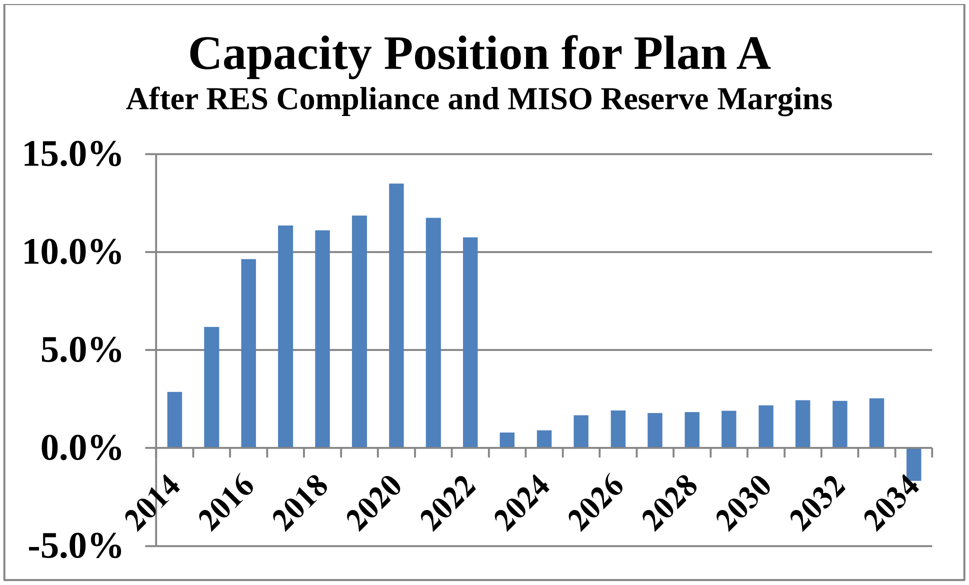
long-term benefits. We must also consider that the path for demand-side programs is not "locked in" for twenty years.

Including RAP DSM in our preferred resource plan allows us to continue to offer highly cost-effective programs to customers at roughly the same level of annual spending budgeted for our first cycle of MEEIA programs while also allowing the potential for increased savings if our experience and expectations indicate they could be achieved in a cost-effective manner. Identifying such opportunities will depend on the results of program implementation and periodic updates of our market research.

Ameren Missouri's resource acquisition strategy includes the adopted preferred resource plan as well as several contingency resource plan options and the events that could lead to a change in preferred resource plan and is shown in the following diagram:



Ameren Missouri's highly confidential capacity balance sheet for the adopted preferred resource plan (Plan A) is included as Addendum C to this Report. Ameren Missouri is expecting to be long on capacity through 2033 under Plan A after compliance with the Renewable Energy Standard ("RES") and with the Midcontinent Independent System Operator ("MISO") planning reserve margin requirements as reflected in the following chart.



As a result of its limited review, Staff identified no deficiencies and two (2) concerns regarding Ameren Missouri's 2014 IRP:

<u>4 CSR 240-22.030 Load Analysis and Forecasting</u>

<u>Summary</u>

4 CSR 240-22.030, Load Analysis and Forecasting, has a stated purpose of setting the "minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing loads, and the purposes to be accomplished by load analysis and by load forecast models. The load analysis discussed in this rule is intended to support both demand-side management efforts of 4 CSR 240-22.050 and the load forecast models of this rule. This rule also sets the minimum standards for the documentation of the inputs, components, and methods used to derive the load forecasts." The Load Analysis and Load Forecasting Rule allows the utility to use multiple analytical methods for performing its load analysis and develop its forecasts, leaving it to the utility's discretion to choose the methods by which it achieves the stated purpose of the rule. Ameren Missouri did not request any waivers from specific provisions of this rule.

In Staff's limited review of Ameren Missouri's load analysis and energy and demand forecasts, Staff found no deficiencies concerning compliance with this rule and Staff has not identified any additional concerns. In Staff's opinion, the Integrated Resource Analysis filing meets the Load Analysis and Forecasting requirements of 4 CSR 240-22.030.

4 CSR 240-22.040 Supply-Side Resource Analysis

Summary

Rule 4 CSR 240-22.040, Supply-Side Resource Analysis**,** requires Ameren Missouri to review existing resources for opportunities to upgrade or retire them, and also to review a wide variety of supply-side resource options to determine cost estimates for each. Resource options are to be ranked based upon their relative levelized annual utility costs,[13] as well as based upon their probable environmental costs. Resources which do not have significant disadvantages pass this pre-screening process and are to be included in the integrated resource analysis process used to select the preferred resource plan. Ameren Missouri reviewed fossil fuel, renewable energy, and nuclear resource options, as well as its transmission and distribution system options.

Ameren Missouri retained the services of Burns & McDonnell to complete a Condition Assessment of the Meramec Energy Center to determine ongoing costs necessary to keep the plant operating safely and reliably through the planning horizon. Ameren Missouri is scheduled to complete two unit upgrades at Keokuk Energy Center (Units 5 and 6) in 2016. In addition, upgrades of Units 14 and 15 at Keokuk Energy Center are scheduled to be complete in 2018. Ameren Missouri is also considering options for Meramec Energy Center including combinations of unit retirements and gas conversion, with all units retired by the end of 2022.

Ameren Missouri engaged Black & Veatch to conduct a supply-side screening analysis of various coal and gas power generation technologies in support of Ameren Missouri's 2011 IRP. This analysis was reviewed by Ameren Missouri subject matter experts and updated as needed for use in this filing. One of the more significant criteria utilized in the scoring was the levelized cost of energy (LCOE)[14]. The LCOE included financial factors, such as fuel costs, tax life, economic life, escalation rates, present worth discount rate, levelized fixed charge rate that were used in the LCOE estimates in the candidate resource screening[15]. Wind energy resources exhibited the lowest cost on an LCOE basis among all candidate resource options[16]. Ameren Missouri has evaluated options for development of wind resources both within Missouri and across the broader region.

[13] 4 CSR 240-22.040(A) Cost rankings of each potential supply-side resource option shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs levelized over the useful life of the potential supply-side resource option using the utility discount rate. The utility shall include the costs of ancillary and/or back-up sources of supply required to achieve necessary reliability levels in connection with intermittent and/or uncontrollable sources of generation (i.e., wind and solar).

[14] Ameren Missouri IRP Chapter 6 Appendix 6, page 19.

[15] Ibid

[16] Ameren Missouri IRP Chapter 6 page 1

Three options were selected as final candidate resource options to represent fossil fuel resource options – gas combined cycle, gas simple cycle combustion turbine, and ultra-super-critical pulverized coal. Gas combined cycle technology exhibits the lowest cost on a levelized cost basis among conventional generation resources. Ameren Missouri ranked these options to obtain a high, base and low range of costs based on a broad range of technology development, probable environmental regulations and cost uncertainties. Ameren Missouri excluded some technologies from its further review because the technologies are in the developmental stage, resource inadequacy, or absence of geological features required for their implementation or use by Ameren Missouri.

Ameren Missouri's supply-side resource screening analysis identified potential cost-effective options that it passed on to consider further in its integrated resource analysis. Ameren Missouri evaluated the efficiency, life extension, environmental enhancements and retirement scenarios of the existing facilities it relies upon for capacity and power.

With respect to rule 4 CSR 240-22.040 Supply-Side Resource Analysis, Ameren Missouri requested, and the Commission granted, in Docket No. EE-2014-0089, one waiver of the following specific provision of that rule:

4 CSR 240-22.040(3)(A)	The analysis shall include the identification of transmission constraints, as estimated pursuant to 4 CSR 240-22.045(3), whether within the Regional Transmission Organization's (RTO's) footprint, on an interconnected RTO, or a transmission system that is not part of an RTO.

Based on its limited review, Staff concludes Ameren Missouri's Supply-Side Resource Analysis filing meets the requirements of rule 4 CSR 240-22.040, and Staff has identified no concerns or deficiencies.

4 CSR 240-22.045 Transmission and Distribution Analysis

Summary

Rule 4 CSR 240-22.045 Transmission and Distribution Analysis specifies the minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting. Rule 4 CSR 240-22.045 is prompted, in part, by the changes in federal law that can affect electric utility resource planning and resource viability, e.g., policies of Regional Transmission Organizations ("RTO"), development of regional power markets, and implementation of Smart Grid technologies. Rule 4 CSR 240-22.045 does not prescribe how analyses are to be done, but rather allows a utility to conduct its own analysis or adopt the RTO or Independent Transmission System Operator ("ISO") transmission plans. Rule 4 CSR 240-22.045 requires analysis and documentation of the RTO/ISO transmission projects and requires the electric utility to review transmission and distribution for the reduction of power losses, interconnection of new generation facilities, facilitation of sales and purchases and incorporation of advance technologies for the optimization of investment in transmission and distribution resources.

With respect to Rule 4 CSR 240-22.045 Ameren Missouri requested, and the Commission granted, in Docket No. EE-2014-0089, two (2) waivers of the following specific provisions of that rule:

4 CSR 240-22.045 (1)(B)	Interconnect new generation facilities. The utility shall assess the need to construct transmission facilities to interconnect any new generation pursuant to 4 CSR 240-22.040(3) and shall reflect those transmission facilities in the cost benefit analyses of the resource options;
4 CSR 240-22.045 (3)(C)	The utility shall provide copies of the RTO expansion plans, its assessment of the plans, and any supplemental information developed by the utility plans, its assessment of the plans, and any supplemental information developed by the utility to fulfill the requirements in subsection (3)(B) of this rule.

Ameren Missouri will construct eight (8) of the eleven (11) transmission projects in Missouri that have been approved by the MISO Board of Directors for completion before 2019.[17]

Based on its limited review, Staff concludes Ameren Missouri's Transmission and Distribution Analysis filing meets the requirements of rule 4 CSR 240-22.045, and Staff has identified no concerns or deficiencies.

4 CSR 240-22.050 Demand-Side Resource Analysis

Summary

Rule 4 CSR 240-22.050, Demand-Side Resource Analysis, specifies the methods by which end-use measures and demand-side programs shall be developed and screened for cost-

[17] Page 1 of Chapter 7 of the IRP Filing.

effectiveness. It also requires the ongoing evaluation of end-use measures and programs, and the use of program evaluation, measurement and verification ("EM&V") to improve program design and cost-effectiveness analysis.

The current Ameren Missouri 2014 IRP filing improves and expands Ameren Missouri's overall consideration and evaluation of demand-side resources from its previous 2011 IRP filing. Ameren Missouri utilizes the knowledge gained from: 1) the actual program implementation and evaluation experience from its previous and current demand-side programs; 2) the incorporation of the 2013 Ameren Missouri DSM Potential Study found within Chapter 8-Appendix B with the supporting documentation found within the work papers; 3) substantial input received as a result of multiple stakeholder workshops and meetings; and 4) Ameren Missouri's active participation in the Electric Power Research Institute's (EPRI) Industrial Center of Excellence (ICOE). The 2014 IRP filing also reflects a demand-side energy efficiency portfolio that includes:

- The addition of formal project management processes and procedures;
- The addition of a DSM data collection and tracking system;
- The addition of a Marketing Manager;
- The development of market segmentation strategies to tailor specific DSM messages to specific market segments;
- The addition of a web-based Technical Reference Manual; and
- The implementation of EM&V processes and procedures.

Ameren Missouri's 2016 - 2018 DSM programs consist of six residential programs and four business programs. The programs are similar to the programs Ameren Missouri successfully implemented during its 2013-2015 MEEIA program. The exceptions are:

- The residential New Construction program originally included in the 2013 - 2015 plan was discontinued, because EM&V demonstrated it was no longer cost effective;
- The residential Home Energy Audit program does not pass the cost effectiveness test for MEEIA 2016 - 2018 and has been eliminated;
- One new residential program, the Energy Efficiency Kits program, has been added for MEEIA 2016 - 2018. This program is an extension of kits included in the Energy Efficient Products program from MEEIA 2013 - 2015 but using a new distribution channel; and
- The residential Lighting and Appliance program no longer includes upstream discounting of CFLs, since CFLs are no longer cost effective due to federal legislation requiring higher levels of lighting efficiency beginning in 2020.

For the 2016 – 2018 programs, 60% of the program-level energy savings are expected to come from business customers and the remaining 40% from residential customers, which is the inverse of what was planned for 2013 – 2015 when 61% of energy savings were to come from residential customers due to the large upstream promotion of CFL bulbs.

Ameren Missouri reports that MISO capacity markets indicate that demand response opportunities have little market capacity value for the immediate future. Since Ameren Missouri is not projecting a need for demand response for reliability purposes, the business case for demand response for Ameren Missouri customers is dependent on the MISO capacity market. Although Ameren Missouri determined that Demand Response (DR) programs are not cost effective for 2016-2018, Ameren Missouri is considering a pilot DR program to better understand the tolerance customers have for various frequencies and durations of DR events.

Ameren Missouri was unable to identify any opportunities for cost-effective combined heat and power applications for their industrial customers.

Ameren Missouri applied for and received from the Commission variances from five (5) provisions of this rule related to the following:

4 CSR 240-22.050(4)(D)2	An assessment of how the interactions between multiple potential demand-side rates, if offered simultaneously, would affect the impact estimates;
4 CSR 240-22.050(4)(D)(3)	An assessment of how the interactions between potential demand-side rates and potential demand-side programs would affect the impact estimates of the potential demand side programs and potential demand-side rates;
4 CSR 240-22.050(5)(B)(3)	For purposes of this test, the costs of potential demand-side programs and potential demand-side rates shall not include lost revenues or utility incentive payments to customers.
4 CSR 240-22.050(B)(E)	The utility shall provide results of the total resource cost test and the utility cost test for each potential demand-side program evaluated pursuant to subsection (5)(B) and for each potential demand–side rate evaluated pursuant to subsection (5)(C) of this rule, including a tabulation of the benefits (avoided costs), demand-side resource costs, and net benefits or costs.

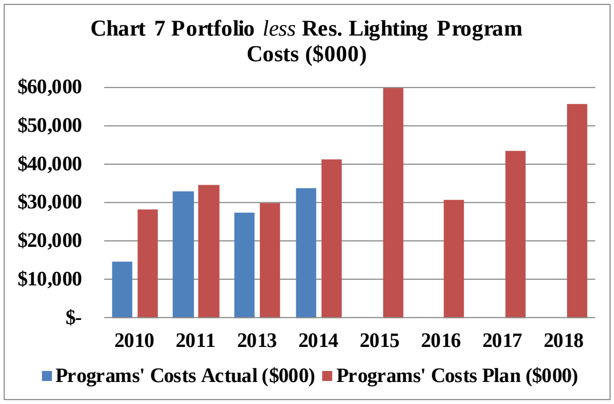
Based on its limited review, Staff concludes Ameren Missouri's Demand-Side Resource Analysis filing meets the requirements of rule 4 CSR 240-22.050 and there are no deficiencies. However, Staff has several concerns regarding the level of annual energy and demand savings expected from Ameren Missouri’s RAP portfolio in its 20-year adopted preferred resource plan

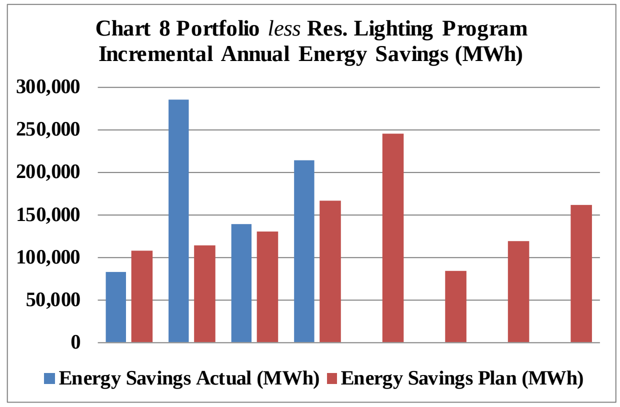
(Plan A) and in the Company's 3-year implementation plan for its RAP portfolio which is also the DSM plan contained in the Company's MEEIA Cycle 2 Plan[18] filed on October 1, 2014 in File No. EO-2015-0055.

Staff performed an analysis of the actual vs. planned programs' costs, deemed annual energy savings and deemed energy savings per dollar of programs' costs for Ameren Missouri's pre-MEEIA programs (program years 2009, 2010 and 2011) and for the Company's MEEIA Cycle 1 (program years 2013 and 2014) and for the planned programs' cost and planned deemed annual energy savings for program years 2015, 2016, 2017 and 2018. Note that 2015 is the last year of MEEIA Cycle 1, while MEEIA Cycle 2 spans 2016 – 2018.

Residential Lighting program will have much less impact on the portfolio's overall performance in the future due in particular to the elimination of energy savings from the CFL bulbs beginning in 2015. Thus, Staff's analysis focuses on total portfolio *less* Residential Lighting program actual and planned programs' costs, deemed annual energy savings and deemed energy savings per dollar of programs' costs. Details of Staff's analysis are included in the tables of data and Charts 1 - 18 in Addendum D, which is best summarized in Charts 7, 8 and 9 of Addendum D as presented below.

[18] MEEIA is the Missouri Energy Efficiency Investment Act of 2009, Section 393.1075, RSMo, Supp. 2013. The Commission's MEEIA rules include: 4 CSR 240-3.163, 4 CSR 240-3.164, 4 CSR 240-20.093 and 4 CSR 240-20.094.





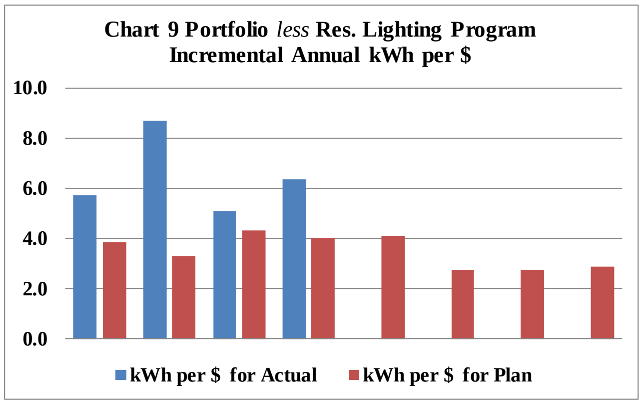
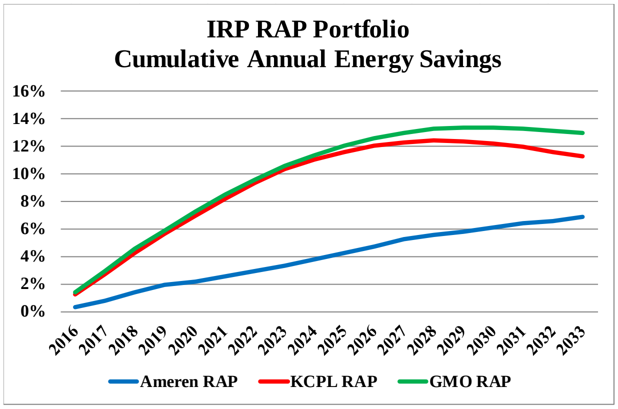
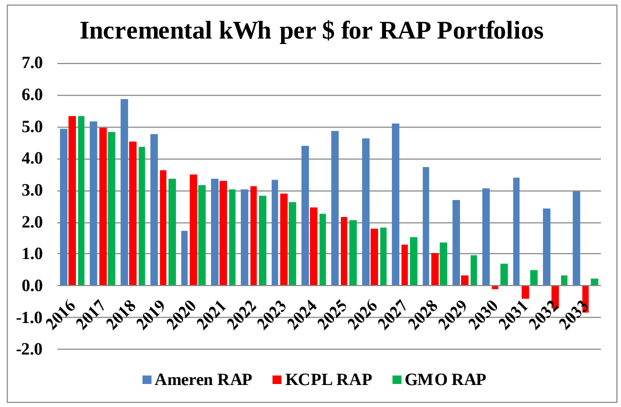


Chart 7 illustrates that actual programs' costs have been less than planned in each year and that the planned programs' costs for MEEIA Cycle 2 are approximately the same as the planned programs' costs for MEEIA Cycle 1. Charts 8 and 9 illustrate that MEEIA Cycle 2's incremental annual energy savings and incremental annual energy savings per $ of portfolio cost are approximately one half of these same planned performance metrics for MEEIA Cycle 1 and may be vastly underestimated given the fact that actual incremental annual energy savings and actual incremental annual energy savings per $ of portfolio cost far exceeded these same planned performance metrics during 2013 and 2014 of MEEIA Cycle 1 as well as 2010 and 2011 of the pre-MEEIA programs.

Staff notes that Ameren Missouri's DSM market potential study for its MEEIA Cycle 1 was performed by Global Energy Partners, LLC, and was issued in January 2011, while its DSM market potential study for its MEEIA Cycle 2 was performed by EnerNoc Utility Solutions Consulting and was issued in December 2013.

Staff also compared Ameren Missouri's IRP RAP portfolio's cumulative annual energy savings and incremental annual kWh per $ of programs' costs over a longer term period (2016 – 2033) to cumulative annual energy savings and incremental annual kWh per $ of programs' costs of the IRP RAP portfolios of Kansas City Power & Light Company ("KCPL") and KCP&L Greater Missouri Operations Company ("GMO") and found that Ameren Missouri's RAP portfolio is expected to produce approximately one-half the annual energy savings levels[19] of the RAP portfolios of KCPL and GMO.





Staff notes that the KCPL and GMO DSM market potential studies were performed by Navigant and issued in August 2013.

Concerns

C. **The incremental annual energy savings expected from Ameren Missouri's RAP portfolio for its MEEIA Cycle 2 (2016 – 2018) may be vastly underestimated, since the kWh and kWh per $ savings are less than half the actual achieved levels of kWh and a kWh per $ during Ameren Missouri's pre-MEEIA programs (2009 – 2011) and MEEIA Cycle 1 programs to date (2013 – 2014).**

D. **The incremental and cumulative annual energy savings expected from Ameren Missouri's RAP portfolio during the long-term planning horizon may be vastly underestimated, since the Ameren Missouri savings are approximately one-half the incremental and cumulative annual energy savings of the IRP RAP portfolios of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company.**

To remedy these concerns, Ameren Missouri should work with parties to its 2014 IRP case and with parties to its MEEIA Cycle 2 case (File No. EO-2015-0055) during joint agreement[20] discussions and during technical conferences, respectively, to help parties understand Staff's concerns and, if necessary, to resolve those concerns.

[19] Annual energy savings are expressed as: 1) a percentage of the baseline forecast for energy sales for customers who have not opted-out of participation in the DSM programs, and 2) kWh per $ of programs' costs.

[20] 4 CSR 240-22.080(9) If the staff, public counsel, or any intervenor finds deficiencies in or concerns with a triennial compliance filing, it shall work with the electric utility and the other parties to reach, within sixty (60) days of the date that the report or comments were submitted, a joint agreement on a plan to remedy the identified deficiencies and concerns. If full agreement cannot be reached, this should be reported to the commission through a joint filing as soon as possible but no later than sixty (60) days after the date on which the report or comments were submitted. The joint filing should set out in a brief narrative description those areas on which agreement cannot be reached. The resolution of any deficiencies and concerns shall also be noted in the joint filing.

4 CSR 240-22.060 Integrated Resource Analysis

Summary

Rule 4 CSR 240-22.060, Integrated Resource Analysis, requires the utility to design alternative resource plans to meet the planning objectives identified in rule 4 CSR 240-22.010(2), to set minimum standards for the scope and level of detail required in resource plan analysis, and to perform a logically consistent and economically-equivalent analysis of alternative resource plans.

Ameren Missouri developed seven attributes or dimensions for use in its creation of alternative resource plans:

1. Three (3) Meramec Retirement Options
   - Retired 12/31/2015
   - Retired 12/31/2022
   - Convert units 1 and 2 to natural gas and units 3 and 4 continue on coal. All units retired 12/31/2022

2. Three (3) Retirements
   - Labadie retired 12/31/2023
   - Rush Island retired 12/31/2024
   - Sioux retired 12/31/2033

3. Seven (7) New Supply-Side Types
   - Combined Cycle (Natural Gas)
   - Simple Cycle (Natural Gas)
   - Nuclear (100% Ownership)
   - Nuclear (75% Ownership)
   - Pumped Hydroelectric
   - Wind
   - Wind with Simple Cycle

4. Two (2) Keokuk Upgrade
   - 50 MW Expansion
   - None

5. Three (3) Energy Efficiency
   - MAP
   - RAP
   - Missouri Energy Efficiency Investment Act (MEEIA) Cycle 1 only.

6. Three (3) Demand Response
    - MAP
    - RAP
    - None

7. Two (2) Renewable Portfolios
    - Missouri Renewable Energy Standard (RES)
    - Balanced[21]

The various combinations of these seven attributes resulted in a robust set of alternative resource plans. However, some combinations result in duplicate alternative resource plans or infeasible alternative resource plans, e.g., the Meramec combined cycle option is contingent on Meramec's retirement so the interaction of Meramec continuing and the Meramec combined cycle option would produce an infeasible plan. Ultimately, Ameren Missouri analyzed 19 alternative resource plans in an initial screening process based on a scorecard approach that embodied the following Ameren Missouri performance measures and relative weights for each performance measure:

1. Environmental and resource diversity (20%) measured by resource diversity, carbon emissions, SO_2 emissions and NO_x emissions;
2. Financial and regulatory (20%) measured by return on equity (ROE), return on invested capital (ROIC), earnings per share (EPS), free cash flow, stranded cost risk, transaction risk and [cost] recovery;
3. Customer satisfaction (20%) measured by average rates and single year rate increase;
4. Economic development (10%) measured by primary job growth (FTE-years); and
5. Cost (30%) measured by net present value of revenue requirements (NPVRR).

For its risk analysis of each candidate resource plan, Ameren Missouri constructed a probability tree which contains four (4) critical dependent uncertain factors (Eastern Interconnection's coal plant retirements, carbon prices, load growth and natural gas prices) and four (4) critical dependent uncertain factors (DSM cost and load impact, long-term interest rates and return on equity, project capital cost, and coal prices) when evaluating each alternative resource plan. Ameren Missouri's final probability tree is included as Addendum A to this

[21] All alternative resource plans that are identified as "Balanced" include investment in renewable resources that are above and beyond those needed for RES compliance. (i.e., 400 MW wind, 45 MW solar, and 20 MW small hydroelectric).

Report. The final probability tree has 1,215 branches with each branch representing a unique combination of the critical uncertain factors. Once the risk adjusted present value of revenue requirements ("PVRR") of all the combinations are calculated, the sum of the individual branch probabilities equals 100%.

Ameren Missouri applied for and received from the Commission variances from five (5) provisions of this rule related to the following:

4 CSR 240-22.060(5)(E)	Total project cost (including siting, permitting and construction costs) for new generation and generation-related transmission facilities;
4 CSR 240-22.060(5)(F)	Total project cost (including siting, permitting and construction costs) for new generation and generation-related transmission facilities;
4 CSR 240-22.060(5)(K)	Future load impacts and marketing and delivery costs of demand-side programs and demand-side rates if the cost and impacts are determined to be highly correlated. Future load impacts and demand-side programs and demand-side rates if the costs and impacts are determined to not be highly correlated;
4 CSR 240-22.060(5)(L)	Future load impacts and marketing and delivery costs of demand-side programs and demand-side rates if the cost and impacts are determined to be highly correlated. Utility marketing and delivery costs for demand-side programs and demand-side rates if the costs and impacts are determined to not be highly correlated;
4 CSR 240-22.060(7)	The utility decision-makers shall assign a probability pursuant to section (5) of this rule to each uncertain factor deemed critical by the utility. The utility shall compute the cumulative probability distribution of the values of 'present value revenue requirements' performance measure for each alternative resource plan. For each of the other performance measures specified in 4 CSR 240-22.060(2)(A)1-6 and for any additional measures chosen by the utility pursuant to 4 CSR 240-22.060(2)(A)7, Ameren Missouri will compute a cumulative probability distribution of its values if inspection of the summary tabulation required by 4 CSR 240-22.060(4)A indicates that the rankings of alternative plans by this performance measure substantially differs from the ranking based on present value revenue requirements. Both the expected performance and the risks of each alternative resource plan shall be quantified. The utility shall describe and document its risk assessment of each alternative resource plan.

Based on its limited review, Staff has identified no deficiencies or concerns for Ameren Missouri's Integrated Resource Plan and Risk Analysis filing.

4 CSR 240-22.070 Risk Analysis and Strategy Selection

Summary

Rule 4 CSR 240-22.070, Risk Analysis and Strategy Selection, requires the utility to select a preferred resource plan, develop an implementation plan, and officially adopt a resource acquisition strategy. The rule also requires the utility to prepare contingency plans and evaluate the demand-side resources that are included in the resource acquisition strategy.

Ameren Missouri did not apply for any waivers from the requirements of this rule.

Ameren Missouri's final probability tree (see Addendum A) consists of the following dependent and independent critical uncertain factors:

Dependent critical uncertain factors

- Coal plant retirements
- CO_2 policy
- Natural gas prices
- Load growth

Independent critical uncertain factors

- DSM costs jointly with DSM load impacts
- Long-term interest rates jointly with return on equity
- Project cost

Ameren Missouri's decision-makers chose to use a Scorecard approach[22] to evaluate its nineteen (19) candidate resource plans during their strategy selection process to adopt a resource acquisition strategy and a preferred resource plan for Ameren Missouri. The Scorecard is included as Addendum B.

Based on its limited review, Staff has identified no deficiencies or concerns for Ameren Missouri's Resource Acquisition Strategy Selection filing.

[22] See the Plan's section 10.2 Assessment of Alternative Resource Plans.

4 CSR 240-22.080 Filing Schedule and Requirements

Summary

Chapter 4 CSR 240-22 Electric Utility Resource Planning sets minimum standards to govern the scope and objectives of the integrated resource planning process of the electric utilities regulated by the Commission. The focus of Chapter 4 CSR 240-22 is on the planning process used to determine the utility's preferred resource plan, not the outcome of that process, i.e., the adopted preferred resource plan. Rule 4 CSR 240-22.080 identifies minimum reporting requirements concerning who is to file, when to file, what to file, the review process and the Commission's authority with respect to compliance filings.

Ameren Missouri has organized its 2014 IRP in eleven (11) chapters of information and discussion which flow smoothly in a narrative form to tell a clear story. At the end of each chapter is a Compliance Reference guide which cross references each Chapter 22 filing requirement met in the chapter tied to the page in the chapter on which the filing requirement is contained. Staff finds this approach to be productive and useful and encourages Ameren Missouri to continue this practice in future filings. Chapter 11 of the IRP includes summary information on Ameren Missouri's IRP stakeholder process, which Staff finds to be very constructive overall.

Based on its limited review, Staff has identified no deficiencies or concerns related to Ameren Missouri's rule 4 CSR 240-22.080 filing.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Ameren Missouri's 2014 Utility Resource Filing pursuant to 4 CSR 240 - chapter 22	)))	Case No. EO-2015-0084

AFFIDAVIT OF JOHN A ROGERS

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

John A. Rogers, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 1-7, 12-15, 19-20; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

John A Rogers
John A. Rogers

Subscribed and sworn to before me this 27th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Ameren Missouri's 2014 Utility Resource Filing pursuant to 4 CSR 240 - chapter 22	)))	Case No. EO-2015-0084

AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

David C. Roos, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 7, 19 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David C. Roos

Subscribed and sworn to before me this 27th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Notary Public

Schedule MM-S3

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Ameren Missouri's 2014 Utility Resource Filing pursuant to 4 CSR 240 - chapter 22	)))	Case No. EO-2015-0084

AFFIDAVIT OF RANDY S. GROSS

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Randy S. Gross, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 8 - 12 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Randy S. Gross

Subscribed and sworn to before me this 27th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Notary Public

Schedule MM-S3

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Ameren Missouri's 2014 Utility Resource Filing pursuant to 4 CSR 240 - chapter 22	)))	Case No. EO-2015-0084

AFFIDAVIT OF MATTHEW J. BARNES

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Matthew J. Barnes, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 16 - 19; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

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Matthew J. Barnes
Matthew J. Barnes

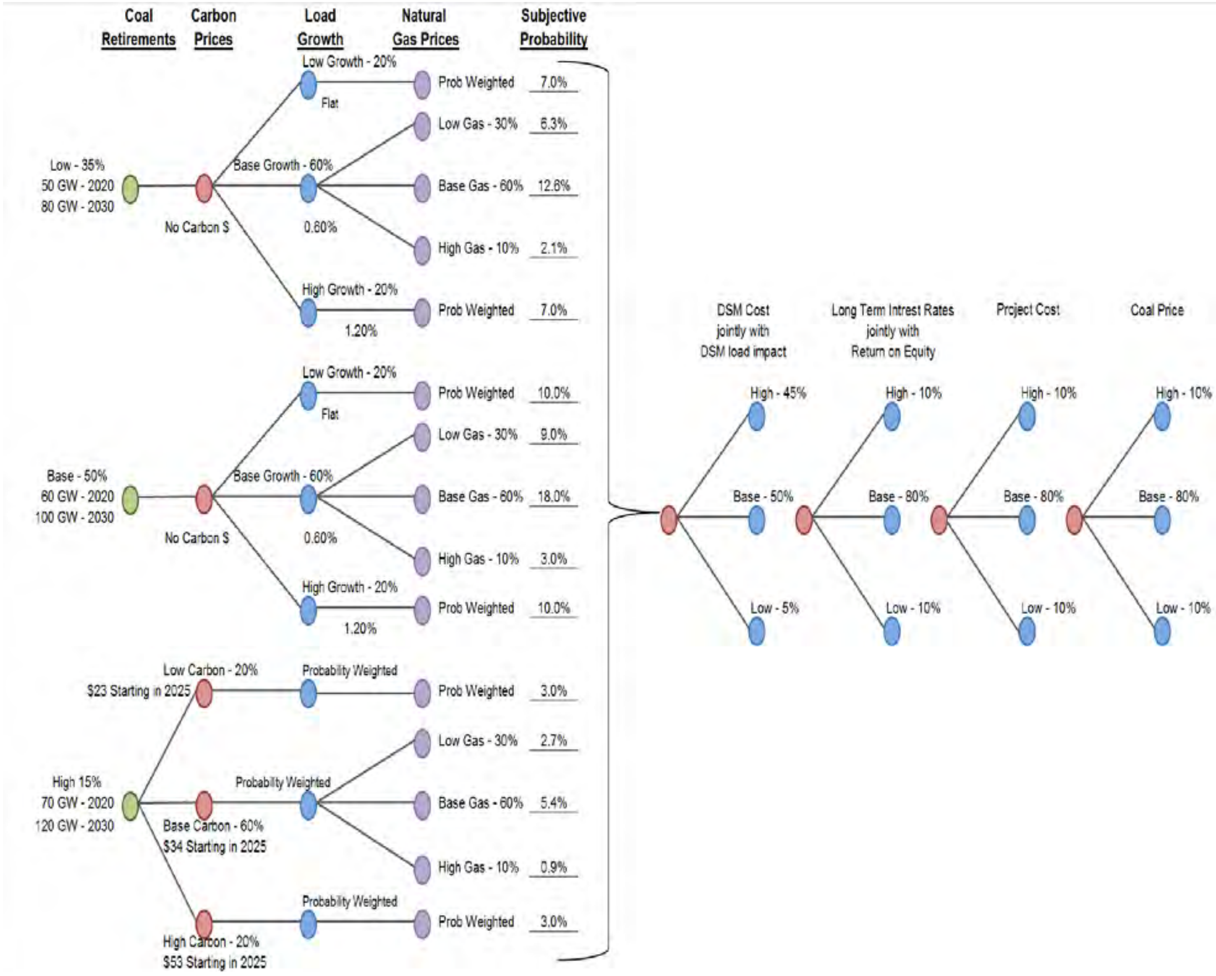
Subscribed and sworn to before me this 27th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L. Sundermeyer
Notary Public

Schedule MM-S3

Figure 9.11 Final Probability Tree



Ameren Missouri 2014 IRP
Preferred Plan Selection Scorecard

Planning Objectives, Weights and Measures							
	Category	Environmental/ Renewable/ Resource Diversity	Financial/ Regulatory	Customer Satisfaction	Economic Development	Cost	Overall Assessment
Plan	Category Weight	20%	20%	20%	10%	30%	100%
R	600MW CC in 2034, MAP, Balanced	3	4	4	4	5	4.10
I	600MW CC in 2034, RAP, Balanced	3	5	5	2	4	4.00
E	800MW Wind in 2034, 352MW SC in 2034, 600MW CC in 2034, RAP	3	4	5	2	4	3.80
G	600MW CC in 2034, MAP	2	4	4	3	5	3.80
A	600MW CC in 2034, RAP	2	5	4	2	4	3.60
C	704MW SC in 2034, RAP	1	5	4	1	5	3.60
S	600MW CC in 2034, MAP EE Only	2	4	3	3	5	3.60
H	169MW Nuke in 2034, 600MW CC in 2034, RAP, Balanced	4	3	4	3	3	3.40
F	1200MW CC in 2034,RAP EE Only	2	4	3	2	4	3.20
D	600MW Pumped Hydro in 2034, RAP	2	4	4	2	3	3.10
Q	169MW Nuke in 2034, MAP, Balanced	3	2	4	4	3	3.10
P	169MW Nuke in 2025, 600MW CC in 2025, 1200MW CC in 2034, RAP, Balanced, RI Ret 12/31/2024	5	2	3	4	2	3.00
B	450MW Nuke in 2034, 600MW CC in 2034, RAP	3	3	2	3	3	2.80
O	169MW Nuke in 2025, 1800MW CC in 2024, 1200MW CC in 2034, RAP, Balanced, LAB Ret 12/31/2023	5	1	3	4	1	2.50
N	600MW CC in 2025, 1200MW CC in 2034, MAP, RI Ret 12/31/2024	3	2	2	4	2	2.40
K	600MW CC in 2023, 600MW CC in 2031, 600MW CC in 2034, MEEIA1, Balanced	2	3	2	1	2	2.10
M	1800MW CC in 2024, 1200MW CC in 2034, MAP, LAB Ret 12/31/2023	3	2	2	4	1	2.10
J	169MW Nuke in 2031, 600MW CC in 2023, 1200MW CC in 2034, MEEIA1, Balanced	3	2	1	2	2	2.00
L	3300MW Wind in 2023, 3300MW Wind in 2027, 6600MW Wind in 2034, MEEIA1	1	2	1	5	1	1.60

Scoring Guide	
Significant Advantage	5
Moderate Advantage	4
No Advantage or Disadvantage	3
Moderate Disadvantage	2
Significant Disadvantage	1

Overall Assessment Guide	
Top-tier Plan	
Mid-tier Plan	
Bottom-tier Plan	

Notes on Scores by Policy Objective	
Environmental/Diversity	Inclusion of MAP or RAP energy efficiency; new nuclear; combined cycle; additional coal retirement beyond Meramec and Sioux; additional renewables; and/or pumped hydro were viewed as advantageous.
Financial Regulatory	Financial and regulatory risks associated with new nuclear; additional coal retirement beyond Meramec and Sioux; cessation of energy efficiency programs; implementation of overly aggressive energy efficiency programs; and/or vast amounts of wind generation were viewed as disadvantageous, as were large negative impacts on cash flow.
Customer Satisfaction	Lower levelized annual rate increases, inclusion of energy efficiency and demand response, and inclusion of renewables were viewed as advantageous.
Economic Development	Plans were rated on a relative scale based on direct jobs (FTE-years) including both construction and operation.
Cost (PVRR)	Plans were rated on a relative scale based on present value of revenue requirements (PVRR).

Key to Abbreviations

EE = Energy Efficiency Only, No Demand Response
MEEIA = Missouri Energy Efficiency Investment Act Cycle 1
RES = Renewable Energy Standard
Balanced = Balanced plan (solar, wind, hydro)
LAB = Labadie Energy Center
MW = Megawatts
RI = Rush Island Energy Center
CC = Combined Cycle Gas Turbine Generator
MAP = Maximum Achievable Potential DSM Portfolio
RAP = Realistic Achievable Potential DSM Portfolio
Ret = Retirement

Addendum B

Schedule MM-S3

Forecast of Capacity Balance (MW) **Highly Confidential**

Ameren Missouri

2014 IRP

A System Generation Capacity		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Existing Generation Capacity																						
Callaway	Nuclear	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190
Keokuk	Hydro	141	141	145	145	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
Labadie Unit 1	Coal	593	593	593	593	593	593	593	593	593	583	583	583	583	583	583	583	583	583	583	583	583
Labadie Unit 2	Coal	593	593	593	593	593	593	593	593	593	583	583	583	583	583	583	583	583	583	583	583	583
Labadie Unit 3	Coal	594	594	594	594	594	594	594	594	571	571	561	561	561	561	561	561	561	561	561	561	561
Labadie Unit 4	Coal	594	594	594	594	594	594	594	594	571	571	561	561	561	561	561	561	561	561	561	561	561
Rush Island Unit 1	Coal	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591
Rush Island Unit 2	Coal	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591	591
Sioux Unit 1	Coal	487	487	487	487	487	487	485	485	485	485	485	485	485	485	485	485	485	485	485	485	0
Sioux Unit 2	Coal	487	487	487	487	487	487	485	485	485	485	485	485	485	485	485	485	485	485	485	485	0
Meramec Unit 1	Coal	119	119	119	119	119	119	119	119	119	0	0	0	0	0	0	0	0	0	0	0	0
Meramec Unit 2	Coal	121	121	121	121	121	121	121	121	121	0	0	0	0	0	0	0	0	0	0	0	0
Meramec Unit 3	Coal	259	259	259	259	259	259	259	259	259	0	0	0	0	0	0	0	0	0	0	0	0
Meramec Unit 4	Coal	335	335	335	335	335	335	335	335	335	0	0	0	0	0	0	0	0	0	0	0	0
Maryland Heights	LFG	9	9	9	9	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
O'Fallon	SOLAR	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Base Capacity		6704	6705	6709	6709	6718	6718	6713	6713	6667	5813	5793	5793	5793	5793	5793	5793	5793	5793	5793	5793	4824
Osage	Hydro	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
Taum Sauk Unit 1	Hydro	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Taum Sauk Unit 2	Hydro	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Audrain 1	Gas	71	71	71	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 2	Gas	71	71	71	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 3	Gas	71	71	71	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 4	Gas	71	71	71	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 5	Gas	71	71	71	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 6	Gas	71	71	71	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 7	Gas	71	71	71	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 8	Gas	71	71	71	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Fairgrounds	Oil	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Goose Creek 1	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Goose Creek 2	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Goose Creek 3	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Goose Creek 4	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Goose Creek 5	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Goose Creek 6	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Howard Bend	Oil	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kinmundy CTG-1	Gas	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Kinmundy CTG-2	Gas	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Kirksville	Gas	13	13	13	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meramec CTG-1	Oil/Gas	54	54	54	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meramec CTG-2	Oil/Gas	45	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mexico	Oil	54	54	54	54	54	54	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moberly	Oil	54	54	54	54	54	54	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moreau	Oil	54	54	54	54	54	54	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peno Creek CTG-1	Gas/Oil	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Peno Creek CTG-2	Gas/Oil	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Peno Creek CTG-3	Gas/Oil	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Peno Creek CTG-4	Gas/Oil	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Pinckneyville CTG-1	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-2	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-3	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-4	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-5	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Pinckneyville CTG-6	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Pinckneyville CTG-7	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Pinckneyville CTG-8	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Racoon Creek 1	Gas	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Racoon Creek 2	Gas	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Racoon Creek 3	Gas	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Racoon Creek 4	Gas	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Venice CTG-2	Gas	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Venice CTG-3	Gas	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168
Venice CTG-4	Gas	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168
Venice CTG-5	Gas	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Total Intermediate/Peaking Capacity		3546	3453	3453	3453	3386	3386	3416	3209	3209	3209	3209	3209	3209	3209	3209	3209	3209	3209	3209	3209	3209
Total Generation Capacity (TGC)		**10250**	**10158**	**10162**	**10162**	**10104**	**10104**	**10129**	**9922**	**9876**	**9022**	**9002**	**9002**	**9002**	**9002**	**9002**	**9002**	**9002**	**9002**	**9002**	**9002**	**8033**

Addendum C-1

Schedule MM-S3

Forecast of Capacity Balance (MW)

Highly Confidential

Ameren Missouri
2014 IRP

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A. System Generation Capacity	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Generation Capacity (TGC)	**10250**	**10158**	**10162**	**10162**	**10104**	**10104**	**10129**	**9922**	**9876**	**9022**	**9002**	**9002**	**9002**	**9002**	**9002**	**9002**	**9002**	**9002**	**9002**	**9002**	**8033**
B. Capacity Transactions	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Purchases																					
102.3 Pioneer Prairie Wind 14%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Purchases = P	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing sales	820	413	125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Sales = S	820	413	125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Transactions = NT = P - S	-820	-413	-125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total System Capacity = TSC = TGC + NT	9430	9745	10037	10162	10104	10104	10129	9922	9876	9022	9002	9002	9002	9002	9002	9002	9002	9002	9002	9002	8033
C. System Peaks & Reserves	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demands																					
Ameren Missouri Forecasted Peak	7983	7985	7990	7995	8013	8036	8022	8059	8118	8163	8211	8226	8274	8352	8407	8445	8482	8521	8559	8603	8648
Voltage Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Full/Partical Requirements Contracts	3	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM - EE RAP	0	0	-30	-65	-111	-169	-220	-270	-313	-360	-421	-484	-543	-606	-660	-700	-755	-803	-833	-883	-929
DSM - DR RAP	0	0	0	0	0	-47	-96	-147	-146	-145	-146	-153	-149	-153	-158	-156	-155	-156	-161	-166	-161
Peak Forecast less DSM = PF	7986	7987	7962	7930	7902	7820	7706	7642	7659	7658	7644	7589	7582	7593	7589	7589	7572	7562	7564	7554	7558
Capacity Reserves = CR = TSC - PF	1444	1757	2075	2232	2202	2284	2423	2280	2216	1364	1357	1413	1420	1408	1412	1413	1430	1440	1438	1448	475
D. Capacity Needs	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
% Reserve Margin = RM	14.8%	14.9%	15.0%	15.1%	15.1%	15.6%	16.0%	16.4%	16.8%	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%
% Capacity Margin = CM = RM/(1+RM)	12.9%	13.0%	13.0%	13.1%	13.1%	13.5%	13.8%	14.1%	14.4%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%
Required Capacity = RC = PF/(1-CM)	9168	9178	9156	9128	9095	9040	8939	8895	8946	8983	8967	8902	8894	8907	8902	8902	8882	8870	8872	8861	8865
Capacity Balance = TSC - RC	262	567	881	1034	1009	1064	1190	1027	930	39	35	100	108	95	100	100	120	132	129	141	(833)
Adjustments before new generation, MWs	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
14.10% Renewable Portfolio - Wind	0	0	0	0	0	7	14	14	28	28	42	42	56	56	56	56	56	56	56	56	56
20% Renewable Portfolio - Solar	0	0	2	2	2	2	2	4	4	4	4	6	6	8	8	8	8	8	8	8	8
Renewable Portfolio - Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	10	20	20	20	20
Total generation adjustments	0	0	2	2	2	9	16	18	32	32	46	48	62	64	64	69	74	84	84	84	84
Capacity position after RES Compliance	262	567	883	1036	1011	1073	1206	1045	962	71	81	148	170	159	164	169	194	216	214	225	-748
New Generation, MWs	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cap position after all adjustments & new PRIMARY generation	**262**	**567**	**883**	**1036**	**1011**	**1073**	**1206**	**1045**	**962**	**71**	**81**	**148**	**170**	**159**	**164**	**169**	**194**	**216**	**214**	**225**	**(148)**
New Purchase (+), or New Sales (-)	**-262**	**-567**	**-883**	**-1036**	**-1011**	**-1073**	**-1206**	**-1045**	**-962**	**-71**	**-81**	**-148**	**-170**	**-159**	**-164**	**-169**	**-194**	**-216**	**-214**	**-225**	**148**

Schedule MM-S3

Addendum C-2

Summary of Actual vs. Plan for Ameren Missouri DSM Programs (1)

Total Portfolio			MEEIA Cycle 1			MEEIA Cycle 2		
	2010	2011	2013	2014	2015	2016	2017	2018
Programs' Costs Actual ($000)	$ 19,900	$ 37,783	$34,432	$41,518				
Programs' Costs Plan ($000)	$ 32,123	$ 39,670	$36,119	$47,121	$64,088	$ 36,408	$ 48,838	$ 62,321
Variance Amount	$ (12,223)	$ (1,887)	$ (1,687)	$ (5,603)				
Percent Variance	-38.1%	-4.8%	-4.7%	-11.9%				
Energy Savings Actual (MWh)	155,551	379,129	337,368	361,915				
Energy Savings Plan (MWh)	145,350	160,249	250,792	263,305	307,723	104,757	137,617	183,859
Variance Amount	10,201	218,880	86,576	98,610				
Percent Variance	7.0%	136.6%	34.5%	37.5%				
kWh per $ for Actual	7.8	10.0	9.8	8.7				
kWh per $ for Plan	4.5	4.0	6.9	5.6	4.8	2.9	2.8	3.0

Residential Lighting Program			MEEIA Cycle 1			MEEIA Cycle 2		
	2010	2011	2013	2014	2015	2016	2017	2018
Programs' Costs Actual ($000)	$ 5,399	$ 4,963	$ 7,077	$ 7,871				
Programs' Costs Plan ($000)	$ 4,076	$ 5,252	$ 6,237	$ 5,924	$ 4,331	$ 5,696	$ 5,500	$ 6,717
Variance Amount	$ 1,323	$ (289)	$ 840	$ 1,947				
Percent Variance	32.5%	-5.5%	13.5%	32.9%				
Energy Savings Actual (MWh)	72,384	93,702	198,735	147,749				
Energy Savings Plan (MWh)	37,179	46,742	121,258	96,837	62,371	20,234	18,345	22,928
Variance Amount	35,205	46,960	77,477	50,912				
Percent Variance	94.7%	100.5%	63.9%	52.6%				
kWh per $ for Actual	13.4	18.9	28.1	18.8				
kWh per $ for Plan	9.1	8.9	19.4	16.3	14.4	3.6	3.3	3.4

Total Portfolio *less* Residential Lighting			MEEIA Cycle 1			MEEIA Cycle 2		
	2010	2011	2013	2014	2015	2016	2017	2018
Programs' Costs Actual ($000)	$ 14,501	$ 32,820	$ 27,355	$ 33,647				
Programs' Costs Plan ($000)	$ 28,047	$ 34,418	$ 29,882	$ 41,196	$ 59,757	$ 30,712	$ 43,338	$ 55,604
Variance Amount	$ (13,546)	$ (1,598)	$ (2,527)	$ (7,549)				
Percent Variance	-48.3%	-4.6%	-8.5%	-18.3%				
Energy Savings Actual (MWh)	83,167	285,427	138,633	214,166				
Energy Savings Plan (MWh)	108,171	113,507	129,535	166,468	245,351	84,523	119,272	160,931
Variance Amount	-25,004	171,920	9,099	47,698				
Percent Variance	-23.1%	151.5%	7.0%	28.7%				
kWh per $ for Actual	5.7	8.7	5.1	6.4				
kWh per $ for Plan	3.9	3.3	4.3	4.0	4.1	2.8	2.8	2.9

	Incremental Annual Energy Savings			
	PY 1	PY 2	PY 3	Total
Pre-MEEIA Actual vs. Plan		0.77	2.51	1.66
Cycle 1 Actual vs. Plan	1.07	1.29		1.19
Cycle 2 Plan vs. Cycle 1 Plan	0.65	0.72	0.66	0.67
Cycle 1 Actual vs. Cycle 2 Plan	1.64	1.80		1.73

(1) Excluding PY 2012 "Bridge" Programs' actual and plan.
(2) 2013, 2014 and 2015 from Ameren Draft Report as of 2 12 2015

Summary of Actual vs. Plan for Ameren Missouri DSM Programs (1)

C&I Custom

	2009-10	2011	2013	2014	2015	2016	2017	2018
			MEEIA Cycle 1			MEEIA Cycle 2		
Programs' Costs Actual ($000)	$ 8,159	$ 10,272	$6,581	$7,519				
Programs' Costs Plan ($000)	$ 8,510	$ 4,415	$8,357	$8,840	$13,133	$ 8,709	$ 16,815	$ 22,538
Variance Amount	$ (351)	$ 5,857	$ (1,776)	$ (1,321)				
Percent Variance	-4.1%	132.7%	-21.3%	-14.9%				
Energy Savings Actual (MWh)	56,642	129,797	51,530	80,374				
Energy Savings Plan (MWh)	54,198	27,099	54,961	54,691	74,509	27,633	53,515	71,962
Variance Amount	2,444	102,698	-3,431	25,682				
Percent Variance	4.5%	379.0%	-6.2%	47.0%				
kWh per $ for Actual	6.9	12.6	7.8	10.7				
kWh per $ for Plan	6.4	6.1	6.6	6.2	5.7	3.2	3.2	3.2

C&I Standard

	2009-10	2011	2013	2014	2015	2016	2017	2018
			MEEIA Cycle 1			MEEIA Cycle 2		
Programs' Costs Actual ($000)	$ 3,007	$ 2,041	$ 2,324	$ 3,915				
Programs' Costs Plan ($000)	$ 11,327	$ 8,320	$ 3,222	$ 4,868	$ 8,051	$ 5,886	$ 6,586	$ 10,963
Variance Amount	$ (8,320)	$ (6,279)	$ (898)	$ (953)				
Percent Variance	-73.5%	-75.5%	-27.9%	-19.6%				
Energy Savings Actual (MWh)	24,515	20,034	22,602	38,875				
Energy Savings Plan (MWh)	68,985	40,753	25,125	33,686	51,784	18,619	20,853	35,004
Variance Amount	-44,470	-20,719	-2,523	5,189				
Percent Variance	-64.5%	-50.8%	-10.0%	15.4%				
kWh per $ for Actual	8.2	9.8	9.7	9.9				
kWh per $ for Plan	6.1	4.9	7.8	6.9	6.4	3.2	3.2	3.2

C&I Portfolio

	2009-10	2011	2013	2014	2015	2016	2017	2018
			MEEIA Cycle 1			MEEIA Cycle 2		
Programs' Costs Actual ($000)	$ 12,361	$ 17,982	$ 9,591	$ 14,776				
Programs' Costs Plan ($000)	$ 27,245	$ 17,134	$ 12,485	$ 15,000	$ 23,301	$ 14,595	$ 30,231	$ 39,364
Variance Amount	$ (14,884)	$ 848	$ (2,894)	$ (224)				
Percent Variance	-54.6%	4.9%	-23.2%	-1.5%				
Energy Savings Actual (MWh)	87,331	234,535	74,616	144,510				
Energy Savings Plan (MWh)	153,384	82,197	85,517	95,067	135,766	46,252	91,927	122,536
Variance Amount	-66,053	152,338	-10,901	49,443				
Percent Variance	-43.1%	185.3%	-12.7%	52.0%				
kWh per $ for Actual	7.1	13.0	7.8	9.8				
kWh per $ for Plan	5.6	4.8	6.8	6.3	5.8	3.2	3.0	3.1

Incremental Annual Energy Savings

	PY 1	PY 2	PY 3	Total
Pre-MEEIA Actual vs. Plan		0.57	2.85	1.37
Cycle 1 Actual vs. Plan	0.87	1.52		1.21
Cycle 2 Plan vs. Cycle 1 Plan	0.54	0.97	0.90	0.82
Cycle 1 Actual vs. Cycle 2 Plan	1.61	1.57		1.59

(1) Excluding PY 2012 "Bridge" Programs' actual and plan.
(2) 2013, 2014 and 2015 from Ameren Draft Report as of 2 12 2015

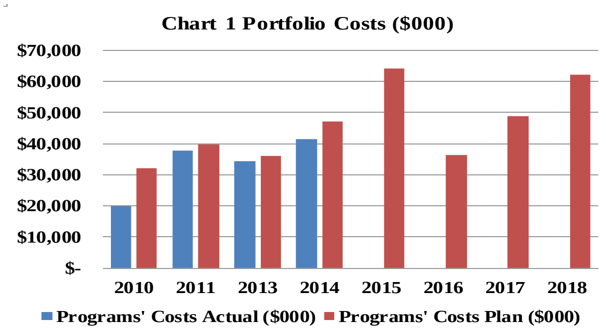


Chart 1 Portfolio Costs ($000)
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$-
2010 2011 2013 2014 2015 2016 2017 2018
Programs' Costs Actual ($000)
Programs' Costs Plan ($000)

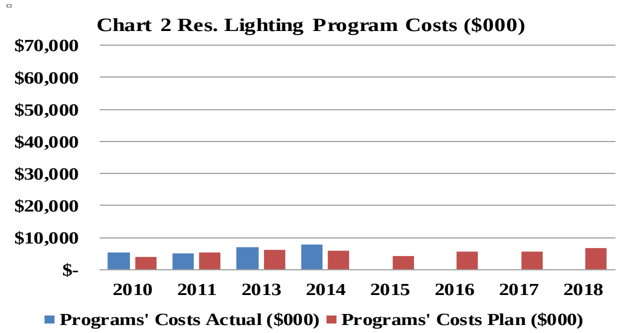


Chart 2 Res. Lighting Program Costs ($000)
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$-
2010 2011 2013 2014 2015 2016 2017 2018
Programs' Costs Actual ($000)
Programs' Costs Plan ($000)

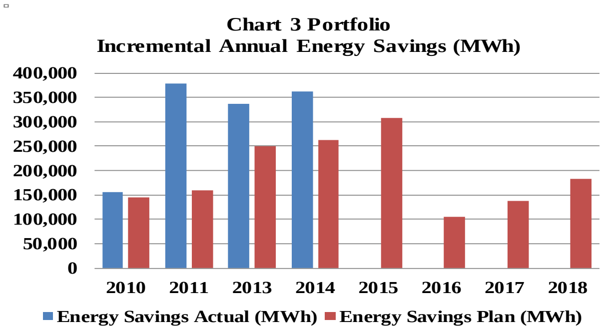


Chart 3 Portfolio
Incremental Annual Energy Savings (MWh)
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2010 2011 2013 2014 2015 2016 2017 2018
Energy Savings Actual (MWh)
Energy Savings Plan (MWh)

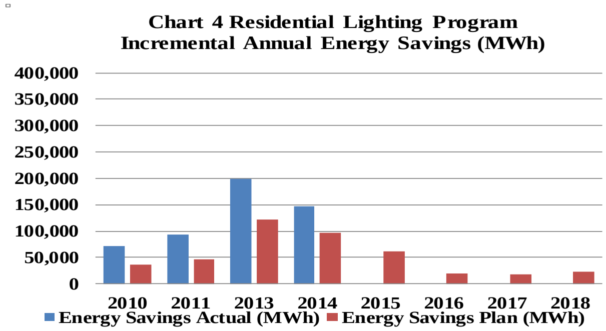


Chart 4 Residential Lighting Program
Incremental Annual Energy Savings (MWh)
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2010 2011 2013 2014 2015 2016 2017 2018
Energy Savings Actual (MWh)
Energy Savings Plan (MWh)

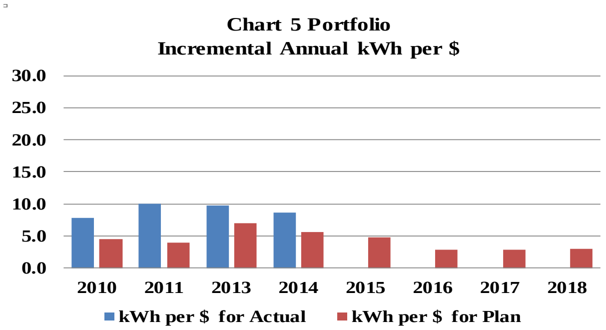


Chart 5 Portfolio
Incremental Annual kWh per $
30.0
25.0
20.0
15.0
10.0
5.0
0.0
2010 2011 2013 2014 2015 2016 2017 2018
kWh per $ for Actual
kWh per $ for Plan

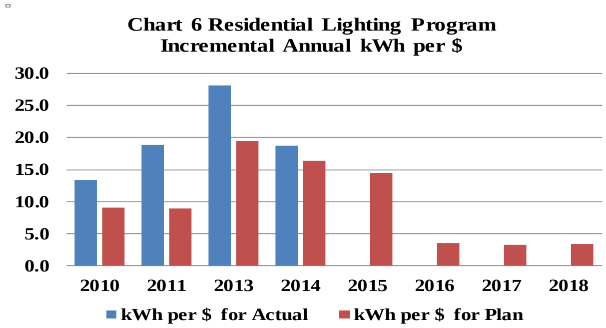


Chart 6 Residential Lighting Program
Incremental Annual kWh per $
30.0
25.0
20.0
15.0
10.0
5.0
0.0
2010 2011 2013 2014 2015 2016 2017 2018
kWh per $ for Actual
kWh per $ for Plan

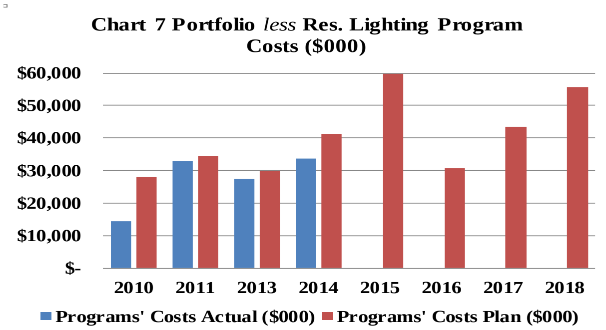


Chart 7 Portfolio *less* Res. Lighting Program
Costs ($000)
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$-
2010 2011 2013 2014 2015 2016 2017 2018
Programs' Costs Actual ($000)
Programs' Costs Plan ($000)

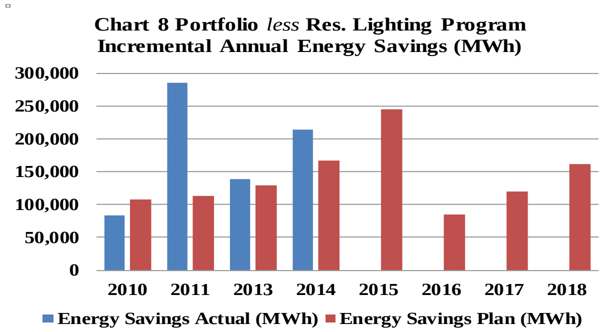


Chart 8 Portfolio *less* Res. Lighting Program
Incremental Annual Energy Savings (MWh)
300,000
250,000
200,000
150,000
100,000
50,000
0
2010 2011 2013 2014 2015 2016 2017 2018
Energy Savings Actual (MWh)
Energy Savings Plan (MWh)

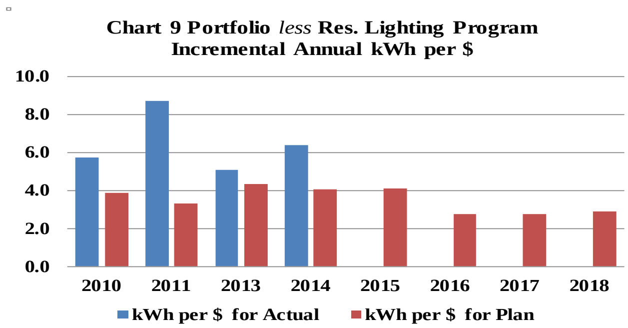


Chart 9 Portfolio *less* Res. Lighting Program
Incremental Annual kWh per $
10.0
8.0
6.0
4.0
2.0
0.0
2010 2011 2013 2014 2015 2016 2017 2018
kWh per $ for Actual
kWh per $ for Plan

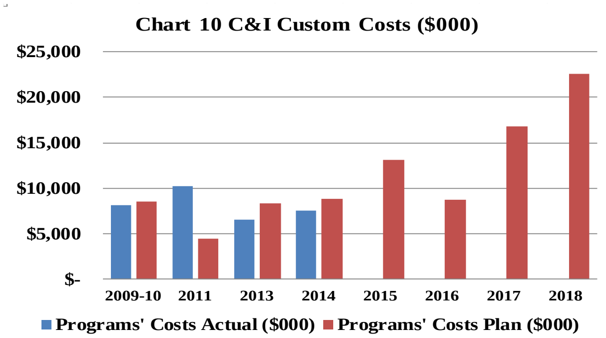


Chart 10 C&I Custom Costs ($000)
$25,000
$20,000
$15,000
$10,000
$5,000
$-
2009-10 2011 2013 2014 2015 2016 2017 2018
Programs' Costs Actual ($000)
Programs' Costs Plan ($000)

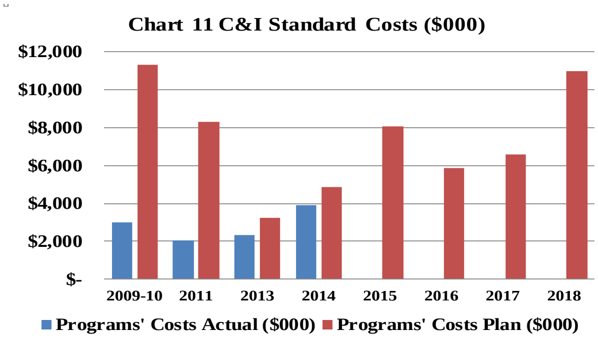


Chart 11 C&I Standard Costs ($000)
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$-
2009-10 2011 2013 2014 2015 2016 2017 2018
Programs' Costs Actual ($000)
Programs' Costs Plan ($000)

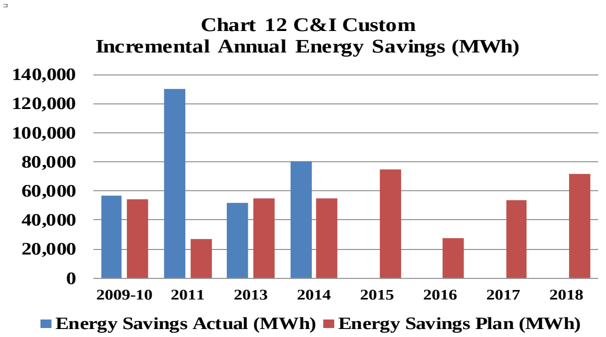


Chart 12 C&I Custom
Incremental Annual Energy Savings (MWh)
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
2009-10 2011 2013 2014 2015 2016 2017 2018
Energy Savings Actual (MWh)
Energy Savings Plan (MWh)

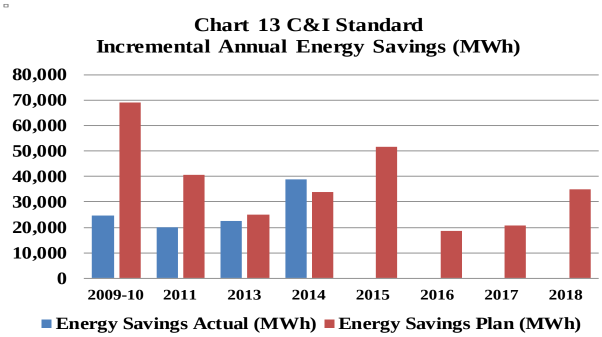


Chart 13 C&I Standard
Incremental Annual Energy Savings (MWh)
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
2009-10 2011 2013 2014 2015 2016 2017 2018
Energy Savings Actual (MWh)
Energy Savings Plan (MWh)

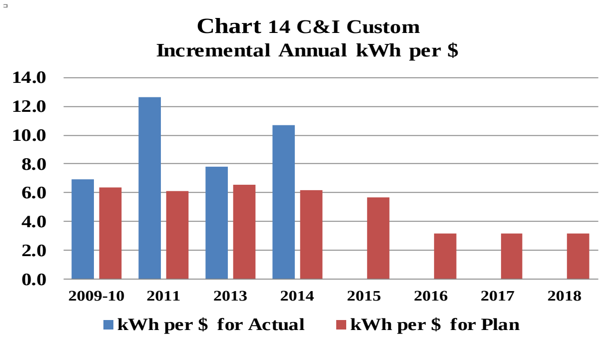


Chart 14 C&I Custom
Incremental Annual kWh per $
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2009-10 2011 2013 2014 2015 2016 2017 2018
kWh per $ for Actual
kWh per $ for Plan

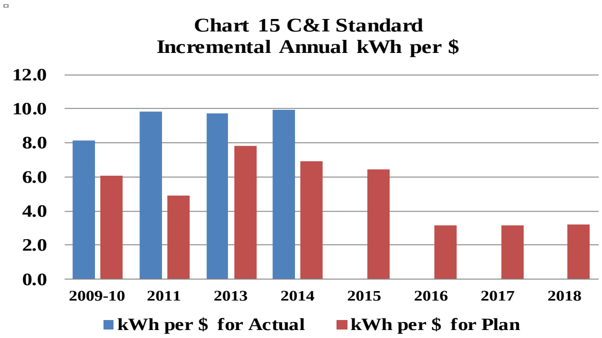


Chart 15 C&I Standard
Incremental Annual kWh per $
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2009-10 2011 2013 2014 2015 2016 2017 2018
kWh per $ for Actual
kWh per $ for Plan

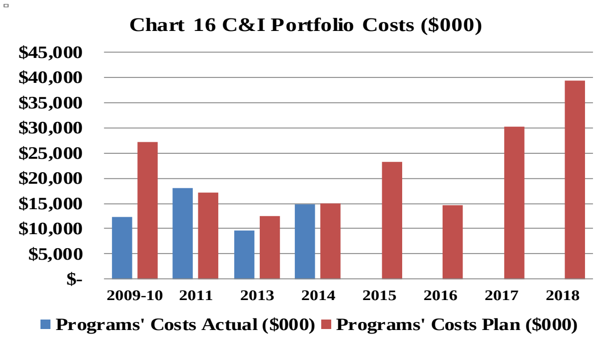


Chart 16 C&I Portfolio Costs ($000)
$45,000
$40,000
$35,000
$30,000
$25,000
$20,000
$15,000
$10,000
$5,000
$-
2009-10 2011 2013 2014 2015 2016 2017 2018
Programs' Costs Actual ($000)
Programs' Costs Plan ($000)

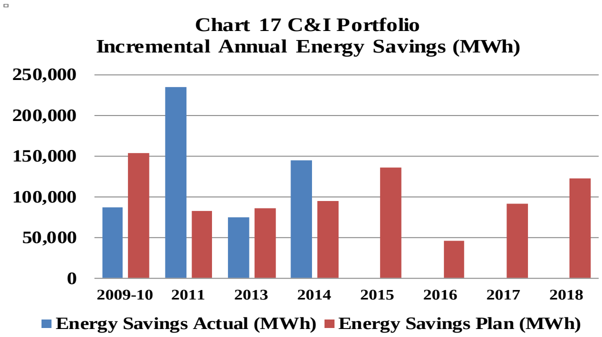


Chart 17 C&I Portfolio
Incremental Annual Energy Savings (MWh)
250,000
200,000
150,000
100,000
50,000
0
2009-10 2011 2013 2014 2015 2016 2017 2018
Energy Savings Actual (MWh)
Energy Savings Plan (MWh)

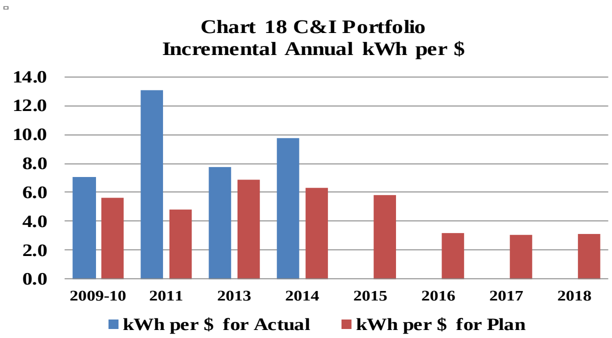


Chart 18 C&I Portfolio
Incremental Annual kWh per $
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2009-10 2011 2013 2014 2015 2016 2017 2018
kWh per $ for Actual
kWh per $ for Plan

MISSOURI PUBLIC SERVICE COMMISSION
STAFF REPORT

UNION ELECTRIC COMPANY
d/b/a AMEREN MISSOURI

2017 ELECTRIC UTILITY RESOURCE PLANNING
COMPLIANCE FILING

FILE NO. EO-2018-0038

Jefferson City, Missouri
February 28, 2018

****** Denotes Confidential Information ******

TABLE OF CONTENTS OF STAFF REPORT

2017 ELECTRIC UTILITY RESOURCE PLANNING COMPLIANCE FILING OF UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

FILE NO. EO-2018-0038

Executive Summary

On September 25, 2017,[1] Union Electric Company, d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), filed its 2017 Integrated Resource Plan ("IRP") triennial compliance filing ("Filing") in File No. EO-2018-0038, as required by 4 CSR 240-22 Electric Utility Resource Planning[2] and the Missouri Public Service Commission's ("Commission") January 11, 2017 *Order Granting Waivers* in File No. EE-2017-0098.[3]

Staff provides this Report as required by Commission Rule 4 CSR 240-22.080(7):

> (7) The staff shall conduct a limited review of each triennial compliance filing required by this rule and shall file a report not later than one hundred fifty (150) days after each utility's scheduled triennial compliance filing date. The report shall identify any deficiencies[4] in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies and shall provide at least one (1) suggested remedy for each identified deficiency. Staff may also identify concerns[5] with the utility's triennial compliance filing, may identify concerns related to the substantive reasonableness of the preferred resource plan or resource acquisition strategy, and shall provide at least one (1) suggested remedy for each identified concern.

As a result of its limited review, and as more fully discussed throughout this report ("Report"), Staff identified two (2) deficiencies and two (2) concerns regarding Ameren Missouri's 2017 IRP. Staff recommended remedy for each deficiency and concern is contained in the body of the Report.

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[1] Commission's July 22, 2015, *Order Granting Variance* in File No. EE-2015-0316, allowed Ameren Missouri to make its 2017 IRP filing on or before October 1, 2017, instead of April 1, 2017.

[2] Chapter 22 Electric Utility Resource Planning rules 4 CSR 240-22.010, .020, 030, .040, .050, .060, .070 and .080 were all revised effective May 31, 2011. Rule 4 CSR 240-22.045 Transmission and Distribution Analysis became a new rule effective May 31, 2011.

[3] Approved waivers include: 4 CSR 240-22.020(12); .040(3)(A); .045(1)(B) and (3)(C); .050(4)(D)2, (5)(B)3, and (5)(E); .060(5)(E), (5)(F), (5)(K), (5)(L) and (7); and .080(2)(C)2 and (5)(A).

[4] 4 CSR 240-22.020(9) Deficiency means deficiencies in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and anything that would cause the electric utility's resource acquisition strategy to fail to meet the requirements identified in Chapter 22.

[5] 4 CSR 240-22.020(6) Concern means concerns with the electric utility's compliance with the provisions of this chapter, any major concerns with the methodologies or analyses required to be performed by this chapter, and anything that, while not rising to the level of a deficiency, may prevent the electric utility's resource acquisition strategy from effectively fulfilling the objectives of Chapter 22.

A. List of Staff's Identified Deficiencies

Deficiency 1 – Ameren Missouri provided only the 30-year PVRR for its Mid-DSM Plan and failed to comply with all other requirements of 4 CSR 240-22.070(1) concerning its Mid-DSM Plan.

Deficiency 2 - Ameren Missouri did not provide its draft of the triennial compliance filing for 4 CSR 240-22.030 at its stakeholder meeting which is required under 4 CSR 240-22.080(5)(A) and (B).[6]

B. List of Staff's Identified Concerns

Concern A – Ameren Missouri's 2017 IRP's MEEIA Cycle 3 implementation plan and Ameren Missouri's MEEIA Cycle 3 RFP to program implementers identifies a 6-year program life for all programs. This 6-year program life creates conflict with the 3-year or triennial compliance requirements of 4 CSR 240-22.050 which specifies the principles by which potential demand-side resource options shall be developed and analyzed for cost effectiveness with the goal of achieving all cost-effective demand-side savings as well as the requirement that demand-side candidate resource options be passed on to integrated resource analysis in 4 CSR 240-22.060.

Concern B – If a 6-year MEEIA Cycle 3 is approved and implemented, Staff is concerned that a 2019 DSM Potential Study may not be performed to comply with 4 CSR 240-22.050(2) including the performance of primary research for Ameren Missouri's marketplace to comply with 4 CSR 240-20.094(3)(A)2.

4 CSR 240-22.010 Policy Objectives

Staff performed its review of the Filing in the context of the Commission's Chapter 22 Rules, the Missouri Energy Efficiency Investment Act of 2009[7] ("MEEIA"), and the Commission's MEEIA Rules.[8] Staff performed its review in this way because the policy objectives of Chapter 22 and of MEEIA are inseparable for electric utilities, since Rule 4 CSR 240-22.010(2) states:

> The fundamental objective of the resource planning process at electric utilities *shall* be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and

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[6] During Ameren Missouri's April 19, 2017, stakeholder workshop to comply with 4 CSR 240-22.080(5)(A) and (B), Ameren Missouri used a PowerPoint presentation to summarize its load analysis and load forecast and stated that the draft of 4 CSR 240-22.030 will be shared once it is finalized. The draft was not supplied to stakeholders until August 23, 2017, over four months later.

[7] 393.1075, RSMo, 2016.

[8] Original MEEIA rules 4 CSR 240-3.163 and 4 CSR 240-3.164 were effective from May 30, 2011 through February 27, 2018, and original MEEIA rules 4 CSR 240-20.093 and 4 CSR 240-20.094 were effective from May 30, 2011 through October 29, 2017. Original rule 4 CSR 240-20.092 became effective October 30, 2017, and revised rules 4 CSR 240-20.093 and 4 CSR 240-20.094 became effective October 30, 2017. Ameren Missouri filed its 2017 IRP thirty-six (36) days before October 30, 2017, on September 25, 2017.

in a manner that serves the public interest and is consistent with state energy and environmental policies. …
(Emphasis added)

MEEIA establishes the following state energy policy for valuing demand-side resources and supply-side resources and for the cost recovery of these resources for Missouri's electrical corporations[9] in Section 393.1075.3 and .4:

> 3. *It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs*. [Emphasis added.] In support of this policy, the commission shall:
> (1) Provide timely cost recovery for utilities;
> (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
> (3) Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.
>
> 4. *The commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings*. . . . [Emphasis added.]

Although electric utilities are not required to request Commission approval of demand-side programs and a demand-side programs investment mechanism ("DSIM") under MEEIA and the Commission's MEEIA rules, electric utilities are required to comply with the Commission's Chapter 22 Rules which establish that the fundamental objective of the electric utility resource planning process at each electric utility shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. Because MEEIA establishes state energy policy, each electric utility is required – as part of its electric utility resource planning –- to develop candidate resource plans and to analyze and document DSIMs which can allow the electric utility to make reasonable progress toward a goal of all cost-effective demand-side savings.[10]

[9] 4 CSR 240-22.020(16): "Electric utility or utility mean any electrical corporation as defined in section 386.020, RSMo, which is subject to the jurisdiction of the commission."
[10] 4 CSR 240-20.094(2) Guideline to Review Progress Toward an Expectation that the Electric Utility's Demand-Side Programs Can Achieve a Goal of All Cost-Effective Demand-Side Savings, which was effective from May 30, 2011 through October 29, 2017. Similar language is contained in 4 CSR 240-20.094(2), which became effective October 30, 2017.

The MEEIA rules provide – in 4 CSR 240-3.164(2)(A)[11] – detailed requirements for conducting current market potential studies including requirements for: 1) use of primary research, 2) updating the potential study no less frequently than every four (4) years, 3) review by Staff and stakeholders of required documentation, and 4) identification and discussion of the twenty (20)-year baseline energy and demand forecasts. Chapter 22 includes specific requirements for demand-side management potential studies in 4 CSR240-22.050(2), demand-side programs potential in 4 CSR 240-22.050(3), and demand-side rates potential in 4 CSR 240-22.050(4).

Staff Expert Witness: John Rogers and Brad Fortson

4 CSR 240-22.030 Load Analysis and Forecasting

4 CSR 240-22.030, Load Analysis and Forecasting, has a stated purpose of setting the "minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing loads, and the purposes to be accomplished by load analysis and by load forecast models. The load analysis discussed in this rule is intended to support both demand-side management efforts of 4 CSR 240-22.050 and the load forecast models of this rule. This rule also sets the minimum standards for the documentation of the inputs, components, and methods used to derive the load forecasts." The Load Analysis and Load Forecasting Rule allows the utility to use multiple analytical methods for performing its load analysis and develop its forecasts, leaving it to the utility's discretion to choose the methods by which it achieves the stated purpose of the rule.

According to Ameren Missouri, given the uncertainty around the former Noranda aluminum smelter which has been inactive since February 2016,[12] Ameren Missouri did not include Noranda's load in its energy and demand load forecasts.[13] Addendum A contains Ameren Missouri's historic and IRP Base annual energy forecasts, and Addendum B contains the High, Base and Low energy forecast for the IRP. Addendum C contains Ameren Missouri's

[11] Effective from May 30, 2011 through October 29, 2017. Similar "utility market potential study" requirements are contained in 4 CSR 240-20.094(3), which became effective October 30, 2017.

[12] The US Bankruptcy Court approved the sale of assets of Noranda Aluminum, Inc. on October 21, 2016. As per the order, debtor has been authorized to sell Gramercy assets and St. Ann assets to New Day Aluminum LLC, stalking-horse bidder for $24.43 million, as per the amended agreement dated October 19, 2016. ARG International AG has been designated as back-up bidder with a purchase price of $24 million.

[13] Page 27 of Chapter 3 Load Analysis and Forecasting.

historic and IRP Base annual peak demand forecasts, and Addendum D contains the High, Base and Low peak demand forecasts for the 2017 IRP.

Ameren Missouri did not request any waivers from specific provisions of this rule.

As a result of Staff's limited review of Ameren Missouri's load analysis and energy and demand forecasts, Staff found no deficiencies concerning compliance with this rule and Staff has not identified any concerns. In Staff's opinion, the Filing meets the Load Analysis and Forecasting requirements of 4 CSR 240-22.030.

Staff Expert Witness: Brad Fortson

4 CSR 240-22.040 Supply-Side Resource Analysis

Rule 4 CSR 240-22.040 Supply-Side Resource Analysis requires Ameren Missouri to review existing resources for opportunities to upgrade or retire existing resources and also review a wide variety of supply-side resource options to determine cost estimates for each type of resource.

Resource options are to be ranked based upon their relative levelized annual costs,[14] including installed capital costs, fixed and variable operation and maintenance costs, and probable environmental costs levelized over the useful life of the potential supply-side resource options using the utility discount rate.[15] Resources which do not have significant disadvantages and pass the pre-screening process are to be included in the integrated resource analysis process used to select a preferred resource plan.

Ameren Missouri selected three technologies based on supply side screening analysis[16] as final candidate resource options to represent fossil fuel resource options which include gas combined cycle, gas simple cycle combustion turbine, and ultra-super-critical pulverized coal. Ameren Missouri selected the Westinghouse AP1000 as the nuclear resource to be evaluated in integration analysis to generally represent new nuclear technology. Ameren Missouri identified wind, solar, hydro, and biomass co-firing as renewable supply side candidate resource options. Ameren Missouri selected pumped hydroelectric storage as the energy storage resource option to be included in the evaluation of alternative resource plans.

[14] 4 CSR 240-22.020(29) Levelized cost means the dollar amount of a fixed annual payment for which a stream of those payments over a specified period of time is equal to a specified present value based on a specified rate of interest.
[15] 4 CSR 240-22.040(2)(A).
[16] 4 CSR 240-22.040(2).

Ameren Missouri evaluated the levelized cost of the existing supply side resources as well as the selected candidate resources as indicated in Addendum E. Capital costs for all of the preliminary candidate supply-side options included transmission interconnection costs.[17]

Table 5.1 from Chapter 5 of the IRP filing summarizes the current environmental regulations for which Ameren Missouri must implement mitigation measures, along with expectations for compliance requirements for certain potential regulations.[18] Table 5.1 is provided as Addendum F of this report for convenience.

With respect to rule 4 CSR 240-22.040 Supply-Side Resource Analysis, Ameren Missouri requested, and the Commission granted, in File No. EE-2017-0089, one variance of the provisions required by 4 CSR 240-22.040(3)(A).[19]

Staff has not identified any deficiencies or concerns related to Ameren Missouri's Supply-Side Resource Analysis.

Staff Expert Witness: J Luebbert

<u>4 CSR 240-22.045 Transmission and Distribution Analysis</u>

Rule 4 CSR 240-22.045 Transmission and Distribution Analysis specifies minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting. Rule 4 CSR 240-22.045 does not prescribe how analyses are to be done, but rather allows a utility to conduct its own analysis or adopt the Regional Transmission Operator ("RTO") or Independent Transmission System Operator ("ISO") transmission plans. Rule 4 CSR 240-22.045 requires analysis and documentation of the RTO/ISO transmission projects and requires the electric utility to review transmission and distribution for the reduction of power losses, interconnection of new generation facilities, facilitation of sales and purchases, and incorporation of advance technologies for the optimization of investment in transmission and distribution resources.

Since 2004, Ameren Missouri has been a member of the Midcontinent Independent System Operator ("MISO"),[20] a RTO. MISO was approved as the nation's first ISO/RTO in 2001 and is an independent nonprofit organization that supports the delivery of wholesale electricity and operates energy and capacity markets in 15 U.S. states and the Canadian province

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[17] IRP Chapter 6, page 2
[18] IRP Chapter 5, page 3
[19] Commission ordered January 11, 2017 and effective February 10, 2017
[20] Formerly the Midwest Independent Transmission System Operator.

of Manitoba. A key responsibility of the MISO is the development of the annual MISO Transmission Expansion Plan ("MTEP"). Ameren Missouri is an active participant in the MISO MTEP development process.

With respect to rule 4 CSR 240-22.045 Transmission and Distribution Analysis, Ameren Missouri requested, and the Commission granted, in File No. EE-2017-0089, variances of the provisions required by 4 CSR 240-22.045(1)(B) and 4 CSR 240-22.045(3)(C).[21]

The Staff has not identified any deficiencies or concerns related to Ameren Missouri's Transmission and Distribution Analysis.

Staff Expert Witness: J Luebbert

4 CSR 240-22.050 Demand-Side Resource Analysis

Rule 4 CSR 240-22.050, Demand-Side Resource Analysis, specifies the methods by which end-use measures and demand-side programs shall be developed and screened for cost-effectiveness. It also requires the ongoing evaluation of end-use measures and programs, and the use of program evaluation, measurement and verification ("EM&V") to improve program design and cost-effectiveness analysis.

Ameren Missouri continues to build on its demand-side management ("DSM") planning, implementation, and evaluation performance from its initial implementation of DSM programs in 2009 followed by MEEIA Cycles 1 from January 1, 2013, through December 31, 2015, and MEEIA Cycle 2, which began March 1, 2016, and is scheduled to end February 28, 2019.[22]

Ameren Missouri contracted with GDS Associates to perform its 2016 DSM Potential Study that was used to inform the Demand-Side Resource Analysis required by 4 CSR 240-22.050 for the 2017 IRP. To maximize the work done by EnerNOC for Ameren Missouri on the 2013 DSM Potential Study, GDS subcontracted with EMI Consulting to review and update the market research content provided in the 2013 DSM Potential Study. The market research task consisted of a comprehensive review and analysis of all relevant existing

[21] Commission ordered January 11, 2017 and effective February 10, 2017

[22] Commission's July 20, 2017, *Order Approving Stipulation And Agreement* in File No. EO-2015-0055, established a process for Cycle 2 long-lead energy efficiency projects' implementation and completion to extend for up to 24 months beyond the February 28, 2019 Cycle 2 end date.

data (primary and secondary[23]) without development of new data generated through primary research. From this data GDS then compiled its market and industry research into estimations of the technical, economic, and achievable levels of energy efficiency and demand response potential for the 2019-2036 timeframe.

Overall conclusions from the 2016 DSM Potential Study included: 1) continuing the trend from the 2016-2018 DSM implementation planning period, 55-60% of the program-level energy-efficiency potential is expected to come from commercial and industrial customers in the immediate future; 2) there is significant energy efficiency and demand response[24] program potential but projected program costs are significantly higher than current spending levels; and 3) the initial analysis of demand-side rates in the study indicate that inclining block rates and time-of-use rates have significant customer energy savings potential. However, Ameren Missouri conducted its own analysis of demand side rate potential which indicates significantly lower impacts.

Additionally, on page 8, Chapter 8 – Demand-Side Resources, Ameren Missouri states:

> Historically, Ameren Missouri has used the potential study results for energy efficiency and modified them where appropriate to create a cost effective portfolio design for its MEEIA implementation plan. Alternatively for its next implementation plan, Ameren Missouri has used the 2016 DSM Potential Study results as an initial basis for its targets in an RFP. The resulting proposals from implementation contractors will then be used by Ameren Missouri to initiate a collaborative dialogue with interested stakeholders to define the demand-side portfolio, budgets, and targets for its next MEEIA plan.
>
> Another notable change is that this RFP is being issued for a 6-year implementation cycle unlike the first two MEEIA cycles which offered a 3-year cycle each. Moving toward a longer program cycle enhances the structure to better enable continuity of a base set of programs and allow more time and energy to focus on new programs, new technologies, and overall improvement opportunities. In past experience, by the time a new program cycle is through the "start-up" phase, planning for the next cycle has to begin and there is little time to incorporate improvement opportunities from the current cycle into the planning process, as the first year results are still being finalized. A longer cycle will provide more opportunity to manage the programs and understand what is or is not working well, so those considerations can be better implemented in the future.

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[23] Primary data is market research which is specific to a utility's service territory, while secondary data is market research which is not specific to a utility's service territory but can be adapted for use by the utility in its market potential study.

[24] Regarding demand response, the 2016 Potential Study found that while there has been volatility in the MISO capacity markets, long term value exists.

Addendum G contains charts which illustrate the following for realistic achievable potential ("RAP") portfolio, Mid DSM portfolio,[25] and maximum achievable potential ("MAP") portfolio: 1) cumulative energy savings from energy efficiency programs, 2) cumulative peak demand savings from energy efficiency programs and 3) cumulative peak demand savings from demand response programs.

With respect to rule 4 CSR 240-22.050 Demand-Side Resource Analysis, Ameren Missouri requested, and the Commission granted, in File No. EE-2017-0089, three variances of the provisions required by 4 CSR 240-22.050(4)(D)2, 4 CSR 240-22.050(5)(B)3, and 4 CSR 240-22.050(5)(E).

Based on its limited review, Staff concludes Ameren Missouri's Demand-Side Resource Analysis filing meets the requirements of rule 4 CSR 240-22.050, and there are no deficiencies.

However, Staff has two concerns in regards to Ameren Missouri's MEEIA implementation plan RFP and Ameren Missouri's next DSM Potential Study.

Concern A – Ameren Missouri's 2017 IRP's MEEIA Cycle 3 implementation plan and Ameren Missouri's MEEIA Cycle 3 RFP to program implementers identifies a 6-year program life for all programs. This 6-year program life creates conflict with the 3-year or triennial compliance requirements of 4 CSR 240-22.050 which specifies the principles by which potential demand-side resource options shall be developed and analyzed for cost effectiveness with the goal of achieving all cost-effective demand-side savings as well as the requirement that demand-side candidate resource options be passed on to integrated resource analysis in 4 CSR 240-22.060.

Concern B – If a 6-year MEEIA Cycle 3 is approved and implemented, Staff is concerned that a 2019 DSM Potential Study may not be performed to comply with 4 CSR 240-22.050(2) including the performance of primary research for Ameren Missouri's marketplace to comply with 4 CSR 240-20.094(3)(A)2.

To remedy Concerns A and B, Ameren Missouri should: 1) perform a 2019 DSM Potential Study to include primary research of its marketplace for its 2020 IRP, and 2) make an application to the Commission for new MEEIA Cycle 3 programs under 4 CSR 240.20.094(4) and/or modify its Commission-approved MEEIA Cycle 3 programs under 4 CSR 240-20.094(5), as necessary, and in accordance with its 2020 IRP's adopted preferred resource plan acquisition strategy and implementation plan.

Staff Expert Witnesses: Brad Fortson and J Luebbert

[25] The Mid DSM portfolio is designed to be a set of programs that will deliver a level of savings half-way between the RAP portfolio and the MAP portfolio.

4 CSR 240-22.060 Integrated Resource Analysis

This Integrated Resource Analysis rule requires the utility to design alternative resource plans to meet the planning objectives identified in Rule 4 CSR 240-22.010(2), and sets minimum standards for the scope and level of detail required in resource plan analysis and for the logically consistent and economically equivalent analysis of alternative resource plans. The utility is to identify the critical uncertain factors that affect the performance of alternative resource plans and comply with minimum standards for the methods used to assess the risks associated with these uncertainties.

The utility shall develop alternative resource plans for analysis that maximize reliance on energy efficiency and renewable energy resources and then develop optimal cases. The rule requires the development of alternative resource plans based on normal conditions and also to assess the robustness of each plan under more extreme conditions (high and low cases). The rule requires inclusion of performance measures of present worth of utility revenue requirements, with and without any financial performance incentives the utility is planning to request. The rule also requires analysis of financial parameters and, if required, description of any changes in legal mandates and cost recovery mechanisms necessary for the utility to maintain an investment grade credit rating and documentation of the methods, analyses, judgments, and data the utility chooses.

Ameren Missouri developed, considered, and analyzed the present worth of long-run utility costs for 18 alternative resource plans by calculating the 30-year present value of revenue requirement ("PVRR") for each plan (see Addendum H). While Ameren Missouri has selected the minimization of PVRR as the primary selection criterion for the preferred plan in accordance with 4 CSR 240-22.010(2)(B), Ameren Missouri does not use minimization of PVRR as the only selection criterion. In addition to calculating the PVRR for each plan, Ameren Missouri considered the performance of each plan when compared to four other planning objectives. These planning objectives are Environmental/Renewable/Resource Diversity, Financial/Regulatory, Customer Satisfaction, and Economic Development. The alternative resource plans (see Addendum I) include various levels of demand side programs and rates, renewable resources, new supply side resources, and coal retirements. All of the alternative resource plans include 700 MW nameplate capacity of wind additions that Ameren Missouri will utilize to meet the requirement of the Missouri Renewable Energy Standard that no less than 15% of calendar year retail sales come from renewable energy resources beginning in 2021.

With respect to rule 4 CSR 240-22.060 Integrated Resource Analysis, Ameren Missouri requested, and the Commission granted, in File No. EE-2017-0089, variances of the provisions required by 4 CSR 240-22.060(5)(E), 4 CSR 240-22.060(5)(F), 4 CSR 240-22.060(5)(K), 4 CSR 240-22.060(5)(L), and 4 CSR 240-22.060(7).[26]

The Staff has not identified any deficiencies or concerns related to Ameren Missouri's integrated resource analysis.

Staff Expert Witness: J Luebbert

4 CSR 240-22.070 Risk Analysis and Strategy Selection

Rule 4 CSR 240-22.070, Risk Analysis and Strategy Selection, requires the utility to select a preferred resource plan, develop an implementation plan, and officially adopt a resource acquisition strategy. The rule also requires the utility to prepare contingency plans and evaluate the demand-side resources that are included in the resource acquisition strategy.

Ameren Missouri did not apply for any waivers from the requirements of this rule.

Ameren Missouri's final probability tree (see Addendum J) consists of the following dependent and independent critical uncertain factors:

Dependent critical uncertain factors

- Coal plant retirements
- CO_2 policy
- Load growth
- Natural gas prices

Independent critical uncertain factors

- DSM costs
- Coal Prices

Ameren Missouri's decision-makers chose to use a Scorecard approach[27] to evaluate its eighteen (18) candidate resource plans during their strategy selection process to adopt a resource

[26] Commission ordered January 11, 2017 and effective February 10, 2017.

acquisition strategy and a preferred resource plan for Ameren Missouri. The Scorecard is included as Addendum K.

Addendum L includes a summary of Ameren Missouri's 2017 IRP's adopted preferred resource plan, contingency resource plans, and resource acquisition strategy implementation plan for the adopted preferred resource plan. Finally, the capacity balance sheet for Ameren Missouri's adopted preferred resource plan is included as Addendum M.

Based on its limited review, Staff has identified one (1) deficiency for Ameren Missouri's Resource Acquisition Strategy Selection filing.

Deficiency 1 – Ameren Missouri provided only the 30-year PVRR for its Mid-DSM Plan and failed to comply with all other requirements of 4 CSR 240-22.070(1) concerning its Mid-DSM Plan.

To remedy Deficiency 1 concerning its Mid-DSM Plan, Ameren Missouri should comply with all requirements of 4 CSR 240-22.070(1) as soon as possible, including revisions to Figure 10.1 and to Chapter 10 – Appendix A Preferred Plan Selection Scorecard so both include a Mid-DSM Plan that complies with all of the requirements of 4 CSR 240-22.070(1) not just the 30-year PVRR facet.

Staff Expert Witness: John Rogers

4 CSR 240-22.080 Filing Schedule and Requirements

This rule specifies the requirements for electric utility filings to demonstrate compliance with the provisions of Chapter 22. The purpose of the compliance review required by Chapter 22 is not Commission approval of the substantive findings, determinations, or analyses contained in the filing. The purpose of the compliance review required by Chapter 22 is to determine whether the utility's resource acquisition strategy meets the requirements of Chapter 22. However, if the Commission determines that the filing substantially meets these requirements, the Commission may further acknowledge that the preferred resource plan or resource acquisition strategy is reasonable in whole, or in part, at the time of the finding. This rule also establishes a mechanism for the utility to solicit and receive stakeholder input to its resource planning process.

The Filing Schedule, Filing Requirements, and Stakeholder Process Rule establish a filing deadline for all electric utilities on April 1 of each year. A triennial compliance filing is due every third year with more informal annual update filings during the years between the full triennial compliance filings. The annual updates are coupled with a stakeholder workshop to communicate changing conditions and utility plans and to seek comments and suggestions from stakeholders during the planning process. Preliminary plans are reviewed with stakeholders to receive input regarding potential concerns and deficiencies. However, once plans are filed, stakeholders again have the opportunity to identify potential concerns and deficiencies. The Commission, with input from stakeholders, will identify special contemporary issues each year for each utility to analyze during its planning process. To make the resource planning process more meaningful, the rule requires action from the utility if its business plan or acquisition strategy becomes inconsistent with the latest adopted preferred resource plan filed by the utility. The rule also requires certification that any request for action from the Commission is consistent with the utility's adopted preferred resource plan.

Ameren Missouri requested and received approval of variances from 4 CSR 240-22.080 (2)(C)2 to postpone the deadline for filing its 2017 IRP from April 1, 2017 to October 1, 2017; and from 4 CSR 240-22.080(5)(A) to allow its DSM market potential study to serve as its draft chapter for 4 CSR 240-22.050.

Staff notes that 4 CSR 240-22.080(1) and 4 CSR 240-22.080(3), require a 12-month interval between an electric utility's Chapter 22 triennial compliance filings and/or annual update filings. However, due to the variances, Ameren Missouri has experienced an 18-month interval – and not a 12-month interval – between its two most recent Chapter 22 triennial compliance filings[28] (October 1, 2014 and October 1, 2017) and its subsequent Chapter 22 annual update filings[29] (April 1, 2016 and April 1, 2019).

Beginning with its 2019 Chapter 22 annual update filing and its 2020 triennial compliance filing, Ameren Missouri should plan for the required 12-month interval between Chapter 22 filings – triennial compliance filings and/or annual update filing required under 4 CSR 240-22.080(1) and 4 CSR 240-22.080(3), respectively. Doing so may result in Ameren Missouri making its Chapter 22 filings on a date other than April 1 or October 1 in order

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[28] In File Nos. EE-2013-0312 and EE-2015-0316, the Commission allowed Ameren Missouri to make its 2014 Chapter 22 triennial compliance filing and its 2017 Chapter 22 triennial compliance filing on October 1, 2014 and October 1, 2017, respectively, and not on April 1, 2014 and April 1, 2017, respectively, as required by 4 CSR 240-22.080(1)(C).

[29] In File Nos. EO-2015-0039 and EE-2018-0040, the Commission did not establish special contemporary issues for and did not require Ameren Missouri to file Chapter 22 annual updates on or about April 1, 2015 and on or about April 1, 2018, respectively, as required by 4 CSR 240-22.080(3).

to maintain a 12-month interval between Chapter 22 filings – both Chapter 22 triennial compliance filings and Chapter 22 annual update filings.

As a result of its review, Staff has identified one (1) deficiency related to 4 CSR 240-22.080 Filing Schedule, Filing Requirements, and Stakeholder Process.

Deficiency 2 - Ameren Missouri did not provide its draft of the triennial compliance filing for 4 CSR 240-22.030 at its stakeholder meeting which is required under 4 CSR 240-22.080(5)(A) and (B).[30]

To remedy Deficiency 2, Ameren Missouri should comply with all requirements of 4 CSR 240-22.080(5) in future Chapter 22 triennial compliance filings.

Staff Expert Witness: John Rogers

[30] During Ameren Missouri's April 19, 2017, stakeholder workshop to comply with 4 CSR 240-22.080(5)(A) and (B), Ameren Missouri used a PowerPoint presentation to summarize its load analysis and load forecast and stated that the draft of 4 CSR 240-22.030 will be shared once it is finalized. The draft was not supplied to stakeholders until August 23, 2017, over four months later.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Ameren Missouri's 2017 Utility Resource Filing Pursuant to 4 CSR 240 – Chapter 22	)))	**File No. EO-2018-0038**

AFFIDAVIT OF BRAD FORTSON

State of Missouri)
) ss.
County of Cole)

COMES NOW Brad Fortson and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached *Staff Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Brad J Fortson
Brad Fortson

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 21th day of February, 2018.

Dianna L. Vaught
NOTARY PUBLIC

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 28, 2019
Commission Number: 15207377

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Ameren Missouri's 2017 Utility Resource Filing Pursuant to 4 CSR 240 – Chapter 22	)))	**File No. EO-2018-0038**

AFFIDAVIT OF J LUEBBERT

State of Missouri)
) ss.
County of Cole)

COMES NOW J Luebbert and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached *Staff Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

J Luebbert

J Luebbert

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 29th day of February, 2018.

Dianna L. Vaught

NOTARY PUBLIC

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 28, 2019
Commission Number: 15207377

Schedule MM-S4

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Ameren Missouri's 2017 Utility Resource Filing Pursuant to 4 CSR 240 – Chapter 22	)))	**File No. EO-2018-0038**

AFFIDAVIT OF JOHN A. ROGERS

State of Missouri)
) ss.
County of Cole)

COMES NOW John A. Rogers and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached *Staff Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

John A. Rogers

John A. Rogers

JURAT

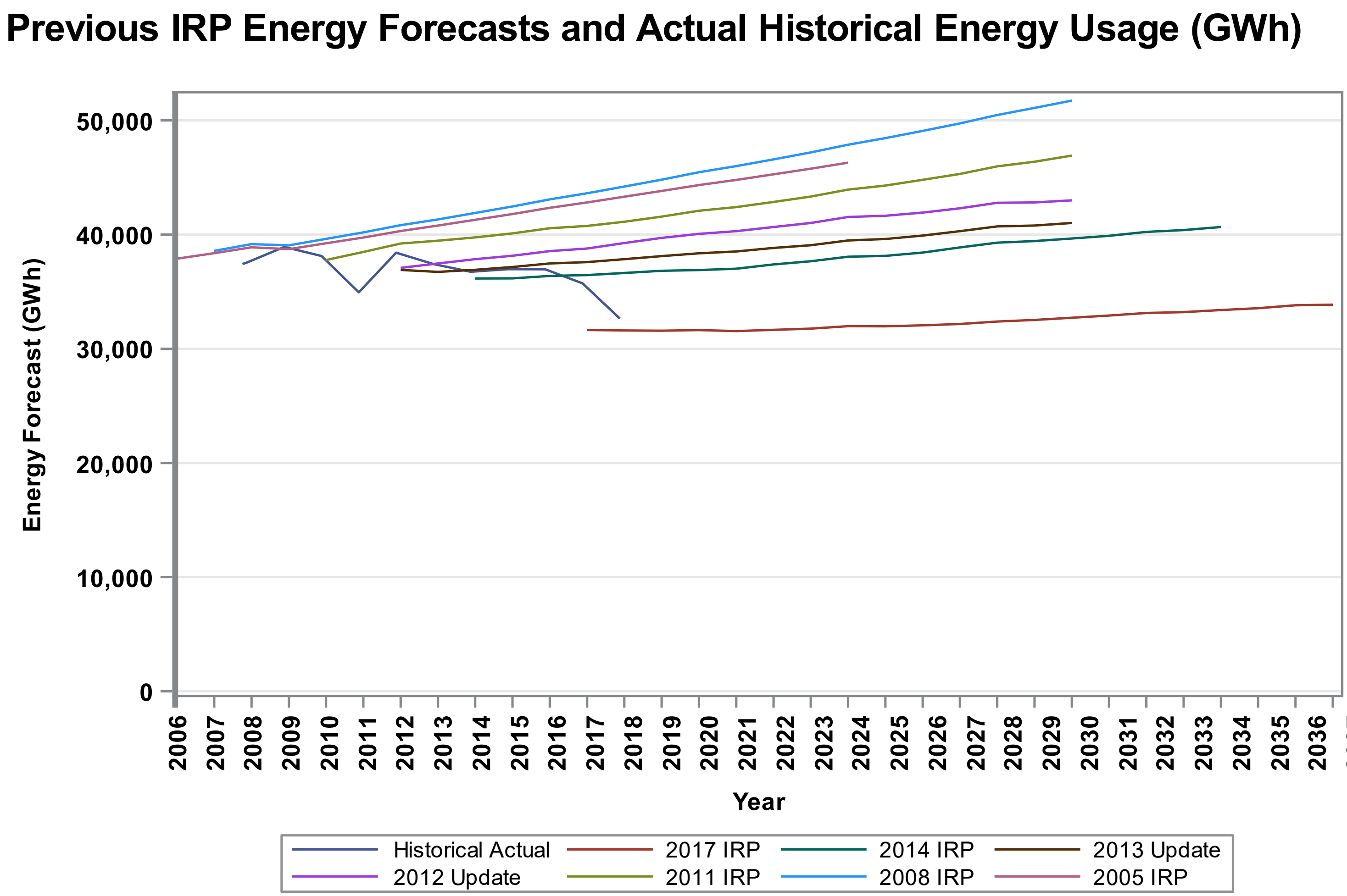
Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 28th day of February, 2018.

Dianna L. Vaught

NOTARY PUBLIC

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 28, 2019
Commission Number: 15207377

Archive of Previous Energy and Peak Demand Forecasts[13]



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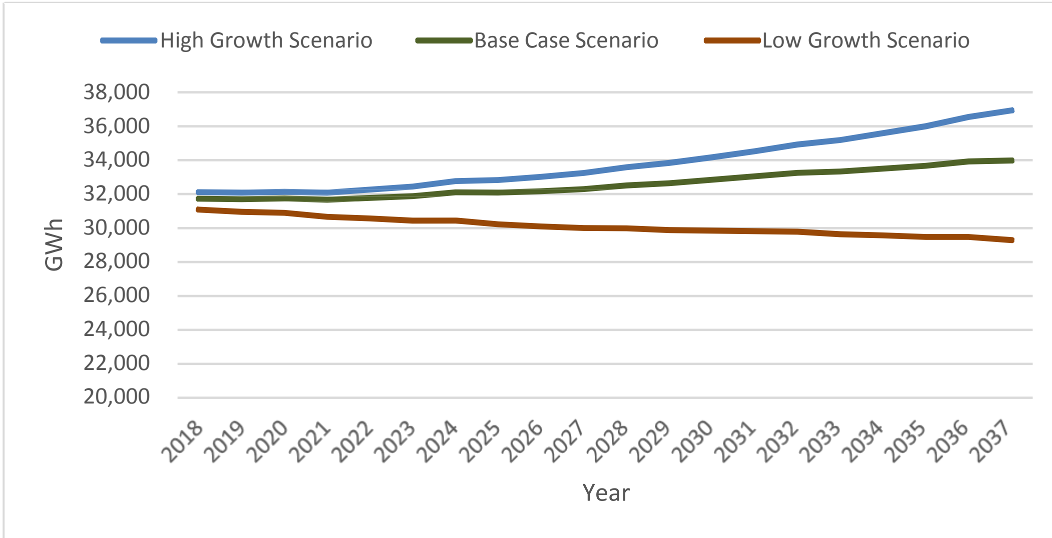
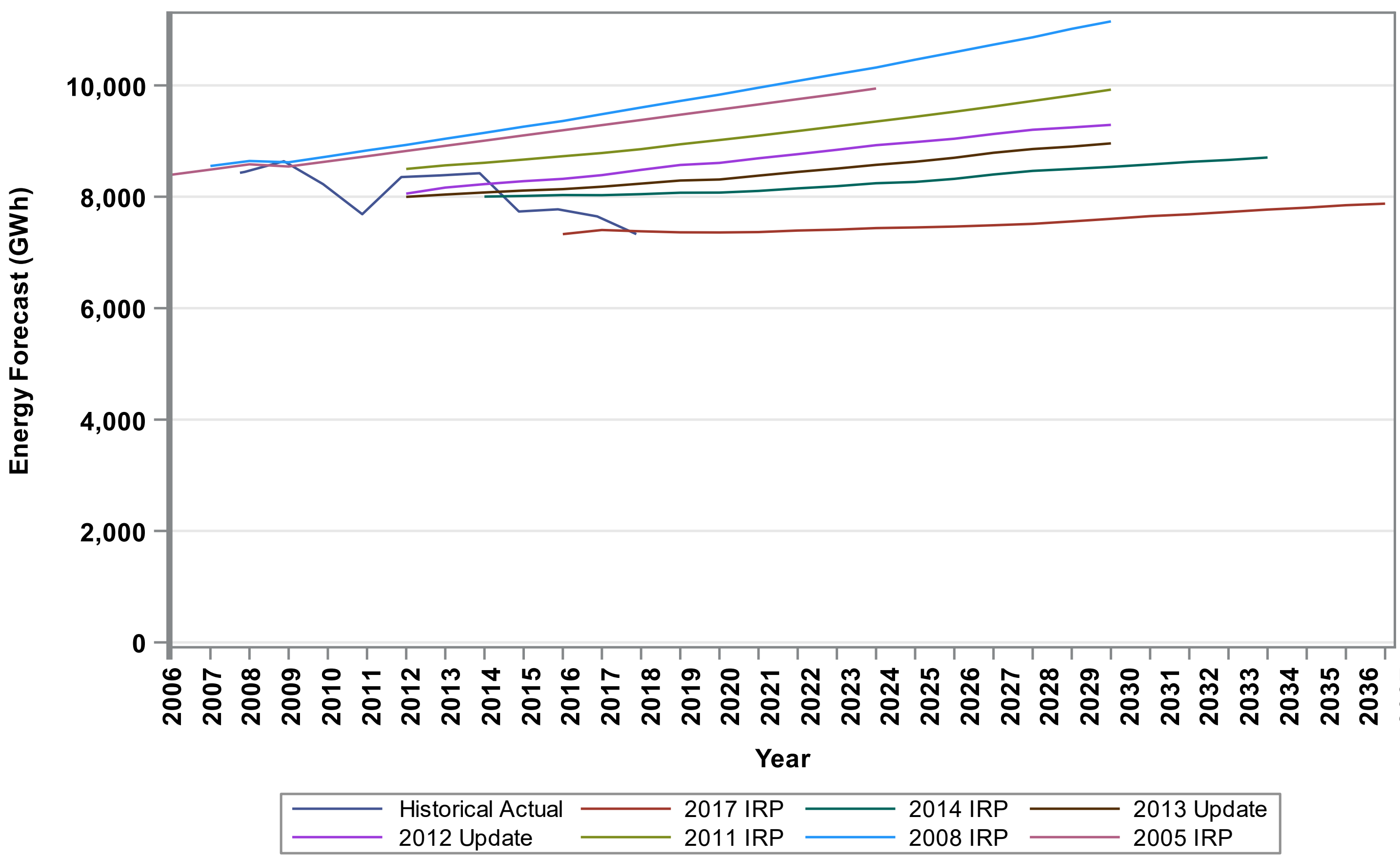
[13] 4 CSR 240-22.030(6)(C)4

Figure 3.10: Total Energy Sales Forecast by Scenario

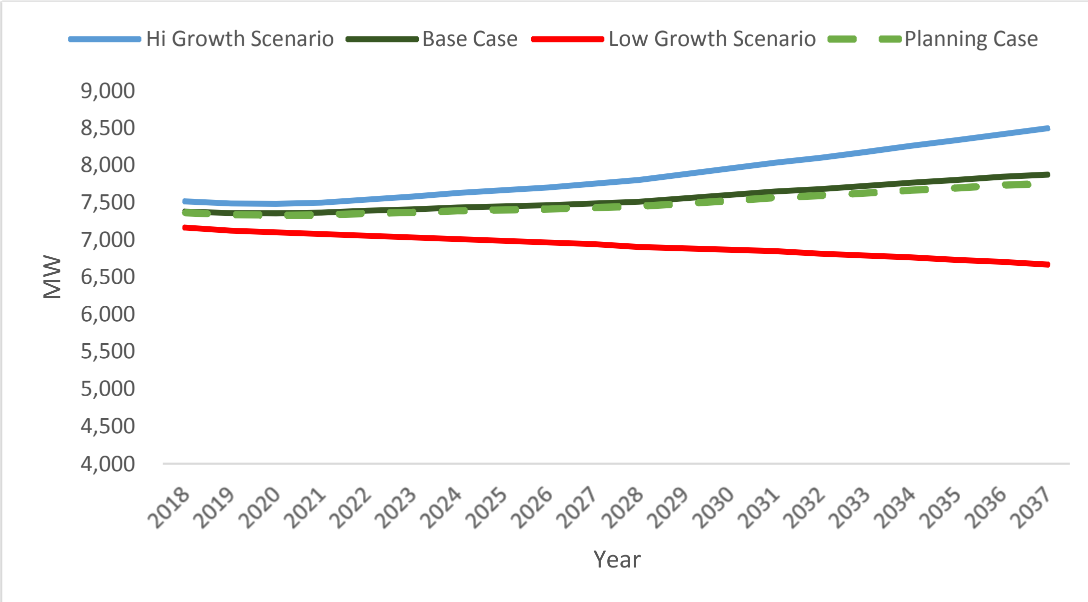


Previous IRP Peak Demand Forecasts and Actual Historical Peaks (MW)



Addendum
Schedule MM-S4

Figure 3.27: IRP Annual Peak Forecast—Planning Case and Scenarios



Levelized Cost of Energy Component Analysis for Existing Resources[1]

Existing Resources	Levelized Cost of Energy (¢/kWh)										
	Non-Environmental Costs					Probable Environmental Costs					Total Cost
	Non-Env Capital	Fixed and Variable O&M	Fuel	Decommission	Pump MWh	Env Capital	Env O&M	CO2	SO2	NOx	
Labadie	0.55	0.30	2.15	--	--	0.16	0.04	0.27	0.00	0.03	**3.49**
Rush Island	0.54	0.40	2.35	--	--	0.20	0.03	0.38	0.00	0.00	**3.92**
Meramec	0.67	2.31	2.37	--	--	1.49	0.04	0.00	0.00	0.01	**6.88**
Sioux	0.67	0.65	2.23	--	--	0.35	0.04	0.17	0.01	0.01	**4.12**
Audrain	0.50	0.29	5.65	--	--	--	0.00	0.17	0.00	0.00	**6.61**
Goose Creek	1.47	0.52	5.38	--	--	--	0.00	0.16	0.00	0.00	**7.54**
Kirksville	0.10	0.04	7.87	--	--	--	--	0.00	0.00	0.00	**8.01**
Pinckneyville	0.77	1.46	4.53	--	--	--	--	0.14	0.00	0.00	**6.89**
Raccoon Creek	0.23	0.74	5.63	--	--	--	--	0.17	0.00	0.00	**6.77**
Kinmundy	0.89	1.19	5.10	--	--	--	--	0.15	0.00	0.00	**7.33**
Meramec CTG	2.52	0.17	5.60	--	--	--	--	0.00	0.00	0.00	**8.30**
Peno Creek	0.86	1.66	4.91	--	--	--	--	0.15	0.00	0.00	**7.57**
Venice	0.57	0.85	4.91	--	--	--	--	0.15	0.00	0.00	**6.48**
Fairgrounds	0.04	0.24	7.87	--	--	--	--	0.00	0.00	0.00	**8.15**
Mexico	0.06	0.42	8.03	--	--	--	--	0.00	0.00	0.00	**8.51**
Moberly	0.06	0.39	5.33	--	--	--	--	0.00	0.00	0.00	**5.79**
Moreau	0.04	0.28	8.79	--	--	--	--	0.00	0.00	0.00	**9.12**
Callaway	1.32	1.81	0.79	0.07	--	--	--	0.00	0.00	0.00	**4.00**
Keokuk	1.91	0.50	0.00	--	--	--	--	0.00	0.00	0.00	**2.40**
Osage	4.65	1.20	0.00	--	--	--	--	0.00	0.00	0.00	**5.85**
Taum Sauk	3.29	1.66	0.00	--	4.78	--	--	0.00	0.00	0.00	**9.73**
Maryland Heights CTG	1.14	3.05	8.05	--	--	--	0.00	0.00	0.00	0.00	**12.24**
O'Fallon (Solar)	0.00	0.41	0.00	--	--	--	0.00	0.00	0.00	0.00	**0.41**

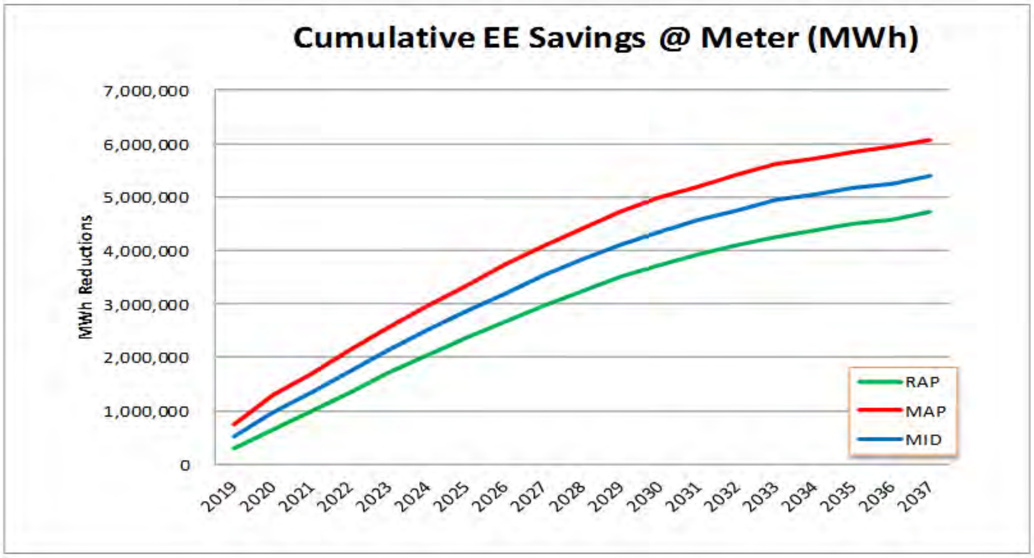
Levelized Cost of Energy Component Analysis

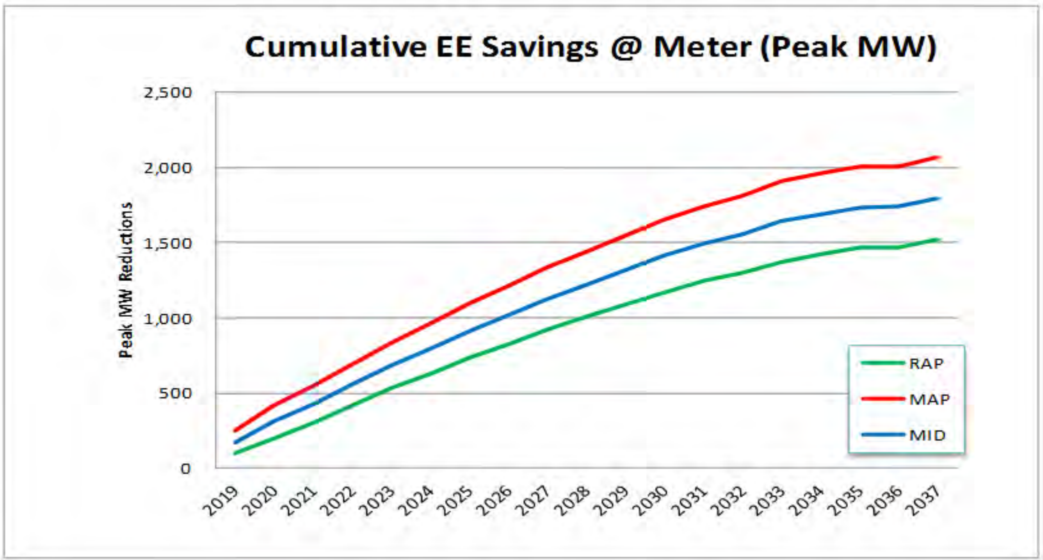
Resource	Levelized Cost of Energy (¢/kWh)									
	Capital	Fixed O&M	Variable O&M	Fuel	Pump Cost	Decommission	CO_2	SO_2	NO_X	Total Cost
New Resources										
Regional Wind	4.35	0.83	0.00	--	--	--	--	--	--	5.18
MO Wind	4.87	0.94	0.00	--	--	--	--	--	--	5.80
Combined Cycle	3.46	0.26	0.52	3.26	--	--	0.14	0.00	0.00	7.64
Hydro: Pomme de Terre	7.56	0.65	--	--	--	--	--	--	--	8.21
Hydro: Mississippi L&D 21	9.67	0.63	--	--	--	--	--	--	--	10.31
Storage: Pumped Hydro	7.17	0.21	0.48	--	4.17	--	--	--	--	12.02
Nuclear	8.68	2.36	0.30	0.84	--	0.17	--	--	--	12.36
Landfill Gas	5.95	1.75	1.44	3.80	--	--	--	0.00	0.00	12.94
Solar	10.14	1.20	--	--	--	--	--	--	--	11.34
Hydro: Clearwater	12.00	0.98	--	--	--	--	--	--	--	12.98
Coal (USCPC with CCS)	9.08	0.63	2.56	2.97	--	--	0.06	0.00		15.30
Biomass	10.50	2.67	1.40	4.84	--	--	--	0.00	0.01	19.42
Simple Cycle	17.50	2.25	0.98	3.99	--	--	0.17	0.00	0.00	24.89

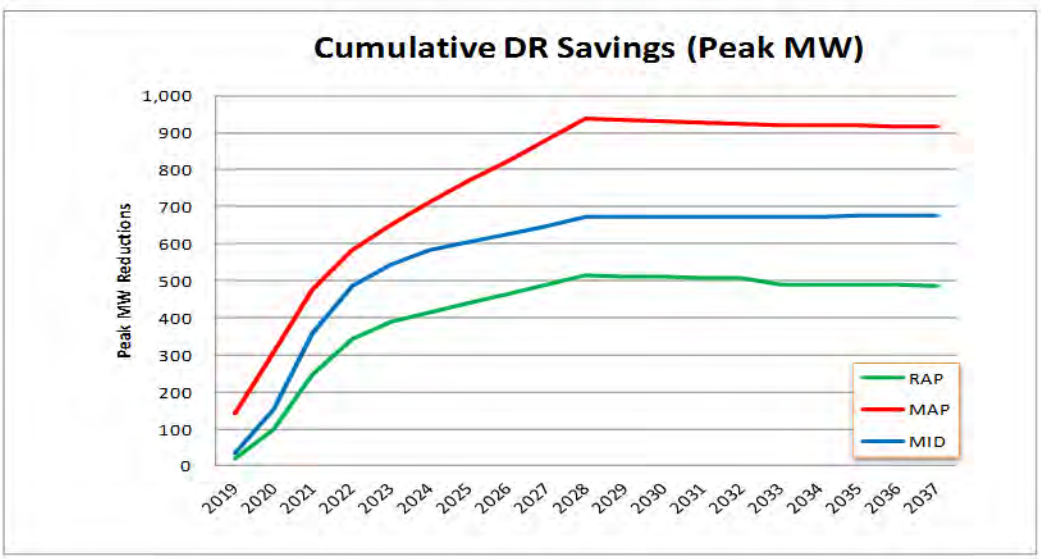
[1] IRP Chapter 4,Table 4.2

Table 5.1 Current & Pending Environmental Regulations

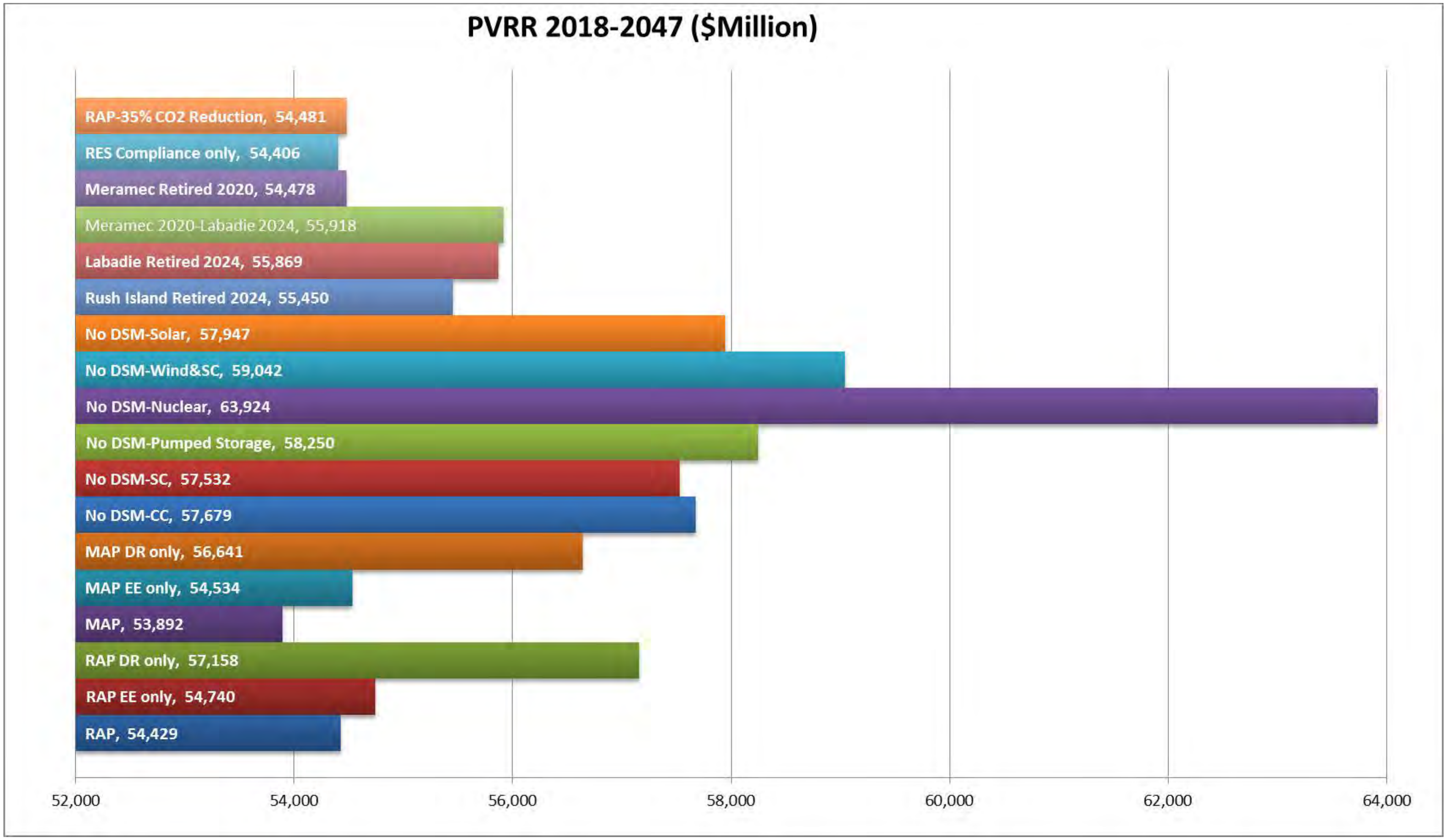
Regulatory Driver	Summary Requirements	Regulation Status	Compliance Timing
Cross-State Air Pollution Rule (CSAPR)	Reduction in NOx and SO2 allowances vs. CAIR; New allowances for trading program (state level caps)	EPA implemented Phase 1 starting on 1/1/2015. On September 7, 2016 EPA finalized an update effective December 27, 2016 to lower the seasonal NOx (May-Sept) allocations beginning with the 2017 ozone season.	Phase 1: 1/1/2015 Phase 2: 1/1/2017
Revisions to National Ambient Air Quality Standards (NAAQS)	Lower PM, NOx and SO2 limits; Expansion of non-attainment areas	SO2 final rule June, 2010; EPA issued a final designation of "unclassifiable" for area around Labadie; final designations for all areas 2016-2020.	SO2: 2017 - 2020
		Fine particulate (PM2.5) lowered 1/15/2013; Attainment designations 03/2015; State Implementation Plans 2018.	PM 2.5: 2020 - 2025
		Ozone standard lowered, final rule 12/2015; Attainment designations 2017; State Implementation Plans 2020	Ozone: 2020+
Mercury and Air Toxics Standards (MATS)	Reduction in emissions of Mercury, HCl (proxy for acid gases) and particulate emissions (proxy for non-mercury metals)	Final rule effective April 16, 2012. Compliance required by April 16, 2015.	Rush Island and Sioux Energy Centers compliant on April 16, 2015; Labadie and Meramec (units 3 & 4) Energy Centers received MDNR approved 1-yr extensions and compliant on April16, 2016.
Clean Air Visibility Rule (CAVR)/Regional Haze Rule	Application of Best Available Retrofit Technology (BART); Targets reduction in transported SO2 and NOx; status of CSAPR may require state to change approach.	Final rule issued by EPA in 1999; States submitted progress reports in 2013; CSAPR resolution may require changes to state rule.	EPA finalized a rule that will move the next deadline from July 31, 2018 to July 31, 2021.
Clean Water Act Section 316(a) Thermal Standards	Implementation through NPDES permit conditions	Evaluation covered by NPDES permits	2015 - 2020
Clean Water Act Section 316(b) Protection of Aquatic Life	Case-by-case determination of controls required to meet entrainment standards; national standard for impingement	Final rule from EPA effective October 2014	Study plans 2014; Studies 2015 - 2017; Compliance 2022 - 2024
Waters of The United States (WOTUS)	Protection of additional streams and tributaries	Final rule issued June 2015; Rule was stayed nation-wide on 10/09/15 by the U.S. Court of Appeals for the 6th Circuit. The EPA and Corps of Engineers has proposed revisions to the definition.	Unknown
Revisions to Steam Electric Effluent Limitations Guidelines (ELG)	Lower effluent emissions for existing parameters; Installation of wastewater treatment facilities; Implemented through NPDES permit conditions	EPA proposal April 19, 2013; final rule Sept 30, 2015; linked to CCR rule; revised rulemaking for steam electric power plant discharges effective January 4, 2016. The EPA has stayed compliance deadlines pending review of the final rule.	2018 - 2023
Coal Combustion Residuals (CCR)	Conversion to dry bottom ash and fly ash; Closure of existing ash ponds; Dry disposal in landfill	Final determination from EPA on haz/non-haz Dec 2014; final rule April 2015, effective October 19, 2015. Fedral legislation (WINN Act) to revise rule signed December 16, 2016.	2018 - 2023
Clean Air Act Regulation of Greenhouse Gases (GHG)/Clean Power Plan (CPP)	Output-based emission limit for new, modified, reconstructed units	New unit NSPS re-proposed Jan 2014; final rule effective 12/22/2015. Challenge filed in DC Circuit Court; oral argument is April 17, 2017.	New unit NSPS applies 1/8/2014
		Proposed rule for modified and reconstructed NSPS June 2014; final effective 12/22/2015. Challenge filed in DC Circuit Court.	Modified/reconstructed applies 6/18/2014
	State emission limits for existing sources	Proposed NSPS for existing units June 2014; final effective 12/22/2015; Rule stayed by Supreme Court 2/9/2016; oral arguments September 2016; DC Circuit Court holding case in abeyance pending EPA review of final rule.	Existing source interim rates 2022 - 2029; final rates 2030+ Compliance dates are suspended due to Supreme Court stay


Cumulative EE Savings @ Meter (MWh)
MWh Reductions
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
RAP
MAP
MID


Cumulative EE Savings @ Meter (Peak MW)
Peak MW Reductions
2,500
2,000
1,500
1,000
500
0
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
RAP
MAP
MID


Cumulative DR Savings (Peak MW)
Peak MW Reductions
1,000
900
800
700
600
500
400
300
200
100
0
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
RAP
MAP
MID

Integration PVRR Results

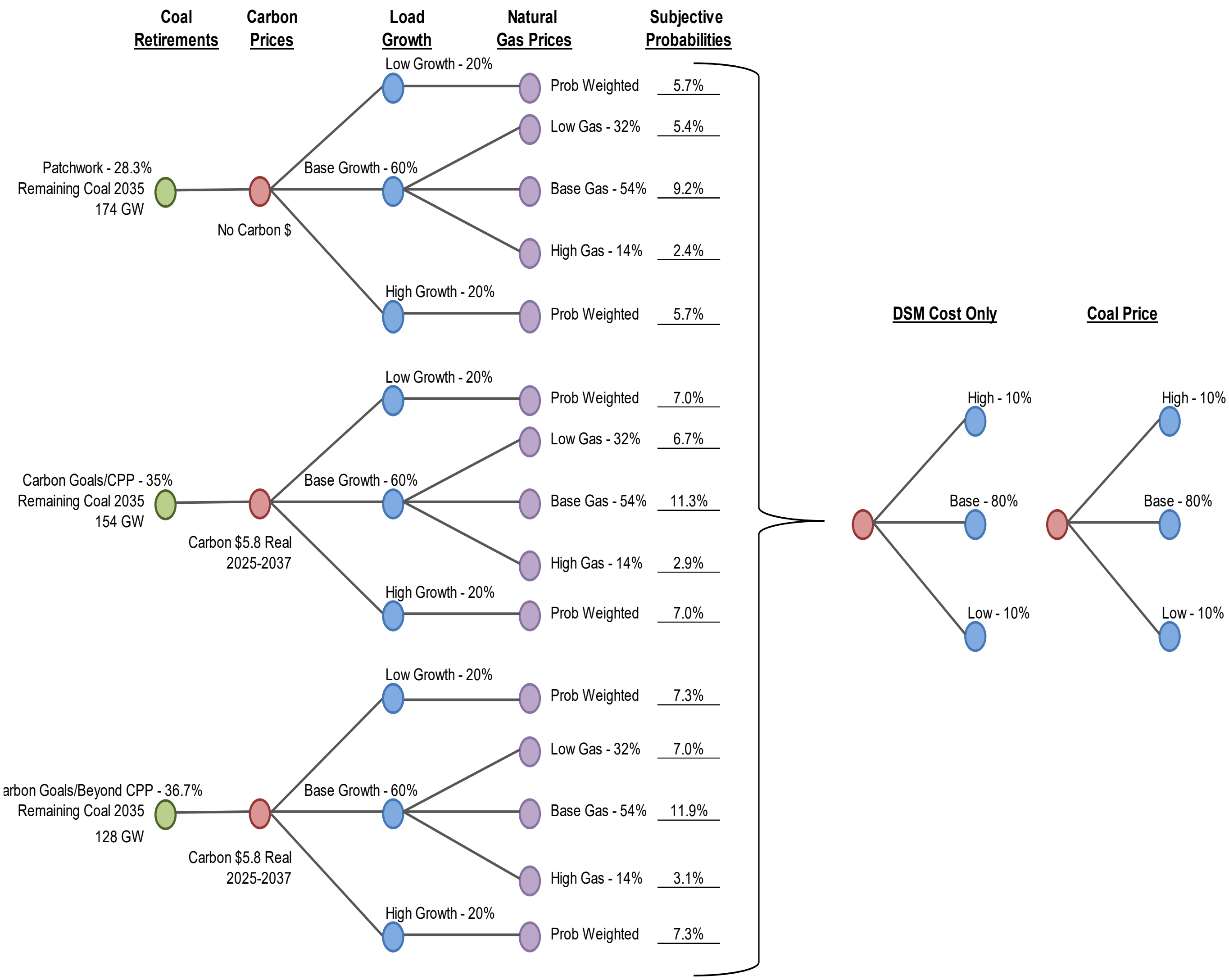


Alternative Resource Plans[1]

Plan Name	Energy Efficiency	Demand Response	Renewables	New Supply Side	Coal Retirements
A-RAP	RAP	RAP	RES Plus	-	Base
B-RAP EE only	RAP	-	RES Plus	-	Base
C-RAP DR only	-	RAP	RES Plus	2 CCs in 2037	Base
D-MAP	MAP	MAP	RES Plus	-	Base
E-MAP EE only	MAP	-	RES Plus	-	Base
F-MAP DR only	-	MAP	RES Plus	CC in 2037	Base
G-No DSM-CC	-	-	RES Plus	CC in 2034 2 CCs in 2037	Base
H-No DSM-SC	-	-	RES Plus	2 SCs in 2034 2 CCs in 2037	Base
I-No DSM-Pumped Storage	-	-	RES Plus	Pumped Hydro in 2034 2 CCs in 2037	Base
J-No DSM-Nuclear	-	-	RES Plus	Nuclear in 2034 CC in 2037	Base
K-No DSM-Wind&SC	-	-	RES Plus	Wind in 2031-2034 (2000 MW total) SC in 2034 2 CCs in 2037	Base
L-No DSM-Solar	-	-	RES Plus	Solar in 2031-2037 (4000 MW total)	Base
M-Rush Island Retired 2024	RAP	RAP	RES Plus	CC in 2037	Rush Island 12/31/2024
N-Labadie Retired 2024	RAP	RAP	RES Plus	CC in 2034	Labadie 12/31/2024
O-Meramec 2020-Labadie 2024	RAP	RAP	RES Plus	CC in 2034	Meramec 12/31/2020 Labadie 12/31/2024
P-Meramec Retired 2020	RAP	RAP	RES Plus	-	Meramec 12/31/2020
Q-RES Compliance only	RAP	RAP	RES	-	Base
R-RAP-35% CO2 Reduction	RAP	RAP	RES Plus	-	Base

[1] IRP Chapter 9, Page 10

Probability Tree



Ameren Missouri 2017 IRP

Preferred Plan Selection Scorecard

Plan	Category / Category Weight / Description	Environmental/ Renewable/ Resource Diversity	Financial/ Regulatory	Customer Satisfaction	Economic Development	Cost	Overall Assessment
	Planning Objectives, Weights and Measures						
	Category Weight	20%	20%	20%	10%	30%	100%
	Description	Resource Diversity	PV Free Cash Flow	Rate Increases	Net Job Growth (FTE-years)	PVRR	
R	RAP-35% CO2 Reduction	2	5	5	4	5	4.30
A	RAP	1	5	4	4	5	3.90
P	Meramec Retired 2020	1	5	4	4	5	3.90
Q	RES Compliance only	1	5	4	4	5	3.90
B	RAP EE only	1	5	3	3	5	3.60
M	Rush Island Retired 2024	3	4	3	4	4	3.60
N	Labadie Retired 2024	4	3	3	4	4	3.60
O	Meramec 2020-Labadie 2024	4	3	3	4	4	3.60
D	MAP	1	4	2	5	5	3.40
E	MAP EE only	1	4	1	3	5	3.00
F	MAP DR only	1	5	4	1	3	3.00
C	RAP DR only	1	5	4	1	2	2.70
L	No DSM-Solar	1	4	4	1	2	2.50
K	No DSM-Wind&SC	2	3	3	2	2	2.40
G	No DSM-CC	2	3	3	1	2	2.30
I	No DSM-Pumped Storage	2	3	3	1	2	2.30
H	No DSM-SC	1	3	3	1	2	2.10
J	No DSM-Nuclear	2	1	1	3	1	1.40

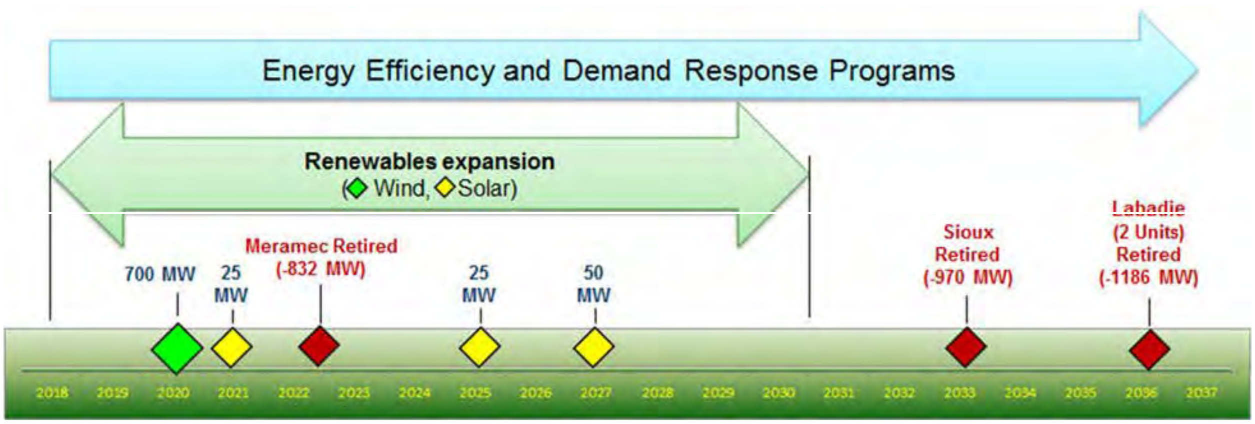
Scoring Guide	
Significant Advantage	5
Moderate Advantage	4
No Advantage or Disadvantage	3
Moderate Disadvantage	2
Significant Disadvantage	1

Overall Assessment Guide
Top-tier Plan
Mid-tier Plan
Bottom-tier Plan

Notes on Scores by Policy Objective	
Environmental/Diversity	Inclusion of MAP or RAP energy efficiency; new nuclear; combined cycle; significant early coal retirement; additional wind, solar or pumped hydro were viewed as advantageous.
Financial Regulatory	Financial and regulatory risks associated with new nuclear; significant early coal retirement; cessation of energy efficiency programs; and/or implementation of overly aggressive energy efficiency programs were viewed as disadvantageous, as were large negative impacts on cash flow.
Customer Satisfaction	Lower levelized annual rate increases, inclusion of energy efficiency and demand response, inclusion of additional new zero carbon resources, and reductions in coal-fired emissions were viewed as advantageous.
Economic Development	Plans were rated on a relative scale based on direct jobs (FTE-years) including both construction and operation.
Cost (PVRR)	Plans were rated on a relative scale based on present value of revenue requirements (PVRR).

Key to Abbreviations
EE Only = Energy Efficiency Only, No Demand Response
RAP = Realistic Achievable Potential DSM Portfolio
CC = Combined Cycle Gas Turbine Generator
MAP = Maximum Achievable Potential DSM Portfolio
RES = Renewable Energy Standard
DR Only = Demand Response Only, No Energy Efficiency
MEEIA = Missouri Energy Efficiency Investment Act Cycle 1
SC = Simple Cycle Gas Turbine Generator


Preferred Resource Plan (2018-2037)
Realistic Achievable Potential (RAP) Demand Side Management
Expansion of Renewable Generation (700 MW Wind, 100 MW Solar)
Meramec Units Units 1-4 Retired 12/31/2022
Sioux Units 1-2 Retired 12/31/2033
Labadie (2 Units) Retired 12/31/2036
Lack of DSM Incentives
No DSM, Combined Cycle Plan
No DSM Programs After March 2019 (MEEIA2)
Expansion of Renewable Generation (700 MW Wind, 100 MW Solar)
Meramec 1-4 Retired 12/31/2022
Sioux 1-2 Retired 12/31/2033
Labadie (2 Units) Retired 12/31/2036
600 MW New Combined Cycle in Service 1/1/2034
1200 MW New Combined Cycle in Service 1/1/2037
New GHG Regulations / Other Changing Conditions
Reassess Options and Plans
Energy Efficiency, Renewables, Natural Gas, Nuclear, Coal Retirements


Energy Efficiency and Demand Response Programs
Renewables expansion
(Wind, Solar)
700 MW
25 MW
Meramec Retired (-832 MW)
25 MW
50 MW
Sioux Retired (-970 MW)
Labadie (2 Units) Retired (-1186 MW)
2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037

Forecast of Capacity Balance (MW)   Confidential

Ameren Missouri 2017 IRP Adopted Preferred Resource Plan

Plan A

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
A. System Generation Capacity																						
Existing Generation Capacity																						
Callaway	Nuclear	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190
Keokuk	Hydro	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
Labadie Unit 1	Coal	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	0
Labadie Unit 2	Coal	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	0
Labadie Unit 3	Coal	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593
Labadie Unit 4	Coal	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593
Rush Island Unit 1	Coal	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589
Rush Island Unit 2	Coal	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589
Sioux Unit 1	Coal	485	485	485	485	485	485	485	485	485	485	485	485	485	485	485	485	485	0	0	0	0
Sioux Unit 2	Coal	485	485	485	485	485	485	485	485	485	485	485	485	485	485	485	485	485	0	0	0	0
Meramec Unit 3	Coal	260	260	260	260	260	260	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meramec Unit 4	Coal	334	334	334	334	334	334	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Maryland Heights	LFG	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
O'Fallon	SOLAR	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total Base Capacity		**6459**	**6459**	**6459**	**6459**	**6459**	**6459**	**5865**	**5865**	**5865**	**5865**	**5865**	**5865**	**5865**	**5865**	**5865**	**5865**	**5865**	**4895**	**4895**	**4895**	**3709**
Osage	Hydro	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
Taum Sauk Unit 1	Hydro	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Taum Sauk Unit 2	Hydro	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Meramec Unit 1	Gas	119	119	119	119	119	119	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meramec Unit 2	Gas	119	119	119	119	119	119	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Audrain 1	Gas	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 2	Gas	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 3	Gas	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 4	Gas	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 5	Gas	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 6	Gas	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 7	Gas	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Audrain 8	Gas	71	71	71	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Fairgrounds	Oil	54	54	54	54	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Goose Creek 1	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Goose Creek 2	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Goose Creek 3	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Goose Creek 4	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Goose Creek 5	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Goose Creek 6	Gas	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Howard Bend	Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kinmundy CTG-1	Gas	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Kinmundy CTG-2	Gas	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Kirksville	Gas	13	13	13	13	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meramec CTG-1	Oil/Gas	54	54	54	54	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meramec CTG-2	Oil/Gas	44	44	44	44	44	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mexico	Oil	53	53	53	53	53	53	53	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moberly	Oil	53	53	53	53	53	53	53	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moreau	Oil	53	53	53	53	53	53	53	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peno Creek CTG-1	Gas/Oil	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Peno Creek CTG-2	Gas/Oil	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Peno Creek CTG-3	Gas/Oil	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Peno Creek CTG-4	Gas/Oil	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Pinckneyville CTG-1	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-2	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-3	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-4	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-5	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Pinckneyville CTG-6	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Pinckneyville CTG-7	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Pinckneyville CTG-8	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Racoon Creek 1	Gas	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Racoon Creek 2	Gas	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Racoon Creek 3	Gas	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Racoon Creek 4	Gas	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Venice CTG-2	Gas	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Venice CTG-3	Gas	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168
Venice CTG-4	Gas	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168
Venice CTG-5	Gas	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Total Intermediate/Peaking Capacity		**3741**	**3741**	**3741**	**3771**	**3771**	**3606**	**3368**	**3209**	**3209**	**3209**	**3209**	**3209**	**3209**	**3209**	**3209**	**3209**	**3209**	**3209**	**3209**	**3209**	**3209**
Total Generation Capacity (TGC)		**10200**	**10200**	**10200**	**10230**	**10230**	**10065**	**9233**	**9074**	**9074**	**9074**	**9074**	**9074**	**9074**	**9074**	**9074**	**9074**	**9074**	**8104**	**8104**	**8104**	**6918**
B. Capacity Transactions		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Purchases																						
102.3 Pioneer Prairie Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Purchases = P		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing sales		212	47	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Sales = S		212	47	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Transactions = NT = P - S		-212	-47	-27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total System Capacity = TSC = TGC + NT		**9988**	**10153**	**10173**	**10230**	**10230**	**10065**	**9233**	**9074**	**9074**	**9074**	**9074**	**9074**	**9074**	**9074**	**9074**	**9074**	**9074**	**8104**	**8104**	**8104**	**6918**
C. System Peaks & Reserves		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Peak Demands																						
Ameren Missouri Forecasted Peak		7365	7365	7340	7333	7337	7358	7371	7393	7402	7415	7434	7451	7489	7528	7569	7595	7630	7669	7698	7735	7760
Voltage Reduction		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Full/Partical Requirements Contracts		3	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM - [RAP		**0**	**0**	**-106**	**-210**	**-329**	**-444**	**-570**	**-677**	**-788**	**-887**	**-985**	**-1080**	**-1168**	**-1258**	**-1334**	**-1399**	**-1475**	**-1529**	**-1573**	**-1622**	**-1682**
DSM - [RAP		**0**	**0**	**-22**	**-107**	**-263**	**-368**	**-419**	**-447**	**-474**	**-500**	**-527**	**-553**	**-551**	**-549**	**-547**	**-545**	**-528**	**-526**	**-526**	**-525**	**-524**
Peak Forecast less DSM = PF		**7368**	**7367**	**7214**	**7016**	**6744**	**6546**	**6381**	**6269**	**6140**	**6027**	**5922**	**5818**	**5770**	**5721**	**5687**	**5650**	**5628**	**5614**	**5599**	**5588**	**5554**
Capacity Reserves = CR = TSC - PF		2620	2786	2959	3214	3487	3520	2852	2805	2934	3047	3152	3257	3304	3354	3387	3424	3447	2491	2505	2517	1365
D. Capacity Needs		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
% Reserve Margin = RM		15.8%	15.6%	15.3%	15.4%	15.5%	15.5%	15.6%	15.6%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%
% Capacity Margin = CM = RM/(1+RM)		13.6%	13.5%	13.3%	13.3%	13.4%	13.4%	13.5%	13.5%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%
Required Capacity = RC = PF/(1-CM)		**8533**	**8517**	**8318**	**8097**	**7789**	**7560**	**7377**	**7247**	**7104**	**6974**	**6852**	**6731**	**6676**	**6619**	**6580**	**6538**	**6511**	**6495**	**6478**	**6465**	**6426**
Capacity Balance = TSC - RC		**1456**	**1637**	**1856**	**2134**	**2441**	**2505**	**1857**	**1827**	**1970**	**2101**	**2222**	**2343**	**2398**	**2455**	**2494**	**2537**	**2563**	**1610**	**1626**	**1639**	**493**

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT ON

UNION ELECTRIC COMPANY, d/b/a AMEREN MISSOURI

ELECTRIC UTILITY RESOURCE PLANNING COMPLIANCE FILING

FILE NO. EO-2021-0021

Jefferson City, Missouri
March 31, 2021

** Denotes Confidential Information **

*** Denotes Highly Confidential Information ***

HC/C

TABLE OF CONTENTS OF

STAFF REPORT ON

ELECTRIC UTILITY RESOURCE PLANNING COMPLIANCE FILING

UNION ELECTRIC COMPANY, d/b/a AMEREN MISSOURI

FILE NO. EO-2021-0021

Schedule MM-S5

STAFF REPORT ON

ELECTRIC UTILITY RESOURCE PLANNING COMPLIANCE FILING

UNION ELECTRIC COMPANY, d/b/a AMEREN MISSOURI

FILE NO. EO-2021-0021

Executive Summary

On September 27, 2020, Union Electric Company, d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), filed its 2020 Integrated Resource Plan ("IRP") triennial compliance filing ("Filing") in File No. EO-2021-0021, as required by 20 CSR 4240-22 Electric Utility Resource Planning and the Missouri Public Service Commission's ("Commission") November 6, 2019 *Order Granting Variances* in File No. EE-2020-0007.[1]

Commission Rule 20 CSR 4240-22.080(7) provides that:

> (7) The staff shall conduct a limited review of each triennial compliance filing required by this rule and shall file a report not later than one hundred fifty (150) days after each utility's scheduled triennial compliance filing date. The report shall identify any deficiencies in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies and shall provide at least one (1) suggested remedy for each identified deficiency. Staff may also identify concerns with the utility's triennial compliance filing, may identify concerns related to the substantive reasonableness of the preferred resource plan or resource acquisition strategy, and shall provide at least one (1) suggested remedy for each identified concern.

As a result of its limited review, and as more fully discussed throughout Staff's Report ("Report"), Staff identified two deficiencies and three concerns regarding Ameren Missouri's 2020 IRP Filing:

[1] Approved waivers include: 20 CSR 4240-22.040(3)(A); .045(1)(B) and (3)(C); .060(5)(E), (5)(F), (5)(K), (5)(L) and (7); and .080(2)(C)2.

List of Staff's Identified Deficiencies

Deficiency 1 – Ameren Missouri did not consider and analyze non-renewable supply-side resources on an equivalent basis as renewable supply-side resources and demand-side resources as required by 20 CSR 4240-22.010(2)(A).

Ameren Missouri did not evaluate non-renewable supply-side resources on an equivalent basis as renewable supply-side resources and demand-side resources. Ameren Missouri also evaluated supply-side resources differently than demand-side resources by utilizing different avoided capacity cost curves.[2] This difference in methodologies does not allow demand-side resources, renewable supply-side resources, and non-renewable supply-side resources to be considered and analyzed on an equivalent basis and skews the result of the subsequent analyses reported within Ameren Missouri's 2020 IRP Filing.

Deficiency 2 – Ameren Missouri did not use a consistent avoided capacity cost throughout its triennial compliance filing as required by 20 CSR 4240-22.050(5)(A)1.

For Ameren Missouri's 2020 IRP Filing, a market-based capacity price was used in evaluating non-renewable supply-side resources. However, a separate capacity price curve was developed to be used in future DSM program cost-effectiveness analyses. This curve is a combination of the market-based capacity price forecast and the cost of new entry ("CONE") value.[3]

List of Staff's Identified Concerns

Concern A – Ameren Missouri's avoided capacity cost is overstated due to the premature move to CONE in 2029.

In determining when to move to a CONE value when developing its avoided capacity costs, Ameren Missouri reviewed a planning scenario in which there were no more DSM programs beyond MEEIA Cycle 3 and with retirement of ** six ** coal-fired units by the end of ** 2028 **. Based on that review, Ameren Missouri states that the first year that a new supply-side resource would be needed in such a scenario to strictly meet Midcontinent Independent

[2] Chapter 2, page 14, of Ameren Missouri's 2020 IRP Filing.
[3] Chapter 2, page 14, of Ameren Missouri's 2020 IRP Filing.

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System Operator ("MISO") planning reserve requirements was found to be 2029. However, the preferred plan selected by Ameren Missouri assumes retirement of ** four ** coal-fired units by the end of ** 2028 **. The preferred plan also assumes roughly ** 1900 ** MW of new renewable generation by the end of ** 2028 **. Both assumptions, if used in the development of avoided capacity costs, would lower the avoided capacity costs by some amount since the move to CONE would likely be pushed out to some year beyond 2029. Further, Staff reviewed all alternative resource plans ("ARPs") in which there were no DSM programs beyond MEEIA Cycle 3 and it appears no new non-renewable supply-side resource is needed prior to ** 2037 **. Ameren Missouri's "no DSM contingency plan" does not show a need for a new non-renewable supply-side resource until ** 2034 **. Staff also has concerns with the move from a market-based cost to CONE in one year's time. Thus, Staff's concern is that Ameren Missouri's avoided capacity cost is overstated due to the premature move to CONE in 2029.

Concern B - The 2020 Market Potential Study began in March 2019 and was completed in March 2020. Therefore, the 2020 Market Potential Study relied on the avoided costs developed as part of Ameren Missouri's 2017 IRP to complete the initial screening analysis and identify cost-effective measures to be included in each demand-side management portfolio of the 2020 IRP.[4]

Concern C – The risk potentially borne by ratepayers from Ameren Missouri's unprecedented shift toward new renewable wind and solar generation.

Ameren Missouri's preferred resource plan and resource acquisition strategy is an aggressive approach that includes its largest ever expansion of renewable wind and solar generation,[5] bringing Ameren Missouri to 3100 MW of wind and solar by 2030 and 5400 MW of wind and solar by 2040.

20 CSR 4240-22.010 Policy Objectives

20 CSR 4240-22.010 Policy Objectives, has a stated purpose that "This rule states the public policy goal that this chapter is designed to achieve and identifies the objectives that the electric utility resource planning process must serve."

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[4] Chapter 8, page 6, of Ameren Missouri's 2020 IRP Filing.
[5] *See* attached Confidential Addendum A for the preferred resource plan renewable additions and non-renewable retirements.

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Schedule MM-S5

20 CSR 4240-22.010(1) and (2) state:

> (1) The commission's policy goal in promulgating this chapter is to set minimum standards to govern the scope and objectives of the resource planning process that is required of electric utilities subject to its jurisdiction in order to ensure that the public interest is adequately served. Compliance with these rules shall not be construed to result in commission approval of the utility's resource plans, resource acquisition strategies, or investment decisions.
>
> (2) The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environment policies The fundamental objective requires that the utility shall —
>
> > (A) Consider and **analyze demand-side resources, renewable energy, and supply-side resources on an equivalent basis**,[6] subject to compliance with all legal mandates that may affect the selection of utility electric energy resources, in the resource planning process; **[Emphasis added.]**

Staff performed its review of Ameren Missouri's 2020 IRP Filing using the Commission's policy goal in promulgating this Chapter and the fundamental objective of the resource planning process as the foundation of its review. Based on its limited review, Staff concludes Ameren Missouri's 2020 IRP Filing does not meet the requirements of rule 20 CSR 4240-22.010 due to the following deficiency.

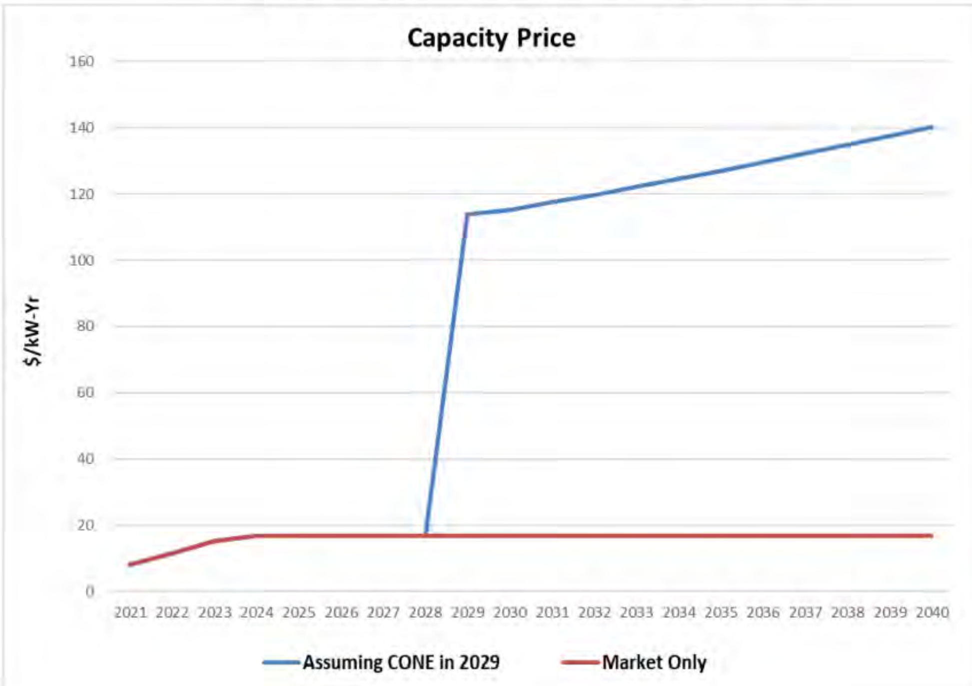
Deficiency

Deficiency 1 – Ameren Missouri did not evaluate non-renewable supply-side resources on an equivalent basis as renewable supply-side resources and demand-side resources. Ameren Missouri also evaluated supply-side resources differently than demand-side resources by utilizing different avoided capacity cost curves.[7] This difference in methodologies does not allow demand-side resources, renewable supply-side resources, and non-renewable supply-side resources to be considered and analyzed on an equivalent basis and skews the result of the subsequent analysis reported within Ameren Missouri's 2020 IRP Filing.

[6] Although the rule does not specifically say renewable and non-renewable supply-side resources, it is implied by listing each separately and including an "and."
[7] Chapter 2, page 14 of Ameren Missouri's 2020 IRP Filing.

As part of Chapter 2 in its 2020 IRP Filing, Ameren Missouri provided Figure 2.5,[8] which depicts the capacity price assumptions utilized as well as descriptions for how the curves were estimated. Ameren Missouri's Figure 2.5 follows.

Figure 2.5 Capacity Price Assumptions



As explained in more detail on Chapter 2, page 14 of Ameren Missouri's IRP filing, the market based capacity curve was used for the integration and risk analysis. According to Ameren Missouri's response to Sierra Club Data Request No. 1, "the value of capacity is used in calculating the PVRR. As a member of MISO, all capacity sold in [sic] into the MISO market and that market revenue is used to reduce revenue requirements… During the planning process, when Ameren Missouri determines that there is insufficient owned capacity resources to meet the need of customers in a planning year, market purchases are made up to 300 MWs of capacity to meet our reserve requirements."

Ameren Missouri is not analyzing and considering non-renewable supply-side resources on an equivalent basis with renewable supply-side resources or demand-side resources as demonstrated by the following excerpt from Chapter 9 of Ameren Missouri's IRP filing:

[8] Chapter 2, page 15 of Ameren Missouri's 2020 IRP Filing.

> 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 are added to eliminate the shortfall. The build threshold was determined to be 300 MW regardless of the type of supply-side resource under consideration and reflects a level that Ameren Missouri trading staff assess as a reasonable level of capacity market dependence.

Ameren Missouri correctly limits non-renewable supply-side resource additions to periods of projected capacity needs. Furthermore, Ameren Missouri staff has identified that 300 MW is a "reasonable level of capacity market dependence" while simultaneously proposing to implement vast demand-side resource programs and invest in thousands of megawatts of renewable resources regardless of the need to do so. These differences in methodologies do not allow the resources to be considered and analyzed on an equivalent basis and can have a drastic impact on the estimation of net present value of revenue requirement ("NPVRR") because *** "Capacity revenues/costs are calculated and included in the total revenue requirements"[9] and "The capacity revenues/costs included in the revenue requirements are calculated using the market only price curve." ***[10] In contrast, "a separate capacity price curve was also developed to be used in future demand-side resource cost effectiveness analyses."[11] This "separate capacity price curve" should be dismissed as it does not realistically reflect costs which may be avoided resulting from implementation of demand-side resources and has the potential to artificially inflate "proposed benefits" of future demand-side programs. Furthermore, the demand-side resources included as options within this analysis were screened utilizing avoided capacity costs which were much higher than not only the "market only curve" but also the "separate capacity price curve." This likely resulted in demand-side programs and measures being included which may not have been deemed cost effective when utilizing the "market only curve." This would also have an impact on the resulting NPVRR of any given plan. Graph 1 below illustrates the differing capacity costs utilized by Ameren Missouri for various resource types within the triennial filing.

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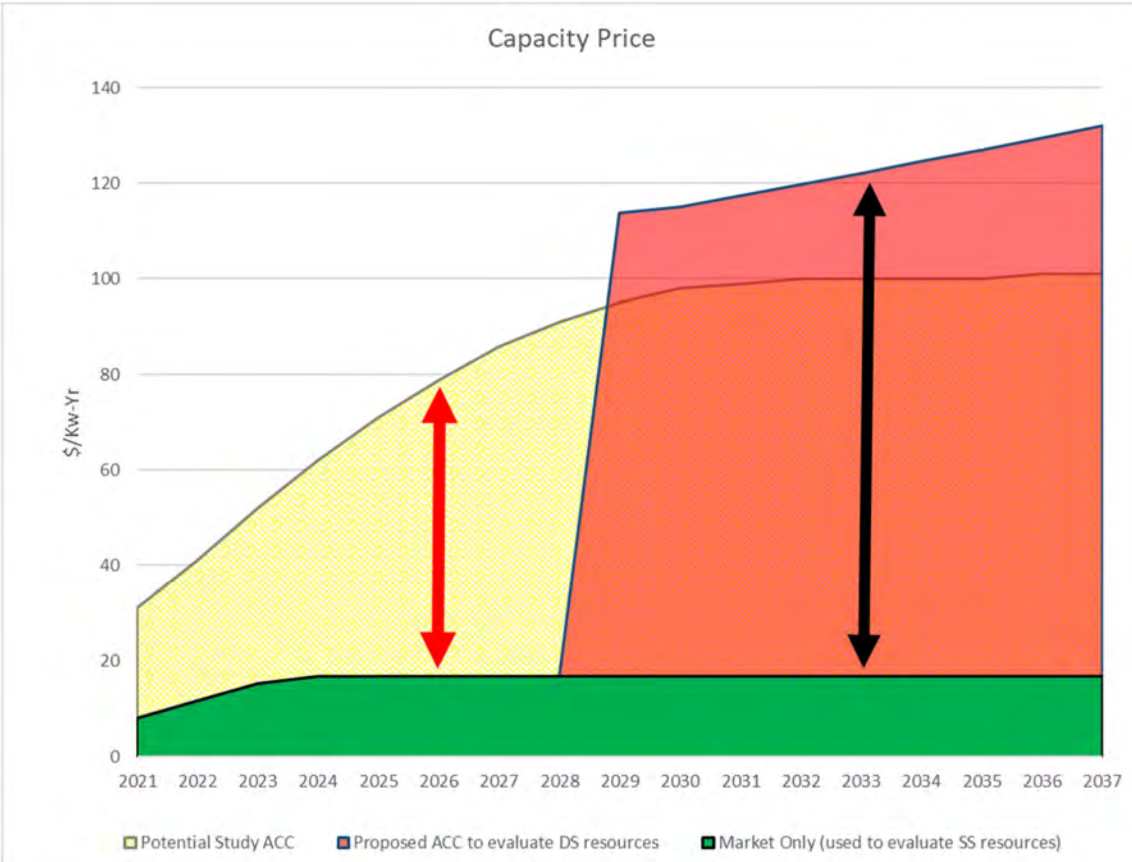
[9] Ameren Response to Sierra Club Data Request No. 01 HC.
[10] Ameren Response to Sierra Club Data Request No. 2.7.
[11] Chapter 2, page 14 of Ameren Missouri's 2020 IRP compliance filing.

Graph 1: Capacity Cost



The black arrow in Graph 1 reflects the difference between the capacity value of supply-side resources within Ameren Missouri's integrated analysis and the capacity cost that Ameren Missouri is proposing to utilize to evaluate future demand-side resources. This drastic difference in valuation of demand-side resources as compared to the valuation of supply-side resources does not allow the two types of resources to be evaluated on an equivalent basis. See Concern B below for the discussion of the red arrow.

To remedy this deficiency, Ameren Missouri should utilize the "market only" capacity cost curve when evaluating any future demand-side resources in order to evaluate supply-side resources on an equivalent basis as demand-side resources. Ameren Missouri should also provide analysis quantifying all savings resulting from the implementation of the demand-side resources within the preferred resource plan that can reasonably be expected to avoid costs to ratepayers through concrete verifiable reductions in rates. This analysis should include evidence of reduced

MISO costs and expected revenue from excess capacity sales. Furthermore, Ameren Missouri should maintain build thresholds for non-renewable supply-side resources as well as renewable supply-side resources and demand-side resources based upon the projected capacity need for reserve requirements.

Staff Expert Witnesses: Brad J. Fortson and J Luebbert

20 CSR 4240-22.030 Load Analysis and Forecasting

Summary

20 CSR 4240-22.030, Load Analysis and Load Forecasting, has a stated purpose of setting the "minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing loads, and the purposes to be accomplished by load analysis and by load forecast models. The load analysis discussed in this rule is intended to support both demand-side management efforts of 20 CSR 4240-22.050 and the load forecast models of this rule. This rule also sets the minimum standards for the documentation of the inputs, components, and methods used to derive the load forecasts." Further, 20 CSR 4240-22.030(1) requires the utility to "describe and document its intended purposes for load analysis methods, why the selected load analysis methods best fulfill those purposes, and how the load analysis methods are consistent with one another and with the end-use consumption data used in the demand-side analysis as described in 20 CSR 4240-22.050."

Accurate load forecasting models are essential to the operation and planning of a utility. Load forecasting helps a utility make important decisions including decisions on purchasing and generating electric power, load switching, and infrastructure development. The Load Analysis and Load Forecasting Rule allows the utility to use multiple analytical methods for performing its load analysis and develop its forecasts, leaving it to the utility's discretion to choose the methods by which it achieves the stated purpose of the Rule.

Ameren Missouri has developed a range of load forecasts deploying the Statistically Adjusted End-use forecasting tools and methods used to develop the forecasts providing a solid analytical basis for testing and refining the assumptions used in the development of the potential demand-side resource portfolios[12]. The planning case forecast projects Ameren Missouri's retail sales to grow by 0.7% annually between 2021 and 2040, and retail peak demand to grow by 0.5% per year.

Ameren Missouri did not request any waivers from specific provisions of this Rule.

Staff found no deficiencies concerning compliance with this rule and Staff has not identified any concerns. In Staff's opinion, the Integrated Resource Analysis filing meets the Load Analysis and Load Forecasting requirements of 20 CSR 4240-22.030.

Staff Expert Witness: Krishna L. Poudel

<u>20 CSR 4240-22.040 Supply-Side Resource Analysis</u>

<u>Summary</u>

Rule 20 CSR 4240-22.040 Supply-Side Resource Analysis requires Ameren Missouri to review existing resources for opportunities to upgrade or retire existing resources and also review a wide variety of supply-side resource options to determine cost estimates for each type of resource.

Resource options are to be ranked based upon their relative levelized annual costs,[13] including installed capital costs, fixed and variable operation and maintenance costs, and probable environmental costs levelized over the useful life of the potential supply-side resource option using the utility discount rate.[14] Resources which do not have significant disadvantages and pass the pre-screening process are to be included in the integrated resource analysis process used to select a preferred resource plan.

Ameren Missouri selected two natural gas technologies as final candidate resource options based on supply-side screening analysis[15]: Gas Combined Cycle and Gas Simple Cycle Combustion. Gas Combined Cycle exhibit the lowest levelized cost of energy ("LCOE") among conventional generation resources. Solar, Wind, Battery storage, and Pump storage have been identified as other candidate resources.

[12] 20 CSR 4240-22.030(1)(A).
[13] 20 CSR 4240-22.020(29) Levelized cost means the dollar amount of a fixed annual payment for which a stream of those payments over a specified period of time is equal to a specified present value based on a specified rate of interest.
[14] 20 CSR 4240-22.040(2)(A).
[15] 20 CSR 4240-22.040(2).

Ameren Missouri evaluated the levelized cost of the existing supply-side resources as well as the selected candidate resources. Capital costs for all of the preliminary candidate supply-side options included transmission interconnection costs.[16]

Table 5.1 from Chapter 5 of the IRP filing summarizes the current environmental regulations for which Ameren Missouri must implement mitigation measures, along with expectations for compliance requirements for certain potential regulations.[17]

With respect to rule 20 CSR 4240-22.040 Supply-Side Resource Analysis, Ameren Missouri requested, and the Commission granted, in File No. EE-2020-0007, one variance of the provisions required by 20 CSR 4240-22.040(3)(A).[18]

Staff has not identified any deficiencies or concerns related to Ameren Missouri's supply-side resource analysis.

Staff Expert Witness: Jordan T. Hull

20 CSR 4240-22.045 Transmission and Distribution Analysis

Summary

Rule 20 CSR 4240-22.045 Transmission and Distribution Analysis specifies minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting. Rule 20 CSR 4240-22.045 does not prescribe how analyses are to be done, but rather allows a utility to conduct its own analysis or adopt the regional transmission operator ("RTO") or Independent Transmission System Operator ("ISO") transmission plans. Rule 20 CSR 4240-22.045 requires analysis and documentation of the RTO/ISO transmission projects and requires the electric utility to review transmission and distribution for the reduction of power losses, interconnection of new generation facilities, facilitation of sales and purchases, and incorporation of advance technologies for the optimization of investment in transmission and distribution resources.

Since 2004, Ameren Missouri has been a member of the Midcontinent Independent System Operator, or MISO, a RTO. MISO was approved as the nation's first RTO in 2001 and is an

[16] Ameren Missouri's 2020 IRP Filing, Chapter 6, page 16.
[17] Ameren Missouri's 2020 IRP Filing, Chapter 5, page 3.
[18] Commission Order issued on November 6, 2019, File No. EE-2020-0007.

independent nonprofit organization that supports the delivery of wholesale electricity and operates energy and capacity markets in 15 U.S. states and the Canadian province of Manitoba. A key responsibility of the MISO is the development of the annual MISO Transmission Expansion Plan ("MTEP"). Ameren Missouri is an active participant in the MISO MTEP development process.

With respect to rule 20 CSR 4240-22.045 Transmission and Distribution Analysis, Ameren Missouri requested, and the Commission granted, in File No. EE-2020-0007, variances of the provisions required by 20 CSR 4240-22.045(1)(B) and 20 CSR 4240-22.045(3)(C).[19]

Staff has not identified any deficiencies or concerns related to Ameren Missouri's transmission and distribution analysis.

Staff Expert Witness: Jordan T. Hull

<u>20 CSR 4240-22.050 Demand-Side Resource Analysis</u>

<u>Summary</u>

Rule 20 CSR 4240-22.050, Demand-Side Resource Analysis, specifies the methods by which end-use measures and demand-side programs shall be developed and screened for cost-effectiveness. It also requires the ongoing evaluation of end-use measures and programs, and the use of program evaluation, measurement and verification ("EM&V") to improve program design and cost-effectiveness analysis.

Ameren Missouri continues to build on its DSM planning, implementation, and evaluation performance from its initial implementation of DSM programs in 2009 followed by MEEIA Cycle 1 from January 1, 2013, through December 31, 2015, MEEIA Cycle 2 from March 1, 2016, through February 28, 2019,[20] and MEEIA Cycle 3 which began March 1, 2019, and is scheduled to end December 31, 2022.[21]

Ameren Missouri contracted with GDS Associates, Brightline Group, and the American Council for an Energy Efficient Economy ("ACEEE") to perform its 2020 DSM Market Potential

[19] Commission Order issued on November 6, 2019, File No. EE-2020-0007.
[20] Commission's July 20, 2017, *Order Approving Stipulation And Agreement* in Case No. EO-2015-0055, established a process for Cycle 2 long-lead energy efficiency projects' implementation and completion to extend for up to 24 months beyond the February 28, 2019 Cycle 2 end date.
[21] Commission's August 5, 2020, *Order Approving Stipulation and Agreements* in Case No. EO-2018-0211, extended MEEIA Cycle 3 through December 31, 2022.

Study to assess energy savings potential to help inform the Demand-Side Resource Analysis required by 20 CSR 4240-22.050 in Ameren Missouri's 2020 IRP Filing. Additionally, Opinion Dynamics Corp. ("ODC"), Ameren Missouri's current EM&V contractor, was also requested to conduct primary market research to help inform key inputs in the 2020 DSM Market Potential Study.

Key components of the 2020 Market Potential Study analysis include: 1) New Primary Research (the first since the 2013 Market Potential Study), including an updated assessment of end use measure penetration and saturation and customer willingness to participate and adoption rates in DSM programs at various incentive levels; 2) Updated methodologies to account for the interactive effects of DSM measures that segregate results by building types and income strata and calibrate first year results to existing program delivery; 3) Income Eligible potential evaluated against a range of new and expanded policy-oriented scenarios and sensitivities, which highlight important considerations for future program implementation; 4) An expanded Distributed Energy Resource potential study, including a sensitivity analysis of increased transmission and distribution avoided costs representing locational value; and 5) A comprehensive scenario analysis across all sectors used to inform the load and cost risk adjusted analysis of DSM portfolios.

The 2020 Market Potential Study began in March 2019 and was completed in March 2020. Therefore, the 2020 Market Potential Study relied on the avoided costs developed as part of Ameren Missouri's 2017 IRP to complete the initial screening analysis and identify cost-effective measures to be included in each portfolio. The financial market-based capacity curve used for Ameren Missouri's 2020 IRP differs from the market-based capacity curve used in Ameren Missouri's 2017 IRP. Ameren Missouri's 2017 IRP was developed using the Midas production cost modeling software. For Ameren Missouri's 2020 IRP, a separate capacity price curve was developed to be used in future DSM program cost-effectiveness analysis. This curve is a combination of the market-based capacity price forecast and the CONE.

Ameren Missouri did not request any waivers from specific provisions of this Rule.

Based on its limited review, Staff concludes Ameren Missouri's Demand-Side Resource Analysis filing does not meet the requirements of rule 20 CSR 4240-22.050 due to the following deficiency. Staff also provides its concerns over the avoided capacity cost used by Ameren Missouri in its 2020 IRP.

Deficiency

Deficiency 2 – Ameren Missouri did not use a consistent avoided capacity cost throughout its triennial compliance filing as required by 20 CSR 4240-22.050(5)(A)1.

20 CSR 4240-22.050(5)(A)1. provides that:

> The utility avoided demand cost shall include the capacity cost of generation, transmission, and distribution facilities, adjusted to reflect reliability reserve margins and capacity losses on the transmission and distribution systems, **or** the corresponding market-based equivalent of those costs. The utility shall describe and document how it developed its avoided demand cost, and **the capacity cost chosen shall be consistent throughout the triennial compliance filing. [Emphasis added.]**

For Ameren Missouri's 2020 IRP Filing, a market-based capacity price was used in evaluating supply-side resources. However, a separate capacity price curve was developed to be used in future DSM program cost-effectiveness analysis. This curve is a combination of the market-based capacity price forecast and the cost of new entry ("CONE") value.[22]

To remedy this deficiency, Ameren Missouri should utilize the "market only" capacity cost curve when evaluating any future demand-side resources in order to evaluate supply-side resources on an equivalent basis as demand-side resources. Ameren Missouri should also provide analysis quantifying all savings resulting from the implementation of the demand-side resources within the preferred resource plan that can reasonably be expected to avoid costs to ratepayers through concrete verifiable reductions in rates. This analysis should include evidence of reduced MISO costs and expected revenue from excess capacity sales. Furthermore, Ameren Missouri should maintain build thresholds for non-renewable supply-side resources as well as renewable supply-side resources and demand-side resources based upon the projected capacity need for reserve requirements.

Concerns

Concern A – Ameren Missouri's avoided capacity cost is overstated due to the premature move to CONE in 2029.

In determining when to move to a CONE value when developing its avoided capacity costs, Ameren Missouri reviewed a planning scenario in which there were no more DSM programs

[22] Chapter 2, page. 14, of Ameren Missouri's 2020 IRP Filing.

beyond MEEIA Cycle 3 and with retirement of ** six ** coal-fired units by the end of ** 2028 **. Based on that review, Ameren Missouri states that the first year that a new supply-side resource would be needed in such a scenario to strictly meet MISO planning reserve requirements was found to be 2029. However, the preferred plan selected by Ameren Missouri assumes retirement of ** four ** coal-fired units by the end of ** 2028 **. The preferred plan also assumes roughly ** 1900 ** MW of new renewable generation by the end of ** 2028 **. Both assumptions, if used in the development of avoided capacity costs, would lower the avoided capacity costs by some amount since the move to CONE would likely be pushed out to some year beyond 2029. Further, Staff reviewed all ARPs in which there were no DSM programs beyond MEEIA Cycle 3 and it appears no new non-renewable supply-side resource is needed prior to ** 2037 **. Ameren Missouri's "no DSM contingency plan" does not show a need for a new non-renewable supply-side resource until ** 2034 **. Thus, Staff's concern is that Ameren Missouri's avoided capacity cost is overstated due to the premature move to CONE in 2029. Artificially inflating avoided capacity costs affects the screened cost effectiveness of each measure and program analyzed and results in unrealistic estimations of the impact of demand-side resources. In order to properly analyze supply-side resources and demand-side resources on an equivalent basis, avoided costs should be applied equally and in a manner that best mirrors the reality of a given scenario.

To remedy Concern A, Ameren Missouri should utilize the "market only" capacity cost curve when evaluating any future demand-side resources in order to evaluate supply-side resources on an equivalent basis as demand-side resources. Ameren Missouri should also provide analysis quantifying all savings resulting from the implementation of the demand-side resources within the preferred resource plan that can reasonably be expected to avoid costs to ratepayers through concrete verifiable reductions in rates. This analysis should include evidence of reduced MISO costs and expected revenue from excess capacity sales. Furthermore, Ameren Missouri should maintain build thresholds for non-renewable supply-side resources as well as renewable supply-side resources and demand-side resources based upon the projected capacity need for reserve requirements.

Concern B - The 2020 Market Potential Study began in March 2019 and was completed in March 2020. Therefore, the 2020 Market Potential Study relied on the avoided costs developed as part of Ameren Missouri's 2017 IRP to complete the initial screening analysis and

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identify cost-effective measures to be included in each demand-side management portfolio of the 2020 IRP. The avoided costs developed as part of Ameren Missouri's 2017 IRP are higher than those developed as part of Ameren Missouri's 2020 IRP. In the years 2021 – 2028, for example, the avoided capacity costs in the 2017 IRP are much higher than those in the 2020 IRP, as much as roughly four times higher in year 2028. Using the higher avoided costs (2017 IRP) for demand-side screening will likely lead to screening in energy efficient measures that would not be cost effective using the lower avoided costs (2020 IRP). Most concerning is the years of 2021 – 2028. Since the 2017 IRP avoided costs, specifically the avoided capacity costs, are so much higher than the 2020 IRP avoided costs in the early years of 2021 – 2028, measures with short lives and lesser savings are very likely to have been screened in as cost-effective in the demand-side portfolios of the ARPs in the 2020 IRP. Using the 2017 avoided costs for demand-side management screening in the 2020 IRP likely creates a mismatch of avoided costs and cost-effective savings for all ARPs which include a demand-side portfolio. The red arrow in Graph 1 above helps illustrate this concern. The shaded area in which the red arrow lies is the portion of concern. Measures that fall within that shaded portion are considered cost-effective using the 2017 IRP avoided capacity costs but would not be considered cost-effective using the 2020 IRP avoided capacity costs.

To remedy Concern B, Ameren Missouri should utilize the "market only" capacity cost curve when evaluating any future demand-side resources in order to evaluate supply-side resources on an equivalent basis as demand-side resources. Ameren Missouri should also provide analysis quantifying all savings resulting from the implementation of the demand-side resources within the preferred resource plan that can reasonably be expected to avoid costs to ratepayers through concrete verifiable reductions in rates. This analysis should include evidence of reduced MISO costs and expected revenue from excess capacity sales. Furthermore, Ameren Missouri should maintain build thresholds for non-renewable supply-side resources as well as renewable supply-side resources and demand-side resources based upon the projected capacity need for reserve requirements.

Staff Expert Witnesses: Brad J. Fortson and Jordan T. Hull

20 CSR 4240-22.060 Integrated Resource Analysis

Summary

This Rule requires the utility to design alternative resource plans to meet the planning objectives identified in Rule 20 CSR 4240-22.010(2), and sets minimum standards for the scope and level of detail required in resource plan analysis and for the logically consistent and economically equivalent analysis of alternative resource plans. The utility is to identify the critical uncertain factors that affect the performance of alternative resource plans and establishes minimum standards for the methods used to assess the risks associated with these uncertainties.

The goal is to develop a set of alternative plans based on substantively different mixes of supply-side resources and demand-side resources and variations in the timing of resource acquisition to assess their relative performance under expected future conditions as well as their robustness under a broad range of future conditions.

Ameren Missouri developed, considered, and analyzed the present worth of long-run utility costs for 28 alternative resource plans by calculating the present value of revenue requirements ("PVRR") for each plan. While Ameren Missouri has selected the minimization of PVRR as the primary selection criterion for the preferred plan in accordance with 20 CSR 4240-22.010(2)(B), Ameren Missouri does not use minimization of PVRR as the only selection criterion. In addition to calculating the PVRR for each plan, Ameren Missouri considered the performance of each plan when compared to four other planning objectives. These planning objectives are Portfolio Transition (formerly Environmental/Renewable/Resource Diversity), Financial/Regulatory, Customer Satisfaction, and Economic Development. The alternative resource plans include various levels of demand-side programs and rates, renewable resources, new supply-side resources, and coal retirements.

With respect to Rule 20 CSR 4240-22.060 Integrated Resource Analysis, Ameren Missouri requested, and the Commission granted, in File No. EE-2020-0007, variances of the provisions required by 20 CSR 4240-22.060(5)(E), 20 CSR 4240-22.060(5)(F), 20 CSR 4240-22.060(5)(K), 20 CSR 4240-22.060(5)(L), and 20 CSR 4240-22.060(7).[23]

[23] Commission Order issued on November 6, 2019, File No. EE-2020-0007.

The Staff has not identified any deficiencies or concerns related to Ameren Missouri's integrated resource analysis.

Staff Expert Witnesses: Jordan T. Hull and Brad J. Fortson

20 CSR 4240-22.070 Risk Analysis and Strategy Selection

Summary

Rule 20 CSR 4240-22.070, Risk Analysis and Strategy Selection, requires the utility to select a preferred resource plan, develop an implementation plan, and officially adopt a resource acquisition strategy. The rule also requires the utility to prepare contingency plans and evaluate the demand-side resources that are included in the resource acquisition strategy.

Ameren Missouri's final probability tree consists of the following dependent and independent critical uncertain factors:

Dependent critical uncertain factors

- Carbon policy
- Natural gas prices

Independent critical uncertain factors

- DSM costs only
- Load Growth

Ameren Missouri's decision-makers chose to use a scorecard approach to evaluate its 28 candidate resource plans during their strategy selection process to adopt a resource acquisition strategy and a preferred resource plan for Ameren Missouri. Ameren Missouri created a scorecard that embodies its planning objectives mentioned above in section 20 CSR 4240-22.060 Integrated Resource Analysis, to evaluate the performance of alternative resource plans. The scorecard with composite scores for each planning objective is included as attached Confidential Addendum B.

Attached Confidential Addendum C includes Ameren Missouri's 2020 IRP adopted preferred resource plan, contingency resource plans, and resource acquisition strategy implementation plan for the adopted preferred resource plan. Finally, the capacity balance sheet for Ameren Missouri's adopted preferred resource plan is included as attached Confidential Addendum D.

Ameren Missouri did not apply for any waivers from the requirements of this rule.

Based on its limited review, Staff has identified one (1) concern for Ameren Missouri's preferred resource plan and resource acquisition strategy.

Concerns

Concern C - Risk potentially borne by ratepayers from Ameren Missouri's unprecedented shift toward new renewable wind and solar generation.

Ameren Missouri's preferred resource plan and resource acquisition strategy is an aggressive approach that includes its largest ever expansion of renewable wind and solar generation, bringing Ameren Missouri to 3100 MW of wind and solar by 2030 and 5400 MW of wind and solar by 2040. On pages 12-14 of Chapter 10 of Ameren Missouri's IRP filing, Ameren Missouri included a subsection titled "Ameren Missouri's Need for Energy Resources." Staff submitted a data request to Ameren Missouri asking for citations of each federal rule or law, Missouri rule or law, and/or MISO tariff that requires Ameren Missouri to generate energy in excess of the Ameren Missouri load. Ameren Missouri's Director of Corporate Analysis, Matt Michels, responded that he was "not aware of any such federal, state, or MISO tariff requirements currently in effect." Due to Ameren Missouri's participation in MISO, Ameren Missouri purchases all energy necessary to meet its customers' load. Conversely, any net output from Ameren Missouri's generating units are sold to MISO at the generation node Locational Marginal Price ("LMP"). Adding large amounts of renewable generation that are not required to meet MISO resource adequacy requirements or Missouri statutory or rule requirements, including providing safe and adequate service, may place an undue level of risk on ratepayers based upon the speculation that the market revenues, which are inherently uncertain, will exceed the overall cost of the assets. Ameren Missouri inherently benefits shareholders by adding large investments from which it can seek a return on the investment through rates throughout the life of the asset. Ameren Missouri also decides which factors to consider within the IRP process as well as the weight to apply to each critical uncertain factor. When a utility needs a generating asset to fulfill the needs of customers or to comply with mandated requirements, the IRP process provides a decision making tool to optimize the necessary generation additions and minimize the net present value of revenue requirements at a point in time when those assets are necessary to meet the expected retail load needs. However, when a utility does not need to build assets to fulfill the needs of customers or comply with mandated requirements, the results of the decision are inherently uncertain, which introduces risk to ratepayers, while the costs of the generation addition are much more certain. At this point in time, Ameren Missouri has not demonstrated the need for the proposed additional renewable generation. Ameren Missouri objected to Staff's request for comparisons of shareholder risks and ratepayer risks for the proposed additional generation resources stating that "it objects to each of them to the extent that they call for a legal conclusion or otherwise seek to require the Company to engage in research or analyses instead of seeking discovery of existing facts, documents, or information and, to that extent, the questions are beyond the scope of proper discovery."

20 CSR 4240-22.080(7) requires Staff to provide at least one (1) suggested remedy for each identified concern. Staff's concern is one of a general nature. However, Staff recommends that Ameren Missouri provide detailed analysis comparing ratepayer risks and shareholder risks for additional generation resources which are not required to meet federal, state, or MISO requirements.

Staff Expert Witnesses: Brad J. Fortson and J Luebbert

20 CSR 4240-22.080 Filing Schedule and Requirements

Summary

This Rule specifies the requirements for electric utility filings to demonstrate compliance with the provisions of Chapter 22. The purpose of the compliance review required by Chapter 22 is not Commission approval of the substantive findings, determinations, or analyses contained in the filing. The purpose of the compliance review required by Chapter 22 is to determine whether the utility's resource acquisition strategy meets the requirements of Chapter 22. However, if the Commission determines that the filing substantially meets these requirements, the Commission may further acknowledge that the preferred resource plan or resource acquisition strategy is reasonable in whole, or in part, at the time of the finding. This Rule also establishes a mechanism for the utility to solicit and receive stakeholder input to its resource planning process.

The Filing Schedule, Filing Requirements, and Stakeholder Process Rule establish a filing deadline for all electric utilities on April 1 of each year.[24] A triennial compliance filing is due every third year with more informal annual update filings during the years between the full triennial compliance filings. The annual updates are coupled with a stakeholder workshop to communicate changing conditions and utility plans and to seek comments and suggestions from stakeholders during the planning process. Preliminary plans are reviewed with stakeholders to receive input regarding potential concerns and deficiencies. However, once plans are filed, stakeholders again have the opportunity to identify potential concerns and deficiencies. The Commission, with input from stakeholders, will identify special contemporary issues each year for each utility to analyze during its planning process. To make the resource planning process more meaningful, the Rule requires action from the utility if its business plan or acquisition strategy becomes inconsistent with the latest adopted preferred resource plan filed by the utility. The Rule also requires certification that any request of action from the Commission is consistent with the utility's adopted preferred resource plan.

Ameren Missouri requested and received approval of a variance from 20 CSR 4240-22.080(2)(C)2.[25]

The Staff has not identified any deficiencies or concerns related to the Filing Schedule and Requirements.

Staff Expert Witness: Brad J. Fortson

Attachments:

Confidential Addendum A - Preferred Resource Plan

Confidential Addendum B - Preferred Plan Selection Scorecard

Confidential Addendum C - Preferred Plan and Contingency Plans

Confidential Addendum D - Forecast of Capacity Balance (MW)

[24] Ameren Missouri filed its *Notice of Case Filing and Request for Variance from 4 CSR 240-22.080(1)(C) and 3* on October 16, 2018, in File No. EE-2019-0104. The Commission granted Ameren Missouri's request in its *Order Granting Variance* issued on November 28, 2018.
[25] Commission Order issued on November 6, 2019, File No. EE-2020-0007.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's 2020 Utility Resource Filing Pursuant to 20 CSR 4240 – Chapter 22	))))	File No. EO-2021-0021

AFFIDAVIT OF BRAD J. FORTSON, J LUEBBERT,
KRISHNA L. POUDEL, JORDAN T. HULL

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COME NOW Brad J. Fortson, J Luebbert, Krishna L. Poudel, Jordan T. Hull, and on their oath declares that they are of sound mind and lawful age; that they contributed to the foregoing *Staff Report*; and that the same is true and correct according to their best knowledge and belief, under penalty of perjury.

Further the Affiants sayeth not.

/s/ Brad J. Fortson
Brad J. Fortson

/s/ J Luebbert
J Luebbert

/s/ Krishna L. Poudel
Krishna L. Poudel

/s/ Jordan T. Hull
Jordan T. Hull

Preferred Resource Plan

* Reductions are presented as of the end of the period indicated and based off of 2005 levels. Wind and solar additions, energy center retirements by end of indicated year.

† Projects expected to be substantially complete in 2020, fully in service in early 2021.

CONFIDENTIAL

Addendum A

Schedule MM-S5

Preferred Plan Selection Scorecard

Ameren Missouri 2020 IRP
Preferred Plan Selection Scorecard

Planning Objectives, Weights and Measures							
	Category	Environmental/ Renewable/ Resource Diversity	Financial/ Regulatory	Customer Satisfaction	Economic Development	Cost	Overall Assessment
	Category Weight	20%	20%	20%	10%	30%	100%
Plan	Description	Resource Diversity	PV Free Cash Flow	Rate Increases	Net Job Growth (FTE-years)	PVRR	
V	Sioux-Rush Early Retirement - Renewable Subscription	5	5	5	4	5	4.90
Y	Sioux-Rush Early Retirement - Grain Belt Express	5	5	4	4	5	4.70
P	Sioux-Rush Early Retirement	4	5	4	4	5	4.50
M	Labadie Early Retirement - 2 units	3	5	4	4	5	4.30
N	Sioux Early Retirement	3	5	4	4	5	4.30
O	Rush Early Retirement	3	5	4	3	5	4.20
Q	Sioux-Rush Early Retirement - No CCs	5	5	4	5	3	4.20
R	Rush Early Retirement 2	3	4	4	3	5	4.00
X	Sioux-Rush Early Retirement - Renewables when needed	3	4	4	2	5	3.90
BB	Sioux-Rush Early Retirement - MAP	4	5	3	5	3	3.80
L	Labadie Early Retirement - 4 units	4	3	4	4	4	3.80
B	Renewable Expansion	2	4	3	4	5	3.70
Z	Sioux-Rush Early Retirement - DOPE 1	4	3	5	2	3	3.50
AA	Sioux-Rush Early Retirement - DOPE 2	4	3	5	1	3	3.40
W	Sioux-Rush Early Retirement - No DSM - Renewable Subscription	4	3	5	2	2	3.20
S	Rush FGD	2	4	3	4	3	3.10
H	MAP DSM - Renewable Expansion	2	4	2	5	3	3.00
J	DOPE1 DSM	2	2	4	4	3	2.90
U	Rush Retirement - Labadie DSI	3	4	3	3	2	2.90
K	DOPE2 DSM	2	2	4	3	3	2.80
A	RAP DSM - RES Compliance	1	4	2	1	4	2.70
T	Rush FGD - Labadie DSI	2	4	2	4	2	2.60
I	MAP DSM - RES Compliance	1	4	1	4	3	2.50
D	No New DSM - All Solar	1	2	3	1	3	2.20
E	No New DSM - Pumped Hydro Storage	2	2	3	2	2	2.20
G	No New DSM - Simple Cycle Gas	1	1	3	2	2	1.80
C	No New DSM -Combined Cycle Gas	1	1	3	1	2	1.70
F	No New DSM - AP1000 Nuclear	2	1	1	5	1	1.60

Scoring Guide	
Significant Advantage	5
Moderate Advantage	4
No Advantage or Disadvantage	3
Moderate Disadvantage	2
Significant Disadvantage	1

Overall Assessment Guide	
Top-tier Plan	
Mid-tier Plan	
Bottom-tier Plan	

Notes on Scores by Planning Objective	
Environmental/Renewable/Diversity	Inclusion of renewable resource transition; renewable acceleration; energy efficiency; new nuclear; storage; accelerated coal retirement; were viewed as advantageous.
Financial Regulatory	Financial and regulatory risks associated with new nuclear; depreciation and cost recovery risk associated with early coal retirement; cessation of energy efficiency programs; and the probability for relatively unfavorable credit metrics were viewed as disadvantageous, as were unfavorable impacts on free cash flow.
Customer Satisfaction	Lower levelized annual rate increases, inclusion of energy efficiency and demand response, inclusion of renewable resource transition, acceleration of coal generation retirements, and availability of expanded customer renewable programs were viewed as advantageous.
Economic Development	Plans were rated on a relative scale based on direct jobs (FTE-years) including both construction and operation.
Cost (PVRR)	Plans were rated on a relative scale based on present value of revenue requirements (PVRR).

Key to Abbreviations
RAP = Realistic Achievable Potential Demand Side Management Portfolio
MAP = Maximum Achievable Potential Demand Side Management Portfolio
DOPE = Dynamically Optimized Potential Estimate (Demand Side Management)
CC = Combined Cycle Gas Turbine Generator
FGD = Flue Gas Desulferization (Scrubber)
DSI = Dry Sorbent Injection
MEEIA = Missouri Energy Efficiency Investment Act Cycle 1
DSM = Demand Side Management
RES = Renewable Energy Standard

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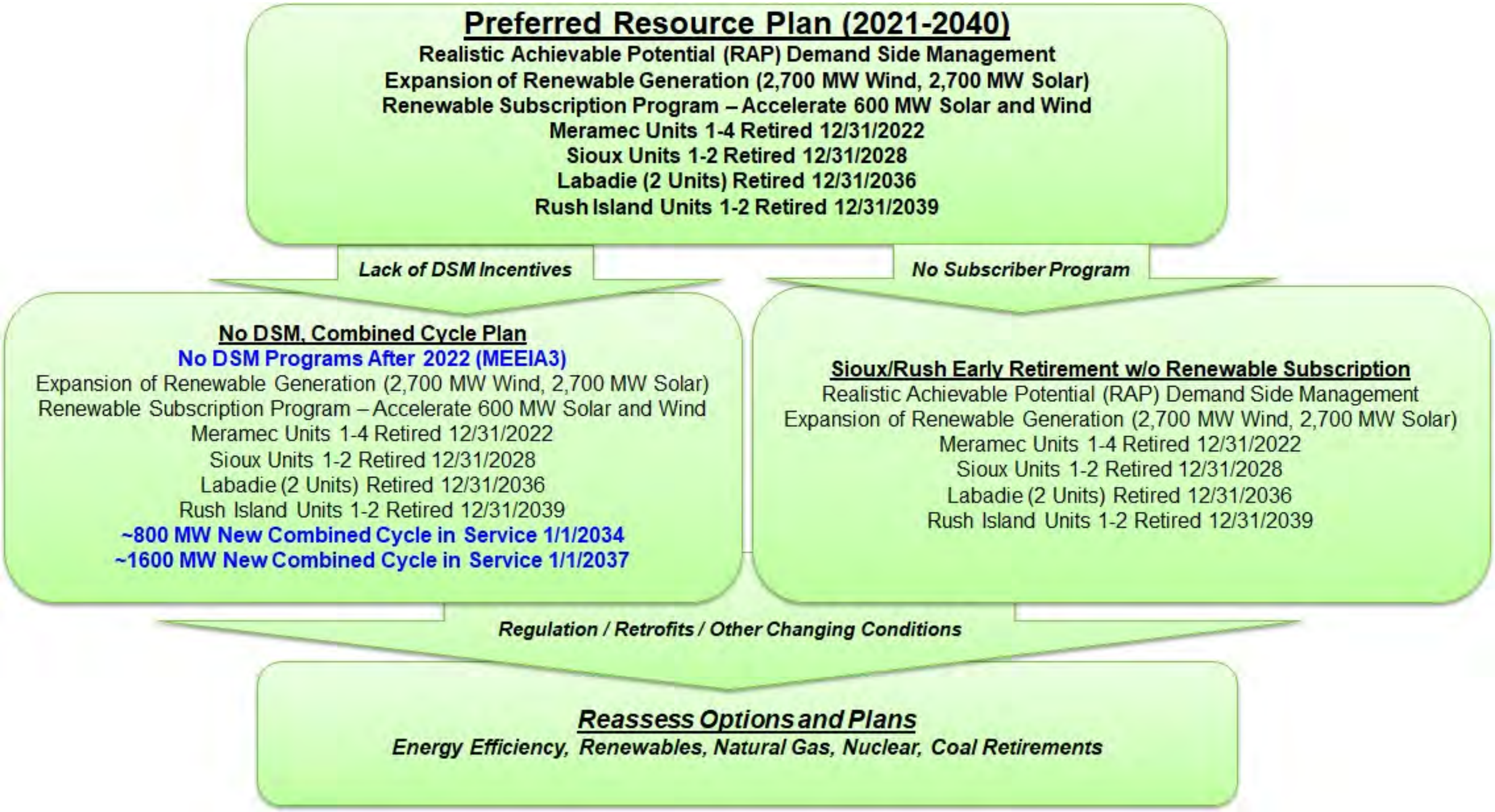
Addendum B

Preferred Plan and Contingency Plans



Forecast of Capacity Balance (MW) **Confidential**

Ameren Missouri
2020 IRP

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
A. System Generation Capacity																						
Existing Generation Capacity																						
Callaway	Nuclear	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194	1194
Keokuk	Hydro	144	144	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148
Labadie Unit 1	Coal	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593
Labadie Unit 2	Coal	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593
Labadie Unit 3	Coal	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	0	0	0	0
Labadie Unit 4	Coal	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	0	0	0	0
Rush Island Unit 1	Coal	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	0
Rush Island Unit 2	Coal	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	589	0
Sioux Unit 1	Coal	486	486	486	486	486	486	486	486	486	0	0	0	0	0	0	0	0	0	0	0	0
Sioux Unit 2	Coal	486	486	486	486	486	486	486	486	486	0	0	0	0	0	0	0	0	0	0	0	0
Meramec Unit 3	Coal	220	220	220	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meramec Unit 4	Coal	320	320	320	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Maryland Heights	LFG	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Total Base Capacity		6408	6408	6412	5872	5872	5872	5872	5872	5872	4900	4900	4900	4900	4900	4900	4900	4900	3714	3714	3714	2536
Osage	Hydro	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235
Taum Sauk Unit 1	Hydro	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Taum Sauk Unit 2	Hydro	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Meramec Unit 1	Gas	113	113	113	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meramec Unit 2	Gas	113	113	113	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Audrain 1	Gas	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Audrain 2	Gas	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Audrain 3	Gas	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Audrain 4	Gas	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Audrain 5	Gas	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Audrain 6	Gas	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Audrain 7	Gas	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Audrain 8	Gas	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Fairgrounds	Oil	55	55	55	55	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Goose Creek 1	Gas	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Goose Creek 2	Gas	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Goose Creek 3	Gas	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Goose Creek 4	Gas	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Goose Creek 5	Gas	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Goose Creek 6	Gas	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Kinmundy CTG-1	Gas	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
Kinmundy CTG-2	Gas	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
Meramec CTG-1	Oil/Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meramec CTG-2	Oil/Gas	46	46	46	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mexico	Oil	55	55	55	55	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moberly	Oil	55	55	55	55	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moreau	Oil	55	55	55	55	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peno Creek CTG-1	Gas/Oil	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Peno Creek CTG-2	Gas/Oil	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Peno Creek CTG-3	Gas/Oil	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Peno Creek CTG-4	Gas/Oil	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Pinckneyville CTG-1	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-2	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-3	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-4	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Pinckneyville CTG-5	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Pinckneyville CTG-6	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Pinckneyville CTG-7	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Pinckneyville CTG-8	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Racoon Creek 1	Gas	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Racoon Creek 2	Gas	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Racoon Creek 3	Gas	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Racoon Creek 4	Gas	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Venice CTG-2	Gas	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Venice CTG-3	Gas	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170
Venice CTG-4	Gas	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170
Venice CTG-5	Gas	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
O'Fallon	SOLAR	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Lambert	SOLAR	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
BJC	SOLAR	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Intermediate/Peaking/Intermittent Capacity		3738	3738	3738	3466	3466	3466	3466	3246	3246	3246	3246	3246	3246	3246	3246	3246	3246	3246	3246	3246	3246
Total Generation Capacity (TGC)		**10146**	**10146**	**10150**	**9338**	**9338**	**9338**	**9338**	**9118**	**9118**	**8146**	**8146**	**8146**	**8146**	**8146**	**8146**	**8146**	**8146**	**6960**	**6960**	**6960**	**5782**

CONFIDENTIAL
Addendum D

Schedule MM-S5

Forecast of Capacity Balance (MW) **Confidential**

Ameren Missouri
2020 IRP

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
B.	**Capacity Transactions**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Purchases																					
	102.3 Pioneer Prairie Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Purchases = P	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Existing sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Sales = S	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Net Transactions = NT = P - S	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total System Capacity = TSC = TGC + NT	10146	10146	10150	9338	9338	9338	9338	9118	9118	8146	8146	8146	8146	8146	8146	8146	8146	6960	6960	6960	5782
C.	**System Peaks & Reserves**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Peak Demands																					
	Ameren Missouri Forecasted Peak	7501	7411	7365	7357	7356	7370	7477	7522	7563	7602	7639	7685	7741	7791	7849	7909	7975	8026	8071	8115	8144
	Voltage Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Full/Partical Requirements Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	DSM - EE RAP	0	0	-107	-203	-303	-408	-516	-634	-714	-798	-883	-969	-1041	-1113	-1182	-1249	-1314	-1358	-1399	-1436	-1471
	DSM - DF RAP	0	0	-155	-190	-221	-257	-281	-303	-317	-338	-359	-346	-364	-383	-402	-413	-432	-427	-444	-453	-470
	Peak Forecast less DSM = PF	7501	7411	7103	6964	6832	6705	6679	6586	6531	6466	6396	6370	6335	6295	6266	6247	6229	6241	6229	6225	6203
	Capacity Reserves = CR = TSC - PF	2645	2734	3046	2373	2505	2633	2658	2532	2586	1680	1749	1775	1810	1851	1880	1899	1917	719	731	735	-422
D.	**Capacity Needs**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	% Reserve Margin = RM	18.0%	18.0%	18.0%	18.0%	18.0%	17.9%	17.9%	18.2%	18.2%	18.1%	18.2%	18.2%	18.3%	18.3%	18.3%	18.3%	18.3%	18.3%	18.3%	18.3%	18.3%
	% Capacity Margin = CM = RM/(1+RM)	15.3%	15.3%	15.3%	15.3%	15.3%	15.2%	15.2%	15.4%	15.4%	15.3%	15.4%	15.4%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%
	Required Capacity = RC = PF/(1-CM)	8851	8745	8382	8218	8062	7905	7875	7784	7720	7636	7561	7530	7495	7447	7412	7390	7369	7383	7368	7364	7339
	Capacity Balance = TSC - RC	1294	1400	1768	1120	1276	1433	1463	1333	1397	509	585	616	651	699	733	756	777	(423)	(409)	(404)	(1557)
	Adjustments before new generation, MWs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Renewable Portfolio - Wind	0	115	114	112	174	172	170	168	211	208	206	233	231	272	270	310	308	347	344	368	365
50%	Renewable Portfolio - Solar	0	0	15	25	275	400	400	600	600	700	850	850	950	950	1050	1050	1150	1150	1350	1350	1350
	Batteries	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total generation adjustments	0	115	129	137	449	572	570	768	811	908	1056	1083	1181	1222	1320	1360	1458	1497	1694	1718	1715
	Capacity position after RES Compliance	1294	1515	1896	1257	1725	2005	2033	2101	2209	1418	1641	1699	1832	1921	2054	2116	2234	1073	1285	1313	157
	New Generation, MWs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cap position after all adjustments & new PRIMARY generation	**1294**	**1515**	**1896**	**1257**	**1725**	**2005**	**2033**	**2101**	**2209**	**1418**	**1641**	**1699**	**1832**	**1921**	**2054**	**2116**	**2234**	**1073**	**1285**	**1313**	**157**

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: demand-side management ("DSM") costs.*
- *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. Development of **planning objectives** to guide the development of alternative resource plans.
4. 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.
5. Identification and screening of **candidate uncertain factors**, which are key variables that can influence the performance of alternative resource plans.
6. **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.

7. **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 6.

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)

- Meramec Retired 2022
- Sioux Retired 2033/2028
- Labadie 2 Units Retired 2036/2028/2028
- Labadie 2 Units Retired 2042/2036/2028
- Rush Island Retired 2045/2039/2028/2024

New Supply-Side Types

- Combined Cycle (Nat. Gas)
- Simple Cycle (Nat. Gas)
- Nuclear
- Pumped Hydro Storage
- Solar
- Wind
- Batteries

Demand-Side Management

- Maximum Achievable Potential ("MAP")
- Realistic Achievable Potential ("RAP")
- Dynamically Optimized Portfolio Estimate ("DOPE") 1
- DOPE 2
- Missouri Energy Efficiency Investment Act ("MEEIA") Cycle 3 Only

Renewable Portfolios

- Missouri Renewable Energy Standard ("RES") with RAP DSM
- RES with MAP DSM
- Renewable Expansion
- Renewable Expansion Plus

***

[1] 20 CSR 4240-22.060(1); 20 CSR 4240-22.060(3)

[2] Pursuant to the Motion for Protective Order filed concurrently with the filing of this IRP, and 20 CSR 4240-2.135(4)(A) and (B), the information for which protection is sought by the Motion has been marked "Highly Confidential" (denoted by three asterisks with two asterisks used for "Confidential" information), and is protected as such pending the Commission's ruling on the Motion.

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Schedule MM-S6

9.2 Capacity Position

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

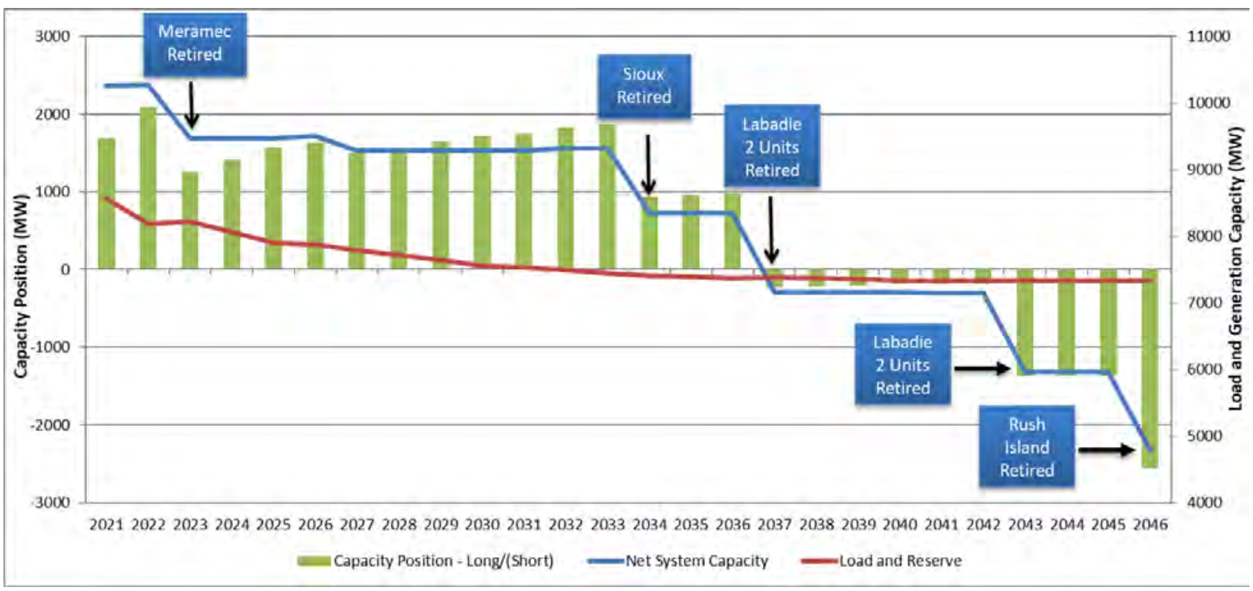
- Existing plant capabilities based on Ameren Missouri's annual generating unit rating update (i.e., August 2020 planned ratings)
- Existing obligations for capacity purchases and sales
- Peak demand forecast, as described in Chapter 3
- Planning reserve margin ("PRM") requirement, based on MISO's Planning Year 2020 Loss of Load Expectation ("LOLE") Study Report (November 2019). Table 9.1 shows the MISO System PRM from 2021 through 2029. The long-range PRM was assumed to continue at 18.3% through the remainder of the analysis period.

Table 9.1 MISO System Planning Reserve Margins 2021 through 2029

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029
PRM Installed Capacity	18.0%	17.9%	17.9%	18.2%	18.2%	18.1%	18.2%	18.2%	18.3%

Figure 9.2 shows Ameren Missouri's net capacity position with no new major generating resources.

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



The chart shows 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, distributed energy resources ("DER"), and DR. The system capacity includes the capacity benefit of the RES Compliance portfolio. 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[3]

Ameren Missouri is considering retirement of some or all of its six older gas- and oil-fired CTG units – Fairgrounds, Meramec CTG-1, Meramec CTG-2, Mexico, Moberly, and Moreau – with a total summer net capacity of 263 MW, over the next 20 years. Chapter 4 - Table 4.3 provides a summary of the planned CTG retirements. The CTG retirements were included in all alternative resource plans.

Coal energy center retirements were also included in the capacity planning process. Meramec retirement by December 31, 2022 is included in all alternative resource plans. Two different Sioux retirement options were considered: 1) retirement by December 31, 2033 based on prior analysis of Ameren Missouri's coal power plant life expectancy by Black and Veatch, and 2) retirement by December 31, 2028. Three different retirement options for Labadie were considered: 1) current retirement dates as determined by the Black and Veatch life expectancy study with two units retired by December 31, 2036 and two units retired by December 31, 2042, 2) two units retired by December 31, 2028 and two units retired by December 31, 2036, 3) all four units retired by December 31, 2028. Four retirement dates were evaluated for Rush Island: 1) retired by December 31, 2045, which is the current retirement date as determined by the Black and Veatch life expectancy study, 2) retired by December 31, 2039, 3) retired by December 31, 2028, and 4) retired by ***<u>**December 31, 2024**</u>***.

The alternative retirement dates were based on the ability to avoid significant ongoing costs, the potential for an explicit price on carbon starting in 2025 included in the scenarios described in Chapter 2, coupled with the time needed to ensure transmission upgrades are in place to continue to reliably serve our customers. ***<u>**The 2024 Rush Island retirement date, along with wet flue gas desulfurization technology ("FGD") at Rush Island and dry sorbent injection system ("DSI") at Labadie**</u>*** are included in order to evaluate specific potential outcomes pending a final judgment in the Rush Island New Source Review ("NSR") litigation which is under appeal and a decision by the federal court of appeals is not expected until 2021. Importantly, numerous potential

[3] EO-2020-0047 1.D; EO-2020-0047 1.O

outcomes are possible, including reversal of the trial court's rulings on both liability and remedy, and the actual outcome may be different than the limited outcomes modeled.

DSM Portfolios

DER, 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 DRs. The following combinations of DSM portfolios were evaluated: 1) RAP, 2) MAP, 3) DOPE1, 4) DOPE2, and 5) 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.[4]

Renewable Portfolios[5]

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 *2020 IRP RES Compliance Filing Model* (model). The model is designed to calculate the retail rate impact, as required by the Commission's RES rules.[6] 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 expected renewable energy credit (REC) position is presented in Figure 9.3.

[4] The extension of MEEIA Cycle 3 should not have a material impact on the analysis.
[5] EO-2020-0047 1.R
[6] 20 CSR 4240-20.100(5)

Schedule MM-S6

Figure 9.3 Ameren Missouri's RES REC Positions

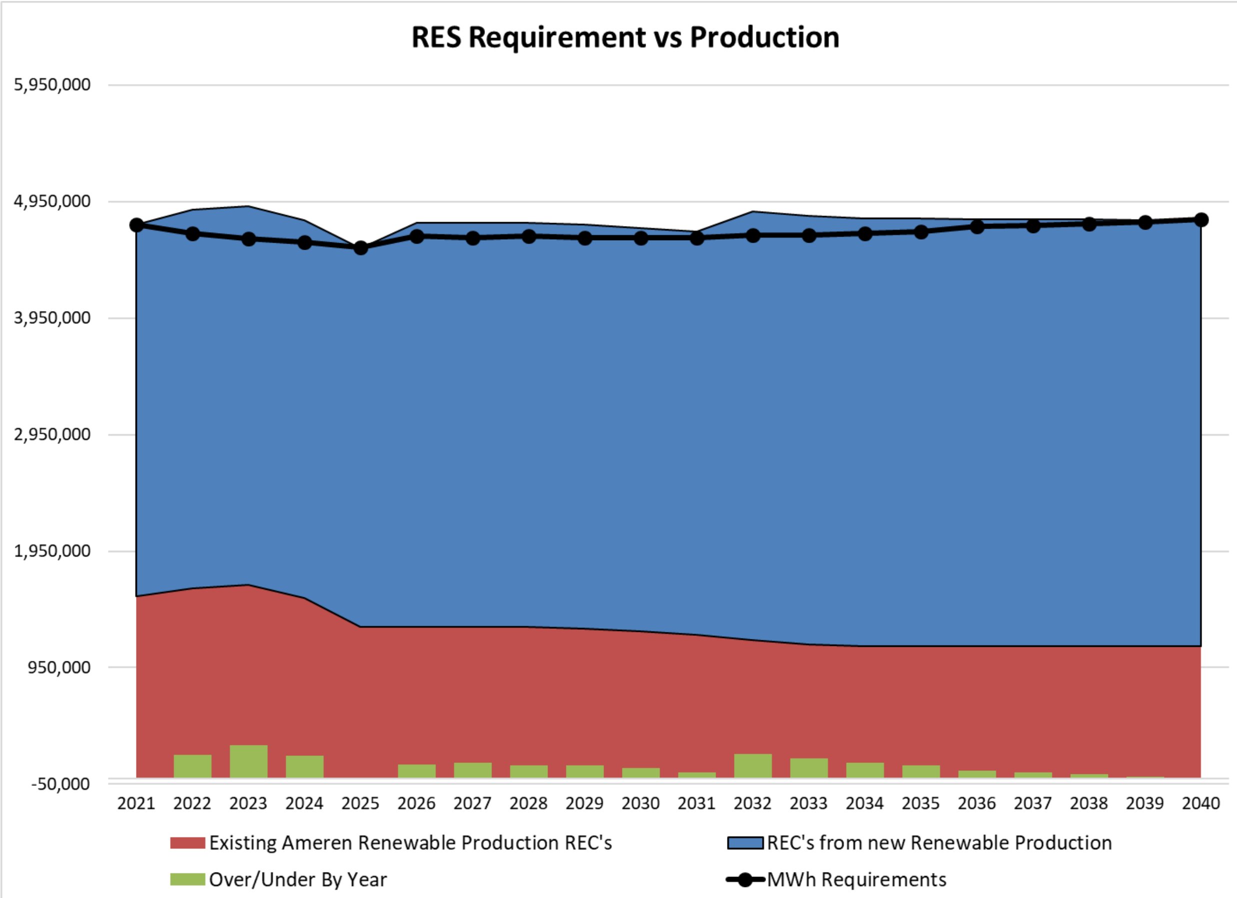


Figure 9.3 shows that Ameren Missouri expects to meet the overall REC requirement through 2040 primarily with owned renewable generation. Year-to-year compliance may also include banked RECs and purchased RECs. Starting in 2021, Ameren Missouri will be able to fully meet the overall standard using RECs generated by its existing qualifying resources, additional wind resources which will largely be completed by the end of 2020, with the remaining generation completed in the first quarter of 2021, and solar RECs acquired from customer rebate programs.

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 (2021-2030) and Term 2 (2031-2040).

When developing the RES compliance investment needs, consideration was given to the potential difference between RAP DSM investment vs MAP DSM investment. As MAP DSM results in more energy savings, the RES Compliance requirements are slightly lower than the requirements when RAP DSM is assumed.

In addition to the RES Compliance portfolios, we also included a "Renewable Expansion" and a "Renewable Expansion Plus" portfolio to evaluate the performance of additional solar and wind resources. The Renewable Expansion portfolio includes a total of 2,700 MW wind and 2,700 MW solar while the Renewable Expansion Plus portfolio includes a total of 3,900 MW wind and 4,000 MW solar resources.[7]

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

Table 9.2 Renewable Portfolios (Nameplate Capacity)

Renewable Additions		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
RES Compliance w/ RAP DSM	Wind	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	-	30	20	-	-	-	-	75	-	-	-	-	75	-	-	-	-	-	-	-
RES Compliance w/ MAP DSM	Wind	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	-	30	20	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Expansion	Wind	700	-	-	300	-	-	-	300	-	-	300	-	300	-	300	-	300	-	200	-
	Solar	-	30	20	-	250	-	400	-	300	400	-	300	-	300	-	300	-	400	-	-
Renewable Expansion Plus	Wind	700	-	-	400	-	400	-	400	-	-	-	-	500	-	500	-	500	-	500	-
	Solar	-	30	295	-	375	-	400	-	400	400	-	400	-	400	-	400	-	400	-	500

With the Renewable Expansion Plus renewable portfolio, batteries were also included: 100 MW in each year from 2031 to 2035, 150 MW in each year from 2036 to 2043 for a total of 1,700 MW.

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 are added to eliminate the shortfall. The build threshold was determined to be 300 MW regardless of the type of supply-side resource under consideration and reflects a level that Ameren Missouri trading staff assess as a reasonable level of capacity market dependence. The full rated capacity and the build thresholds for each supply side type are shown in Table 9.3. 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

[7] EO-2020-0047 1.K

also shown in Table 9.3. The in-service date constraints represent the expectations for construction lead time as well as the commercial availability of each technology.

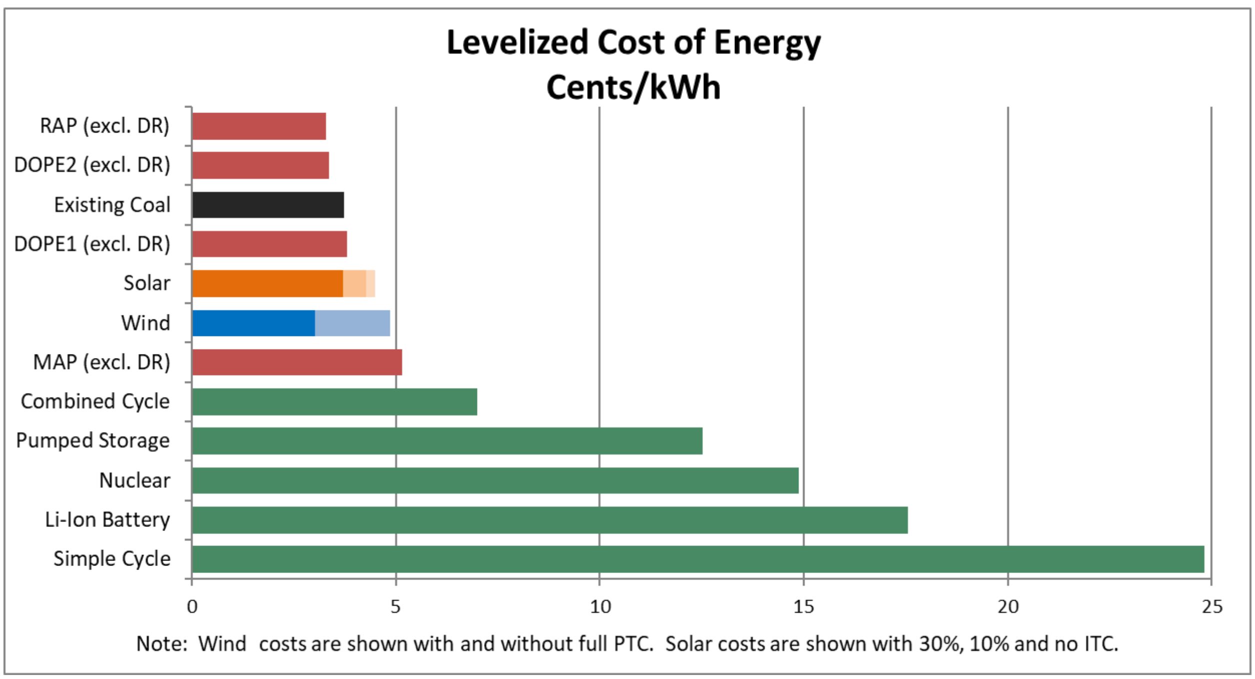
Table 9.3 Build Threshold for Supply Side Types

Supply Side Type	Capacity (MW)	Build Threshold (MW)	Earliest Year In-Service
CC-Natural Gas	824	300	2025
SC-Natural Gas	690 (3x230)	300	2025
Nuclear	1100	300	2030
Pumped Hydro	600	300	2029
Solar	800	300	2022

The remaining net capacity position was represented in the financial model as capacity purchases and sales priced at the market-based capacity costs as discussed in Chapter 2. The capacity purchases and sales were also adjusted for the various peak demand forecasts associated with each of the 15 scenarios and DSM impacts.

Figure 9.4 summarizes the levelized cost of energy ("LCOE") for all potential future resources evaluated in the alternative resource plans.

Figure 9.4 Levelized Cost of Energy – All Resources[8]



[8] 20 CSR 4240-22.010(2)(A)

Schedule MM-S6

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.[9] 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.[10]

Portfolio Transition

Ameren Missouri has relied for many years on a portfolio that consists, in large part, of large, efficient coal-fired generators. Current and potential future environmental regulations may have a significant impact on Ameren Missouri's coal-fired fleet 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.

[9] 20 CSR 4240-22.010(2)
[10] 20 CSR 4240-22.010(2)(C)

This includes measures of cash flow, profitability, and creditworthiness as well as assessment of risks associated with investment management and cost recovery.[11]

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.[12]

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.[13] 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, but it is a very important factor in making resource decisions. Therefore, minimization of the present value of revenue requirements was used as the primary selection criterion.[14]

9.4 Determination of Alternative Resource Plans[15]

Twenty-one 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?

[11] 20 CSR 4240-22.060(2)(A)6
[12] 20 CSR 4240-22.060(2)(A)4
[13] 20 CSR 4240-22.060(2)(A)7
[14] 20 CSR 4240-22.060(2)(A)1; 20 CSR 4240-22.010(2)(B)
[15] 20 CSR 4240-22.060(3)

- What level of DSM – RAP, MAP, DOPE1 or DOPE2 – results in lower costs?
- Is early retirement of Rush Island Energy Center cost effective?
- Is early retirement of Labadie Energy Center cost effective?
- Is early retirement of Sioux Energy Center cost effective?
- Is early retirement of the Sioux and Rush Energy Centers cost effective?
- What is the impact of reducing SO_2 emissions further?
- What are the benefits of including renewables beyond those needed for RES compliance?
- What is the impact of pursuing only new renewables?
- How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?
- How do various supply side resource options compare?

Table 9.4 provides a summary of the alternative resource plans.

***

Table 9.4 Alternative Resource Plans[16]

	Plan Name	DSM	Renewables	New Supply Side	Coal Retirements/ Modifications
A	RAP DSM - RES Compliance	RAP	RES Compliance	2 CCs in 2043, CC in 2046	Base
B	Renewable Expansion	RAP	Renewable Expansion	CC in 2046	Base
C	No New DSM - CCs	-	Renewable Expansion	CC in 2037, 2 CCs in 2043, CC in 2046	Base
D	No New DSM - All Solar	-	Renewable Expansion	6400 MW 2034-2046	Base
E	No New DSM - Pumped Hydro	-	Renewable Expansion	PS in 2037, CC in 2037, 2043, 2046	Base
F	No New DSM - AP1000	-	Renewable Expansion	Nuke 2037, CC in 2043, 2 CCs in 2046	Base
G	No New DSM - Simple Cycles	-	Renewable Expansion	SC 2037, CC in 2037, 2043, 2046	Base
H	MAP DSM - Renewable Expansion	MAP	Renewable Expansion	-	Base
I	MAP DSM - RES Compliance	MAP	RES Compliance	2 CCs in 2046	Base
J	DOPE1 DSM	DOPE	Renewable Expansion	CC in 2043, 2046	Base
K	DOPE2 DSM	DOPE	Renewable Expansion	CC in 2043, 2046	Base
L	Labadie Early Retirement - 4 units	RAP	Renewable Expansion	CC in 2034	Labadie 4U Dec-2028
M	Labadie Early Retirement - 2 units	RAP	Renewable Expansion	CC in 2046	Labadie 2U Dec-2028 Labadie 2U Dec-2036
N	Sioux Early Retirement	RAP	Renewable Expansion	CC in 2046	Sioux Dec-2028
O	Rush Early Retirement	RAP	Renewable Expansion	CC in 2043	Rush Island Dec-2028
P	Sioux-Rush Early Retirement	RAP	Renewable Expansion	CC in 2043	Sioux Dec-2028 Rush Island Dec-2039
Q	Sioux-Rush Early Retirement - No CCs	RAP	Renewable Expansion Plus	Battery 1700MW 2031-2043	Sioux Dec-2028 Rush Island Dec-2039
R	Rush Early Retirement 2	RAP	Renewable Expansion	CC in 2043	Rush Island Dec-2024
S	Rush FGD	RAP	Renewable Expansion	CC in 2046	Base Rush Island FGD
T	Rush FGD - Labadie DSI	RAP	Renewable Expansion	CC in 2046	Base Rush Island FGD Labadie DSI
U	Rush Early Retirement 2 - Labadie DSI	RAP	Renewable Expansion	CC in 2043	Rush Island Dec-2024 Labadie DSI

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[16] 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; EO-2020-0047 1.D; EO-2020-0047 1.K

Does inclusion of DSM programs reduce overall customer costs?

Plans B, H, J, and K include RAP, MAP, DOPE1 and DOPE2 level of DSM programs, respectively. Therefore, these plans can be compared against plans C, D, E, F, and G that have 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.

What level of DSM -RAP, MAP, DOPE1 or DOPE2- results in lower costs?

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.

Is early retirement of Rush Island Energy Center cost effective?[17]

Plan O evaluates the cost effectiveness of early retirement of Rush Island Energy Center by the end of 2028.

Is early retirement of Labadie Energy Center cost effective?[18]

Plans L and M evaluate the cost effectiveness of early retirement of all four units by the end of 2028, and two units by the end of 2028 followed by two units by the end of 2036, respectively.

Is early retirement of Sioux Energy Center cost effective?[19]

Plan N evaluates the cost effectiveness of early retirement of Sioux Energy Center alone.

Is early retirement of Sioux and Rush Island Energy Centers cost effective?[20]

Plan P evaluates the cost effectiveness of early retirements of Sioux Energy Center by the end of 2028 and Rush Island Energy Center by the end of 2039.

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[17] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O
[18] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O
[19] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O
[20] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O

What is the impact of potential outcomes of the active NSR litigation?[21]

Four plans are constructed in order to evaluate different potential outcomes for the active NSR litigation: ***Plan R includes Rush Island Energy Center retirement by the end of 2024, Plan S includes installation of FGD at Rush Island Energy Center in 2025, Plan T is similar to Plan S but also includes a DSI system installation at Labadie Energy Center in 2023, and Plan U includes early retirement of Rush Island Energy Center by the end of 2024 as well as addition of DSI system at Labadie Energy Center.***

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

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 A and B with RAP DSM and Plans H and I with MAP DSM can be compared to assess the costs/benefits of additional renewables. Furthermore, Plans P and Q can be compared to assess additional renewables coupled with batteries. Also included is resource plan D that features solar as a major supply-side resource and the only supply-side resource addition during the planning horizon in addition to the 'renewable expansion' level of wind and solar resource additions.

What is the impact of pursuing only new renewables?

Plan D is the all renewables alternative resource plan without DSM beyond MEEIA Cycle 3.[22]

How do various supply-side resource options compare?

The relative performance of the new supply-side resources can be determined by comparing Plans C through G, and by comparing Plan P against Plan Q.

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

Plans C through G also evaluate the impact if DSM cost recovery and incentive requirements are not met.

[21] EO-2020-0047 1.D
[22] 20 CSR 4240-22.060(3)(A)2

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.[23]

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 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 9.5. Results for the remaining performance measures for integration analysis are provided in the workpapers.[24]

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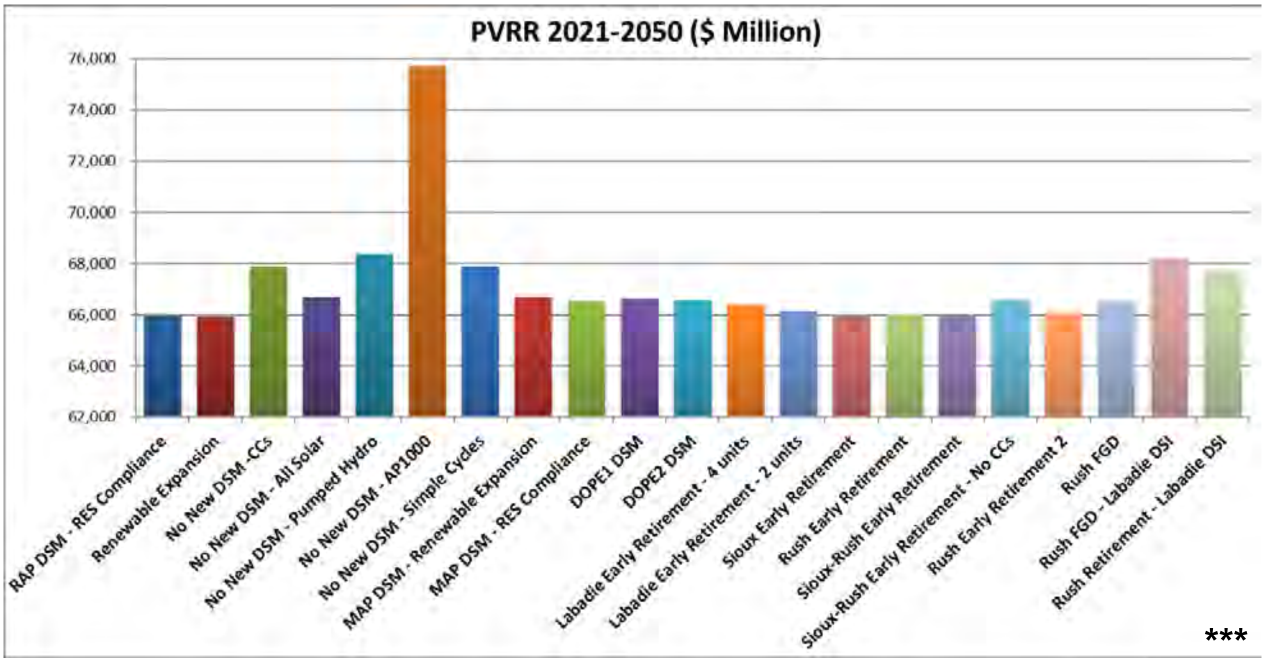
Figure 9.5 Integration PVRR Results[25]



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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 6.04% 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).[26]

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[23] 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)
[24] 20 CSR 4240-22.060(4)
[25] All plans include RAP DSM unless otherwise noted.
[26] 20 CSR 4240-22.060(2)(B)

9.5 Sensitivity Analysis

Sensitivity analysis involves determining which of the candidate independent uncertain factors are critical independent 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.

9.5.1 Uncertain Factors[27]

Ameren Missouri developed a list of uncertain factors to determine which factors are critical to resource plan performance. Table 9.5 contains the list as well as information about the screening process.

Table 9.5 Uncertain Factor Screening

Uncertain Factor	Candidates?	Critical?	Included in Final Probability Tree?
Load Growth	✓	--	✓
Carbon Policy	✓ #	--	✓
Fuel Prices Coal	✓	✗	✗
Natural Gas	✓ #	--	✓
Nuclear	✗	✗	✗
Project Cost (includes transmission interconnection costs)	✓	✗	✗
Project Schedule	✓	✗	✗
Emissions Prices SO_2	✗	✗	✗
NO_x	✗	✗	✗
CO_2	✓ #	--	✓

[27] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5) (B) through (F); EO-2020-0047 1.A(i)-(iii); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5) (A) through (M)

Uncertain Factors	Candidate?	Critical?	Included in Final Probability Tree?
Purchased Power	✗	✗	✗
Forced Outage Rate	✓	✗	✗
DSM Cost Only	✓	✓	✓
DSM Load Impacts & Costs	✓	✗ α	✗ α
Foreseeable Demand Response Technologies	✓	✗ β	✗ β
Foreseeable Distributed Energy Resources	✓	✗ β	✗ β
Foreseeable Energy Storage Technologies	✓	✗	✗
Fixed and Variable O&M	✓	✗	✗
Return on Equity	✓	✗ ε	✗ ε
Interest Rates	✓	✗ ε	✗ ε

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.

β Included as part of DSM load impacts and costs sensitivity

ε Return on Equity and Long-term Interest rates were combined

Chapter 2 describes how two of the candidate uncertain factors were determined to be critical dependent 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; 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.
- SO_2 and NO_x Emissions Prices – SO_2 and NO_x Emissions Prices were excluded as candidates because of the expectation for very low prices as a result of current and expected environmental regulations.

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. 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[28]

We use the sensitivity analysis to examine whether or not 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.

[28] 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

Schedule MM-S6

Unless the meaning of low, base, and high are treated in a standardized manner, the probability of occurrence for the value used for “low” for one uncertain factor could be significantly different than the probability of occurrence for the value used for “low” for other uncertain factors. Thus, for all of the uncertain factors, Ameren Missouri standardized the meaning of low to be the value found at the 5th percentile of a probability distribution of values for an uncertain factor, the value at the 50th percentile to be the base value, and the value at the 95th percentile to be the high value. The probability distribution for each candidate uncertain factor was inferred from a series of estimated values produced by subject matter experts for each uncertain factor.

For the majority of candidate uncertain factors, probability distributions were used to obtain the values for low, base, and high. This process began with subject matter experts providing/revising estimates of (A) an expected value, (B) estimates of deviations from that expected value, and (C) the probabilities of those deviations from the expected value. That information was used to create the probability distribution collectively implied by that data. Values at the 5th, 50th, and 95th percentiles of those implied probability distributions were then obtained for use as the values for low, base, and high for the various candidate independent uncertain factors. Appendix A contains the standard value, estimated deviation and probabilities for project costs, project schedule, fixed operations & maintenance ("FOM"), variable operations & maintenance ("VOM"), equivalent forced outage rate ("EFOR"), environmental capital expenditures, and transmission-retirement expenditures.

Example

The expected value for total project cost including transmission interconnection costs for the Greenfield Combined Cycle option is $1,245/kW-year (2019$). Project cost and some other candidate uncertain factors are characterized by differing standard values among various supply-side types, while standard values for some other candidate uncertain factors are not uniquely correlated to each supply side type. For example the Long Term Interest Rates uncertain factor does not differ depending on the supply-side type; it is the same across all supply-side types.

The subject matter experts, in this example, members of Ameren Missouri’s generation organization, provided estimates of deviations from the standard value as well as the probabilities of those deviations. An example of that initial uncertainty distribution is shown in Table 9.6. In this example, the first of these estimates for project cost deviations was a -15% deviation from the expected

Table 9.6

CC Project Cost Uncertainty Distribution

Deviation	Probability
-15%	10%
-10%	20%
0%	50%
15%	15%
30%	5%

value with a 10% probability of occurring. These deviation estimates provide sufficient information to derive continuous probability distributions from which the low/base/high values can be derived.

The process of developing the probability distributions involve using the deviation estimates like the ones shown above, the probability distribution can be determined for the uncertain factor in question. An example of the result of analyzing deviation estimates is shown in Figure 9.6.

From this distribution, the deviation values for the low, base, and high values (84,1, 1.17) are obtained at the respective percentiles in Figure 9.6. By multiplying these values by the expected value $1,245/kW-year, we estimate the costs at the 5th, 50th, and 95th percentiles; e.g., the low value at the 5th percentile would be:

.84 x 1,245 = $1,046

Figure 9.6 Example of Probability Distribution---CC Project Cost

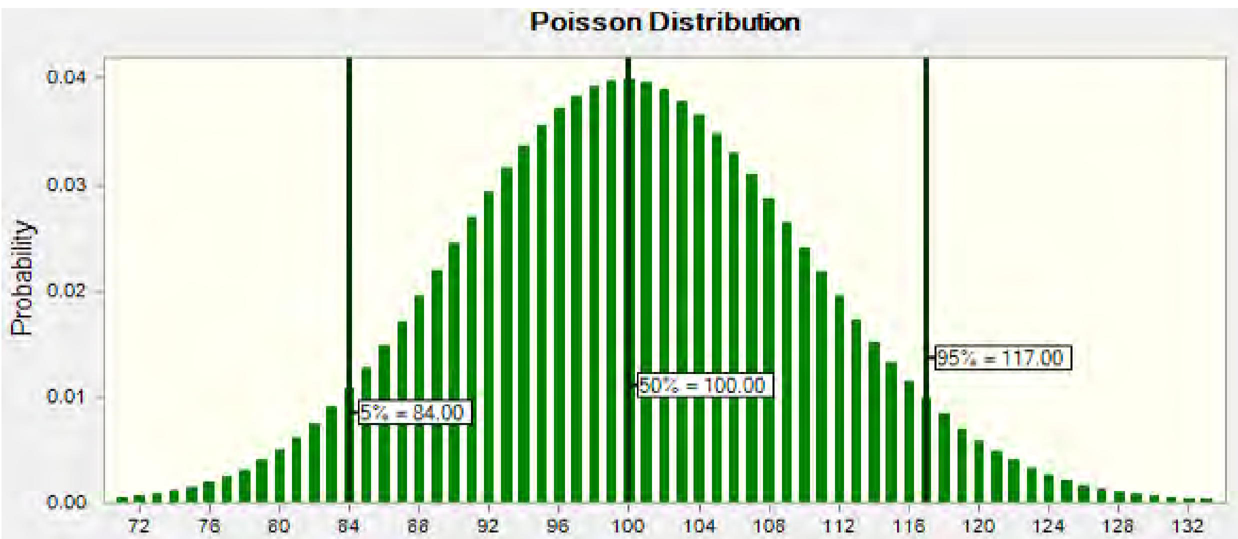

Figure 9.7 shows the resulting range of project costs, which also include interconnection costs estimates, for each new supply-side resource. For most of the technologies shown in Figure 9.7, base values found at 50th percentile were very close to their expected values. For the nuclear technology, however, the base value inferred from the probability distribution was 27% higher than the expected value- $11,302/kW vs $8,899/kW.

Figure 9.7 Resource-Specific Project Cost Ranges (2019$/kW)

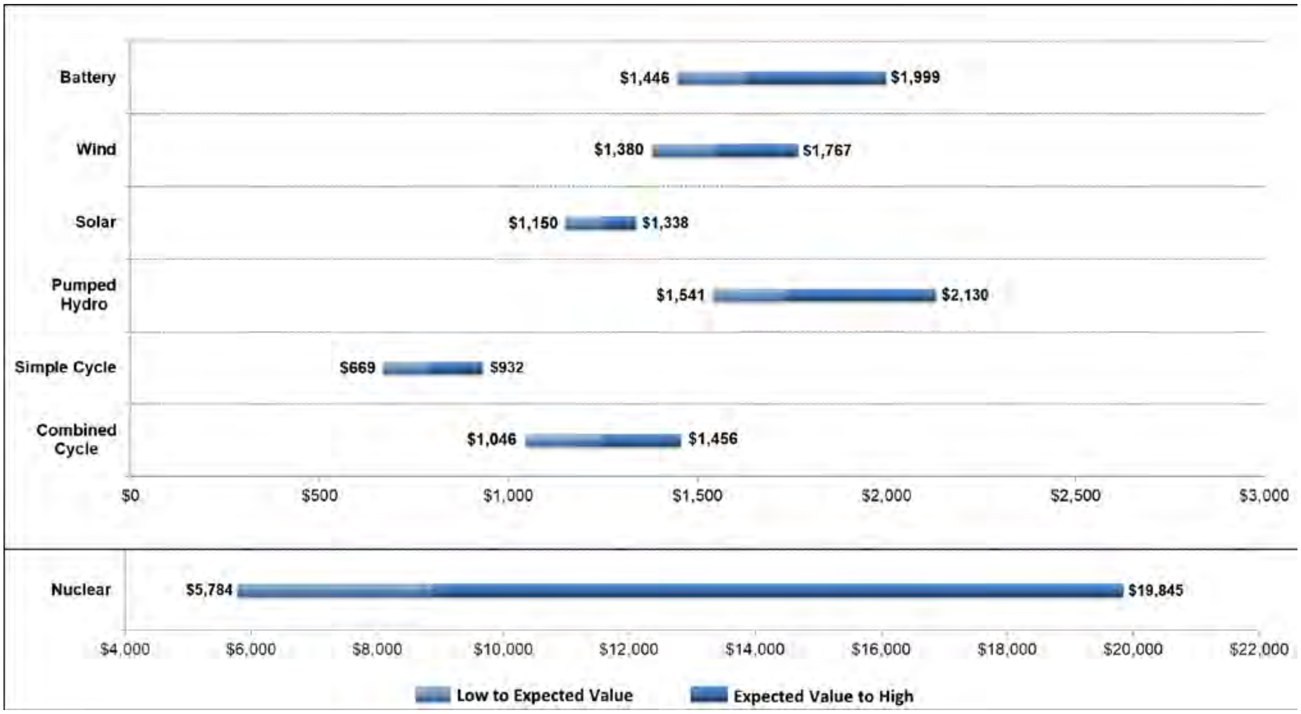

Table 9.7 Resource-Specific Uncertain Factor Ranges[29]

Uncertain Factor	Value	Probability	CC (Nat. Gas)	SC (Nat. Gas)	Pumped Hydro	Nuclear	Solar*	Wind*	Battery*
Project Cost	Low	10%	$1,046	$669	$1,541	$5,784	$1,150	$1,380	$1,446
($/kW)	Base	80%	$1,245	$796	$1,836	$11,302	$1,250	$1,550	$1,625
2019 $	High	10%	$1,456	$932	$2,130	$19,845	$1,338	$1,767	$1,999
Project Schedule (Months)	Low	10%	27	27	55	68	18	36	18
	Base	80%	36	36	73	91	24	48	24
	High	10%	48	48	95	119	32	63	32
Fixed O&M	Low	10%	$23.25	$6.98	$3.16	$102.54	$3.32	$25.74	$0.83
($/kW-yr)	Base	80%	$25.69	$8.18	$3.81	$126.02	$4.01	$31.07	$1.00
2019 $	High	10%	$29.30	$9.95	$4.76	$155.44	$5.03	$38.95	$1.26
Variable O&M	Low	10%	$0.98	$9.16	$2.50	$1.95	-	-	-
($/MWh)	Base	80%	$2.55	$10.90	$3.15	$2.41	-	-	-
2019 $	High	10%	$4.11	$12.64	$3.96	$3.05	-	-	-
EFOR (%)	Low	10%	1%	0%	0%	1%	-	-	-
	Base	80%	2%	5%	5%	2%	-	-	-
	High	10%	5%	10%	10%	3%	-	-	-

29 * Denotes that Ameren Missouri used a declining cost curve for solar, wind and batteries, and multipliers were applied to estimate base, low and high project costs. Assumed capacity factor for solar, wind and battery resources include effects of FOR.

Table 9.7 shows 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.

Table 9.8 contains the non-resource specific uncertain factor ranges analyzed.

Table 9.8 Non-Resource Specific Uncertain Factor Ranges

Uncertain Factors	Low	Base	High
Probability -->>	**10%**	**80%**	**10%**
Coal Price		Varies By Year	
Long Term Interest Rates	2.5%	3.7%	4.0%
Return on Equity	10.0%	10.5%	10.6%
DSM Load Impact and Cost			
MAP - EE&DER Load Impact	84%	100%	107%
MAP - EE&DER Cost	82%	100%	108%
MAP - DR Load Impact	99%	100%	116%
MAP - DR Cost	99%	100%	101%
RAP - EE&DER Load Impact	88%	100%	113%
RAP - EE&DER Cost	82%	100%	113%
RAP - DR Load Impact	99%	100%	116%
RAP - DR Cost	99%	100%	101%
DOPE1 - EE&DER Load Impact	100%	100%	100%
DOPE1 - EE&DER Cost	100%	100%	100%
DOPE1 - DR Load Impact	100%	100%	100%
DOPE1 - DR Cost	100%	100%	100%
DOPE2 - EE&DER Load Impact	100%	100%	100%
DOPE2 - EE&DER Cost	100%	100%	100%
DOPE2 - DR Load Impact	100%	100%	100%
DOPE2 - DR Cost	100%	100%	100%
DSM Cost Only			
MAP - EE&DER Cost	85%	100%	135%
MAP - DR Cost	85%	100%	125%
RAP - EE&DER Cost	80%	100%	140%
RAP - DR Cost	85%	100%	125%
DOPE1 - EE&DER Cost	80%	100%	170%
DOPE1 - DR Cost	85%	100%	170%
DOPE2 - EE&DER Cost	80%	100%	170%
DOPE2 - DR Cost	85%	100%	170%

Schedule MM-S6

As discussed in Chapter 2, long-range interest rate assumptions are based on the December 1, 2019, semi-annual Blue Chip Financial Forecast, a consensus survey of 44 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 2020 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.

Note that the DOPE1 and DOPE2 portfolios have no variations under the DSM Load Impact and Cost uncertainty. By definition, DOPE portfolios are "optimized" to provide a threshold load savings target. Any deviations in load savings would be proactively managed through the budget, with lesser or greater programming as needed. 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.

9.5.2 Sensitivity Analysis Results[30]

To conduct the sensitivity analysis, each of the 21 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.

The sensitivity analysis identified one critical independent uncertain factor: DSM Cost Only. Table 9.9 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.

[30] 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(7)(A); 20 CSR 4240-22.060(7)(C)1A

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Table 9.9 Critical Independent Uncertain Factors – Change in PVRR Ranking[31]

Plan		Integration Ranking	DSM Cost Only		
			PWA	Low	High
A	RAP DSM - RES Compliance	4	0	0	0
B	Renewable Expansion	1	0	0	0
C	No New DSM - CCs	18	0	0	2
D	No New DSM - All Solar	15	1	0	7
E	No New DSM - Pumped Hydro	20	0	0	1
F	No New DSM - AP1000	21	0	0	0
G	No New DSM - Simple Cycles	17	0	0	2
H	MAP DSM - Renewable Expansion	14	-1	4	-3
I	MAP DSM - RES Compliance	10	-2	2	-4
J	DOPE1 DSM	13	0	-1	0
K	DOPE2 DSM	11	1	-2	-1
L	Labadie Early Retirement - 4 units	8	0	-1	-1
M	Labadie Early Retirement - 2 units	7	0	0	0
N	Sioux Early Retirement	2	0	0	0
O	Rush Early Retirement	5	0	0	0
P	Sioux-Rush Early Retirement	3	0	0	0
Q	Sioux-Rush Early Retirement - No CCs	12	1	0	1
R	Rush Early Retirement 2	6	0	0	0
S	Rush FGD	9	0	0	0
T	Rush FGD - Labadie DSI	19	0	0	0
U	Rush Early Retirement 2 - Labadie DSI	16	0	0	0

***

Table 9.10 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.

[31] All plans include RAP DSM portfolio unless otherwise noted.

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Schedule MM-S6

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Table 9.10 Critical Independent Uncertain Factors – Change in PVRR (Million $)[32]

Plan		Integration PVRR	DSM Cost Only		
			PWA	Low	High
A	RAP DSM - RES Compliance	66,000	19	(260)	447
B	Renewable Expansion	65,940	19	(260)	447
C	No New DSM - CCs	67,880	-	-	-
D	No New DSM - All Solar	66,709	-	-	-
E	No New DSM - Pumped Hydro	68,384	-	-	-
F	No New DSM - AP1000	75,700	-	-	-
G	No New DSM - Simple Cycles	67,877	-	-	-
H	MAP DSM - Renewable Expansion	66,758	71	(498)	1,210
I	MAP DSM - RES Compliance	66,611	71	(498)	1,210
J	DOPE1 DSM	66,678	43	(161)	587
K	DOPE2 DSM	66,598	35	(137)	486
L	Labadie Early Retirement - 4 units	66,397	19	(260)	447
M	Labadie Early Retirement - 2 units	66,155	19	(260)	447
N	Sioux Early Retirement	65,973	19	(260)	447
O	Rush Early Retirement	66,035	19	(260)	447
P	Sioux-Rush Early Retirement	65,977	19	(260)	447
Q	Sioux-Rush Early Retirement - No CCs	66,602	19	(260)	447
R	Rush Early Retirement 2	66,097	19	(260)	447
S	Rush FGD	66,555	19	(260)	447
T	Rush FGD - Labadie DSI	68,219	19	(260)	447
U	Rush Early Retirement 2 - Labadie DSI	67,761	19	(260)	447

***

Ameren Missouri low-base-high load growth cases along with the DSM Cost Only 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 9.8, with the two uncertain factors shown on the right-hand side.

[32] All plans include RAP DSM portfolio unless otherwise noted.

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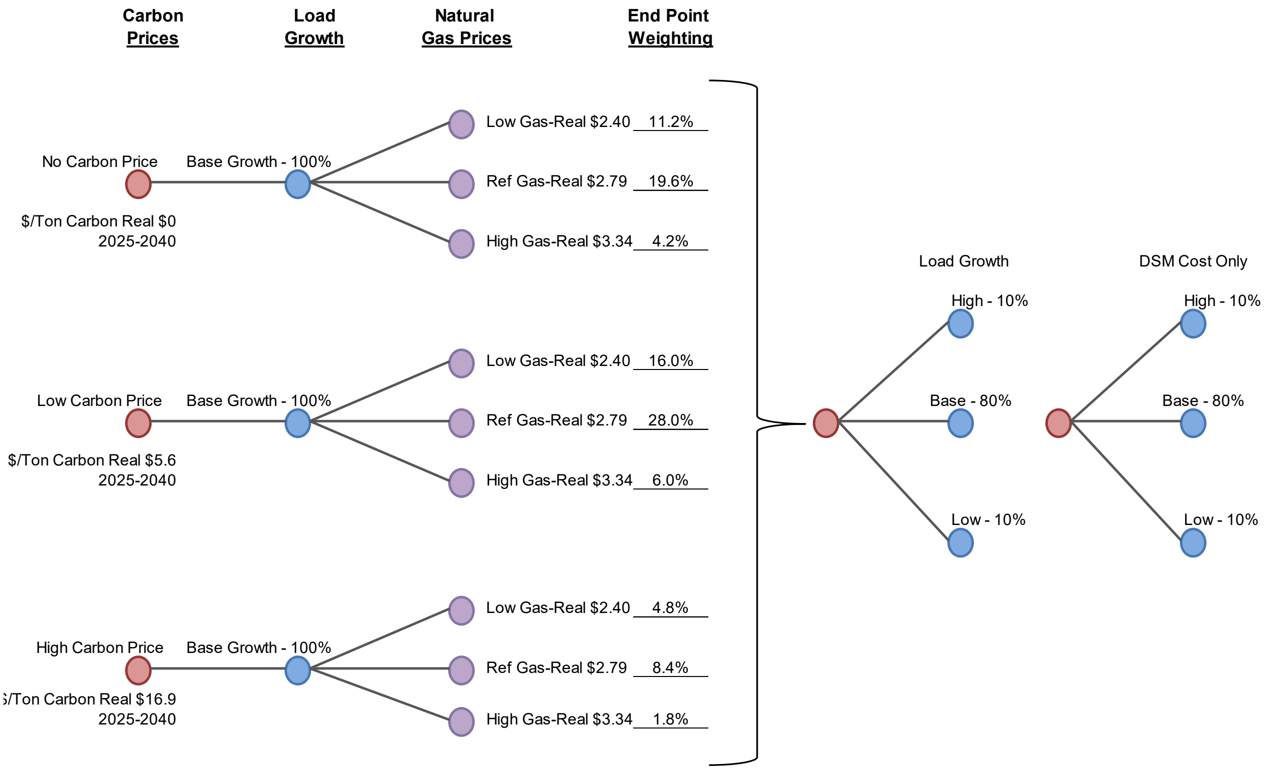
Schedule MM-S6

Figure 9.8 Final Probability Tree Including Sensitivity Analysis Results[33]



9.6 Risk Analysis[34]

The Risk Analysis consisted of running each of the candidate resource plans in Table 9.4 through each of the branches on the final probability tree shown in Figure 9.8. 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 (DSM 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%.

[33] 20 CSR 4240-22.060(6)
[34] 20 CSR 4240-22.060(6)

9.6.1 Risk Analysis Results

The PVRR results of the risk analysis of the 21 alternative resource plans are shown in Figure 9.9. The levelized rate results for the risk analysis are shown in Figure 9.10. The PVRR results are lower for plans with RAP compared to plans without DSM. Plan B, with renewable expansion and RAP DSM has the lowest PVRR followed very closely by Plan P, which include the Sioux and Rush Island early retirements. Plan F (No DSM-Nuclear) exhibits the highest PVRR and the highest levelized rates followed by Plan E (No DSM-Pumped Hydro), which has the second highest PVRR, and by Plan I (MAP DSM-Res Compliance), which has the second highest levelized rates. Results for other performance measures can be found in Chapter 9 - Appendix A.

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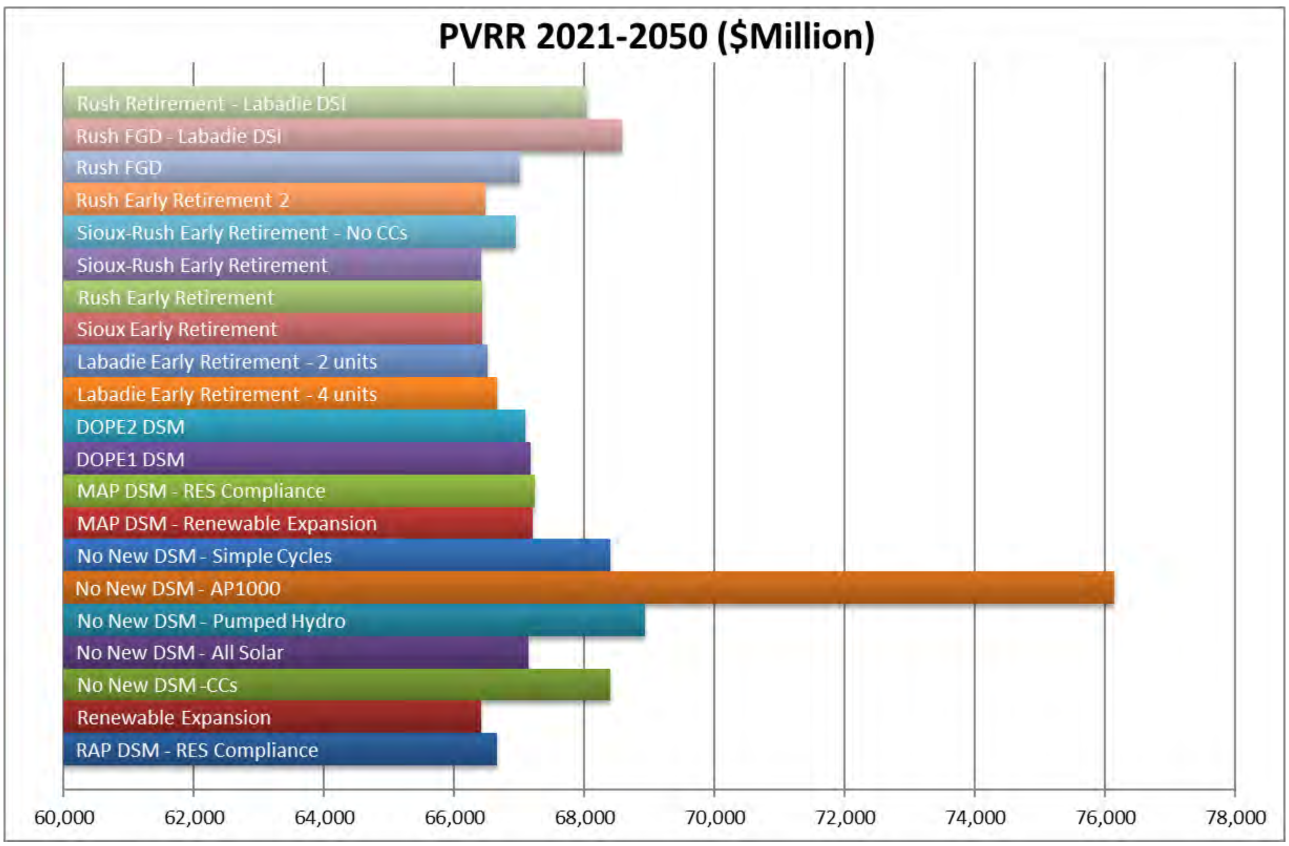
Figure 9.9 Probability-Weighted PVRR Results[35]



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[35] All plans include RAP DSM portfolio unless otherwise noted.

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Schedule MM-S6

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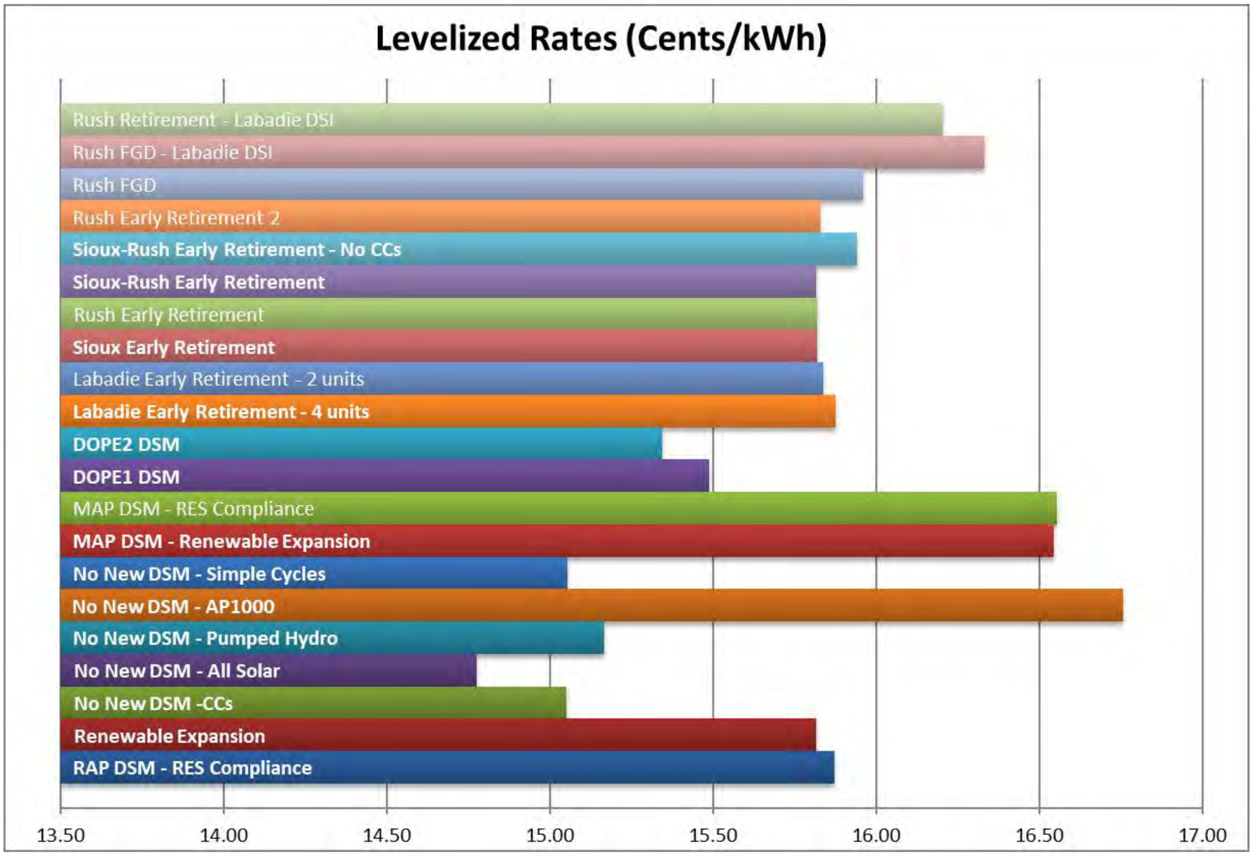
Figure 9.10 Probability-Weighted Levelized Rate Results[36]



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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 21 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.

[36] All plans include RAP DSM portfolio unless otherwise noted.

9.7 Conclusions from Integration and Risk Analysis

Below are several conclusions from the integration and risk analysis.

- RAP DSM results in the lowest PVRR compared to plans with different levels of DSM.
- Inclusion of DSM resources in general results in lower costs than the supply-side alternatives. This finding demonstrates that using an avoided capacity curve that excludes capacity impacts of DSM resources for cost effectiveness analyses (as explained 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.
- Sioux 2028 and Rush Island 2039 retirement results in the lowest cost among the early retirement options while early retirement of Labadie's four units by the end of 2028 results in the highest costs among the same plans.
- *****Adding an FGD and/or DSI result in significantly higher costs and levelized rates. Retirement of Rush Island Energy Center by the end of 2024 is less costly than the energy center modifications.*****
- Plans with additional renewable resources beyond those included for RES compliance as in Plans B and H reduce costs and customer rates. Coupling even more renewable resources with batteries, on the contrary, results in higher cost and levelized rates.[37]
- Plan D, which assumes all future resource needs are met with only renewable resources, performs better than it did in the previous IRP due to reductions in the cost of solar resources; it is the 10th most costly alternative resource plan. From a cost standpoint, it is very competitive with other supply-side resources.
- Wind, solar, and natural gas combined cycle resources are attractive options for development due to their competitive overall cost, relatively low capital cost, and relatively short lead time.
- *****The five highest cost alternative resource plans are those with no DSM or with FGD and DSI additions at the two energy centers.***** The alternative resource plan including new nuclear is by far the most costly.

[37] 20 CSR 4240-22.060(4)(E)

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Schedule MM-S6

9.8 Resource Plan Model

Ameren Missouri has used a modular approach to modeling for this IRP as it did in the 2017 IRP. 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 Simtec, Inc., typically referred to as RTSim ("Real-Time Simulation") for production cost modeling.[38] RTSim provides a realistic simulation of an electric generating system for a period of a few days to multiple years.

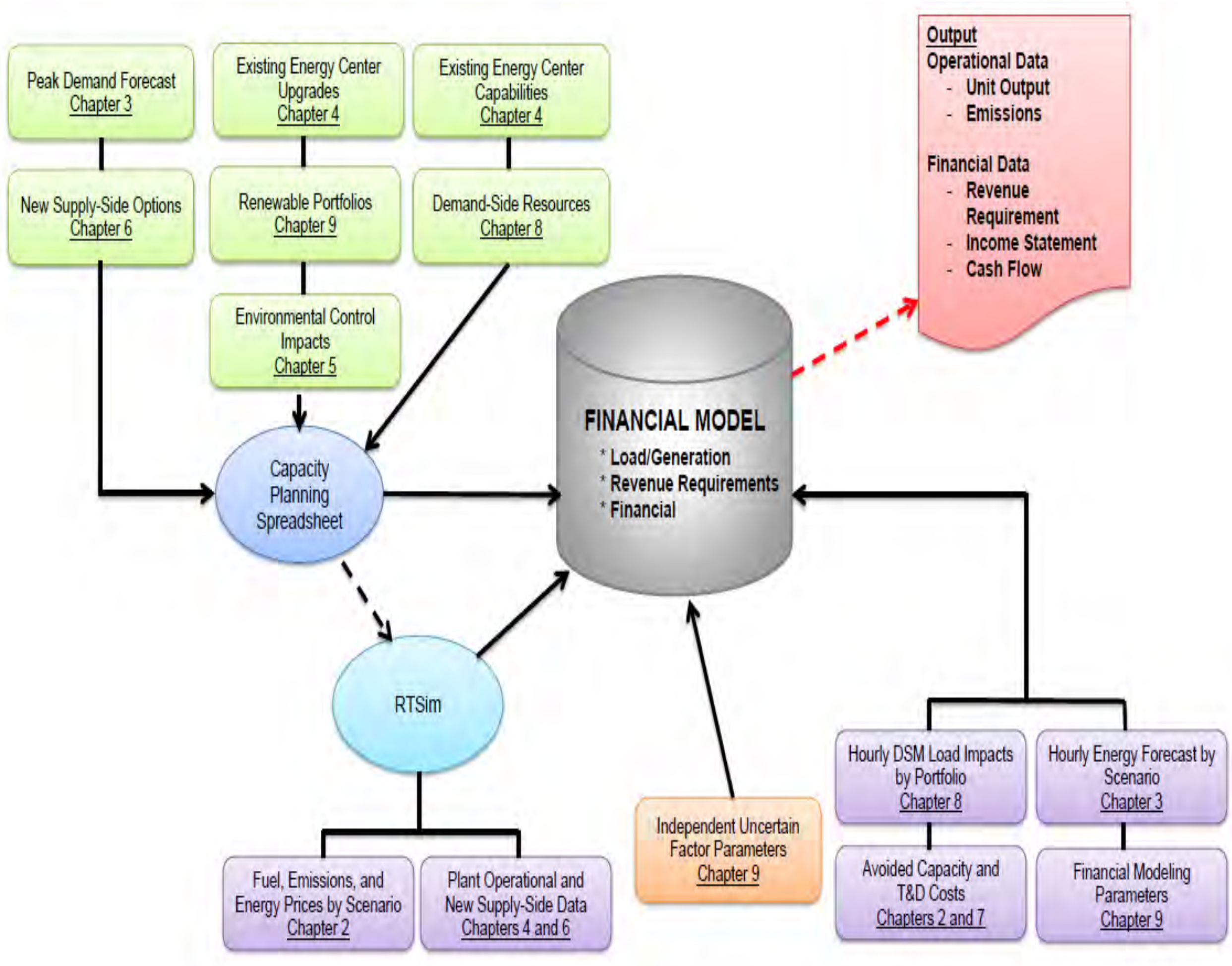
RTSim simulates hourly chronological dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The model plans are based on a capacity planning spreadsheet, which was used to determine the timing of new resources. The RTSim 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. The generation fleet is dispatched competitively against market prices. The multi-area mode of the Ventyx Midas® model was used for the creation of forward price curves as described in Chapter 2.

Ameren Missouri developed its own revenue requirements and financial model using Microsoft Excel. This model incorporates the capacity position and RTSim 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 9.11 shows how the various assumptions are integrated into the financial model.

[38] 20 CSR 4240-22.060(4)(H)

Figure 9.11 Resource Plan Model Framework[39]



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

[39] 20 CSR 4240-22.060(4)(H)

Schedule MM-S6

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 2021. The nature and timing of any changes we 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 our business needs and objectives.

9.9 Compliance References

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, demand response, various types of new renewable and conventional generation, and conversion and/or retirement of each of its existing coal-fired generators.*

- *Ameren Missouri has evaluated several reasonable alternatives for its Meramec Energy Center, including conversion of units to natural gas-fired operation and retirement in either 2015 or 2022.*

- *In addition to the scenario variables and modeling discussed in Chapter 2, four critical independent uncertain factors have been included in the final probability tree for risk analysis: Financing Rates, Coal Prices, DSM Impacts and Costs, and Capital Project Costs.*

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 existing supply side resource options such as retirement, conversion and environmental retrofits.
2. Development of the **baseline capacity position**, which reflects forecasted peak demand, reserve requirements and existing resources.
3. Pre-analysis was used to determine certain key base elements for alternative resource plans. This included analysis of various options for the Meramec Energy Center and expansion opportunities at our Keokuk hydroelectric facility.
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, the results of the pre-analysis conducted in step 3, and the planning objectives identified in step 4.
6. Identification and screening of **candidate uncertain factors**, which are key variables that can influence the performance of alternative resource plans.

Schedule MM-S7

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 includes 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 9.4. 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. As has been mentioned, a pre-analysis was used to determine which Meramec and Keokuk options would be included in all alternative resource plans.

Figure 9.1 Attributes of Alternative Resource Plans

Meramec Retirement Options
- Retired 12/31/2015
- Retired 12/31/2022
- Convert Units 1&2 to Natural Gas 12/31/2015 and Units 3&4 Continue on coal; All Units Retired 12/31/2022

Retirements
- Labadie Retired 12/31/2023
- Rush Island Retired 12/31/2024
- Sioux Retired 12/31/2033

New Supply-Side Types
- Combined Cycle (Nat. Gas)
- Simple Cycle (Nat. Gas)
- Nuclear (100% Ownership)
- Nuclear (75% Ownership)
- Pumped Hydroelectric
- Wind
- Wind with Simple Cycle

Keokuk Upgrade
- 50 MW Expansion
- None

Energy Efficiency
- Maximum Achievable Potential (MAP)
- Realistic Achievable Potential (RAP)
- Missouri Energy Efficiency Investment Act (MEEIA) Cycle 1 Only

Demand Response
- MAP
- RAP
- None

Renewable Portfolios
- Missouri Renewable Energy Standard (RES)
- Balanced

[1] 4 CSR 240-22.060(1); 4 CSR 240-22.060(3)

9.2 Capacity Position

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

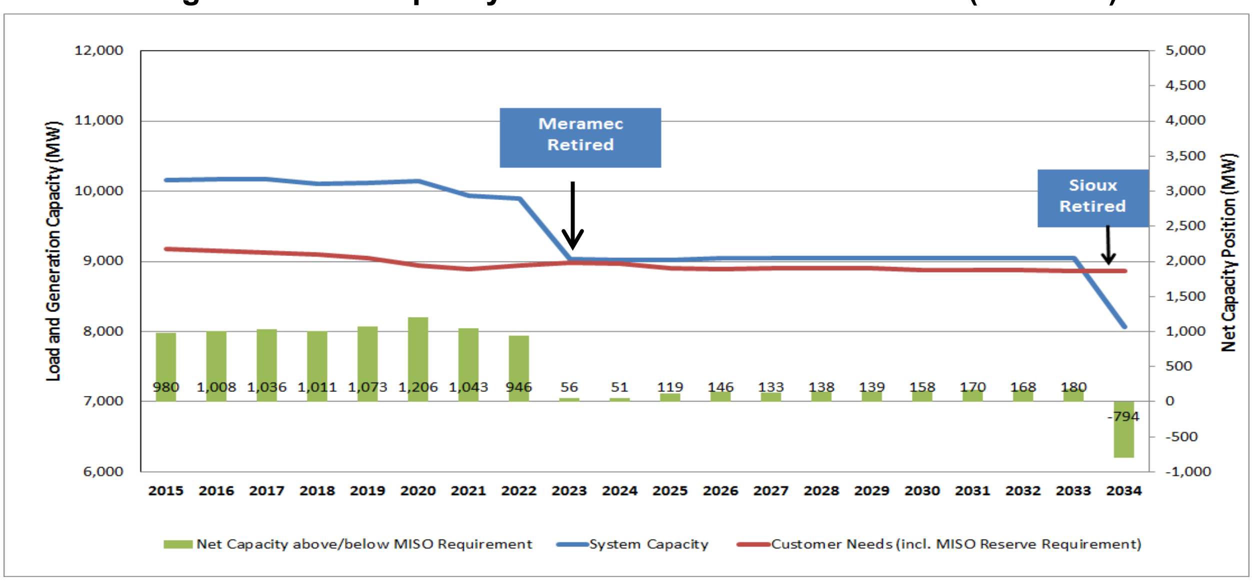
- Existing plant capabilities based on Ameren Missouri's annual generating unit rating update (i.e., July 2014 planned ratings)
- Existing obligations for capacity purchases and sales
- Peak demand forecast, as described in Chapter 3
- Planning reserve margin (PRM) requirement, based on MISO's Planning Year 2014 Loss of Load Expectation (LOLE) Study Report (November 2013). Table 9.1 shows the MISO System PRM from 2015 through 2023. The long-range PRM was assumed to continue at 17.3% through the remainder of the planning horizon.

Table 9.1 MISO System Planning Reserve Margins 2015 through 2023

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023
PRM $_{\text{Installed Capacity}}$	14.9%	15.0%	15.1%	15.1%	15.6%	16.0%	16.4%	16.8%	17.3%

Figure 9.2 shows Ameren Missouri's net capacity position with no new major generating resources. The chart shows 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 energy efficiency and demand response. The system capacity includes the capacity benefit of the RES Compliance portfolio.

Figure 9.2 Net Capacity Position – No New Resources (Baseline)



Existing Unit Upgrades

The capacity position reflects various upgrade projects for Ameren Missouri's existing generating units. Below is a list of the plant upgrade projects that were included in all resource plans.

- Keokuk Units 5 and 6 – 4 MW in 2016
- Keokuk Units 14 and 15 – 4 MW in 2018

The Keokuk unit upgrade projects listed above have been planned and budgeted based on Ameren Missouri's capital project justification process, which includes an evaluation of the costs and benefits of each project, including the value of energy and capacity provided or saved.

Retirements

Ameren Missouri is considering retirement of some or all of its eight older gas- and oil-fired CTG units – Kirksville, Howard Bend, Fairgrounds, Meramec CTG-1, Meramec CTG-2, Mexico, Moberly, and Moreau – with a total net capacity of 367 MW, over the next 20 years. Chapter 4 - Table 4.2 provides a summary of the planned CTG retirements. The CTG retirements were included in all resource plans.

Coal energy center retirements were also included in the capacity planning process. Sioux retirement by December 31, 2033, was common in all resource plans, based on prior analysis of Ameren Missouri's coal power plant life expectancy by Black and Veatch. Three different Meramec retirement options were considered: 1) retirement by December 31, 2015, 2) retirement by December 31, 2022, and 3) conversion of Units 1&2 to natural gas-fired operation by December 31, 2015, and Units 3&4 continuing to operate on coal with retirement of all four units by December 31, 2022. As discussed in Section 9.3, a pre-analysis was used to determine a single option for Meramec for inclusion in alternative resource plans. While the retirement dates for Labadie and Rush Island, as determined by the Black and Veatch life expectancy study, are beyond the 20-year planning horizon, we have evaluated potential early retirements for both energy centers. Retirement of Labadie by December 31, 2023 was evaluated as was retirement of Rush Island by December 31, 2024. The alternative retirement dates for Labadie and Rush Island were based on the ability to avoid significant costs associated with environmental compliance or environmental risk. In the case of Labadie, the expected need for a scrubber in the 2020-2025 timeframe was the primary driver for the alternative retirement date. In the case of Rush Island, the potential for an explicit price on carbon starting in 2025, included in the scenarios described in Chapter 2, was the primary driver for the alternate retirement date.

Potential Keokuk Expansion

A potential Keokuk Energy Center expansion project was evaluated in the capacity planning process. As discussed in Chapter 4, Option 3 (3-5k)---the addition of five units to the spare bays---was the least cost option and was evaluated further in the integration analysis. The Keokuk expansion would provide 50 MW of additional capacity.

DSM Portfolios

DSM portfolios were included in capacity planning separately as energy efficiency and demand response. Energy efficiency (EE) and demand response (DR) 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) RAP EE Only, 3) MAP EE and DR, 4) MAP EE Only and 5) MEEIA Cycle 1 Only[2]. The MEEIA Cycle 1 Only DSM portfolio reflects completion of Ameren Missouri's current three-year program cycle with no further energy efficiency during the planning horizon and does not include DR.

Renewable Portfolios

Compliance with Missouri's renewable energy standard (RES) was updated to reflect current assumptions, including baseline revenue requirements, and an updated 10 year forward looking methodology which impacts the calculation of a 1% rate cap.

Ameren Missouri performed its RES compliance analysis with the *2014 IRP RES Compliance Filing Model* (model). The model is designed to calculate the retail rate impact, as required by the Commission's RES rules[3]. This model determines the quantity of renewable energy needed to meet both the overall RES portfolio standard and the 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 expected renewable energy credit (REC) position is presented in Figure 9.3.

[2] EO-2012-0142 12
[3] 4 CSR 240-20.100(5)

Figure 9.3 Ameren Missouri's RES REC Positions

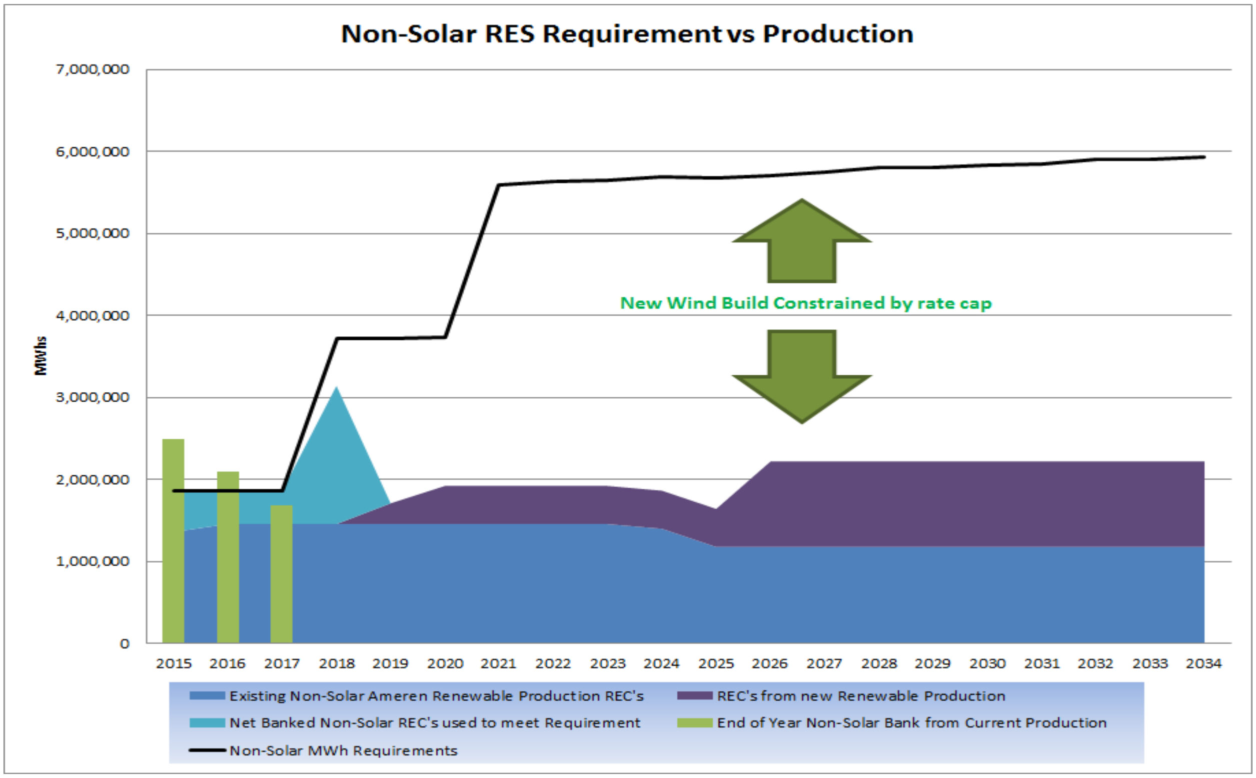


Figure 9.3 shows that Ameren Missouri expects to meet the overall REC requirement until 2018, without being constrained by the 1% rate impact limitation. Ameren Missouri is able to meet the overall standard until 2018 using RECs generated by its existing qualifying resources, including hydro, wind, and landfill gas, and banked RECs from prior years.

Once the standard increases to 10% in 2018, Ameren Missouri exhausts its remaining REC bank then places new wind generation into service starting in 2019. The model shows the amounts of planned new wind and solar resources needed to meet the standard subject to the 1% rate cap. In addition, the model is used to provide a view on RES compliance for both an unconstrained and constrained (i.e., 1% rate impact cap) view of compliance. Table 9.2 shows the unconstrained and constrained amounts of wind, landfill gas (LFG), and solar resources needed. This model was used to develop the RES compliance portfolios for the alternative resource plans. Appendix A shows the unconstrained and constrained amounts of wind, LFG, and solar resources needed in Term 1 (2014-2023) and Term 2 (2025-2034) by year.

Schedule MM-S7

Table 9.2 2014 IRP Compliance Filing Model

Description	10 Year Sum TERM 1 (2015-2024)	10 Year Sum TERM 2 (2025-2034)	20 Year Sum (2015-2034)
Unconstrained Full RES REC Requirement met with new builds			
MW's Installed New Solar	5	54	59
MW's Installed New LFG	5	0	5
MW's Installed New Wind	1,003	110	1,114
RES Requirement within 1% Rate Cap Limit			
MW's Installed New Solar	16	10	26
MW's Installed New LFG	5	0	5
MW's Installed New Wind	100	142	242

Several renewable portfolios were evaluated in the capacity planning process using *2014 IRP RES Compliance Filing Model*: 1) RES compliance with RAP or MAP, 2) RES Compliance with MEEIA Cycle 1 Only, and 3) Balanced (i.e., 400 MW Wind, 45 MW Solar, and 20 MW Small Hydroelectric). The RES portfolios were developed using the described in Section 9.2.

When developing the RES compliance investment needs, consideration was given to the potential difference between RAP DSM investment vs a MAP DSM investment due to their differing impacts on customer sales, which is used as the basis for determining the amount of renewable energy needed to comply with the RES portfolio requirements. After modeling both, the difference in the level of renewable generation added was determined to be insignificant, primarily because of the effect of the 1% rate impact limitation on investment levels. Specifically, the difference was less than 1 MW of investment in solar for Term 1 and less than 4 MW's of wind investment for Term 2. Therefore MAP and RAP portfolios are accompanied by the same level of renewable investment when included in alternative resource plans.

Table 9.3 shows the timing of resources for renewable portfolios included in the alternative resource plans.

Table 9.3 Alternative Resource Plans - Renewable Portfolios

Renewable Portfolios		Nameplate Capacity (MW)																				
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	TOTAL
RES with RAP or MAP	Wind	0	0	0	0	50	50	0	0	0	0	0	142	0	0	0	0	0	0	0	0	242
	Solar	5	10	0	0	0	0	2	0	0	0	10	0	0	0	0	0	0	0	0	0	26
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RES with MEEIA Cycle 1	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	5	10	0	0	0	0	2	0	0	0	10	0	0	0	0	0	0	0	0	0	26
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Balanced	Wind	0	0	0	0	50	50	0	100	0	100	0	100	0	0	0	0	0	0	0	0	400
	Solar	5	10	0	0	0	0	10	0	0	0	10	0	10	0	0	0	0	0	0	0	45
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	10	0	0	0	20

Non-renewable Supply-side Resources

Non-renewable supply-side resource types were added last in the capacity planning process. If the capacity shortfall in a given year met or exceeded the build threshold, then supply side resources would be added to eliminate the shortfall. The build threshold was determined to be 300 MW (based on half the size of a combined cycle) regardless of the type of supply side resource under consideration. The full rated capacity and the build thresholds 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 into the market. The earliest in-service for each supply-side resource is 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.

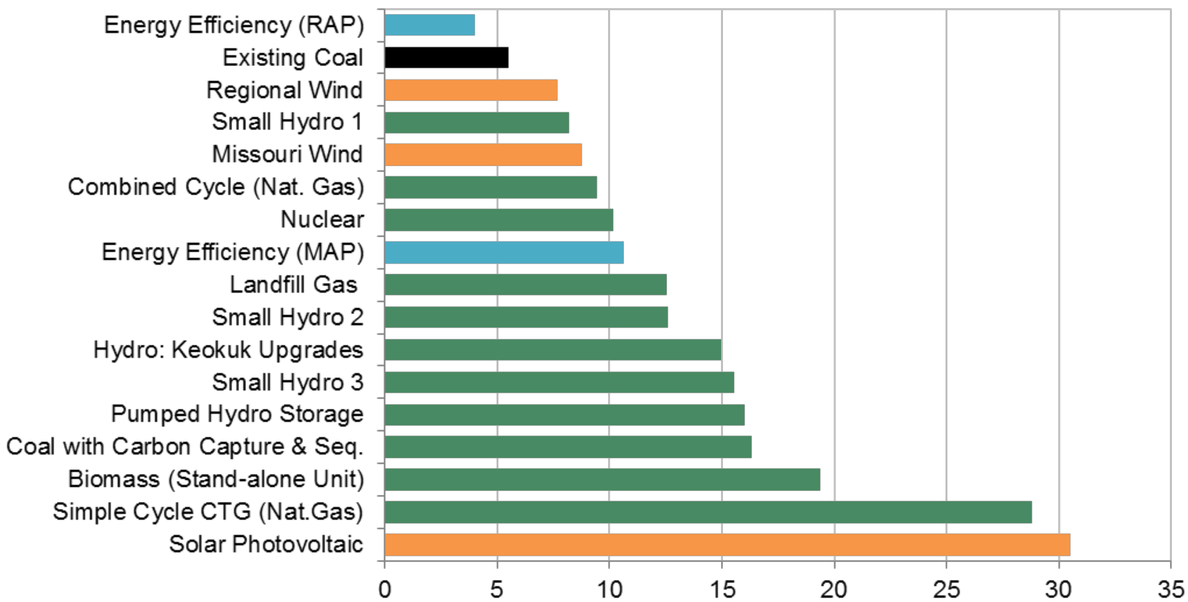
Table 9.4 Build Threshold for Supply Side Types

Supply Side Type	Capacity, MWs	Build Threshold, MWs	Earliest Year In-Service
CC-Natural Gas	600	300	2019
SC-Natural Gas	704	300	2019
Nuclear (100%)	225	300	2025
Nuclear (75%)	169	300	2025
Pumped Hydro	600	300	2020
Wind	465	300	2018
Wind and Simple Cycle	465	300	2020

The remaining net capacity position was modeled in the financial model as capacity purchases and sales priced at the avoided capacity costs as discussed in Chapter 2 and Chapter 8. The capacity purchases and sales were also adjusted for the various peak demand forecasts associated with each of the 15 scenarios and DSM impacts.

Figure 9.4 below summarizes the LCOE for all resources evaluated in the alternative resource plans.

Figure 9.4 Levelized Cost of Energy – All Resources[4]



Note: Does not reflect inclusion of tax incentives. Orange denotes intermittent resources. MAP energy efficiency reflects costs and energy savings incremental to RAP

9.3 Pre-Analysis

A pre-analysis consisting of two phases was conducted prior to development of the alternative resource plans to determine two key elements for inclusion in alternative resource plans. This included analysis of various options for the Meramec Energy Center and expansion opportunities at our Keokuk hydroelectric facility. Figure 9.5 provides a high-level overview of the alternative resource plan development process.

Figure 9.5 Alternative Resource Plan High-Level Overview

[4] 4 CSR 240-22.010(2)(A)

Meramec Energy Center Solution

The first phase was to determine a preferred retirement path for the Meramec Energy Center, our oldest coal-fired facility. Three different Meramec retirement options were considered: 1) retirement by December 31, 2015, 2) retirement by December 31, 2022, and 3) conversion of Units 1&2 to natural gas-fired operation by December 31, 2015, and continued operation of Units 3&4 on coal, with retirement of all four units by December 31, 2022. These plans were run against the scenario tree only (no independent uncertain factors) to determine the Meramec solution to be included in all other alternative resource plans.

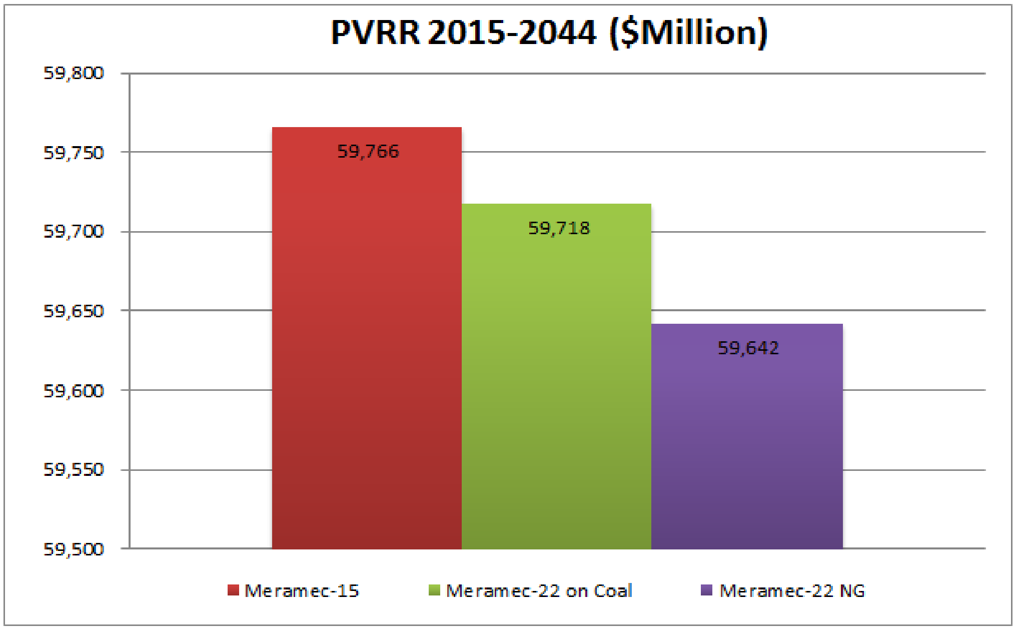
In 2014, Burns & McDonnell completed a Condition Assessment for the Meramec Energy Center to determine ongoing costs to keep the plant operating safely and reliably through the planning horizon. The Condition Assessment was used to inform the development of the Meramec retirement options. The retirement dates for Meramec were also informed by the expectation for additional costs that would be incurred due to future environmental regulations and GHG regulations. In particular, and as discussed in Chapter 5, we would expect the need for a scrubber and other environmental mitigation investments at Meramec in the 2020-2025 timeframe.

Ameren Missouri conducted an internal preliminary evaluation for the potential conversion of the Meramec Energy Center Units 1-4 from coal to natural gas-fired operations. Units 1&2 were designed with the capability to operate on natural gas; however, these units have not operated at full load on natural gas since 1993. Therefore, restoration of devices and equipment is needed for Units 1&2 to operate fully on natural gas. The expected cost to restore Units 1&2 to natural-gas operations is estimated to be less than $2 million. Units 3&4 are currently capable of coal-fired operations only. The expected cost to convert Units 3&4 to natural-gas operations is expected to be over $40 million.

The PVRR results of the pre-analysis of the three Meramec options are shown in Figure 9.6. Conversion of Units 1&2 to natural gas-fired operation by December 31, 2015, and continued operation of Units 3&4 on coal, with retirement of all four units by December 31, 2022 result in the lowest PVRR and is the preferred solution.

Schedule MM-S7

Figure 9.6 Integration PVRR Results: Meramec Pre-Analysis



Keokuk Energy Center Solution

The second phase of the pre-analysis was to determine whether or not the potential Keokuk expansion project would be included in all other alternative resource plans. As discussed in Section 4.3, seven of the 14 potential expansion options from the *Keokuk Hydroelectric Project Expansion Study Concept Report*[5] were evaluated further with approximate additional generating capacity ranging from 4.5 to 162 MW. Option 3 (3-5K) was determined to be the least cost option and was selected for further evaluation in the pre-analysis. Table 9.5 provides a summary of the operating and cost characteristics for Option 3 (3-5K).

Table 9.5 Keokuk Expansion Option: Operating and Cost Characteristics

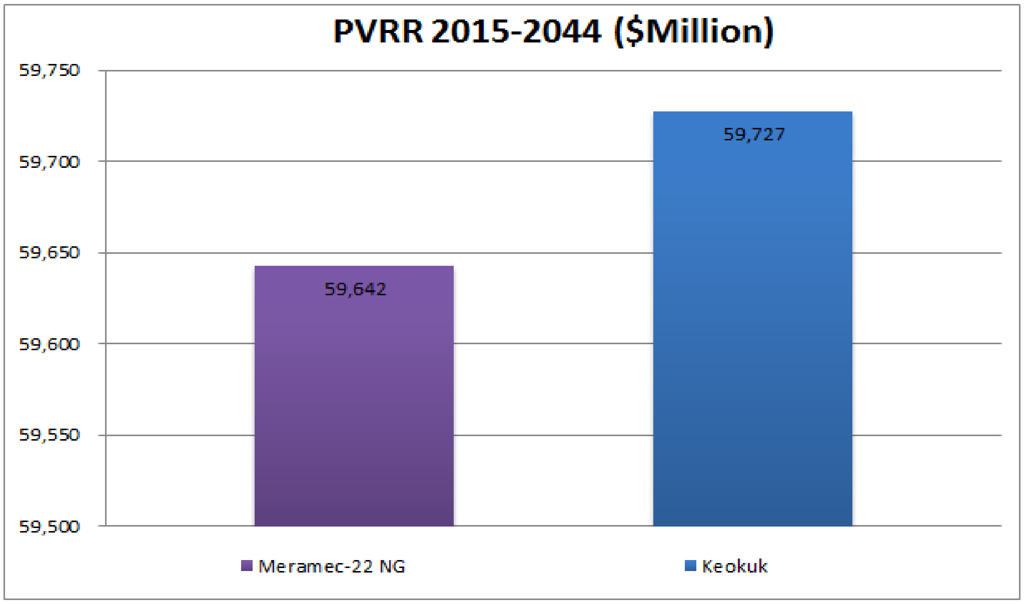
Option	Additional Capacity (MW)	Additional Average Annual Energy (MWh)	Project Cost ($1,000)	Annual Fixed O&M ($/yr), ($1,000)	Annual Variable O&M ($/yr), ($1,000)
3-5K New Units to Spare Bays (Add 5 Kaplan Units)	50	170,408	255,884	255	74

The Keokuk expansion was added to the preferred Meramec solution in the second phase. Figure 9.7 shows the PVRR results from the pre-analysis; adding Keokuk Expansion (50 MW) results in a higher PVRR than that resulting from the preferred Meramec solution without the Keokuk expansion.

[5] HDR Engineering, Inc. (HDR|DTA). *Keokuk Hydroelectric Project Expansion Study Concept Report.* April 20, 2011.

As discussed in Section 9.8, the results of the pre-analysis were validated by evaluating the same options under the full range of scenarios and critical uncertain factors used in risk analysis.

Figure 9.7 Integration PVRR Results: Keokuk Pre-Analysis



9.4 Planning Objectives

The fundamental objective of Missouri's electric resource planning process is to provide energy to its 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.[6] Ameren Missouri considers several factors, or planning objectives, that must be considered in meeting the fundamental objective. Planning objectives provide a guide to 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: Environmental/Renewable/Resource Diversity, Financial/Regulatory, Customer Satisfaction, Economic Development, and Cost. These planning objectives, which are the same as those discussed in Ameren Missouri's 2011 IRP, were selected by Ameren Missouri decision makers and are discussed below[7]:

[6] 4 CSR 240-22.010(2)
[7] 4 CSR 240-22.010(2)(C)

Environmental/Renewable/Resource Diversity

Ameren Missouri has relied for many years on a portfolio that consists, in large part, of large, efficient coal-fired generators. Current and potential future environmental regulations may have significant impact on Ameren Missouri's coal-fired fleet 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 MAP or RAP energy efficiency, renewables in addition to those required for RES compliance, new gas-fired generation, new nuclear generation, storage resources, and additional coal retirements.

Financial/Regulatory

The continued financial health of Ameren Missouri is crucial as it will need access to large amounts of capital for complying with renewable energy standards and environmental regulations, investing in new supply side resources, and funding continued energy efficiency programs while maintaining or improving safety and reliability. While making its investment decisions, it is important for Ameren Missouri to consider factors that may influence its access to capital markets. This includes measures of cash flow, profitability, and creditworthiness as well as assessment of risks associated with investment management and recovery.[8]

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 energy efficiency and demand response programs, and inclusion of renewables to assess relative customer satisfaction expectations.[9]

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) including both construction and operation.[10] We have assumed that second and third level economic impacts would not significantly affect the relative economic development potential of alternative resource plans.

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[8] 4 CSR 240-22.060(2)(A)6
[9] 4 CSR 240-22.060(2)(A)4
[10] 4 CSR 240-22.060(2)(A)7

Cost

Ameren Missouri is mindful of the impact that its future resource choices will have on its customers' rate 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, but it is a very important factor in making resource decisions. Therefore, minimization of present value of revenue requirements was used as the primary selection criterion.[11]

9.5 Determination of Alternative Resource Plans[12]

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

- Does inclusion of Demand Response reduce overall customer costs?
- What level of DSM, RAP or MAP, results in lower costs?
- Is early retirement of Labadie Energy Center and replacement with MAP cost effective?
- Is early retirement of Rush Island Energy Center and replacement with MAP cost effective?
- What are the benefits of including renewables beyond those needed for RES compliance?
- What is the impact of pursuing only new renewables?
- How do various supply side resource options compare?
- How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?

Table 9.6 provides a summary of the alternative resource plans, including the results of the pre-analysis for Meramec and Keokuk.

[11] 4 CSR 240-22.060(2)(A)1; 4 CSR 240-22.010(2)(B)
[12] 4 CSR 240-22.060(3)

Table 9.6 Alternative Resource Plans[13]

Pre-Analysis

	Plan Name	Meramec Option	Keokuk Expansion	Retirements	DSM	Renewables	Other New Supply
1	*Meramec Option 1*	Retired 12/31/22	None	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles
2	*Meramec Option 2*	U1-2 NG 12/31/15 Retired 12/31/22	None	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles
3	*Meramec Option 3*	Retired 12/31/15	None	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles
4	*Keokuk Expansion*	U1-2 NG 12/31/15 Retired 12/31/22	50 MW Expansion	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles

Alternative Resource Plans

	Plan Name	Meramec Option	Retirements	DSM	Renewables	Other New Supply
A	*Combined Cycle*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycle
B	*Nuclear*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	CC & Nuclear (450 MW)
C	*Simple Cycle CTGs*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	CTGs
D	*Pumped Hydro*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	Pumped Hydro
E	*Wind Plus CTGs*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	CC & Wind+CTGs
F	*No Demand Response - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE Only	RES Compliance	Combined Cycles
G	*Maximum DSM*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE&DR	RES Compliance	Combined Cycle
H	*Balanced Portfolio - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear (169 MW), Combined Cycle
I	*Balanced Portfolio - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Combined Cycle
J	*Balanced w/ No Further DSM After 2015 - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	MEEIA Cycle 1 only	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW), Combined Cycles
K	*Balanced w/ No Further DSM After 2015 - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	MEEIA Cycle 1 only	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Combined Cycles
L	*All Renewables*	U1-2 NG, Retired'22	Sioux 12/31/33	MEEIA Cycle 1 only	RES Compliance	Wind Only

[13] 4 CSR 240-22.010(2)(A); 4 CSR 240-22.060(3); 4 CSR 240-22.060(3)(A)1 through 8; 4 CSR 240-22.060(3)(B); 4 CSR 240-22.060(3)(C)1; 4 CSR 240-22.060(3)(C)2; 4 CSR 240-22.060(3)(C)3

Alternative Resource Plans

	Plan Name	Meramec Option	Retirements	DSM	Renewables	Other New Supply
M	*Add'l Coal Retirement - 1a*	U1-2 NG, Retired'22	Sioux 12/31/33 Labadie 12/31/23	MAP EE&DR	RES Compliance	Combined Cycles
N	*Add'l Coal Retirement - 2a*	U1-2 NG, Retired'22	Sioux 12/31/33 Rush Island 12/31/24	MAP EE&DR	RES Compliance	Combined Cycles
O	*Add'l Coal Retirement - 1b*	U1-2 NG, Retired'22	Sioux 12/31/33 Labadie 12/31/23	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW), Combined Cycles
P	*Add'l Coal Retirement - 2b*	U1-2 NG, Retired'22	Sioux 12/31/33 Rush Island 12/31/24	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW), Combined Cycles
Q	*Balanced Portfolio w/ Maximum DSM - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW)
R	*Balanced Portfolio w/ Maximum DSM - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Combined Cycle
S	*No Demand Response - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE Only	RES Compliance	Combined Cycle

Does inclusion of Demand Response reduce overall customer costs?

Plans F and S differ from plans A and G, respectively, only in that they do not include DR. Therefore, these plans can be compared to assess the impact on cost and other performance measures due to inclusion of DR.

What level of DSM, RAP or MAP, results in lower costs?[14]

Two alternative resource plans provide a comparison to evaluate the cost-effectiveness of RAP vs MAP energy efficiency. Plan F includes RAP EE only and Plan S includes MAP EE only. Additionally, plans with the same attributes except for the level of energy efficiency and demand response resources have been evaluated and provide a comparison for the DSM portfolios: Plans A and G, Plans H and Q, and Plans I and R.

Is early retirement of Labadie Energy Center and replacement with MAP cost effective?

Two alternative resource plans include the early retirement of Labadie Energy Center (i.e., Plans M and O). Plan M evaluates the cost effectiveness of early retirement of Labadie Energy Center and replacement with MAP.[15]

[14] Ameren Missouri added demand response programs to the alternative resource plans starting in 2019 and not only in years where there was a need to reduce peak demand due to shortfalls in Ameren Missouri's planning capacity reserve margins; EO-2012-0142 12; 4 CSR 240-22.060(3)(A)7

[15] EO-2011-0271 Order; 4 CSR 240-22.060(3)(A)7

Schedule MM-S7

Is early retirement of Rush Island Energy Center and replacement with MAP cost effective?

Two alternative resource plans include the early retirement of Rush Island Energy Center (i.e., Plans N and P). Plan N evaluates the cost effectiveness of early retirement of Rush Island Energy Center and replacement with MAP.[16]

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

Each alternative resource plan evaluated at least meets the minimum requirements of the RES. 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. All alternative resource plans that are identified as "Balanced" (i.e., Plans H, I, J, K, O, P, Q, and R) include investment in renewable resources that are above and beyond needed for RES compliance. Also included are resource plans that feature wind as a major supply side resource (Plans E and L).

What is the impact of pursuing only new renewables?

Plan L is the all renewables alternative resource plan without DSM beyond MEEIA Cycle 1.[17]

How do various supply-side resource options compare?

The relative performance of the new supply-side resources can be determined by comparing Plans A through E.

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

Plans J, K, and L evaluate the impact if DSM cost recovery and incentive requirements are not met.

The type, size, and timing of resource additions/retirements for the alternative resource plans (i.e., Plans A-S) are provided in Appendix A and also in the electronic workpapers.[18]

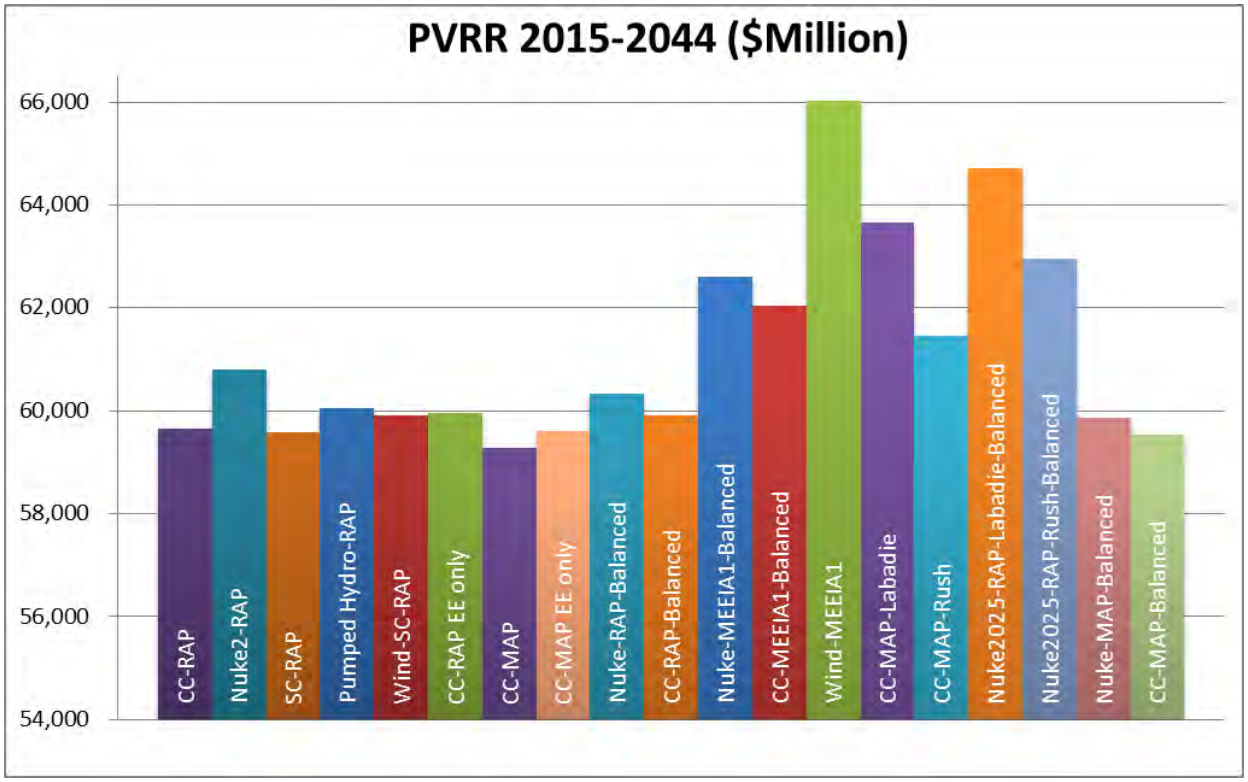
Integration, sensitivity and risk analyses for the evaluation of alternative resource plans were done assuming that rates would be adjusted annually for the 20-year planning horizon and 10 additional years for end effects, and by treating both supply-side and

[16] EO-2011-0271 Order; 4 CSR 240-22.060(3)(A)7
[17] 4 CSR 240-22.060(3)(A)2
[18] None of the alternative resource plans analyzed include any load-building programs 4 CSR 240-22.060(3)(B); 4 CSR 240-22.080(2)(D); 4 CSR 240-22.060(3)(D)

Schedule MM-S7

demand-side resources on an equivalent basis. Integration analysis was performed on the most likely scenario of the probability tree (Scenario 8) as explained in Chapter 2. Integration analysis PVRR results are shown below in Figure 9.8 Results for the remaining performance measures for integration analysis are provided in the workpapers.[19]

Figure 9.8 Integration PVRR Results



It should be noted that all costs and benefits in all analyses were expressed in nominal dollars, and Ameren Missouri's current discount rate 6.46% was used for present worth and levelization calculations. Also, in all integration, sensitivity, and risk analyses, it was assumed that rates are adjusted annually (no regulatory lag).[20]

9.6 Sensitivity Analysis

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

[19] 4 CSR 240-22.060(4)
[20] 4 CSR 240-22.060(2)(B); EO-2011-0271 Order

Schedule MM-S7

9.6.1 Uncertain Factors[21]

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	Candidates?	Critical?	Included in Final Probability Tree?
Load Growth	✓**	--	✓
Interest Rates	✓	✗	✓‡
Carbon Policy	✓**	--	✓
Fuel Prices			
Coal	✓	✓	✓
Natural Gas	✓**	--	✓
Nuclear	✓	✗	✗
Project Cost (includes transmission interconnection costs)	✓	✓	✓
Project Schedule	✓	✗	✗
Purchased Power	✗	✗	✗
Emissions Prices			
SO_2	✗	✗	✗
NOx	✗	✗	✗
CO_2	✓**	--	✓
Forced Outage Rate	✓	✗	✗
DSM Load Impacts	✓	✓†	✓†
DSM Cost	✓	✓†	✓†
Fixed and Variable O&M	✓	✗	✗
Return on Equity	✓	✗	✓‡
Nuclear Incentives	✓	✗	✗
Wind Capacity Factor	✓	✗	✗

** Included in the scenario probability tree
-- Not tested in sensitivity analysis
† DSM impacts and costs were combined
‡ Return on Equity and Long-term Interest rates were combined

[21] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5) (B) through (F)
4 CSR 240-22.060(5); 4 CSR 240-22.060(5) (A) through (M)

Chapter 2 describes how three of the candidate uncertain factors were determined to be critical dependent uncertain factors, which defined the scenarios. The three critical dependent uncertain factors are: load growth, environmental policy, and natural gas prices. Energy prices are an output of the scenarios 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 quantitative analysis.

- 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.
- SO_2 and NOx Emissions Prices – SO_2 and NOx Emissions Prices were excluded as candidates because of the expectation for very low prices as a result of current and expected environmental regulations.

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

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

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.

Uncertain Factor Ranges[22]

We use the sensitivity analysis to examine whether or not candidate independent uncertain factors have a significant impact on the performance of alternative resource plans, as measured by their impact on PVRR.

Most of 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. One of the candidates, nuclear tax incentive, had a 2-level range of values, which were a low value and a high value.

[22] 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

Schedule MM-S7

Unless the meaning of low, base, and high are treated in a standardized manner, the probability of occurrence for the value used for “low” for one uncertain factor could be significantly different than the probability of occurrence for the value used for “low” for other uncertain factors. Thus, for majority of the uncertain factors, Ameren Missouri standardized the meaning of low to be the value found at the 5th percentile of a probability distribution of values for an uncertain factor, the value at the 50th percentile to be the base value, and the value at the 95th percentile to be the high value. The probability distribution for each candidate uncertain factor was inferred from a series of estimated values produced by subject matter experts for each uncertain factor.

For the majority of candidate uncertain factors, probability distributions were used to obtain the values for low, base, and high. This process began with subject matter experts providing/revising estimates of (A) an expected value, (B) estimates of deviations from that expected value, and (C) the probabilities of those deviations from the expected value. That information was used to create the probability distribution collectively implied by that data. Values at the 5th, 50th, and 95th percentiles of those implied probability distributions were then obtained for use as the values for low, base, and high for the various candidate independent uncertain factors. Appendix A contains the standard value, estimated deviation and probabilities for project costs, project schedule, fixed operations & maintenance (FOM), variable operations & maintenance (VOM), equivalent forced outage rate (EFOR), environmental capital expenditures, and transmission-retirement expenditures.

Example

The standard value for Fixed Operations & Maintenance (FOM), for the greenfield Combined Cycle option is $7.62/kW-year (2013$). FOM and some other candidate uncertain factors are characterized by differing standard values among various supply-side types, while standard values for some other candidate uncertain factors are not uniquely correlated to each supply side type. For example the Long Term Interest Rates uncertain factor does not differ depending on the supply-side type; it is the same across all supply-side types.

The subject matter experts, in this example, members of Ameren Missouri’s generation organization, provided estimates of deviations from the standard value as well as the probabilities of those deviations. An example of that initial uncertainty distribution is shown in Table 9.8. In this example, the first of these estimates for FOM deviations was a -20% deviation from the FOM standard value with a 5% probability of occurring. These deviation estimates provide sufficient information to derive continuous

Table 9.8

CC Fixed O&M Uncertainty Distribution	
Deviation	**Probability**
-20%	5%
-10%	25%
0%	40%
15%	25%
30%	5%

probability distributions from which the low/base/high values can be derived.

The process of developing the probability distributions involved using Crystal Ball software. This software, when provided with a series of observations like these deviation estimates, can determine the probability distribution implied by the set of estimates. An example of the result of analyzing deviation estimates using Crystal Ball is shown Figure 9.9. From this distribution the values for the low, base, and high values ($6.32, $7.64, $9.59) are shown at the respective percentiles in Figure 9.9 and represent the 5th, 50th, and 95th percentiles.

Figure 9.9 Example of Probability Distribution---CC Fixed O&M

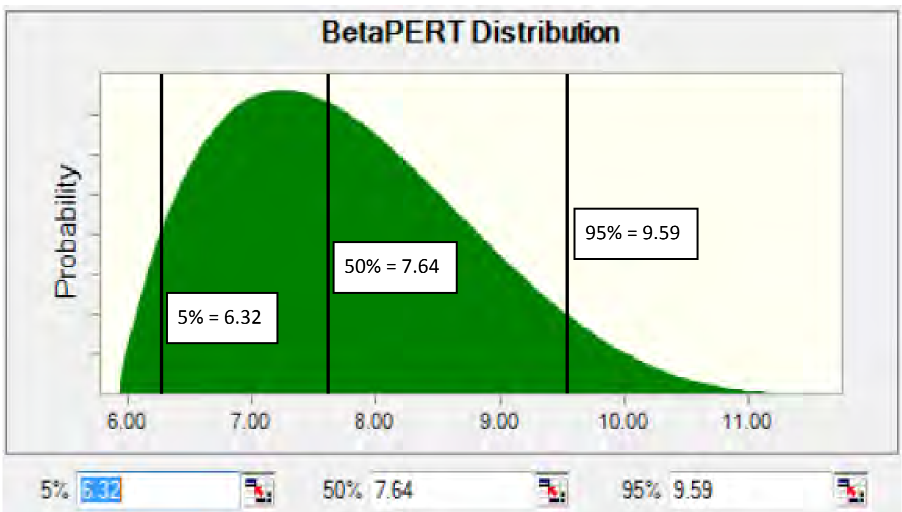


Figure 9.10 shows the resulting range of project costs, which also include interconnection costs estimates, for each new supply-side resource. For most of the technologies shown in Figure 9.10, base values found at 50th percentile were very close to their expected values. For nuclear technology, however, the base value inferred from the probability distribution was 27% higher than the expected value, $6,350/kW vs $5,000/kW.[23] Table 9.9 and Table 9.10 contain 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.

[23] EO-2011-0271 Order

Figure 9.10 Resource-Specific Project Cost Ranges ($/kW)

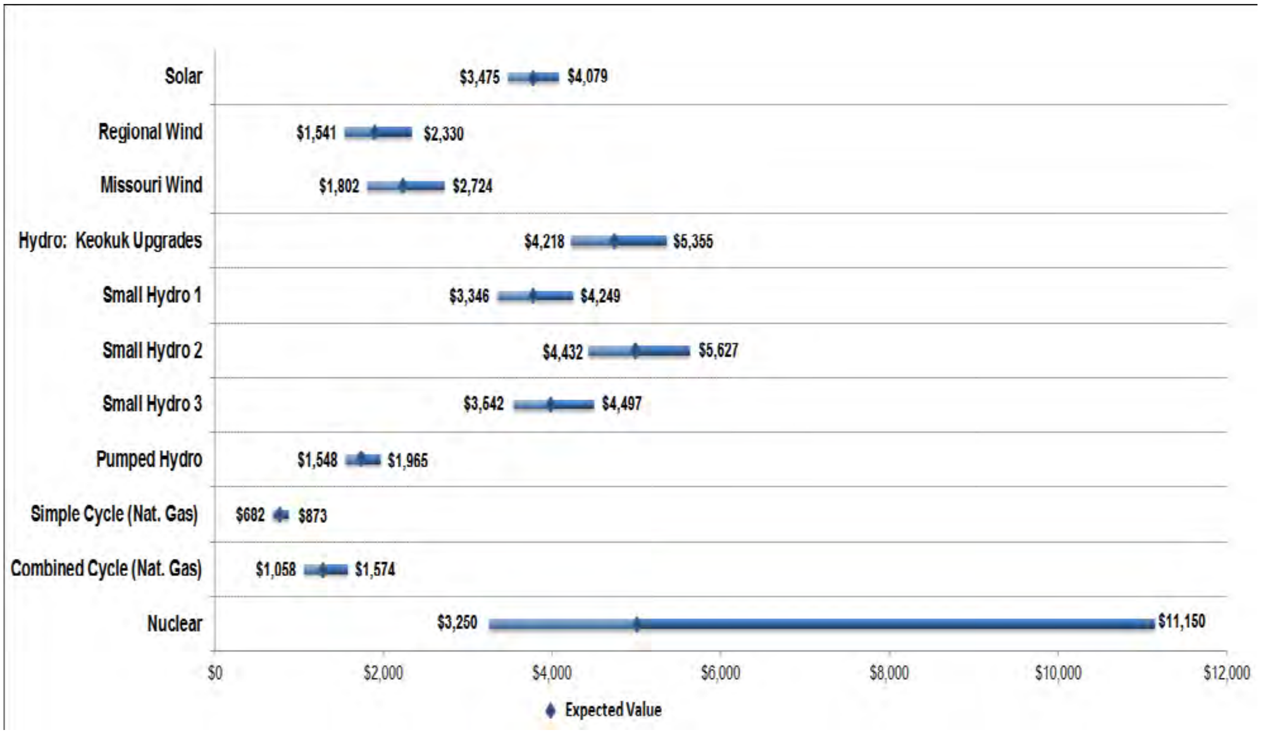


Table 9.9 Resource-Specific Uncertain Factor Ranges

Uncertain Factor	Value	Probability	CC (Nat. Gas)	SC (Nat. Gas)	Pumped Hydro	Hydro: Keokuk Upgrades	Nuclear (100%)	Small Hydro 1	Small Hydro 2	Small Hydro 3	Solar	Regional Wind	Missouri Wind
Project Cost ($/kW)	Low	10%	$1,058	$682	$1,548	$4,218	$3,250	$3,346	$3,542	$4,432	$3,475	$1,541	$1,802
	Base	80%	$1,297	$774	$1,756	$4,786	$6,350	$3,798	$4,020	$5,030	$3,777	$1,898	$2,219
	High	10%	$1,574	$873	$1,965	$5,355	$11,150	$4,249	$4,497	$5,627	$4,079	$2,330	$2,724
Project Schedule (months)	Low	10%	27	27	55	46	46	46	46	46	18	36	36
	Base	80%	36	36	73	61	61	61	61	61	24	48	48
	High	10%	48	48	95	79	79	79	79	79	32	63	63
Fixed O&M ($/kW-yr)	Low	10%	$6.32	$6.20	$2.81	$4.23	$111.38	$0.00	$0.00	$0.00	$20.76	$24.08	$24.08
	Base	80%	$7.64	$7.48	$3.39	$5.11	$136.89	$0.00	$0.00	$0.00	$25.06	$29.07	$29.07
	High	10%	$9.59	$9.36	$4.23	$6.41	$168.85	$0.00	$0.00	$0.00	$31.42	$36.44	$36.44
Variable O&M ($/MWh)	Low	10%	$1.52	$11.69	$2.82	$0.41	$1.75	$4.35	$4.35	$4.35	$0.00	$0.00	$0.00
	Base	80%	$3.94	$13.92	$3.50	$0.51	$2.17	$5.41	$5.41	$5.41	$0.00	$0.00	$0.00
	High	10%	$6.36	$16.15	$4.42	$0.65	$2.74	$6.83	$6.83	$6.83	$0.00	$0.00	$0.00
EFOR (%)	Low	10%	1%	0%	0%	*	1%	*	*	*	*	*	*
	Base	80%	2%	5%	5%	*	2%	*	*	*	*	*	*
	High	10%	5%	10%	10%	*	3%	*	*	*	*	*	*
Wind Capacity Factor (%)	Low	10%	---	---	---	---	---	---	---	---	---	33.4%	---
	Base	80%	---	---	---	---	---	---	---	---	---	38.5%	---
	High	10%	---	---	---	---	---	---	---	---	---	40.3%	---

Notes: * Assumed capacity factor includes effects of Forced Outage Rate
--- Not Applicable

The Regional Wind capacity factors are based on the Black & Veatch Renewable Portfolio Study for Priority Development Areas 1, 2, 3, 11, 18, and 19 as mentioned in Chapter 6. The low and high capacity factor values are the lowest and highest values, respectively, among the specified priority development areas.

As discussed in Chapter 2, the long-range interest rate assumptions are based on the December 1, 2013, semi-annual Blue Chip Financial Forecast, a consensus survey of 49 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 2014 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 (ROE) using the same process as discussed in Chapter 2.

Table 9.10 Non-Resource Specific Uncertain Factor Ranges

Uncertain Factors	Low	Base	High
Probability -->>	10%	80%	10%
Nuclear Fuel Price	Varies By Year		
Coal Price	Varies By Year		
Long Term Interest Rates	5.8%	6.7%	7.6%
Return on Equity	11.0%	11.4%	11.8%
Probability -->>	50%		50%
Nuclear Incentives	No Incentive		$0.018/kWh
Probability -->>	45%	50%	5%
Energy Efficiency Load Impact			
MAP	82%	100%	100%
RAP	91%	100%	109%
Demand Response Load Impact			
MAP	21%	100%	286%
RAP	1%	100%	330%
Demand Side Management Cost			
MAP	78%	100%	113%
RAP	82%	100%	131%

One of the candidates, nuclear tax incentives, was characterized by a 2-level range of values, which were a low value (no incentives) and a high value. As a default, with a 50% probability, no nuclear tax incentives were included. As an alternative, with a 50% probability, a nuclear tax incentive of $0.018/kWh up to $125 million per year was included for the first eight years of operation for nuclear resources.

9.6.2 Sensitivity Analysis Results[24]

To conduct the sensitivity analysis, each of the 19 candidate resource plans was analyzed using the varying value levels (low/base/high or default/alternative) for each of the candidate independent uncertain factors, for the most likely scenario in the probability tree (Scenario 8). An uncertainty-probability weighted result (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.

The sensitivity analysis identified four critical independent uncertain factors: DSM Impacts and Costs, Project Costs, Coal Prices and ROE/Interest Rates. Table 9.11 shows the change in PVRR ranking (i.e., number of positions the plan moved in the ranking) for the four critical independent uncertain factors compared to the integration/base value. Table 9.12 shows the change in PVRR ($) for the four critical independent uncertain factors compared to the integration/base value.

Table 9.11 Critical Independent Uncertain Factors – Change in PVRR Ranking

			Critical Independent Uncertain Factors											
			DSM Impacts			Project Cost			Coal Price			ROE/Interest Rates		
Plan	Plan Description	Integration	DSM-PWA	DSM-Low	DSM-High	Prj Cost-PWA	Prj Cost-Low	Prj Cost-High	Coal Price-PWA	Coal Price-Low	Coal Price-High	ROE-PWA	ROE-Low	ROE-High
A	CC-RAP	5	0	(1)	(1)	0	1	0	0	0	0	0	0	0
B	Nuke2-RAP	12	0	0	0	0	(1)	1	0	0	1	0	0	0
C	SC-RAP	3	(1)	(1)	(1)	0	2	(1)	0	0	0	0	1	0
D	Pumped Hydro-RAP	10	0	(1)	(2)	0	2	(3)	0	0	0	0	0	0
E	Wind-SC-RAP	8	0	0	(2)	0	(1)	1	0	0	0	0	(1)	0
F	CC-RAP EE only	9	(3)	(4)	2	0	0	(1)	0	0	0	0	0	0
G	CC-MAP	1	0	0	0	0	0	0	0	0	0	0	0	0
H	Nuke-RAP-Balanced	11	0	0	(1)	0	(1)	0	0	0	0	0	0	0
I	CC-RAP-Balanced	7	0	0	(2)	0	1	(1)	0	0	0	0	1	0
J	Nuke-MEEIA1-Balanced	15	0	0	1	0	0	0	0	0	2	0	0	0
K	CC-MEEIA1-Balanced	14	0	0	0	0	0	0	0	(1)	0	0	0	0
L	Wind-MEEIA1	19	0	0	0	0	(2)	0	0	(1)	0	0	0	0
M	CC-MAP-Labadie	17	0	0	0	0	1	0	0	0	(1)	0	0	0
N	CC-MAP-Rush	13	0	0	0	0	0	(1)	0	1	(1)	0	0	0
O	Nuke2025-RAP-Labadie-Balanced	18	0	0	0	0	1	0	0	1	0	0	0	0
P	Nuke2025-RAP-Rush-Balanced	16	0	0	(1)	0	0	0	0	0	(1)	0	0	0
Q	Nuke-MAP-Balanced	6	3	4	1	0	(3)	4	0	0	0	0	0	0
R	CC-MAP-Balanced	2	2	4	1	0	0	2	0	0	0	0	0	0
S	CC-MAP EE only	4	(1)	(1)	5	0	0	(1)	0	0	0	0	(1)	0

[24] 4 CSR 240-22.060(5); 4 CSR 240-22.060(7)(A); 4 CSR 240-22.060(7)(C)1A

Table 9.12 Critical Independent Uncertain Factors – Change in PVRR ($)

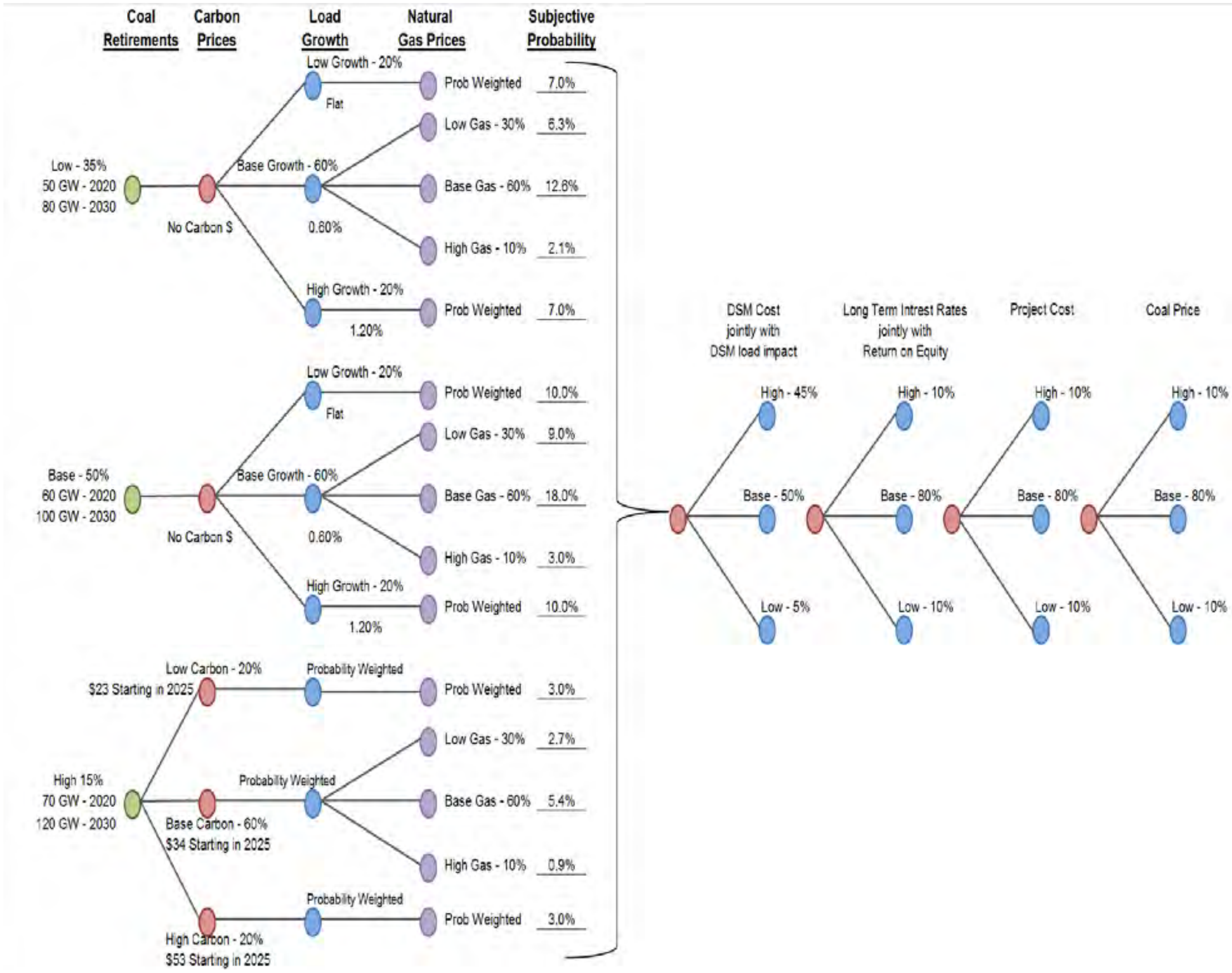
			Critical Independent Uncertain Factors											
			DSM Impacts			Project Cost			Coal Price			ROE/Interest Rates		
Plan	Plan Description	Integration	DSM-PWA	DSM-Low	DSM-High	Prj Cost-PWA	Prj Cost-Low	Prj Cost-High	Coal Price-PWA	Coal Price-Low	Coal Price-High	ROE-PWA	ROE-Low	ROE-High
A	CC-RAP	59,642	129	349	(575)	29	(735)	1,022	(109)	(3,816)	2,729	(12)	(864)	748
B	Nuke2-RAP	60,778	129	349	(575)	75	(1,575)	2,322	(109)	(3,816)	2,729	(13)	(974)	844
C	SC-RAP	59,579	129	349	(575)	28	(690)	968	(109)	(3,816)	2,729	(12)	(857)	742
D	Pumped Hydro-RAP	60,036	129	349	(575)	27	(734)	1,008	(109)	(3,816)	2,729	(12)	(887)	768
E	Wind-SC-RAP	59,890	129	349	(575)	32	(918)	1,241	(109)	(3,816)	2,729	(12)	(905)	783
F	CC-RAP EE only	59,941	62	156	(156)	30	(816)	1,115	(109)	(3,816)	2,729	(12)	(887)	767
G	CC-MAP	59,266	242	588	(463)	29	(735)	1,022	(109)	(3,816)	2,729	(12)	(861)	745
H	Nuke-RAP-Balanced	60,331	129	349	(575)	47	(1,133)	1,607	(109)	(3,816)	2,729	(12)	(926)	801
I	CC-RAP-Balanced	59,888	129	349	(575)	30	(817)	1,119	(109)	(3,816)	2,729	(12)	(883)	764
J	Nuke-MEEIA1-Balanced	62,597	0	0	0	56	(1,469)	2,031	(109)	(3,816)	2,729	(14)	(1,011)	875
K	CC-MEEIA1-Balanced	62,029	0	0	0	34	(1,088)	1,432	(109)	(3,816)	2,729	(13)	(962)	832
L	Wind-MEEIA1	66,021	0	0	0	103	(4,238)	5,266	(109)	(3,816)	2,729	(22)	(1,554)	1,339
M	CC-MAP-Labadie	63,654	242	588	(463)	33	(1,262)	1,594	(65)	(2,194)	1,547	(13)	(936)	804
N	CC-MAP-Rush	61,433	242	588	(463)	30	(934)	1,236	(89)	(2,954)	2,062	(12)	(881)	762
O	Nuke2025-RAP-Labadie-Balanced	64,702	129	349	(575)	66	(1,856)	2,514	(65)	(2,194)	1,547	(14)	(1,018)	875
P	Nuke2025-RAP-Rush-Balanced	62,935	129	349	(575)	64	(1,608)	2,250	(89)	(2,954)	2,062	(13)	(984)	852
Q	Nuke-MAP-Balanced	59,846	242	588	(463)	46	(1,052)	1,514	(109)	(3,816)	2,729	(12)	(901)	780
R	CC-MAP-Balanced	59,512	242	588	(463)	30	(817)	1,119	(109)	(3,816)	2,729	(12)	(880)	762
S	CC-MAP EE only	59,582	161	358	0	29	(735)	1,022	(109)	(3,816)	2,729	(12)	(863)	747

DSM Impacts & Costs and Project Costs were selected as critical independent uncertain factors because of the variety in the change in PVRR ranking. Coal price was selected as a critical independent uncertain factor because of the high impact potential on relative results of early retirement plans compared to other plans. ROE/Interest Rates was selected as a critical independent uncertain factor as a degree of conservatism since it was selected as a critical independent uncertain factor in previous Ameren Missouri IRP's and since it can significantly influence the results of different levels of capital intensiveness between plans in combination with project cost uncertainty.

These four critical independent uncertain factors 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 9.11, with the four critical independent uncertainty factors shown on the right-hand side.

Schedule MM-S7

Figure 9.11 Final Probability Tree Including Sensitivity Analysis Results[25]



9.7 Risk Analysis[26]

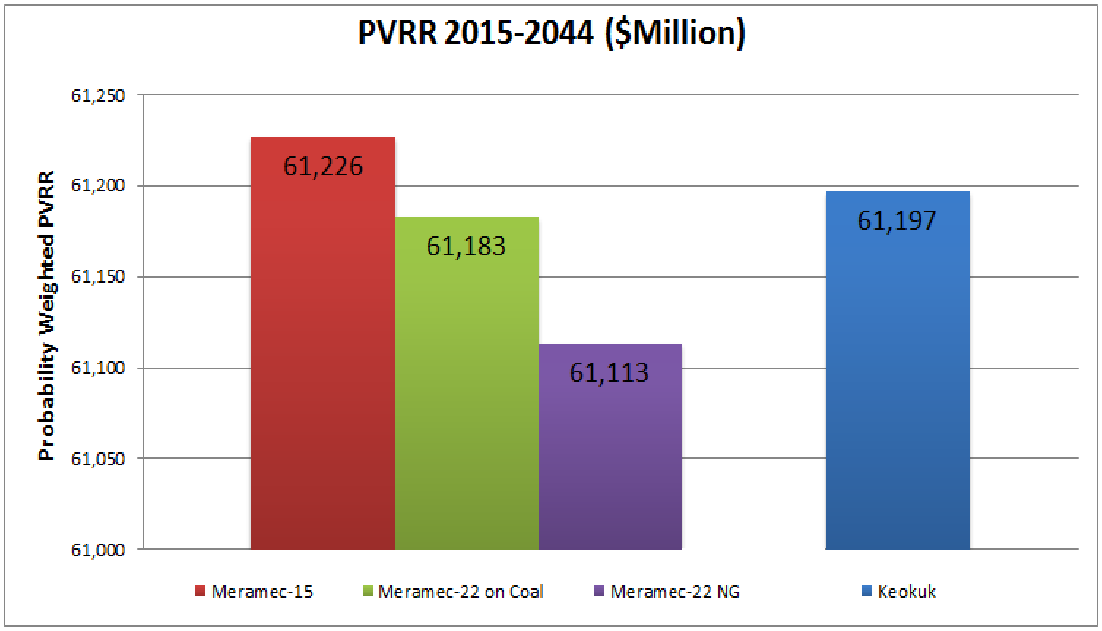
The Risk Analysis consisted of running each of the candidate resource plans (i.e., pre-analysis plans and Plans A-S) in Table 9.6 through each of the branches on the final probability tree shown in Figure 9.11. The probability tree consisted of 1,215 different branches. Each branch is the combination of different value levels among the fifteen scenarios, themselves defined by combinations of the three critical dependent uncertain factors (load growth, gas prices, and environmental regulations/carbon policy), and the four critical independent uncertain factors (DSM cost together with DSM load impacts, interest rates together with return on equity, project cost, and coal price). 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%.

[25] 4 CSR 240-22.060(6)
[26] 4 CSR 240-22.060(6)

9.7.1 Risk Analysis Results

As mentioned in Section 9.3, the conclusions of the pre-analysis were tested by evaluating them under the full range of scenarios and critical uncertain factors used for risk analysis. The pre-analysis PVRR results from the risk analysis are shown in Figure 9.12. Figure 9.12 shows that the PVRR results under risk analysis are consistent with the initial findings for both Meramec and Keokuk and have therefore been appropriately included in all alternative resource plans.

Figure 9.12 Probability Weighted PVRR Results: Pre-Analysis



The PVRR results of the risk analysis of the 19 alternative resource plans are shown in Figure 9.13. The levelized rate results for the risk analysis are shown in Figure 9.14. It is important to consider both the PVRR and levelized rate impacts. The PVRR results are lower for plans with RAP or MAP DSM compared to the other plans. In addition, the plans with RAP or MAP exhibit lower levelized rates compared to the other plans. The additional coal retirement plans (i.e., Plans M through P) exhibit much higher PVRR results and much higher levelized rates compared to the other plans. Plan L (Wind-MEEIA1) exhibits the highest PVRR and the second highest levelized rates. Results for other performance measures can be found in Appendix A.

Figure 9.13 Probability-Weighted PVRR Results: Alternative Resource Plans

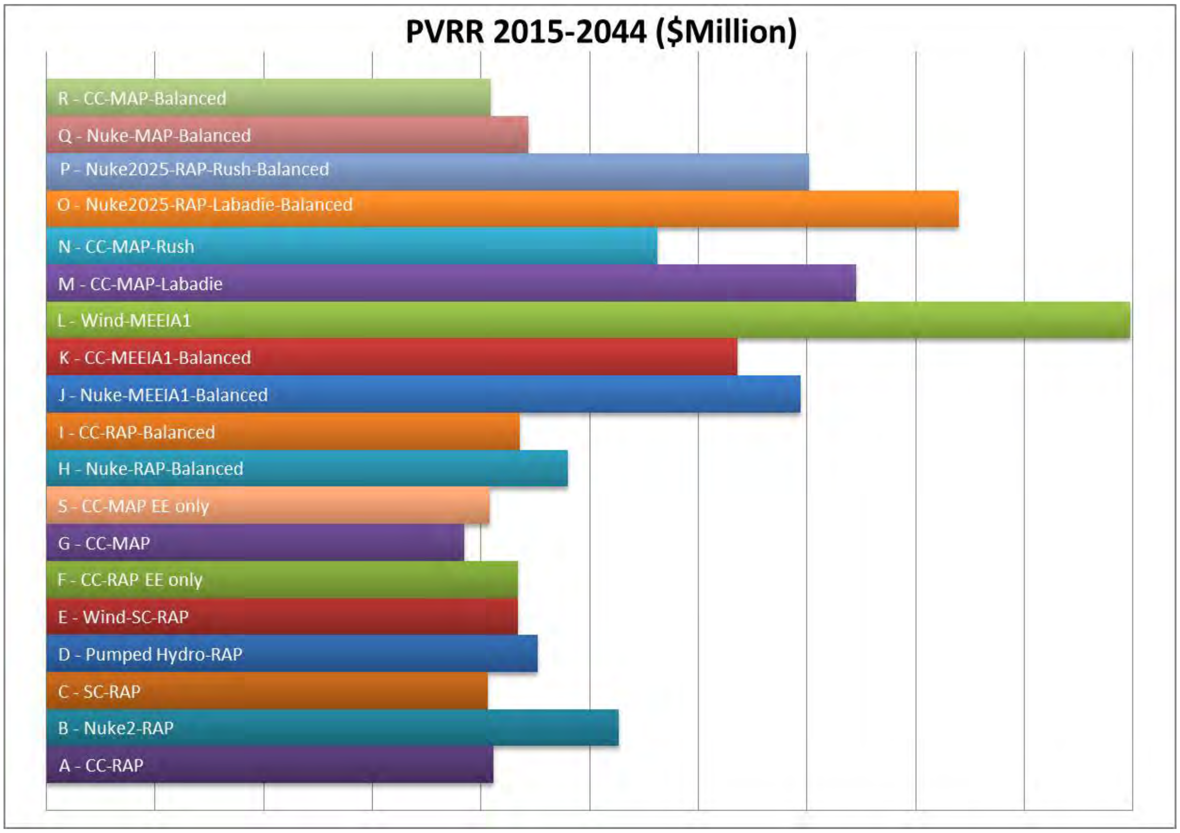
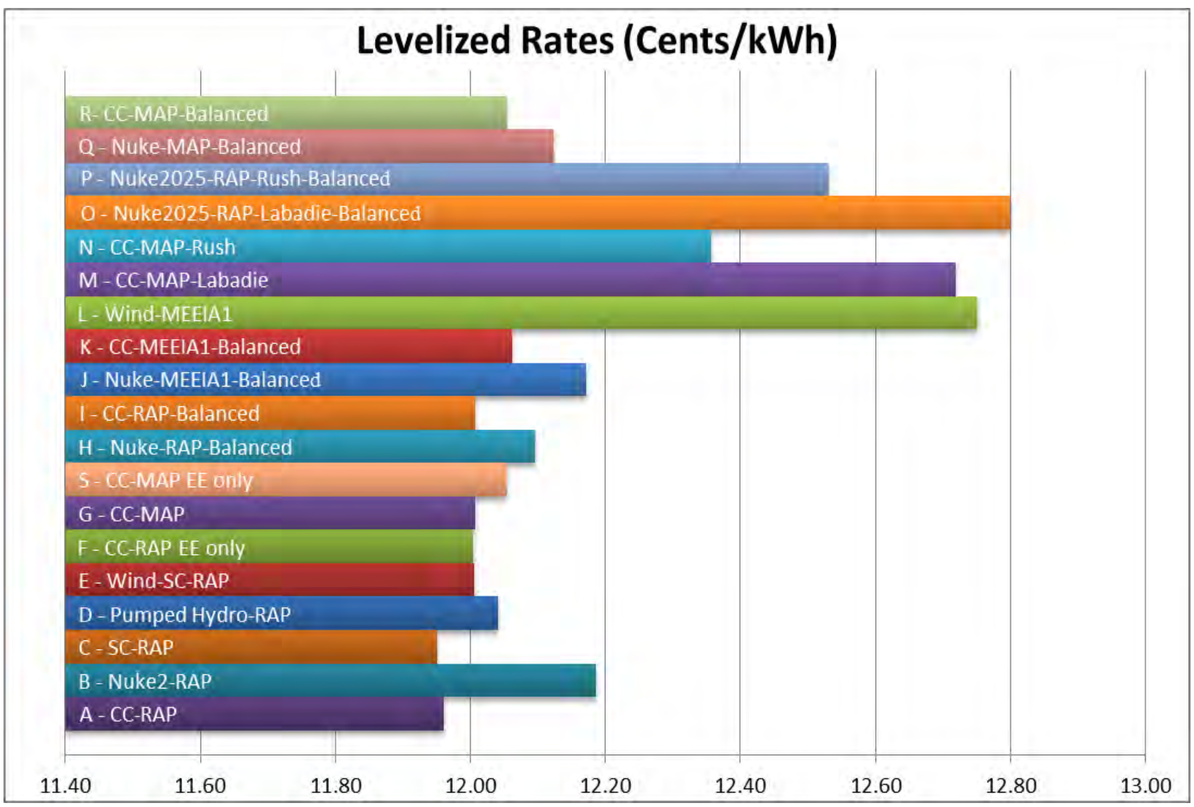


Figure 9.14 Probability-Weighted Levelized Rates: Alternative Resource Plans



Schedule MM-S7

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 19 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.

- The risk analysis validates the Meramec Retirement Solution---conversion of Meramec Units 1&2 to Natural Gas December 31, 2015 and Units 3&4 continue on coal with retirement by December 31, 2022---is the solution for the candidate alternative resource plans.
- The risk analysis validates the exclusion of the potential Keokuk expansion from alternative resource plans.
- Inclusion of energy efficiency and demand response results in generally lower costs and rates
- Combined cycle resources are an attractive option for near-term development due to their competitive overall cost, relatively low capital cost and relatively short lead time.
- Meeting all future resource needs with renewable resources (Plan L) results in the highest PVRR and the second highest levelized rates.
- Plans with additional renewable resources beyond those included for RES compliance are competitive from a cost standpoint.
- Nuclear generation remains a competitive resource for future baseload capacity.
- Early retirement of coal generation, even if replaced with cost-effective demand side resources, results in significantly higher costs to customers and rates.

9.9 Resource Plan Model

Ameren Missouri has used a modular approach to modeling for this IRP. Certain challenges associated with the use of the MIDAS model – financial modeling limitations, trouble-shooting difficulty, etc… – led us to reevaluate our modeling tools and approach. Discussions in recent years with Ventyx, the vendor that licenses MIDAS, have indicated that their long-term model plans do not include continued development of MIDAS. After identifying and assessing the capabilities of other "off-the-shelf" alternatives, Ameren Missouri elected to replace MIDAS for integration and risk analysis with 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 Simtec, Inc., typically referred to as RTSim (Real-Time Simulation) for production cost modeling.[27] RTSim provides a realistic simulation of an electric generating system for a period of a few days to multiple years. According to Simtec's marketing materials, RTSim finds higher profitability, lower risk, "free market" transactions, maintenance schedules, emission compliance strategies and fuel procurement schedules while maintaining reliable, reasonable cost service to the traditional regulated market sector.

RTSim simulates hourly chronological dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The model plans are based on a capacity planning spreadsheet, which was used to determine the timing of new resources. The RTSim 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 allowance costs, scheduled maintenance outages, and forced and partial outage rates. The generation fleet is dispatched competitively against market prices. The multi-area mode of the Ventyx Midas® model was used for the creation of forward price curves as described in Chapter 2.

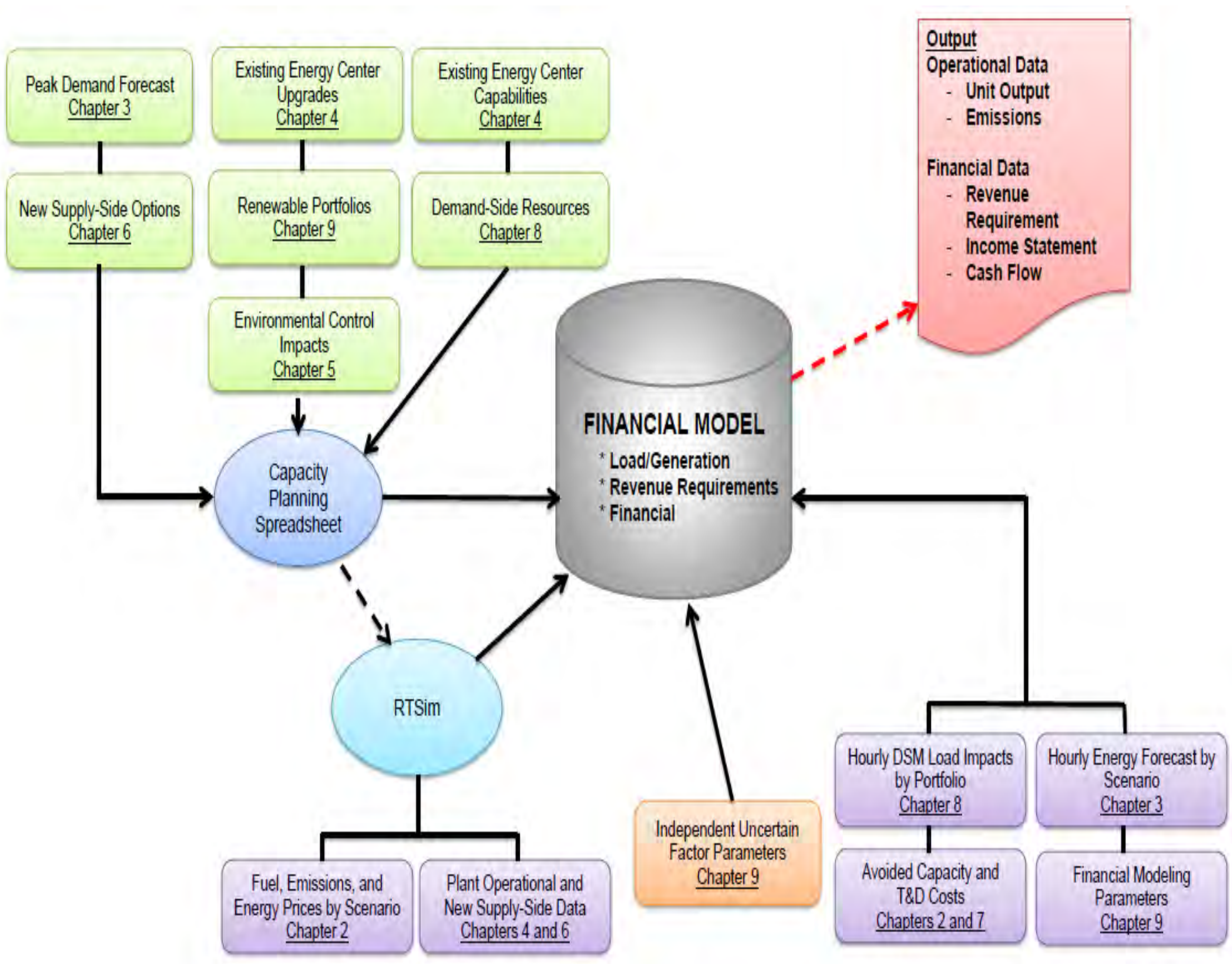
Ameren Missouri developed its own revenue requirements and financial model using Microsoft Excel. This model incorporates the capacity position and RTSim outputs, as well as other financial aspects regarding costs exterior to the direct operation of units and other valuable information that is necessary to properly evaluate the economics of a

[27] 4 CSR 240-22.060(4)(H); EO-2014-0062 d

resource portfolio. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts along with revenue requirement and various financial and credit metrics.

Figure 9.15 shows how the various assumptions are integrated into the financial model.

Figure 9.15 Resource Plan Model Framework[28]



[28] 4 CSR 240-22.060(4)(H)

Schedule MM-S7

Future Plans for Modeling Tools[29]

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 for this IRP, 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 long 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 may be able to identify a production costing solution that can be applied to long-term resource planning, fuel budgeting, and possibly shorter-term trading support analysis.

We expect to continue our efforts to improve the efficiency, effectiveness and transparency of our modeling tools into 2015. The nature and timing of any changes we 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 our business needs and objectives.

[29] EO-2014-0062 e

Schedule MM-S7

9.10 Compliance References

Schedule MM-S7

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, demand response, various types of new renewable and conventional generation, and retirement of each of its existing coal-fired generators.*
- *In addition to the scenario variables and modeling discussed in Chapter 2, two critical independent uncertain factors have been included in the final probability tree for risk analysis: coal prices and demand-side management (DSM) costs.*

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. Development of **planning objectives** to guide the development of alternative resource plans.
4. 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.
5. Identification and screening of **candidate uncertain factors**, which are key variables that can influence the performance of alternative resource plans.
6. **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.
7. **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 6.

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 includes 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. As has been mentioned, a pre-analysis was used to determine which Meramec and Keokuk options would be included in all alternative resource plans.

Figure 9.1 Attributes of Alternative Resource Plans

Retirements (End of Year)
- Meramec Retired 2022/2020
- Sioux Retired 2033
- Labadie 2 Units Retired 2036/2024
- Labadie 2 Units Retired 2042/2024
- Rush Island Retired 2045/2024

Energy Efficiency
- Maximum Achievable Potential (MAP)
- Realistic Achievable Potential (RAP)
- Missouri Energy Efficiency Investment Act (MEEIA) Cycle 2 Only

Demand Response
- MAP
- RAP
- None

New Supply-Side Types
- Combined Cycle (Nat. Gas)
- Simple Cycle (Nat. Gas)
- Nuclear
- Pumped Hydroelectric
- Solar
- Wind with Simple Cycle

Renewable Portfolios
- Missouri Renewable Energy Standard (RES)
- RES Plus

9.2 Capacity Position

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

- Existing plant capabilities based on Ameren Missouri's annual generating unit rating update (i.e., July 2017 planned ratings)
- Existing obligations for capacity purchases and sales
- Peak demand forecast, as described in Chapter 3

[1] 4 CSR 240-22.060(1); 4 CSR 240-22.060(3)

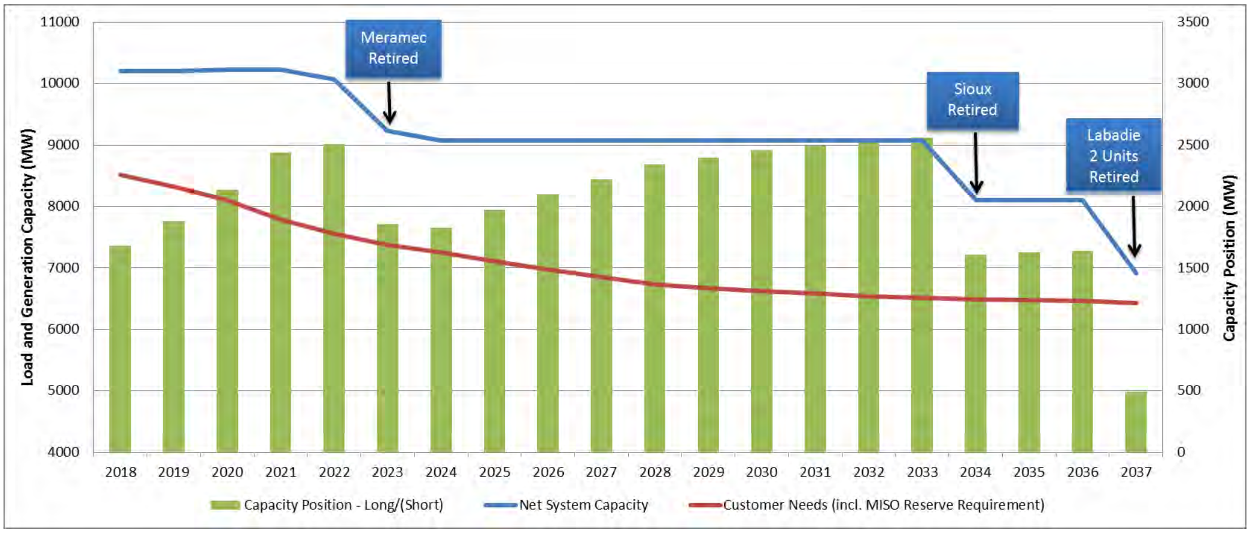
- Planning reserve margin (PRM) requirement, based on MISO's Planning Year 2017 Loss of Load Expectation (LOLE) Study Report (November 2016). Table 9.1 shows the MISO System PRM from 2018 through 2026. The long-range PRM was assumed to continue at 15.7% through the remainder of the planning horizon.

Table 9.1 MISO System Planning Reserve Margins 2015 through 2023

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026
PRM Installed Capacity	15.6%	15.3%	15.4%	15.5%	15.5%	15.6%	15.6%	15.7%	15.7%

Figure 9.2 shows Ameren Missouri's net capacity position with no new major generating resources. The chart shows 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 energy efficiency and demand response. The system capacity includes the capacity benefit of the RES Compliance portfolio.

Figure 9.2 Net Capacity Position – No New Resources (Baseline)



Retirements

Ameren Missouri is considering retirement of some or all of its six older gas- and oil-fired CTG units – Fairgrounds, Kirksville, Meramec CTG-1, Meramec CTG-2, Mexico, Moberly, and Moreau – with a total net capacity of 324 MW, over the next 20 years. Chapter 4 - Table 4.3 provides a summary of the planned CTG retirements. The CTG retirements were included in all alternative resource plans.

Coal energy center retirements were also included in the capacity planning process. Sioux retirement by December 31, 2033, was common in all resource plans, based on prior analysis of Ameren Missouri's coal power plant life expectancy by Black and Veatch. Two different Meramec retirement options were considered: 1) retirement by December 31, 2020, and 2) retirement by December 31, 2022. While the retirement dates for two units at Labadie and Rush Island, as determined by the Black and Veatch life expectancy study, are beyond the 20-year planning horizon, we have evaluated potential early retirements for both energy centers - by December 31, 2024. The alternative retirement dates for Labadie and Rush Island were based on the ability to avoid significant costs associated with environmental regulations; the potential for an explicit price on carbon starting in 2025, included in the scenarios described in Chapter 2, was the primary driver for the alternate retirement date. Labadie retirement by the end of 2024 coupled with Meramec retirement by the end of 2020 was also evaluated in an alternative resource plan.[2]

DSM Portfolios

DSM portfolios were included in capacity planning separately as energy efficiency and demand response. Energy efficiency (EE) and demand response (DR) 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) RAP EE Only, 3) RAP DR Only, 4) MAP EE and DR, 5) MAP EE Only, 6) MAP DR Only, and 7) No DSM after MEEIA Cycle 2. The No DSM portfolio reflects completion of Ameren Missouri's current three-year program cycle with no further energy efficiency or demand response during the planning horizon.

Renewable Portfolios[3]

Compliance with Missouri's Renewable Energy Standard (RES) was updated to reflect current assumptions, including baseline revenue requirements, and an updated 10 year forward looking model which calculates the impact of a 1% rate cap.

Ameren Missouri performed its RES compliance analysis with the *2017 IRP RES Compliance Filing Model* (model). The model is designed to calculate the retail rate impact, as required by the Commission's RES rules.[4] This model determines the quantity of renewable energy needed to meet both the overall RES portfolio standard and the 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 expected renewable energy credit (REC) position is presented in Figure 9.3.

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[2] EO-2017-0073 1.E
[3] EO-2017-0073 1.N
[4] 4 CSR 240-20.100(5)

Figure 9.3 Ameren Missouri's RES REC Positions

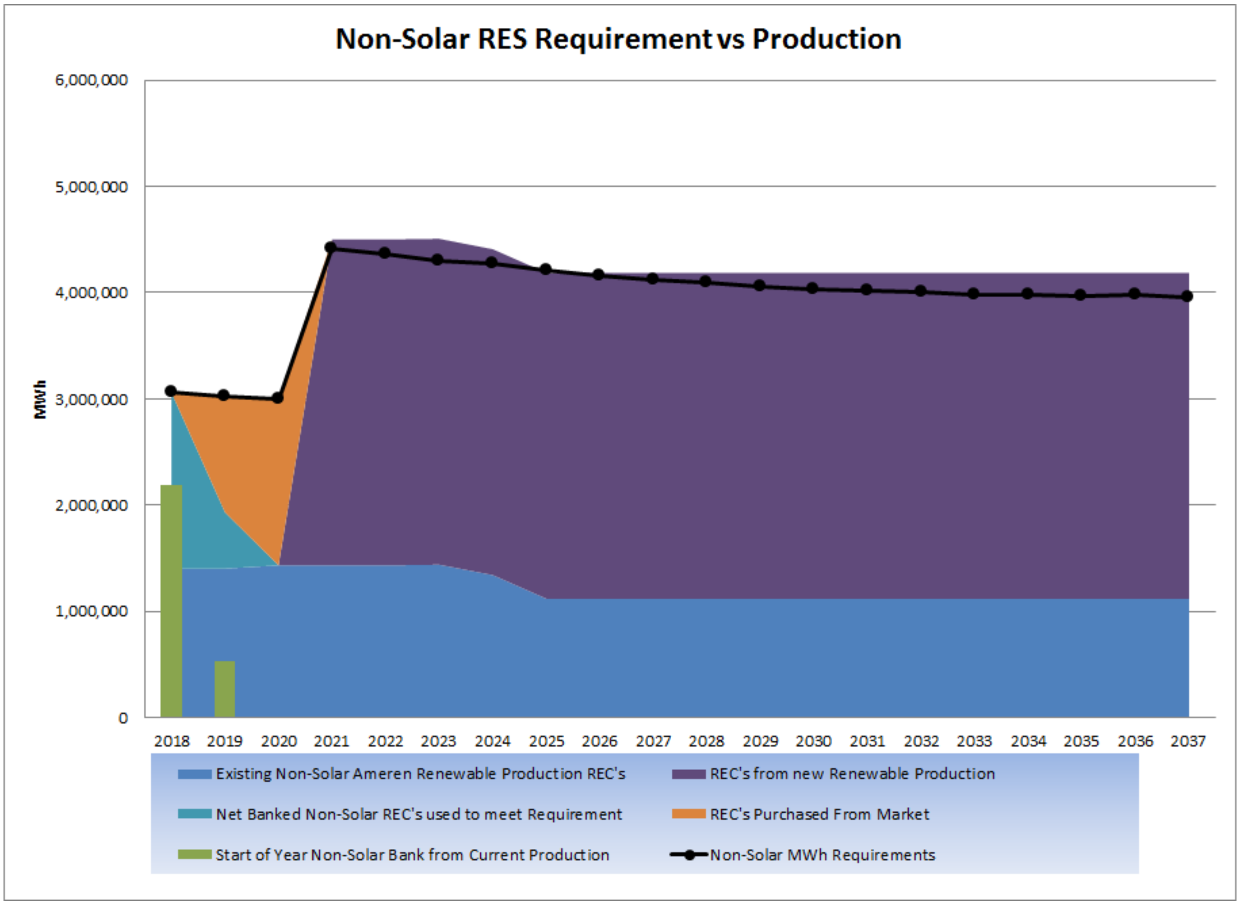


Figure 9.3 shows that Ameren Missouri expects to meet the overall REC requirement until 2021 with a combination of banked RECs, renewable generation and purchased RECs. Starting in 2021, Ameren Missouri will be able to fully meet the overall standard using RECs generated by its existing qualifying resources and additional wind resources.

Table 9.2 shows the amounts of wind and solar resources needed. The RES compliance portfolio established by the model is used for alternative resource plans and reflects wind resource additions that take advantage of Production Tax Credits, allowing full compliance with the Renewable Energy Standard while remaining under the one percent rate cap limitation. Appendix A shows the amounts of wind, and solar resources needed in Term 1 (2018-2027) and Term 2 (2028-2037).

When developing the RES compliance investment needs, consideration was given to the potential difference between RAP DSM investment vs MAP DSM investment. After modeling both, the difference in the level of renewable generation added was determined to be insignificant. Specifically, the difference was 3 MW of investment in solar and 28 MW's of wind investment for the entire 20 year term of the IRP. Therefore to provide a level comparison between plans with regard to RES compliance all portfolios are accompanied by the same level of renewable investment when evaluating alternative resource plans.

In addition to the RES Compliance portfolio, we also included a "RES Plus" portfolio to evaluate the cost of additional solar resources. The economics of solar resources may improve over time if trends toward lower cost continue while power market prices increase.

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

Table 9.2 Alternative Resource Plans - Renewable Portfolios

Renewable Additions		Nameplate Capacity (MW)																			
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
RES Compliance	Wind	0	0	0	700	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	0	0	0	0	25	0	0	11	0	0	0	0	0	0	0	0	0	0	0	0
RES Plus	Wind	0	0	0	700	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	0	0	0	0	25	0	0	25	0	50	0	0	0	0	0	0	0	0	0	0

Non-renewable Supply-side Resources

Non-renewable supply-side resource types were added last in the capacity planning process. If the capacity shortfall in a given year met or exceeded the build threshold, then supply side resources would be added to eliminate the shortfall. The build threshold was determined to be 300 MW (based on half the size of a combined cycle) regardless of the type of supply side resource under consideration. The full rated capacity and the build thresholds for each supply side type are shown in Table 9.3. 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 into the market. The earliest in-service for each supply-side resource is also shown in Table 9.3. The in-service date constraints represent the expectations for construction lead time as well as the commercial availability of each technology.

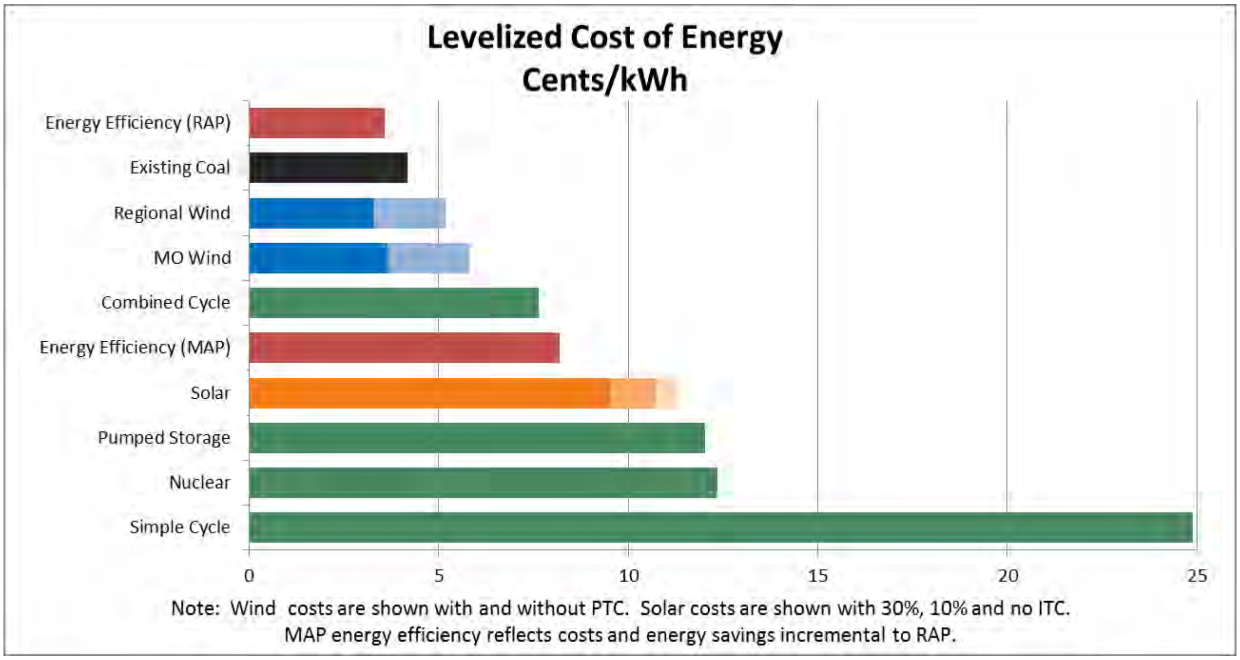
Table 9.3 Build Threshold for Supply Side Types

Supply Side Type	Capacity (MW)	Build Threshold (MW)	Earliest Year In-Service
CC-Natural Gas	600	300	2022
SC-Natural Gas	704	300	2022
Nuclear	1100	300	2027
Pumped Hydro	600	300	2024
Solar	1000	300	2019
Wind and Simple Cycle	664	300	2022

The remaining net capacity position was modeled in the financial model as capacity purchases and sales priced at the avoided capacity costs as discussed in Chapter 2. The capacity purchases and sales were also adjusted for the various peak demand forecasts associated with each of the 15 scenarios and DSM impacts.

Figure 9.4 below summarizes the LCOE for all resources evaluated in the alternative resource plans.

Figure 9.4 Levelized Cost of Energy – All Resources[5]



9.3 Planning Objectives

The fundamental objective of Missouri's electric resource planning process is to provide energy to its 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.[6] 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: Environmental/Renewable/Resource Diversity, Financial/Regulatory, Customer

[5] 4 CSR 240-22.010(2)(A)
[6] 4 CSR 240-22.010(2)

Schedule MM-S8

Satisfaction, Economic Development, and Cost. These planning objectives, which are the same as those discussed in Ameren Missouri's 2011 and 2014 IRPs, were selected by Ameren Missouri decision makers and are discussed below:[7]

Environmental/Renewable/Resource Diversity

Ameren Missouri has relied for many years on a portfolio that consists, in large part, of large, efficient coal-fired generators. Current and potential future environmental regulations may have a significant impact on Ameren Missouri's coal-fired fleet 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 MAP or RAP energy efficiency, renewables in addition to those required for RES compliance, new gas-fired generation, new nuclear generation, storage resources, early coal retirements, and additional reductions in CO_2 emissions.

Financial/Regulatory

The continued financial health of Ameren Missouri is crucial as it will need access to large amounts of capital for complying with renewable energy standards and environmental regulations, investing in new supply side resources, and funding continued energy efficiency programs while maintaining or improving safety, reliability, 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 capital markets. This includes measures of cash flow, profitability, and creditworthiness as well as assessment of risks associated with investment management and recovery.[8]

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 energy efficiency and demand response programs, inclusion of new clean energy resources, and significant reductions in CO_2 emissions to assess relative customer satisfaction expectations.[9]

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-

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[7] 4 CSR 240-22.010(2)(C)
[8] 4 CSR 240-22.060(2)(A)6
[9] 4 CSR 240-22.060(2)(A)4

years) including both construction and operation.[10] 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' rate 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, but it is a very important factor in making resource decisions. Therefore, minimization of present value of revenue requirements was used as the primary selection criterion.[11]

9.4 Determination of Alternative Resource Plans[12]

Eighteen 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 Energy Efficiency/Demand Response reduce overall customer costs?
- What level of DSM, RAP or MAP, results in lower costs?
- Is early retirement of Rush Island Energy Center cost effective?
- Is early retirement of Labadie Energy Center cost effective?
- Is early retirement of Meramec Energy Center cost effective?
- Is it cost effective to advance retirement of Meramec Energy Center coupled with advancing another energy center retirement, if necessary, such that Ameren Missouri is not more than 10% long in net capacity?
- What are the benefits of including renewables beyond those needed for RES compliance?
- What is the impact of pursuing only new renewables?
- How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?
- How do various supply side resource options compare?
- What is the impact of reducing CO_2 emissions further?

Table 9.4 provides a summary of the alternative resource plans.

[10] 4 CSR 240-22.060(2)(A)7
[11] 4 CSR 240-22.060(2)(A)1; 4 CSR 240-22.010(2)(B)
[12] 4 CSR 240-22.060(3)

Table 9.4 Alternative Resource Plans[13]

Plan Name	Energy Efficiency	Demand Response	Renewables	New Supply Side	Coal Retirements
A-RAP	RAP	RAP	RES Plus	-	Base
B-RAP EE only	RAP	-	RES Plus	-	Base
C-RAP DR only	-	RAP	RES Plus	2 CCs in 2037	Base
D-MAP	MAP	MAP	RES Plus	-	Base
E-MAP EE only	MAP	-	RES Plus	-	Base
F-MAP DR only	-	MAP	RES Plus	CC in 2037	Base
G-No DSM-CC	-	-	RES Plus	CC in 2034 2 CCs in 2037	Base
H-No DSM-SC	-	-	RES Plus	2 SCs in 2034 2 CCs in 2037	Base
I-No DSM-Pumped Storage	-	-	RES Plus	Pumped Hydro in 2034 2 CCs in 2037	Base
J-No DSM-Nuclear	-	-	RES Plus	Nuclear in 2034 CC in 2037	Base
K-No DSM-Wind&SC	-	-	RES Plus	Wind in 2031-2034 (2000 MW total) SC in 2034 2 CCs in 2037	Base
L-No DSM-Solar	-	-	RES Plus	Solar in 2031-2037 (4000 MW total)	Base
M-Rush Island Retired 2024	RAP	RAP	RES Plus	CC in 2037	Rush Island 12/31/2024
N-Labadie Retired 2024	RAP	RAP	RES Plus	CC in 2034	Labadie 12/31/2024
O-Meramec 2020-Labadie 2024	RAP	RAP	RES Plus	CC in 2034	Meramec 12/31/2020 Labadie 12/31/2024
P-Meramec Retired 2020	RAP	RAP	RES Plus	-	Meramec 12/31/2020
Q-RES Compliance only	RAP	RAP	RES	-	Base
R-RAP-35% CO2 Reduction	RAP	RAP	RES Plus	-	Base

Does inclusion of Energy Efficiency/Demand Response reduce overall customer costs?

Plans A and D include both EE and DR at RAP and MAP levels, respectively. Plans B and E differ from plans A and D, respectively, only in that they do not include DR, while plans C and F differ from plans A and D, respectively, only in that they do not include EE programs. Therefore, these plans can be compared to assess the impact on cost and other performance measures due to inclusion of EE or DR at either the RAP or MAP level.

What level of DSM, RAP or MAP, results in lower costs?[14]

Plans with the same attributes except for the level of energy efficiency and/or demand response resources have been evaluated and provide a comparison for the DSM portfolios as described above.

[13] 4 CSR 240-22.010(2)(A); 4 CSR 240-22.060(3); 4 CSR 240-22.060(3)(A)1 through 8; 4 CSR 240-22.060(3)(B); 4 CSR 240-22.060(3)(C)1; 4 CSR 240-22.060(3)(C)2; 4 CSR 240-22.060(3)(C)3

[14] Ameren Missouri added demand response programs to the alternative resource plans starting in 2019 and not only in years where there was a need to reduce peak demand due to shortfalls in Ameren Missouri's planning capacity reserve margins; 4 CSR 240-22.060(3)(A)7

Is early retirement of Rush Island Energy Center cost effective?

Plan M evaluates the cost effectiveness of early retirement of Rush Island Energy Center.[15]

Is early retirement of Labadie Energy Center cost effective?

Plan N evaluates the cost effectiveness of early retirement of Labadie Energy Center.[16]

Is early retirement of Meramec Energy Center cost effective?

Plan P evaluates the cost effectiveness of early retirement of Meramec Energy Center.[17]

Is it cost effective to advance retirement of Meramec Energy Center coupled with advancing another energy center retirement, if necessary, such that Ameren Missouri is not more than 10% long in net capacity??

Plan O evaluates the cost effectiveness of early retirements of Meramec and Labadie Energy Centers.[18]

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

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 (alternative resource plans except for plan Q). Plans A and Q can be compared to assess the costs/benefits of additional renewables. Also included are resource plans K and L that feature wind and solar, respectively, as a major supply side resource.

What is the impact of pursuing only new renewables?

Plan L is the all renewables alternative resource plan without DSM beyond MEEIA Cycle 2.[19]

How do various supply-side resource options compare?

The relative performance of the new supply-side resources can be determined by comparing Plans G through L.

[15] 4 CSR 240-22.060(3)(A)7
[16] 4 CSR 240-22.060(3)(A)7
[17] 4 CSR 240-22.060(3)(A)7
[18] 4 CSR 240-22.060(3)(A)7; EO-2017-0073 1.E
[19] 4 CSR 240-22.060(3)(A)2

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

Plans G through L also evaluate the impact if DSM cost recovery and incentive requirements are not met.

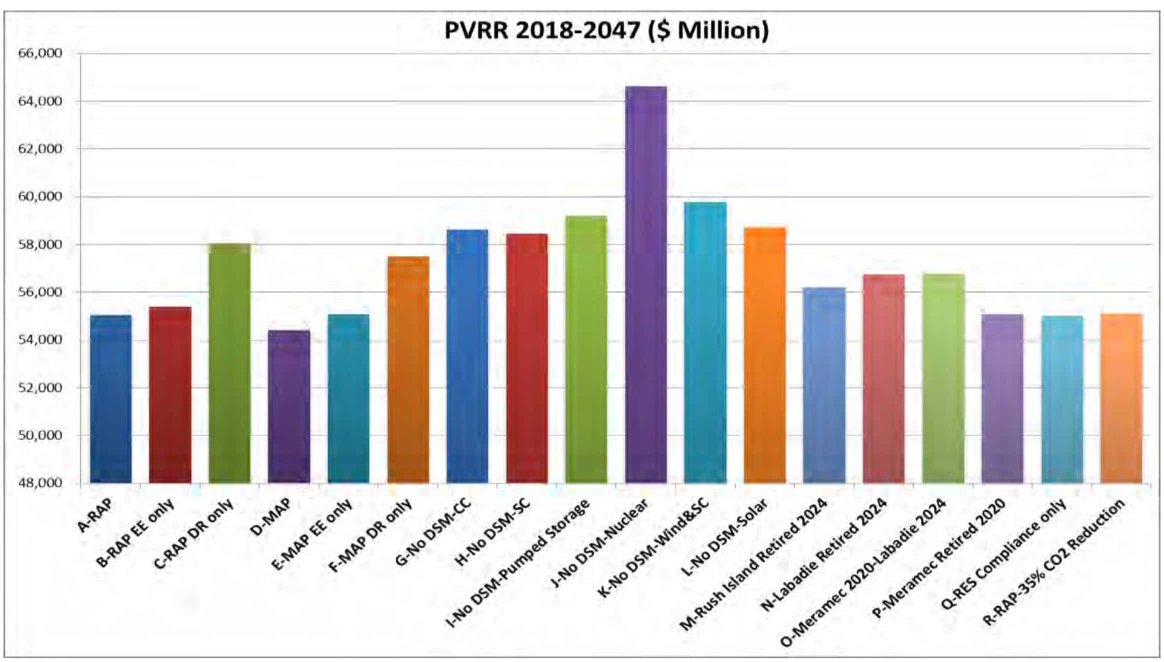
What is the impact of reducing CO_2 emissions further?

Plan R is constructed with the same plan attributes as plan A, but has reduced coal generation such that CO_2 emissions are at least 35% below 2005 emissions by 2030.

The type, size, and timing of resource additions/retirements for the alternative resource plans (i.e., Plans A-R) are provided in Appendix A and also in the electronic workpapers.[20]

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 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 13) as explained in Chapter 2. Integration analysis present value of revenue requirements (PVRR) results are shown below in Figure 9.5. Results for the remaining performance measures for integration analysis are provided in the workpapers.[21]

Figure 9.5 Integration PVRR Results



[20] None of the alternative resource plans analyzed include any load-building programs 4 CSR 240-22.060(3)(B); 4 CSR 240-22.080(2)(D); 4 CSR 240-22.060(3)(D)

[21] 4 CSR 240-22.060(4)

Schedule MM-S8

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 5.95% 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).[22]

9.5 Sensitivity Analysis

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

9.5.1 Uncertain Factors[23]

Ameren Missouri developed a list of uncertain factors to determine which factors are critical to resource plan performance. Table 9.5 contains the list as well as information about the screening process.

Table 9.5 Uncertain Factor Screening

Uncertain Factor	Candidates?	Critical?	Included in Final Probability Tree?
Load Growth	✓ **	--	✓
Carbon Policy	✓ **	--	✓
Fuel Prices			
Coal	✓	✓	✓
Natural Gas	✓ **	--	✓
Nuclear	✗	✗	✗
Project Cost (includes transmission interconnection costs)	✓	✗	✗
Project Schedule	✓	✗	✗
Purchased Power	✗	✗	✗
Emissions Prices			
SO_2	✗	✗	✗
NO_x	✗	✗	✗
CO_2	✓ **	--	✓
Forced Outage Rate	✓	✗	✗
DSM Cost Only	✓	✓	✓

[22] 4 CSR 240-22.060(2)(B)
[23] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5) (B) through (F); EO-2017-0073 1.A(1)-(3)
4 CSR 240-22.060(5); 4 CSR 240-22.060(5) (A) through (M)

Uncertain Factor	Candidates?	Critical?	Included in Final Probability Tree?
DSM Load Impacts&Costs	✓	✗ α	✗ α
Foreseeable Emerging EE Technologies	✓	✗ β	✗ β
Foreseeable Distributed Generation	✓	✗ β	✗ β ✓ γ
Foreseeable Energy Storage Technologies	✓	✗	✗
Fixed and Variable O&M	✓	✗	✗
Return on Equity	✓	✗ ε	✗ ε
Interest Rates	✓	✗ ε	✗ ε

** 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.
β Included as part of DSM load impacts and costs sensitivity
γ Included as part of load forecast sensitivity
ε Return on Equity and Long-term Interest rates were combined

Chapter 2 describes how three of the candidate uncertain factors were determined to be critical dependent uncertain factors, which defined the fifteen scenarios. The three critical dependent uncertain factors are: load growth, market effects of environmental policy, and natural gas prices. Energy and capacity prices are an output of the scenarios 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 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; 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.
- SO_2 and NOx Emissions Prices – SO_2 and NOx Emissions Prices were excluded as candidates because of the expectation for very low prices as a result of current and expected environmental regulations.

Schedule MM-S8

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. 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[24]

We use the sensitivity analysis to examine whether or not 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.

Unless the meaning of low, base, and high are treated in a standardized manner, the probability of occurrence for the value used for "low" for one uncertain factor could be significantly different than the probability of occurrence for the value used for "low" for other uncertain factors. Thus, for all of the uncertain factors, Ameren Missouri standardized the meaning of low to be the value found at the 5th percentile of a probability distribution of values for an uncertain factor, the value at the 50th percentile to be the base value, and the value at the 95th percentile to be the high value. The probability distribution for each candidate uncertain factor was inferred from a series of estimated values produced by subject matter experts for each uncertain factor.

[24] 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

For the majority of candidate uncertain factors, probability distributions were used to obtain the values for low, base, and high. This process began with subject matter experts providing/revising estimates of (A) an expected value, (B) estimates of deviations from that expected value, and (C) the probabilities of those deviations from the expected value. That information was used to create the probability distribution collectively implied by that data. Values at the 5th, 50th, and 95th percentiles of those implied probability distributions were then obtained for use as the values for low, base, and high for the various candidate independent uncertain factors. Appendix A contains the standard value, estimated deviation and probabilities for project costs, project schedule, fixed operations & maintenance (FOM), variable operations & maintenance (VOM), equivalent forced outage rate (EFOR), environmental capital expenditures, and transmission-retirement expenditures.

Example

The expected value for total project cost including transmission interconnection costs for the greenfield Combined Cycle option is $1,282/kW-year (2016$). Project cost and some other candidate uncertain factors are characterized by differing standard values among various supply-side types, while standard values for some other candidate uncertain factors are not uniquely correlated to each supply side type. For example the Long Term Interest Rates uncertain factor does not differ depending on the supply-side type; it is the same across all supply-side types.

The subject matter experts, in this example, members of Ameren Missouri's generation organization, provided estimates of deviations from the standard value as well as the probabilities of those deviations. An example of that initial uncertainty distribution is shown in Table 9. 9.6. In this example, the first of these estimates for project cost deviations was a -10% deviation from the expected value with a 20% probability of occurring. These deviation estimates provide sufficient information to derive continuous probability distributions from which the low/base/high values can be derived.

Table 9.6

CC Project Cost Uncertainty Distribution

Deviation	Probability
-10%	20%
0%	50%
15%	20%
30%	10%

The process of developing the probability distributions involved using Crystal Ball software. This software, when provided with a series of observations like these deviation estimates, can determine the probability distribution implied by the set of estimates. An example of the result of analyzing deviation estimates using Crystal Ball is shown in Figure 9.6. From this distribution, the deviation values for the low, base, and high values (.84, 1.03, 1.25) are obtained at the respective percentiles in Figure 9.6. By multiplying these values by the expected value $1,282/kW-year, we estimate

Schedule MM-S8

the costs at the 5th, 50th, and 95th percentiles; e.g., the low value at the 5th percentile would be:

.84 x 1,282 = $1,077

Figure 9.6 Example of Probability Distribution---CC Project Cost

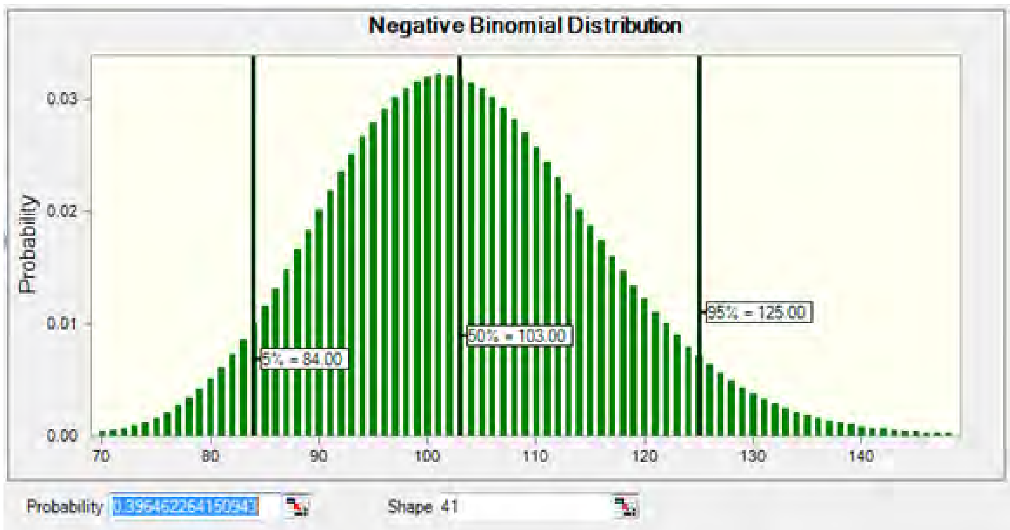


Figure 9.7 shows the resulting range of project costs, which also include interconnection costs estimates, for each new supply-side resource. For most of the technologies shown in Figure 9.7, base values found at 50th percentile were very close to their expected values. For the nuclear technology, however, the base value inferred from the probability distribution was 27% higher than the expected value- $7,545/kW vs $6,134/kW.

Figure 9.7 Resource-Specific Project Cost Ranges ($/kW)

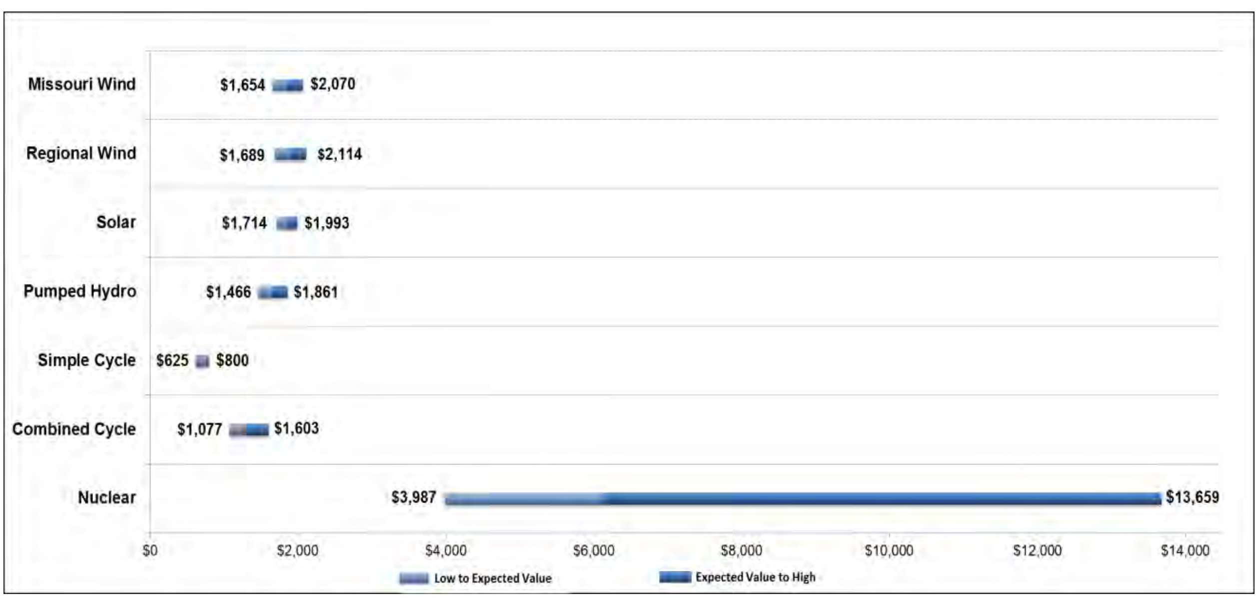


Table 9.7 shows the uncertain factor ranges for the various candidate uncertain factors. It should be noted that, for the project schedule uncertainty, as the number of years in a project schedule change, the distribution of the cash flows was also updated to be consistent with those changes.

Table 9.7 Resource-Specific Uncertain Factor Ranges

Uncertain Factor	Value	Probability	CC (Nat. Gas)	SC (Nat. Gas)	Pumped Hydro	Nuclear	Solar *	Regional Wind	Missouri Wind
Project Cost	Low	10%	$1,077	$625	$1,466	$3,987	$1,714	$1,689	$1,654
($/kW)	Base	80%	$1,320	$709	$1,663	$7,790	$1,863	$1,917	$1,877
2016 $	High	10%	$1,603	$800	$1,861	$13,679	$1,993	$2,114	$2,070
Project Schedule	Low	10%	27	27	55	68	9	36	36
(Months)	Base	80%	36	36	73	91	12	48	48
	High	10%	48	48	95	119	16	63	63
Fixed O&M	Low	10%	$6.71	$6.57	$2.98	$125.60	$13.29	$21.89	$21.89
($/kW-yr)	Base	80%	$8.11	$7.93	$3.60	$154.37	$16.04	$26.42	$26.42
2016 $	High	10%	$10.18	$9.92	$4.49	$190.41	$20.11	$33.12	$33.12
Variable O&M	Low	10%	$1.61	$6.64	$2.95	$1.86	$0.00	$0.00	$0.00
($/MWh)	Base	80%	$4.18	$7.91	$3.71	$2.31	$0.00	$0.00	$0.00
2016 $	High	10%	$6.75	$9.18	$4.66	$2.91	$0.00	$0.00	$0.00
EFOR	Low	10%	1%	0%	0%	1%	-	-	-
(%)	Base	80%	2%	5%	5%	2%	-	-	-
	High	10%	5%	10%	10%	3%	-	-	-

* Ameren Missouri used a declining cost curve for solar, but the same multipliers were applied to estimate low and high project costs.
- Assumed capacity factor for solar and wind resources include effects of FOR.

Table 9.8 contains the non-resource specific uncertain factor ranges analyzed.

As discussed in Chapter 2, long-range interest rate assumptions are based on the December 1, 2016, semi-annual Blue Chip Financial Forecast, a consensus survey of 49 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 2017 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 (ROE) using the same process as discussed in Chapter 2.

Schedule MM-S8

Table 9.8 Non-Resource Specific Uncertain Factor Ranges

Uncertain Factors	Low	Base	High
Probability -->>	10%	80%	10%
Coal Price		Varies By Year	
Long Term Interest Rates	5.3%	6.0%	6.7%
Return on Equity	10.3%	10.6%	10.9%
DSM Load Impact and Cost			
MAP - EE Load Impact	82%	100%	111%
MAP - EE Cost	84%	100%	117%
RAP - EE Load Impact	82%	100%	111%
RAP - EE Cost	84%	100%	118%
MAP - DR Load Impact	81%	100%	108%
MAP - DR Cost	119%	100%	111%
RAP - DR Load Impact	81%	100%	108%
RAP - DR Cost	119%	100%	111%
DSM Cost Only			
MAP - EE Cost	80%	100%	135%
RAP - EE Cost	80%	100%	135%
MAP - DR Cost	85%	100%	125%
RAP - DR Cost	85%	100%	125%

Note that the DSM Load Impact and Cost uncertain factor includes higher costs for the DR low load impacts, because when items such as avoided costs are varied, the program mix changes as the cost effectiveness changes, and more expensive programs fill the gap. Chapter 8 includes details on how low and high ranges were obtained for DSM portfolios.

9.5.2 Sensitivity Analysis Results[25]

To conduct the sensitivity analysis, each of the 18 candidate 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 13). 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

[25] 4 CSR 240-22.060(5); 4 CSR 240-22.060(7)(A); 4 CSR 240-22.060(7)(C)1A

the candidate independent uncertain factors (resource-specific and non-resource specific) are presented in Appendix A.

The sensitivity analysis identified two critical independent uncertain factors: DSM Cost Only and Coal Prices. Table 9.9 shows the change in PVRR ranking (i.e., number of positions the plan moved in the ranking) for the two critical independent uncertain factors compared to the integration/base value.

Table 9.9 Critical Independent Uncertain Factors – Change in PVRR Ranking

	Integration	DSM Cost Only			Coal Price		
Plan	Ranking	PWA	Low	High	PWA	Low	High
A-RAP	3	0	1	0	0	0	0
B-RAP EE only	7	0	0	-1	0	0	0
C-RAP DR only	12	0	0	0	0	0	0
D-MAP	1	0	0	0	0	0	0
E-MAP EE only	5	0	-3	2	0	-1	1
F-MAP DR only	11	0	0	0	0	0	0
G-No DSM-CC	14	0	0	0	0	0	0
H-No DSM-SC	13	0	0	0	0	0	0
I-No DSM-Pumped Storage	16	0	0	0	0	0	0
J-No DSM-Nuclear	18	0	0	0	0	0	0
K-No DSM-Wind&SC	17	0	0	0	0	0	0
L-No DSM-Solar	15	0	0	0	0	0	0
M-Rush Island Retired 2024	8	0	0	0	0	0	0
N-Labadie Retired 2024	9	0	0	0	0	0	0
O-Meramec 2020-Labadie 2024	10	0	0	0	0	0	0
P-Meramec Retired 2020	4	0	1	0	0	1	1
Q-RES Compliance only	2	0	1	0	0	0	0
R-RAP-35% CO2 Reduction	6	0	0	-1	0	0	-2

Schedule MM-S8

Table 9.10 shows the change in PVRR ($) for the two critical independent uncertain factors compared to the integration/base values.

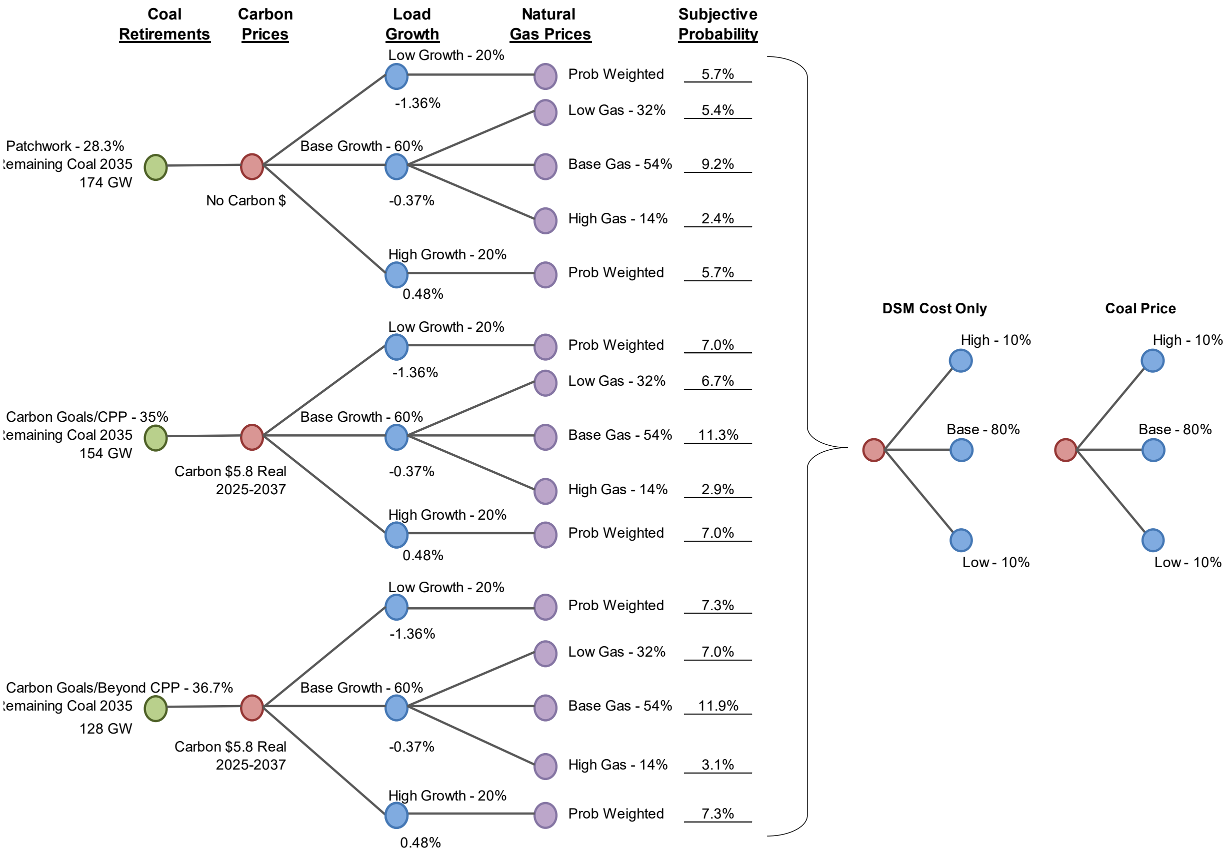
Table 9.10 Critical Independent Uncertain Factors – Change in PVRR (Million $)

Plan	Integration PVRR	DSM Cost Only			Coal Price		
		PWA	Low	High	PWA	Low	High
A-RAP	55,037	25	-336	589	-51	-1,878	1,364
B-RAP EE only	55,374	21	-281	493	-51	-1,878	1,364
C-RAP DR only	58,041	4	-55	96	-51	-1,878	1,364
D-MAP	54,398	46	-609	1,068	-51	-1,878	1,364
E-MAP EE only	55,083	39	-517	904	-51	-1,878	1,364
F-MAP DR only	57,485	7	-92	164	-51	-1,878	1,364
G-No DSM-CC	58,614	0	0	0	-51	-1,878	1,364
H-No DSM-SC	58,457	0	0	0	-51	-1,878	1,364
I-No DSM-Pumped Storage	59,182	0	0	0	-51	-1,878	1,364
J-No DSM-Nuclear	64,610	0	0	0	-51	-1,878	1,364
K-No DSM-Wind&SC	59,761	0	0	0	-51	-1,878	1,364
L-No DSM-Solar	58,695	0	0	0	-51	-1,878	1,364
M-Rush Island Retired 2024	56,202	25	-336	589	-45	-1,465	1,019
N-Labadie Retired 2024	56,736	25	-336	589	-40	-1,294	897
O-Meramec 2020-Labadie 2024	56,766	25	-336	589	-37	-1,252	884
P-Meramec Retired 2020	55,067	25	-336	589	-49	-1,836	1,351
Q-RES Compliance only	55,018	25	-336	589	-51	-1,878	1,364
R-RAP-35% CO2 Reduction	55,102	25	-336	589	-52	-1,828	1,311

The DSM Cost Only uncertain factor was selected as a critical independent uncertain factor because of the variety in the change in PVRR ranking. Coal price was selected as a critical independent uncertain factor because of the high impact potential on relative results of early retirement plans compared to other plans.

These two critical independent uncertain factors 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 9.8, with the two critical independent uncertain factors shown on the right-hand side.

Figure 9.8 Final Probability Tree Including Sensitivity Analysis Results[26]



9.6 Risk Analysis[27]

The Risk Analysis consisted of running each of the candidate resource plans in Table 9.4 through each of the branches on the final probability tree shown in Figure 9.8. The probability tree consisted of 135 different branches. Each branch is the combination of different value levels among the fifteen scenarios, themselves defined by combinations of the three critical dependent uncertain factors (load growth, gas prices, and environmental regulations/carbon policy), and the two critical independent uncertain factors (DSM cost and coal price). 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%.

[26] 4 CSR 240-22.060(6)
[27] 4 CSR 240-22.060(6)

Schedule MM-S8

9.6.1 Risk Analysis Results

The PVRR results of the risk analysis of the 18 alternative resource plans are shown in Figure 9.9. The levelized rate results for the risk analysis are shown in Figure 9.10. The PVRR results are lower for plans with RAP or MAP DSM compared to plans without DSM. The advancement of Labadie and Rush Island Energy Centers exhibit much higher PVRR results and higher levelized rates compared to plans with similar attributes but without early retirement assumptions. Plan J (No DSM-Nuclear) exhibits the highest PVRR and the highest levelized rates followed by Plan K (No DSM-Wind&SC), which has the second highest PVRR, and by Plan E (MAP EE Only), which has the second highest levelized rates. Results for other performance measures can be found in Chapter 9 - Appendix A.

Figure 9.9 Probability-Weighted PVRR Results

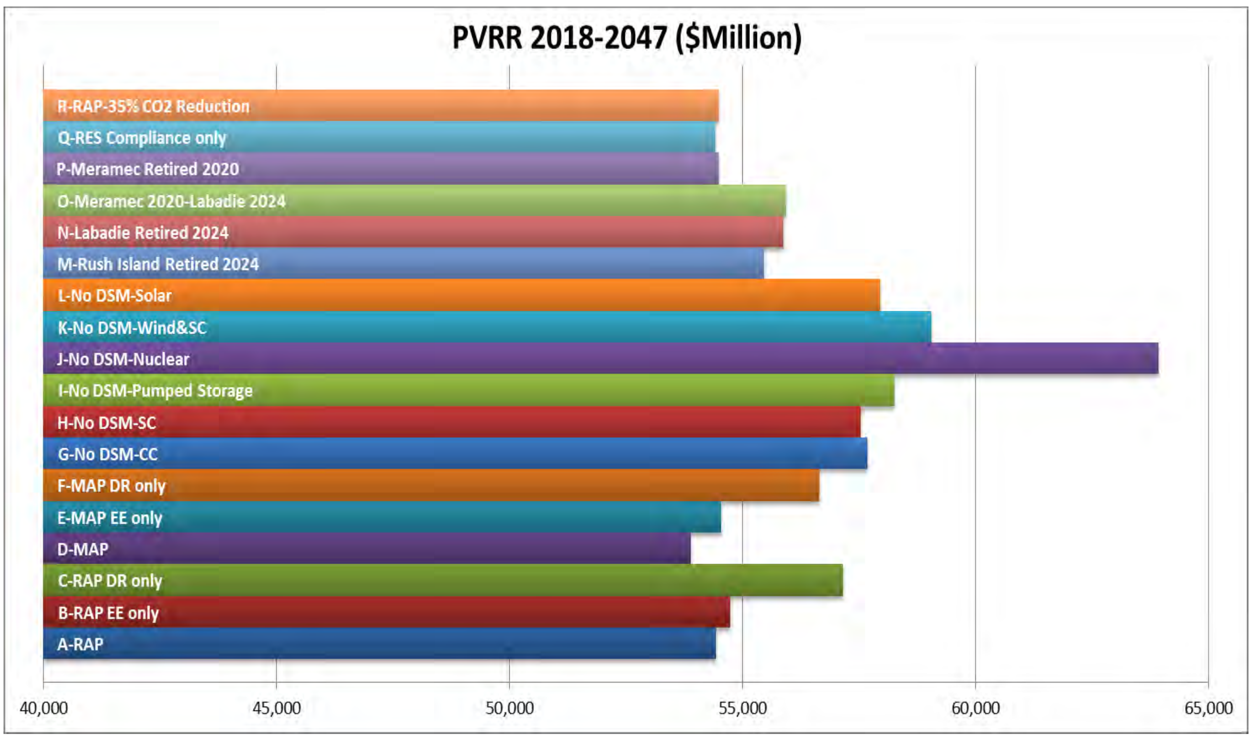
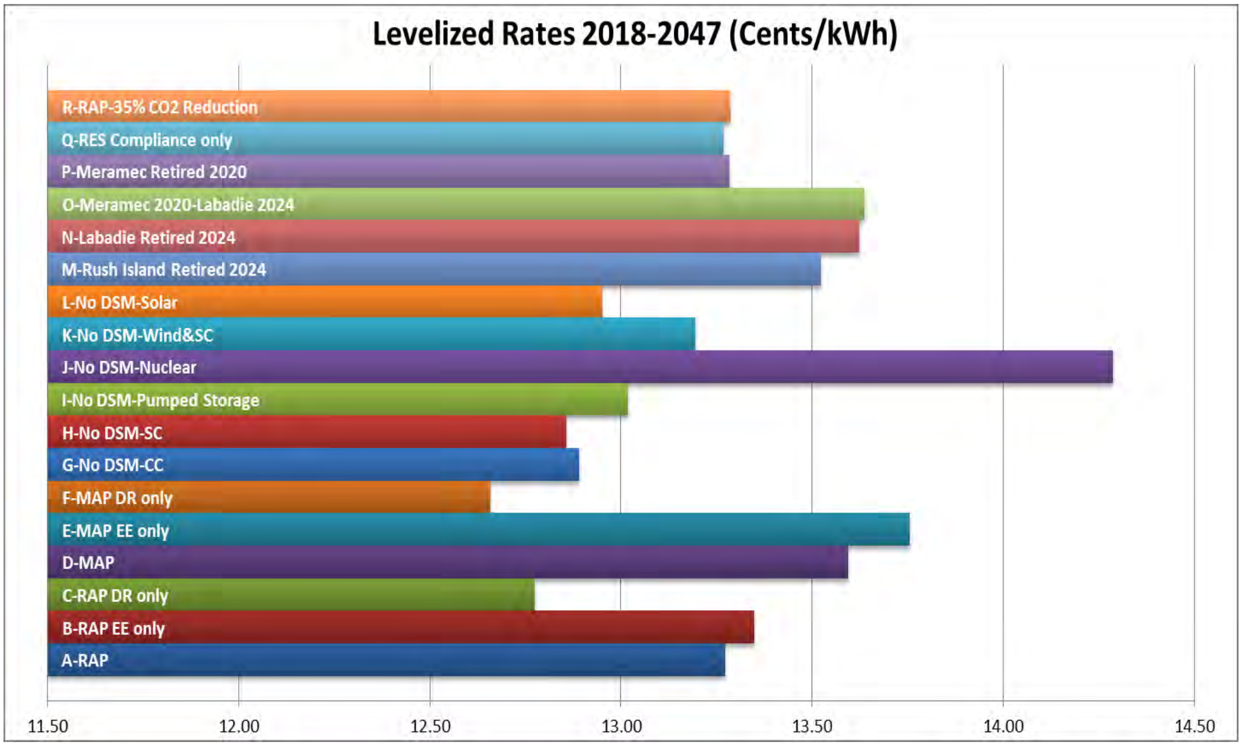


Figure 9.10 Probability-Weighted Levelized Rate Results



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 18 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.

9.7 Conclusions from Integration and Risk Analysis

Below are several conclusions from the integration and risk analysis.

- Inclusion of energy efficiency and demand response results in generally lower costs.
- Wind, solar and natural gas combined cycle resources are attractive options for development due to their competitive overall cost, relatively low capital cost and relatively short lead time.

- Early retirement of coal generation resources (plans M-O) results in significantly higher costs to customers and rates. Advancing retirement of Meramec Energy Center also increases costs to customers.
- Plans with additional renewable resources beyond those included for RES compliance are competitive from a cost standpoint.[28]
- Meeting all future resource needs with renewable resources (Plan L) results in the fourth highest PVRR among the eighteen plans. However, this plan is competitive with other supply side only plans, and greater reductions in the cost of solar resources could further improve their comparative economics.
- Meaningful reductions in CO_2 as analyzed in Plan R can be achieved at a modestly higher cost.

9.8 Resource Plan Model

Ameren Missouri has used a modular approach to modeling for this IRP as it did in the 2014 IRP. 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 Simtec, Inc., typically referred to as RTSim (Real-Time Simulation) for production cost modeling.[29] RTSim provides a realistic simulation of an electric generating system for a period of a few days to multiple years. According to Simtec's marketing materials, RTSim finds higher profitability, lower risk, "free market" transactions, maintenance schedules, emission compliance strategies and fuel procurement schedules while maintaining reliable, reasonable cost service to the traditional regulated market sector.

RTSim simulates hourly chronological dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The model plans are based on a capacity planning spreadsheet, which was used to determine the timing of new resources. The RTSim 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

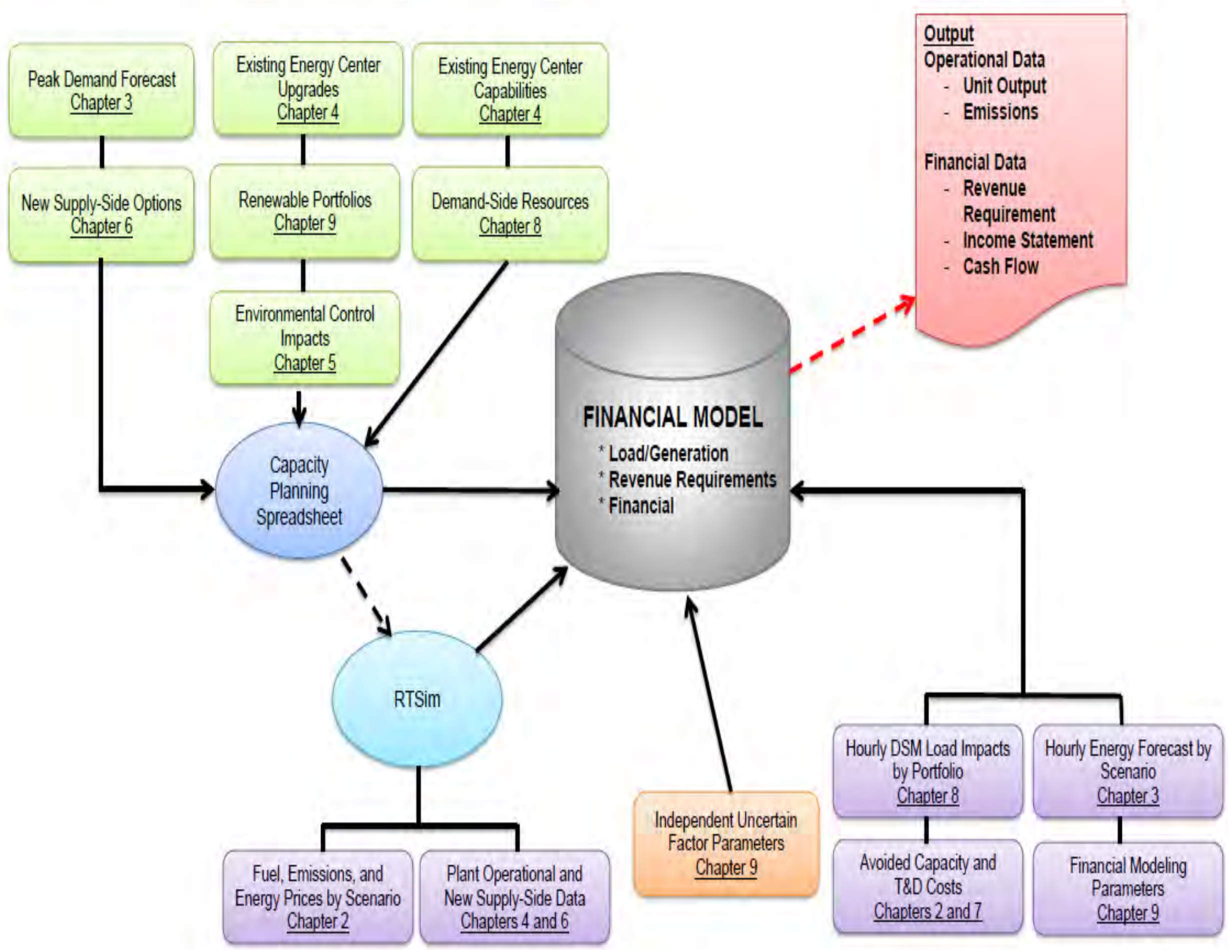
[28] 4 CSR 240-22.060(4)(E)
[29] 4 CSR 240-22.060(4)(H)

maintenance costs, emission rates, emission allowance costs, scheduled maintenance outages, and full and partial forced outage rates. The generation fleet is dispatched competitively against market prices. The multi-area mode of the Ventyx Midas® model was used for the creation of forward price curves as described in Chapter 2.

Ameren Missouri developed its own revenue requirements and financial model using Microsoft Excel. This model incorporates the capacity position and RTSim 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 9.11 shows how the various assumptions are integrated into the financial model.

Figure 9.11 Resource Plan Model Framework[30]



[30] 4 CSR 240-22.060(4)(H)

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 may be able to identify a production costing solution that can be applied to long-term resource planning, fuel budgeting, and possibly shorter-term trading support analysis.

We expect to continue our efforts to improve the efficiency, effectiveness and transparency of our modeling tools into 2018. The nature and timing of any changes we 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 our business needs and objectives.

9.9 Compliance References

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.

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.

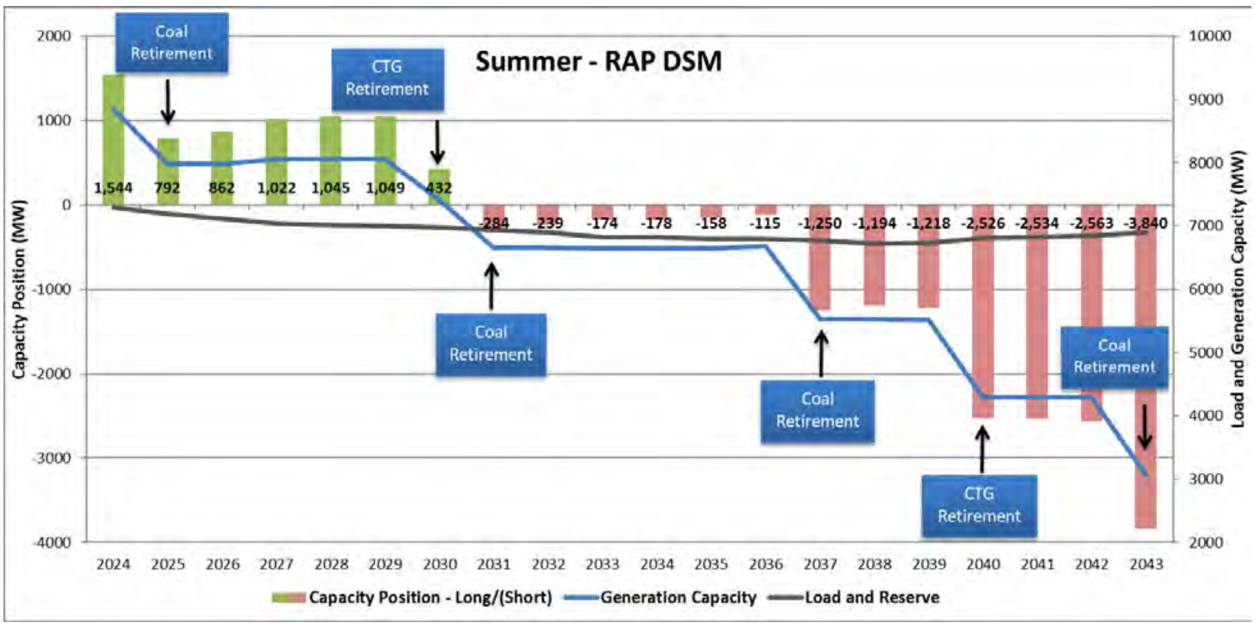
9.2 Capacity Position

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.

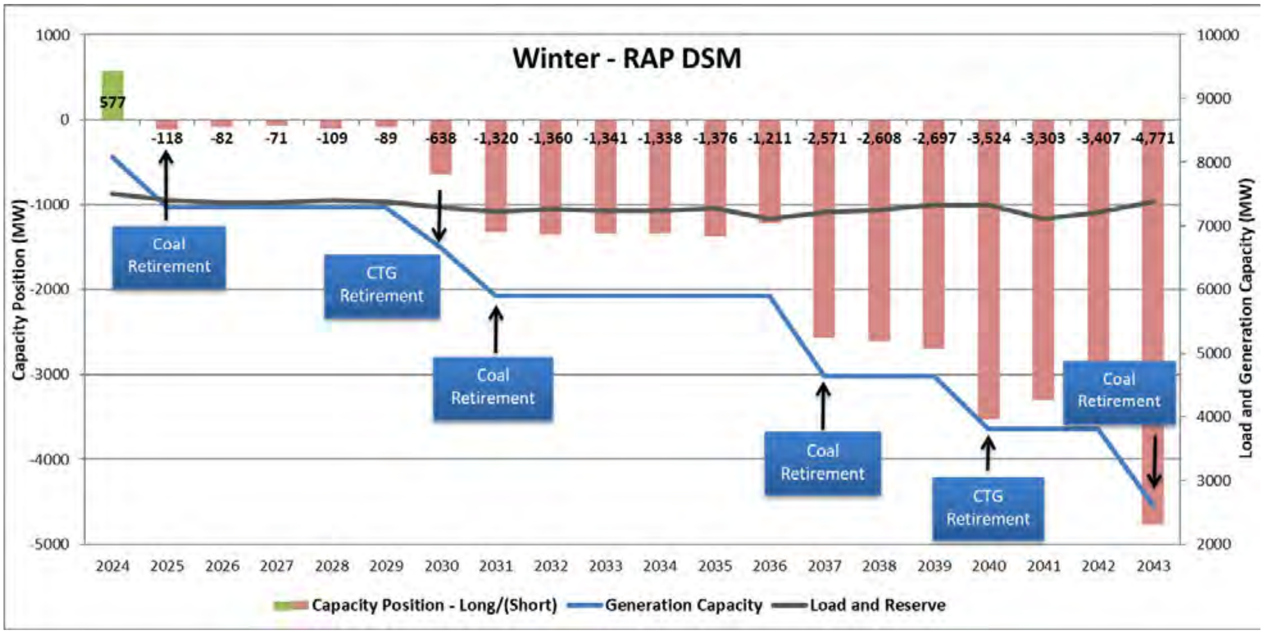
Figures 9.2 and 9.3 show Ameren Missouri's net capacity position with no new major generating resources for summer and winter.[3]

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	-	-	-

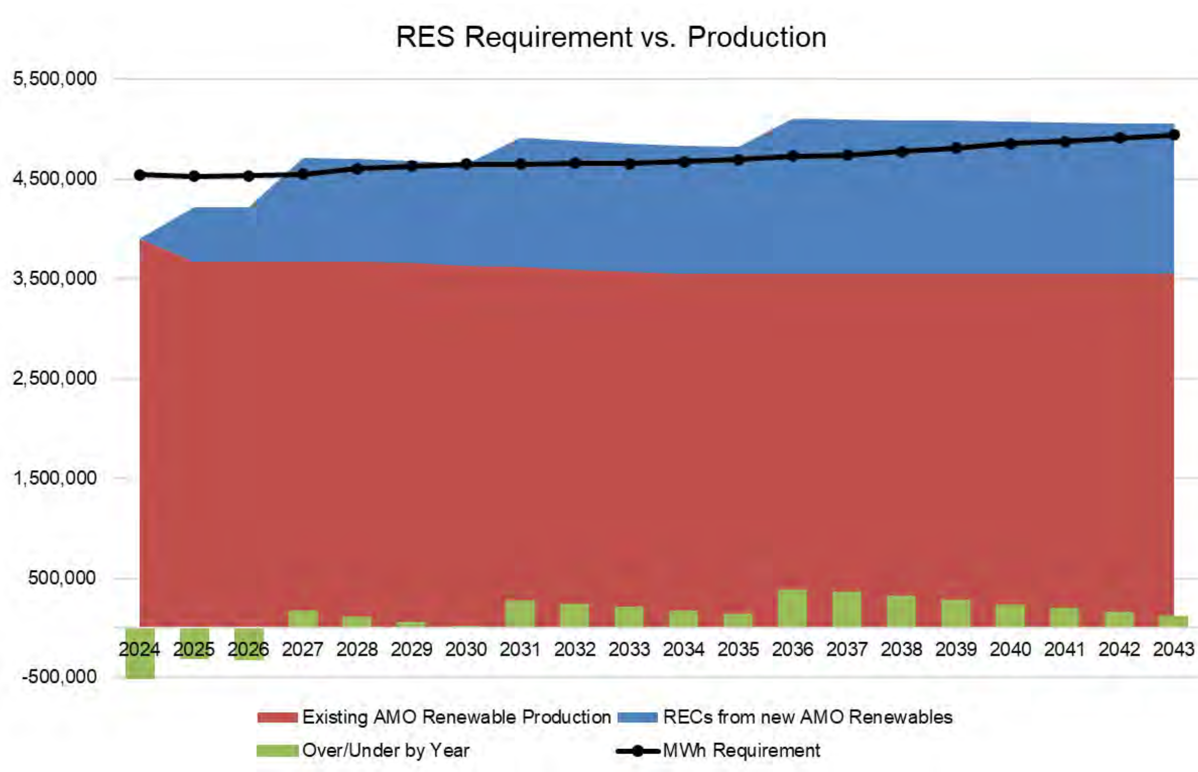
[5] An additional energy efficiency portfolio that achieves 80% of RAP level energy and demand savings.
[6] The extension of MEEIA Cycle 3 should not have a material impact on the analysis.

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



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[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.

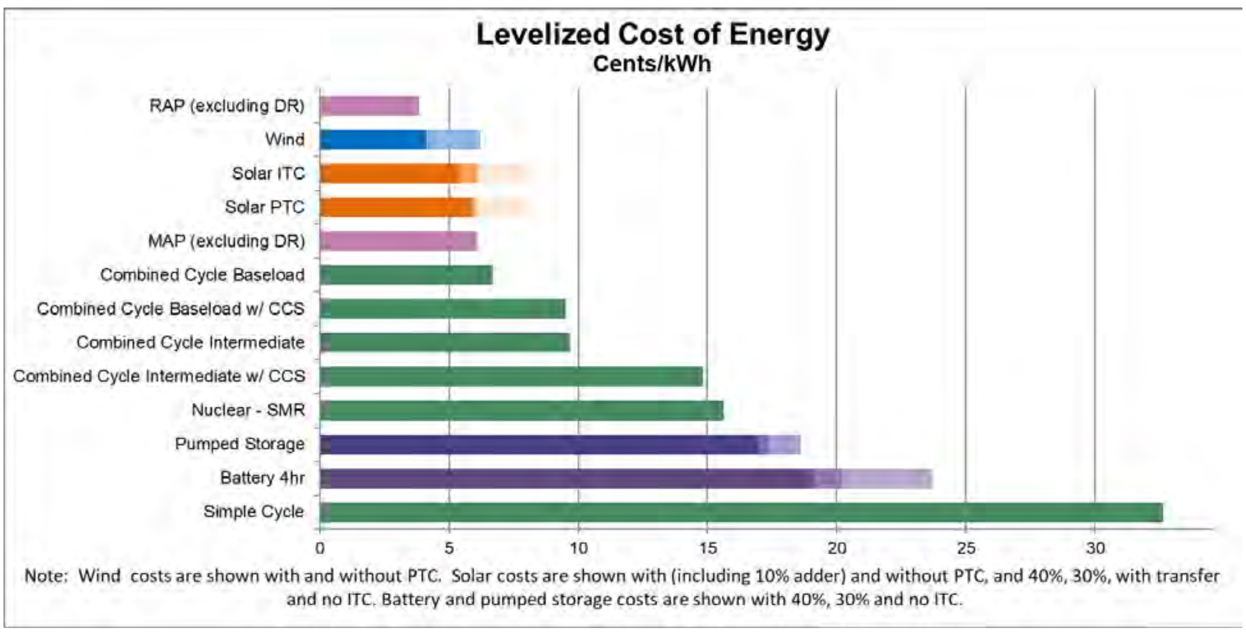
Table 9.4 Summer and Winter Capacity for Supply-Side Types[12]

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.

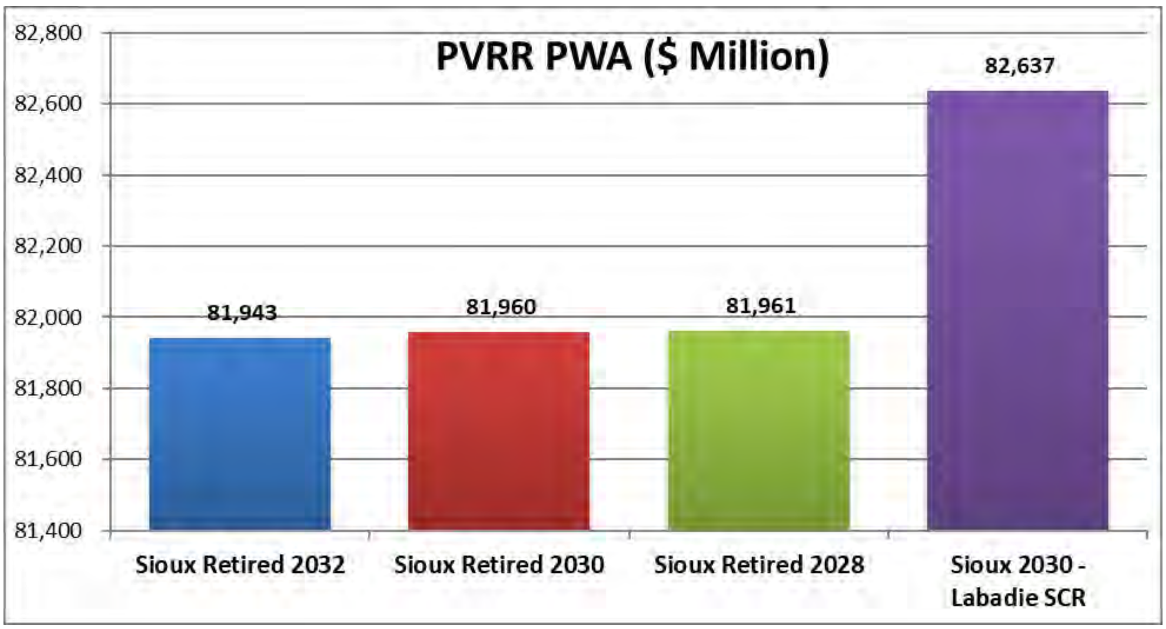
[16] 20 CSR 4240-22.060(2)(A)6
[17] 20 CSR 4240-22.060(2)(A)4
[18] 20 CSR 4240-22.060(2)(A)7
[19] 20 CSR 4240-22.060(2)(A)1; 20 CSR 4240-22.010(2)(B); 20 CSR 4240-22.060(2)(B)

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	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.

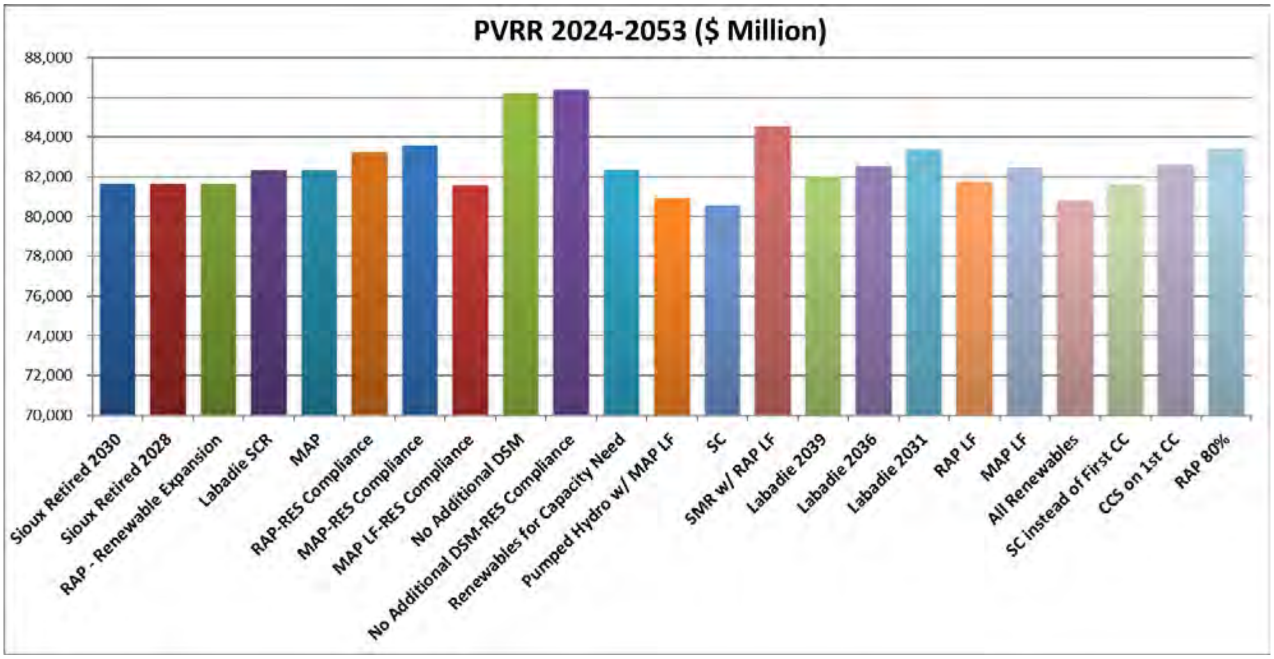
The type, size, and timing of resource additions/retirements for the alternative resource plans are provided in Appendix A and also in the electronic workpapers.[29]

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 critical independent 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 critical dependent 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)

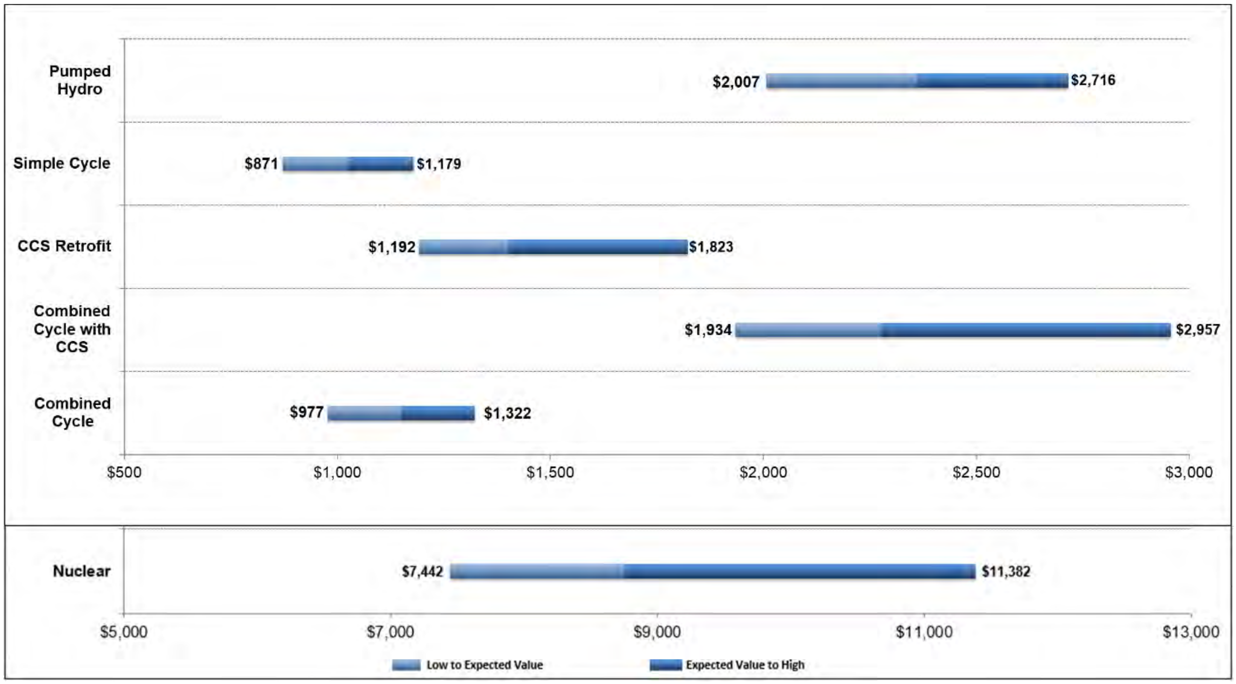


Figure 9.9 Solar, Wind and Battery Project Cost Ranges[35]

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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.

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[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.

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.

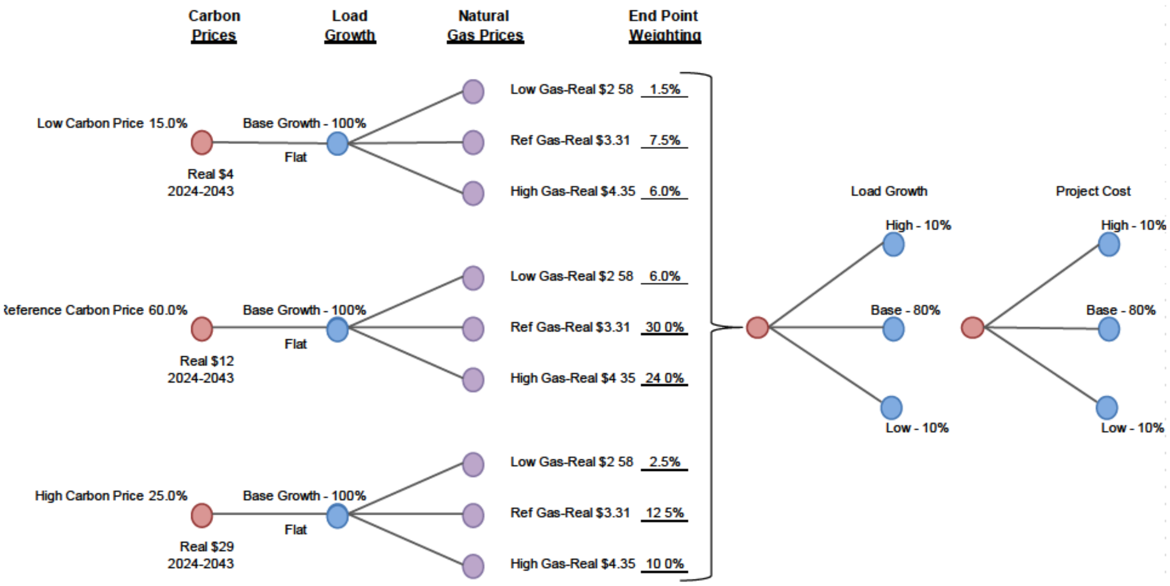
Table 9.12 Critical Independent Uncertain Factors – Change in PVRR (Million $)[38]

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%.

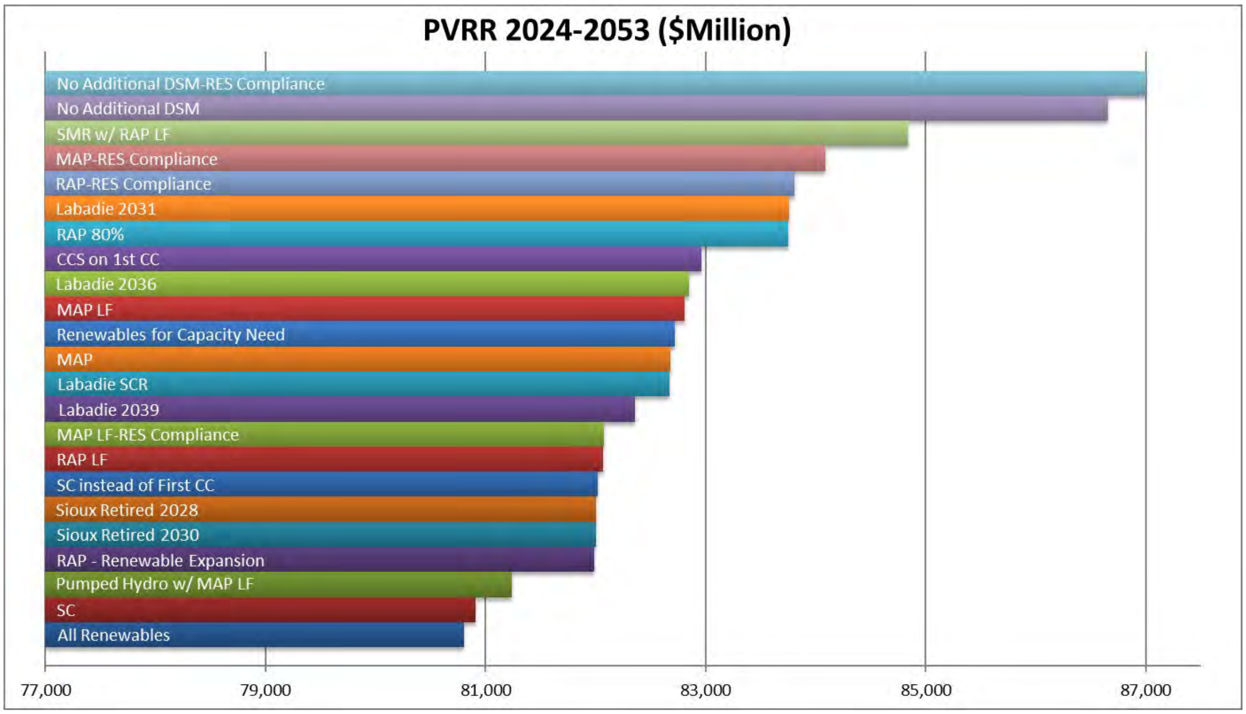
9.7.1 Risk Analysis Results

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)

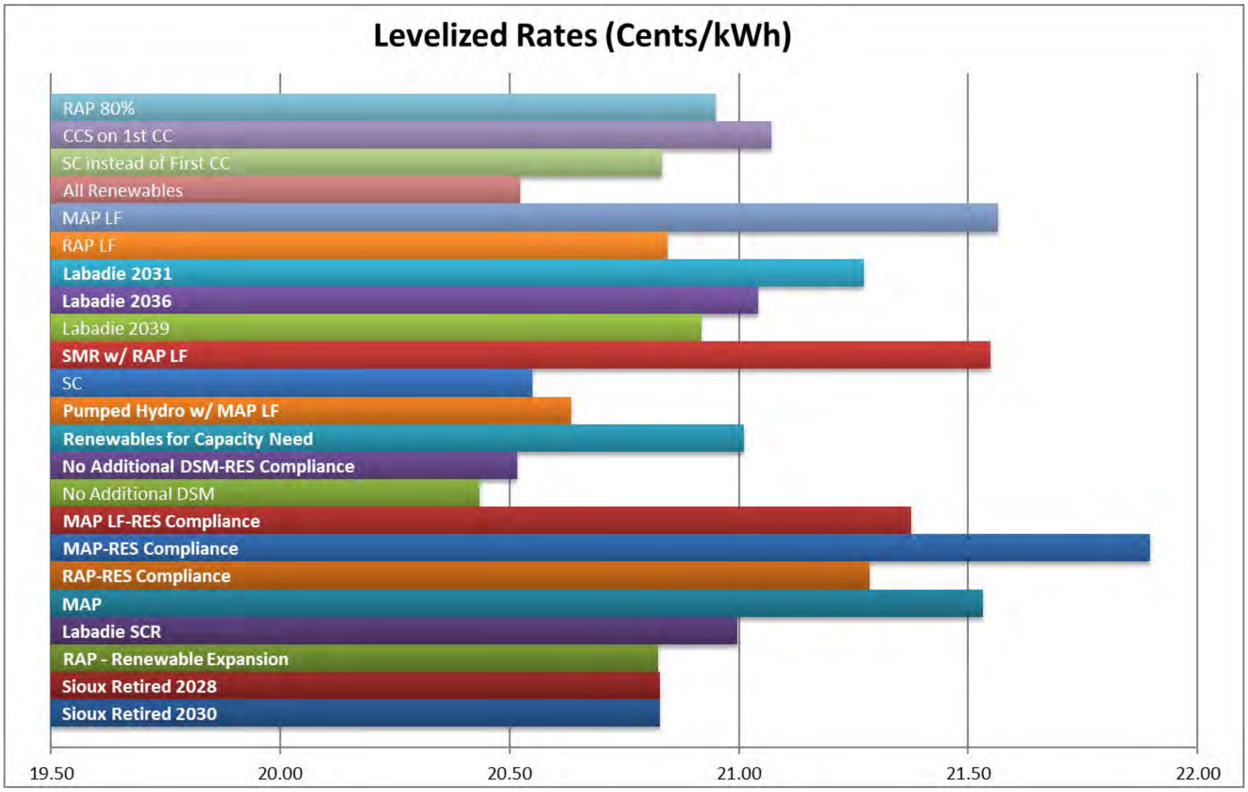
Plan T with Renewable Plus portfolio and RAP DSM has the lowest PVRR followed by Plan M, which includes Renewable Expansion portfolio, RAP DSM and an SC instead of a CC in 2040. Plan J with RES Compliance only renewable portfolio and no further DSM exhibits the highest PVRR and second to lowest levelized 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.

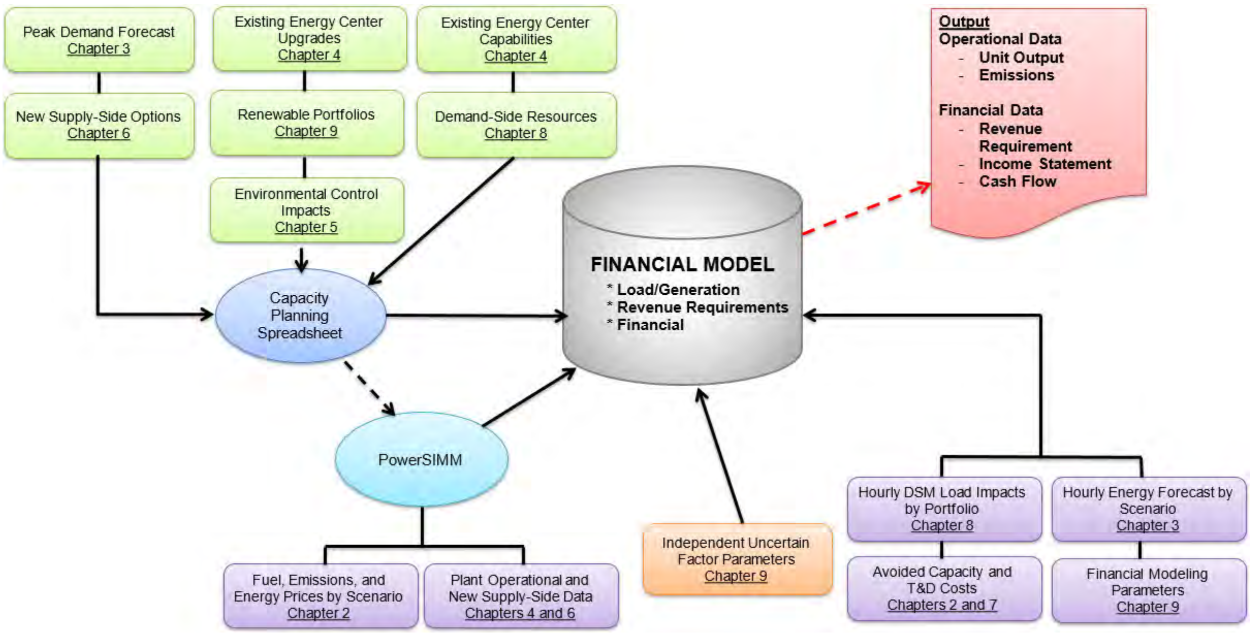
PowerSIMM simulates hourly dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The PowerSIMM model contains all unit operating variables required to simulate the units. These variables include, 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

10. Strategy Selection

Highlights

- *Ameren Missouri has developed and is executing on a plan that is focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio in a responsible fashion over the next 20 years to ensure we provide service to our customers that is safe, reliable and environmentally responsible at a reasonable cost.*
    - *Our plan includes continued customer energy efficiency program offerings, retirement of approximately one-third of our coal-fired generating capacity, which will be reaching the end of its useful life, and expansion of renewable and cleaner-burning natural gas-fired generation.*
    - *Our plan allows us to continue to rely on our existing, low-cost and dependable nuclear generation while also preserving options for future carbon-free nuclear generation.*
    - *By 2035, our plan would result in a diverse, balanced and dependable mix of coal, nuclear, natural gas and renewable energy resources that result in further significant reductions in emissions of carbon dioxide, sulfur dioxide, nitrogen oxides, mercury and particulate matter in addition to those we have achieved since 1990.*
- *Our plan allows us to achieve the goals of the U.S. EPA's proposed Clean Power Plan, reducing carbon dioxide emissions by 30% from 2005 levels, but at a customer cost savings of $4 billion.*
- *Our implementation plan for the next three years includes seeking approval for a new three-year portfolio of customer energy efficiency programs, construction of our second utility-scale solar energy center, identification of potential sites for renewable and gas-fired generation, and actions to preserve contingency resource options and enable us to quickly respond to changing needs and conditions while continuing to ensure safe, reliable and cost-effective service to our customers.*
- *Ameren Missouri will continue to monitor critical uncertain factors to assess their potential impacts on our preferred plan, contingency plans and implementation.*

Ameren Missouri has selected its preferred resource plan and contingency plans in accordance with its planning objectives and practical considerations that inform our decision making. Our selection process consists of several key elements:

- ✓ Establishing planning objectives and associated performance measures to develop and assess alternative resource plans
- ✓ Creating a scorecard based on our planning objectives and performance measures to evaluate the degree to which various alternative resource plans would satisfy our planning objectives
- ✓ Critically analyzing the most promising alternative resource plans to ensure that we select a plan that best balances competing objectives

In addition, Ameren Missouri has subjected its preferred resource plan to testing under several scenarios that represent events that, while not necessarily considered probable, could have a significant impact on our resource needs and the performance of our preferred resource plan. These include 1) the loss of significant customer demand due to a proliferation of distributed solar generation, 2) loss of our largest retail customer, and 3) compliance with proposed regulation of emissions of greenhouse gases (GHG) by existing power plants.

We have established an implementation plan for 2015-2017 that allows us to begin implementing the resource decisions embodied in our preferred resource plan and to preserve contingency options to allow us to effectively respond to changing needs and conditions while continuing to ensure safe, reliable and cost-effective electric service to our customers.

10.1 Planning Objectives

The fundamental objective of the resource planning process in Missouri is to ensure delivery of electric service to customers that is safe, reliable and efficient, at just and reasonable rates in a manner that serves the public interest. This includes compliance with state and federal laws and consistency with state energy policies.[1] Ameren Missouri considers several factors, or planning objectives, that are critical to meeting this fundamental objective. Planning objectives provide guidance to our decision making process and ensure that resource decisions are consistent with business planning and strategic objectives that drive our long-term ability to satisfy the fundamental objective of resource planning. Following are the planning objectives, established in the development of our 2011 IRP, that continue to inform our resource planning decisions.

[1] 4 CSR 240-22.010(2); 4 CSR 240-22.010(2)(A)

Cost (to Customers): Ameren Missouri is mindful of the impact that its future energy choices will have on cost to its customers. Therefore, minimization of present value of revenue requirements is our primary selection criterion.[2]

Costs alone do not and should not dictate resource decisions. Our other planning objectives, reaffirmed by Ameren Missouri decision makers, are discussed below.

Customer Satisfaction: Ameren Missouri is dedicated to improving customer satisfaction. While there are many factors that can be measured, for practical reasons Ameren Missouri focused primarily on measures that can be significantly impacted by resource decisions: 1) rate impacts – average rates and maximum single-year rate increases – and 2) customer preferences – cleaner energy sources and demand-side programs that provide customers with options to manage their usage and costs.

Environmental & Resource Diversity: Ameren Missouri, like other electric utilities in Missouri, produces the majority of the energy it generates from coal. Current and potential future environmental regulations may have a significant impact on Ameren Missouri's existing coal-fired energy centers and its selection of future generation resources. Ameren Missouri is focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio. To assess resource diversity and environmental considerations, we evaluate the composition of future portfolio options in terms of capacity and energy and assess the relative levels of various emissions for different alterntives.

Financial/Regulatory: The continued financial health of Ameren Missouri is crucial to ensuring safe, reliable and cost-effective service in the future. Ameren Missouri will continue to need the ability to access large amounts of capital for investments needed to comply with renewable energy standards and environmental regulations and invest in demand and/or supply side resources to meet customer demand and reliability needs. Measures of expected financial performance and creditworthiness are evaluated along with potential risks.

Economic Development: Ameren Missouri is committed to support the communities it serves beyond providing reliable and affordable energy. Ameren Missouri assesses the economic development opportunities, for its service territory and for the state of Missouri, associated with our resource choices. We do this by examining the potential for primary job growth, which in turn promotes additional economic activity.

Table 10.1 summarizes our planning objectives and the primary measures used to asses our ability to achieve these objectives with our alternative resource plans.

[2] 4 CSR 240-22.010(2)(B)

Table 10.1 Planning Objectives and Measures[3]

Planning Objective Categories	Measures
Cost	Present Value of Revenue Requirements
Customer Satisfaction	Customer Preferences, Levelized Rates, Single-Year Rate Increase
Environmental & Resource Diversity	Resource Diversity, CO_2 Emissions, Probable Environmental Costs
Financial/Regulatory	ROE, EPS, FCF, Financial Ratios, Stranded Cost Risk, Transaction Risk, Cost Recovery Risk
Economic Development	Primary Job Growth (FTE-years)

10.2 Assessment of Alternative Resource Plans

Ameren Missouri used a scorecard to evaluate the performance of alternative resource plans with respect to our planning objectives and measures described above. The scorecard and measures include both objective and subjective elements that together represent the trade-offs between competing objectives. It is important to keep in mind that the scorecard is a tool for decision makers and does not, in and of itself, determine the preferred resource plan. The selection of the preferred resource plan is informed by the scorecard and by a more critical analysis of the relative merits of alternative resource plans, including an assessment of any risks or other constraints.

10.2.1 Scoring of Alternative Resource Plans[4]

To score each of the alternative resource plans, we employed a standard approach to scoring for each planning objective on a 5-point scale and determined a composite score by applying a weighting to each planning objective. As Cost is the primary selection criterion, it was given the greatest weight – 30% -- just as it was in the scoring performed for our 2011 IRP.[5] Economic Development carried a weight of 10%. Each of the other three planning objectives – Customer Satisfaction, Environmental & Resource Diversity, and Financial/Regulatory – carried a weight of 20%. The scoring approach for each planning objective is as follows:

[3] 4 CSR 240-22.060(2); 4 CSR 240-22.060(2)(A)1 through 7

[4] 4 CSR 240-22.010(2)(C); 4 CSR 240-22.010(2)(C)1; 4 CSR 240-22.010(2)(C)2; 4 CSR 240-22.010(2)(C)3; 4 CSR 240-22.070(1); 4 CSR 240-22.070(1)(A) through (D)

[5] 4 CSR 240-22.010(2)(B)

Cost – The 19 alternative resource plans were separated into five groups according to probability weighted average PVRR results from the risk analysis discussed in Chapter 9 – four groups of 4 plans and 1 group of 3 plans. The lowest cost group of plans were given a score of 5, the next lowest cost group a score of 4, and so on, with the highest cost group of plans receiving a score of 1.

Customer Satisfaction – Alternative resource plans were evaluated based on levelized annual average rates for a portion of the score. As was done with the PVRR results, the alternative resource plans were separated into five groups according to the probability-weighted average levelized annual average rate results produced from our risk analysis. The plans resulting in the lowest rates were given a score of 5, the next lowest rate group a score of 4, and so on, with the highest rate group of plans receiving a score of 1. Plans that yielded a score greater than 3 for rates were given 2 points in the overall scoring for Customer Satisfaction. In addition, plans which include continued energy efficiency programs (RAP or MAP) were given a point. Also, plans which included demand response programs were given an additional point. Finally, plans that include additional renewable generation sources beyond those needed to comply with legal mandates were given an additional point.

Environmental & Resource Diversity – Alternative resource plans were awarded points for each plan attribute contributing to greater resource diversity and/or environmental impact in terms of emission reductions. Plans were awarded one point each for each of the following:

- ✓ Inclusion of demand-side programs
- ✓ Addition of nuclear generation
- ✓ Addition of combined cycle gas generation
- ✓ Addition of renewables (beyond those needed to comply with legal mandates)
- ✓ Addition of storage resources
- ✓ Retirement of coal generation (beyond Meramec and Sioux)

Financial/Regulatory – Scoring for Financial/Regulatory is based on a default score of 5 with deductions for risks and financial impacts that may detrimentally affect Ameren Missouri's ability to continue to access lower cost sources of capital. Plans that would result in relatively lower free cash flow were reduced by one point. Plans were also reduced by one point each for potential risks associated with:

- ✓ Lack of customer energy efficiency programs
- ✓ Significant risk of not achieving energy efficiency targets
- ✓ Nuclear construction costs
- ✓ Retirement and replacement of additional coal units beyond Meramec and Sioux (one point deduction for every 1,200 MW of additional retirement)

Economic Development – Alternative plans were scored based on direct job creation, including construction and ongoing operation. Estimates for direct job creation were developed using the Jobs and Economic Development Impact (JEDI) Model, developed by Marshall Goldberg of MRG & Associates under contract with the National Renewable Energy Laboratory, or more specific estimates where available (e.g., nuclear). Construction and operating jobs were translated into full-time equivalent years (FTE-years). Alternative plans were ranked based on FTE-years and divided into five groups based on relative rank. The group of plans resulting in the highest FTE-year values were given a score of 5 points each, the next highest FTE-year group a score of 4, and so on, with the lowest FTE-year group of plans receiving a score of 1.

Table 10.2 Alternative Resource Plan Scoring Results

Plan	Description	Overall Assessment
R	600MW CC in 2034, MAP, Balanced	4.10
I	600MW CC in 2034, RAP, Balanced	4.00
E	800MW Wind in 2034, 352MW SC in 2034, 600MW CC in 2034, RAP	3.80
G	600MW CC in 2034, MAP	3.80
A	600MW CC in 2034, RAP	3.60
C	704MW SC in 2034, RAP	3.60
S	600MW CC in 2034, MAP EE Only	3.60
H	169MW Nuke in 2034, 600MW CC in 2034, RAP, Balanced	3.40
F	1200MW CC in 2034,RAP EE Only	3.20
D	600MW Pumped Hydro in 2034, RAP	3.10
Q	169MW Nuke in 2034, MAP, Balanced	3.10
P	169MW Nuke in 2025, 600MW CC in 2025, 1200MW CC in 2034, RAP, Balanced, RI Ret 12/31/2024	3.00
B	450MW Nuke in 2034, 600MW CC in 2034, RAP	2.80
O	169MW Nuke in 2025, 1800MW CC in 2024, 1200MW CC in 2034, RAP, Balanced, LAB Ret 12/31/2023	2.50
N	600MW CC in 2025, 1200MW CC in 2034, MAP, RI Ret 12/31/2024	2.40
K	600MW CC in 2023, 600MW CC in 2031, 600MW CC in 2034, MEEIA1, Balanced	2.10
M	1800MW CC in 2024, 1200MW CC in 2034, MAP, LAB Ret 12/31/2023	2.10
J	169MW Nuke in 2031, 600MW CC in 2023, 1200MW CC in 2034, MEEIA1, Balanced	2.00
L	3300MW Wind in 2023, 3300MW Wind in 2027, 6600MW Wind in 2034, MEEIA1	1.60

Table 10.2 shows the composite scores for each of the 19 alternative resource plans. The full scorecard with scores for each planning objective for each alternative resource plan is shown in Appendix A.

Based on the scoring results, the alternative resource plans were separated into three tiers – Top, Mid, and Bottom. The range of composite scores across the 19 alternative resource plans is 1.6 to 4.1, a difference of 2.5. This range was divided into thirds to establish the plan tiers. Plans with scores greater than 3.27 were placed in the Top Tier. Plans with scores between 2.43 and 3.27 were placed in the Mid-Tier. Plans with scores below 2.43 were placed in the Bottom Tier.

All Top Tier plans include energy efficiency and demand response at the realistic achievable potential (RAP) or maximum achievable potential (MAP) level. In general, plans that include combined cycle gas generation and renewable generation beyond that required for RES compliance scored highest. Only one plan with a Cost score greater than 3 is not included in the Top Tier – Plan F, which includes combined cycle generation and RAP energy efficiency, but no demand response.

10.2.2 DSM Portfolio Considerations

The top two plans identified in the plan scoring include either RAP DSM or MAP DSM. While MAP DSM results in lower total customer costs over the 30 years evaluated in our risk analysis, it is important to further evaluate the performance of MAP relative to RAP, in particular because MAP is defined as the hypothetical upper boundary of achievable demand-side potential, assuming ideal conditions for implementation. To further investigate the relative merits of RAP and MAP DSM portfolios, we evaluated:

- ✓ The inclusion in revenue requirements of the cost to customers of the incentives needed to align customer and utility interests in energy efficiency
- ✓ The inclusion in revenue requirements of participant costs
- ✓ The year-by-year relative net benefits for RAP and MAP
- ✓ A “Mid DSM” portfolio between RAP and MAP

Total Costs with Incentives and Participant Costs

In addition to the risk analysis discussed in Chapter 9, which excludes the cost of DSM incentives and participant out-of-pocket costs for energy efficiency measures, we also examined revenue requirements including these two components, both separately and in combination. Table 10.3 shows the results for the top two plans – one with RAP and one with MAP – under various combinations of assumptions for inclusion of incentive costs and participant out-of-pocket costs.

Table 10.3 PVRR Comparison of RAP and MAP

$ Million	PVRR	PVRR w/ Incentives	PVRR w/ DSM Participant Costs	PVRR w/ Incentives & DSM Participant Costs
R - CC-MAP-Balanced	61,081	61,420	61,834	62,172
I - CC-RAP-Balanced	61,352	61,635	61,928	62,211
MAP Cost Advantage	271	215	94	38

As the table shows, the cost advantage for MAP is reduced when either or both incentives and participant costs are included. Including only the incentives results in a cost advantage of $215 million for MAP, compared to a cost advantage of $271 million excluding incentives. Including participant out-of-pocket costs (and excluding incentive costs) reduces the advantage to $94 million, while including both incentives and participant out-of-pocket costs reduces it to $38 million.

The Missouri Energy Efficiency Investment Act (MEEIA) includes three requirements to ensure the alignment of utility incentives with helping customers use energy more efficiently:

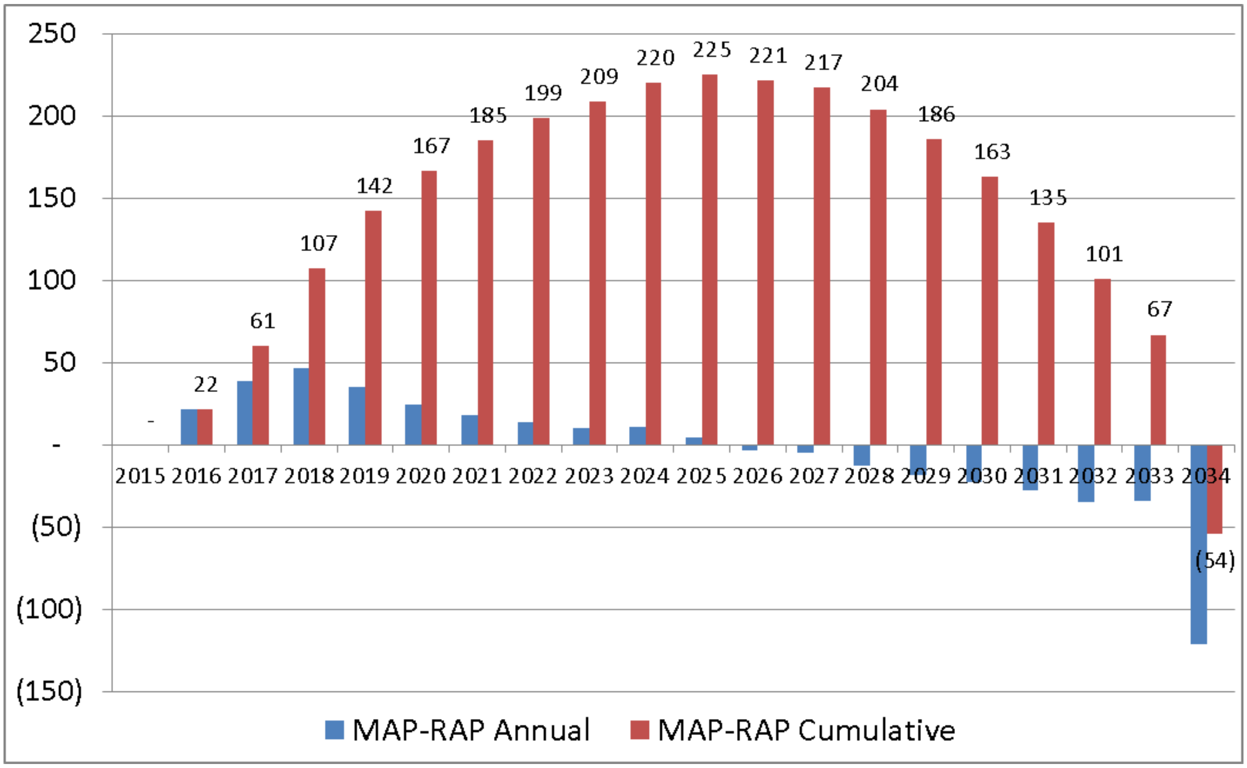
- ✓ Timely recovery of program costs
- ✓ Alignment of incentives to reduce energy consumption (i.e., elimination of the so-called “throughput disincentive”)
- ✓ Timely earnings opportunities

The incentives included for RAP and MAP are based on an analysis of equivalency between demand side and supply side resources. Because the top scoring plans include gas-fired combined cycle generation, we based our equivalency analysis on the displacement of combined cycle generation by demand-side programs. We evaluated the earnings opportunity available to Ameren Missouri from a plan with no DSM programs after our current three-year cycle of programs (i.e., 2013-2015) and with combined cycle generation to meet load and reserve margin requirements instead of DSM. The present value earnings opportunity for each of RAP and MAP was levelized over the planning horizon. This amount was then included in the PVRR results including DSM incentives.

Year-by-Year Net Costs/Benefits

Implementation of the MAP energy efficiency portfolio would require a program budget for 2016-2018 that is roughly twice the budget needed to implement the RAP portfolio, although MAP reflects energy savings that are only roughly 35% greater than those for RAP. For the entire planning horizon, the program budget for MAP would total $2.45 billion compared to $1.27 billion for RAP, or 93% more costly than RAP, with energy savings that are only roughly 36% greater. We analyzed the year-by-year revenue requirement impacts of the RAP EE Only plan (Plan F) and the MAP EE Only plan (Plan S), including all costs and benefits. Figure 10.1 shows the annual and cumulative revenue requirement differences between the two plans.

Figure 10.1 Year-by-Year PVRR Differences for RAP and MAP Plans



As the chart shows, the MAP plan results in higher overall costs than the RAP plan through 2025. While the MAP plan results in lower overall costs starting in 2026, the cumulative increase in costs for the MAP plan reaches $225 million in 2025 and persists until 2034, the last year of the twenty-year planning horizon, when an additional combined cycle plant is assumed to be placed in service in the RAP EE Only plan. The greater net benefits of MAP relative to RAP increase significantly once program spending ceases and the persistent energy savings continue to yield benefits in the form of capacity and energy value in addition to deferral of the combined cycle plant.

Portfolios between RAP and MAP

To further evaluate the economics of DSM portfolios and to assist us in addressing the policy goal of MEEIA to achieve all cost-effective demand-side savings, we evaluated the possibility of a DSM portfolio that results in savings that are between those represented by RAP and MAP. Because primary market research exists only to support the development of RAP and MAP portfolios, we must estimate the costs and savings for any other portfolio assumptions.

We started by estimating the costs and savings for a portfolio that lies midway between the RAP and MAP portfolios, called the "Mid DSM" portfolio. The costs and savings were estimated by interpolating between the costs and savings associated with the RAP and MAP portfolios resulting from the primary market research included in our 2013 DSM potential study, described in Chapter 8. We then constructed a test plan including this portfolio and supply side resources necessary to meet load and reserve requirements. The plan was evaluated using the same ranges of assumptions used to evaluate alternative resource plans in our risk analysis. The results of the analysis, with a comparison of comparable plans including RAP and MAP portfolios (Plans I and R), is shown in Table 10.4. As the table shows, the PVRR results for the Mid DSM portfolio are midway between the results for plans with RAP and MAP DSM portfolios.

Table 10.4 PVRR Comparison of RAP and MAP

DSM Portfolio	PVRR
RAP	61,352
MAP	61,081
Mid	61,217

While it is possible to repeat this process, estimating other portfolios between RAP and MAP at different points on a continuum between the two portfolios, it would not provide additional insight into the merits of these various portfolios. Based on the results of our analysis of the Mid DSM portfolio, we would expect such additional portfolios to produce results that are similarly predictable. We would also expect the year-by-year analysis to produce similarly predictable results, showing a net advantage for RAP through 2025 on an annual basis and through 2033 on a cumulative basis.

Pursuing the Policy Goal of MEEIA[6]

As stated previously, the stated goal of MEEIA is to achieve all cost-effective demand-side savings by aligning utility incentives with helping customers to use energy more

[6] EO-2014-0062 a; EO-2014-0062 b

efficiently. Ameren Missouri has demonstrated its commitment to pursuing this goal by implementing the largest utility energy efficiency program in Missouri history. And while we believe this is a goal worth pursuing, it cannot be quantified with any degree of accuracy for the next twenty years. Rather, it is a goal that will constantly be shaped and reshaped through continuous implementation, evaluation, research, testing and readjustment.

As noted earlier, Ameren Missouri has conducted a DSM Potential Study, prepared by a nationally recognized independent contractor team. That study reflects an energy efficiency market assessment using 100% Ameren Missouri appliance saturation surveys, demographics surveys and customer psychographic surveys. The primary objective of the study was to assess and understand the technical, economic, and achievable potential for all Ameren Missouri customer segments for the period from 2016 to 2034. The amount of energy efficiency achieved by customers as a direct result of Ameren Missouri sponsored customer energy efficiency programs is defined as realistic achievable potential (RAP). Assuming regulatory treatment that reflects the requirements of MEEIA, RAP represents all cost-effective energy efficiency because, by definition, it represents a forecast of likely customer behavior under realistic program design and implementation.

10.3 Preferred Plan Selection[7]

In selecting its Preferred Resource Plan, Ameren Missouri decision makers[8] relied on the planning objectives discussed earlier in this chapter and the considerations reflected in the scoring and comparison of DSM portfolios highlighted in the previous section. As was noted previously, the Top Tier plans identified through scoring include combinations of RAP and MAP DSM portfolios as well as renewables, gas-fired resources and nuclear. These define the key options for consideration in the selection of the preferred resource plan.

DSM Portfolio[9] – RAP and MAP DSM portfolios both performed well in the scoring and, importantly, both result in reduced total costs to customers. The decision between the two must involve a consideration of risk and reward from the perspective of both customers and Ameren Missouri. Based on our analysis of the year-by-year cost differences between RAP and MAP, and an understanding of the increased level of risk

[7] 4 CSR 240-22.010(2)(C); 4 CSR 240-22.010(2)(C)1; 4 CSR 240-22.010(2)(C)2
4 CSR 240-22.010(2)(C)3; 4 CSR 240-22.060(3)(A)5; 4 CSR 240-22.070(1); 4 CSR 240-22.070(1)(A) through (D)

[8] Names, titles and roles of decision makers are provided in Appendix B.

[9] EO-2014-0062 c

in achieving MAP relative to RAP, Ameren Missouri has chosen to include the RAP portfolio in its preferred resource plan.

This is not to say that there couldn't be additional potential energy savings that can be realized. Indeed our uncertainty range for the RAP portfolio includes some significant amount of upside. However, we must consider the immediate cost impact to all customers of a large increase in DSM expenditures (the 2016-2018 budget would be nearly double for MAP) and the uncertainty of the relative long-term benefits. We must also consider that the path for demand-side programs is not “locked in” for twenty years.

Including RAP DSM in our preferred resource plan allows us to continue to offer highly cost-effective programs to customers at roughly the same level of annual spending budgeted for our first cycle of MEEIA programs while also allowing the potential for increased savings if our experience and expectations indicate they could be achieved in a cost-effective manner. Identifying such opportunities will depend on the results of program implementation and periodic updates of our market research.

Renewable Resources – One of Ameren Missouri's planning objectives is to transition our generation portfolio to one that is cleaner and more fuel diverse in a responsible fashion. Compliance with the Missouri RES is reflected in all of our alternative resource plans. This includes approximately 300 MW of wind, solar, hydro and landfill gas generation. While the addition of these resources does help to transition our portfolio, additional renewable resources would further advance this objective while also further mitigating fuel price risks and the risks associated with additional environmental regulation, including regulation of emissions of greenhouse gases. We have therefore included additional wind and solar generation in our preferred resource plan to bring our renewable generation additions to approximately 500 MW.

Supply Side Resources – Considering costs, risks and the ability to further diversify our generating portfolio, we have included combined cycle generation in our preferred resource plan when needed to meet customer load and reliability reserve margin requirements. Based on our planning assumptions, we expect to need new capacity by 2034 to replace our Sioux energy center, which would be retired by the end of 2033. Because combined cycle generation technology is relatively mature, although still continuing to evolve, and is characterized by relatively short lead times, its inclusion preserves a measure of flexibility with respect to deployment for meeting load and reserve requirements. While simple cycle combustion turbine generators (CTGs) also exhibit short lead times and are relatively inexpensive, their operating characteristics prevent them from providing significant benefits in terms of energy diversity, and Ameren Missouri currently has a robust fleet of CTGs. Nuclear remains an attractive option for carbon-free around-the-clock generation with newer commercial and developing technologies.

The plan that embodies these key choices is listed in Table 10.2 as "Plan I". It includes RAP energy efficiency and demand response programs, roughly 500 MW of new renewable generation, and a new 600 MW combined cycle energy center in 2034 along with conversion of Meramec Units 1&2 to natural gas-fired operation in 2016, retirement of all Meramec units by the end of 2022, and retirement of Sioux Energy Center at the end of 2033.

10.4 Contingency Planning[10]

Because any assumptions about the future are subject to change, we must be prepared for changing circumstances by evaluating such potential circumstances and options for providing safe, reliable, cost-effective and environmentally responsible service to our customers. We have identified several cases which could significantly impact the performance of our preferred resource plan. These include cases that may result in 1) significantly higher or lower demand, 2) altered costs and feasibility of continuing to operate existing generating units, and 3) policies that may encourage the development of new nuclear generation.

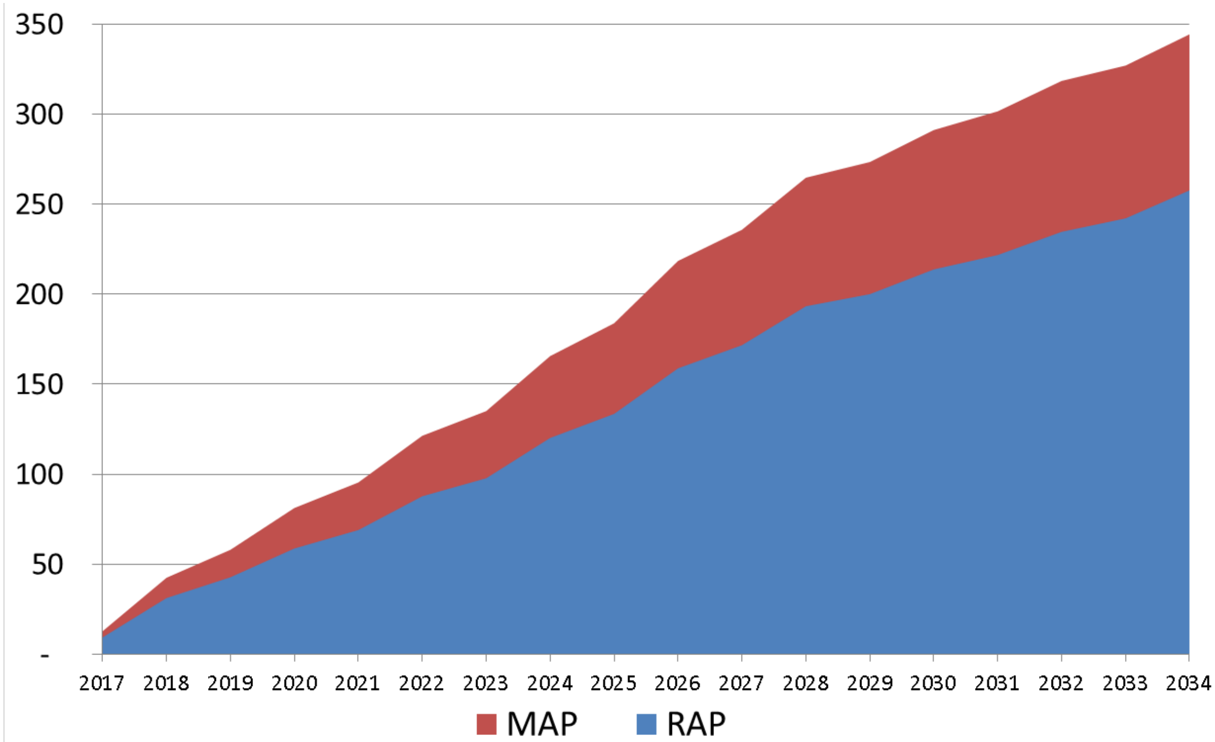
10.4.1 DSM Cost Recovery and Incentives

As stated previously, MEEIA provides for cost recovery and incentives for utility-sponsored demand-side programs to align utility incentives with helping customers to use energy more efficiently. In 2012, the Missouri Public Service Commission (Commission) approved our first cycle of MEEIA programs and supporting cost recovery and incentives. Our preferred resource plan is based on the expectation that supporting cost recovery and incentives will continue to be approved in the future. If such alignment is not achieved, it may be necessary for Ameren Missouri to change its preferred resource plan.

Ameren Missouri expects to file a request with the Commission for approval of a new three-year portfolio of demand-side programs in the fourth quarter of 2014. This portfolio would be implemented in 2016-2018. Program costs are expected to be recovered through our Rider Energy Efficiency Investment Charge (Rider EEIC). In our request, we will also seek recovery of costs associated with the so-called "throughput disincentive." The throughput disincentive results from reduced sales due to energy efficiency programs and rates that are designed to recover fixed costs based on sales volume. Figure 10.2 illustrates the impact of the throughput disincentive on Ameren Missouri's sales revenues for inclusion vs. exclusion of customer energy efficiency programs.

[10] 4 CSR 240-22.070(4)

Figure 10.2 Cumulative Throughput Disincentive for RAP and MAP Plans ($Millions)



In addition to recovery of program costs and addressing the throughput disincentive, MEEIA also mandates that utilities be provided with timely earnings opportunities that serve to make investments in demand-side resources equivalent to investments in supply-side resources. Ameren Missouri will seek such incentives in its upcoming MEEIA filing.

10.4.2 Expansion of Distributed Generation

The deployment of customer-owned distributed generation, particularly solar photovoltaic systems, continues to expand. Ameren Missouri has included its expectation for the deployment of customer-owned solar resources in its load forecast assumptions, described in Chapter 3. Because the economics of distributed generation can change rapidly, as we have seen in recent years, it is important for us to assess a greater-than-expected expansion of these resources. As described in Chapter 3, we identified the potential for additional distributed solar generation consistent with the U.S. DOE's Sunshot Initiative. Based on the DOE assumptions, Ameren Missouri would see an additional 614 MW of distributed solar generation in its service territory by 2034.

We have evaluated the impact of this change in load in two ways. First, we analyzed the impact on the cost of our preferred resource plan if the plan itself were not changed. Second, we analyzed the impact of the reduction in load on our need for, and timing of, new resources. If our resource plan is altered as a result of this significant change in customer load, we would expect to be able to defer the combined cycle generator that is shown in service in 2034 in our preferred resource plan.

The costs (PVRR) and levelized rates for our preferred resource plan, including that for the plan in which the combined cycle generator is deferred, are shown in Table 10.5 for our base distributed solar assumption and for the Sunshot case. The table shows that PVRR would be reduced by over $1.8 billion, while rates would increase by 0.21 cents/kWh if the timing of resources in the preferred plan did not change. It also shows that PVRR would be reduced by over $2 billion, and rates would increase by 0.17 cents/kwh if the combined cycle were deferred beyond the end of the planning horizon. Because the Sunshot Initiative would impact customer load across the Eastern Interconnect, we developed a price scenario using the process discussed in Chapter 2 to reflect the impacts of this additional change in load on power prices.

Table 10.5 Impact of Distributed Generation Expansion

Plan	PVRR ($Million)
Preferred Plan	61,352
DG Expansion-CC in 2034	59,513
DG Expansion-No CC in 2034	59,320

It is important to note that our preferred resource plan provides flexibility in responding to significant changes in load like the change that could be driven by a proliferation of distributed generation, solar or otherwise.

10.4.3 Loss of Large Customer Load

Ameren Missouri's largest customer is the aluminum smelter operated by Noranda Aluminum, Inc., in New Madrid, Missouri. The smelter uses 4,169 GWh of electricity annually with a peak demand of approximately 495 MW and is served at retail rates regulated by the Commission under a contract with Ameren Missouri that expires in May 2020. To evaluate the impact on our preferred plan of a loss of Noranda's load at the end of their current contract, we examined cases in which 1) the resources and timing reflected in our preferred plan are not changed and 2) the resources and timing reflected in our preferred plan are changed. This is similar to the analysis we conducted for the proliferation of distributed solar generation described in the previous section.

The loss of Noranda's load would allow us to defer the combined cycle that is shown going into service in 2034 in our preferred resources plan. The costs (PVRR) and levelized rates for our preferred resource plan, including that for the plan in which the combined cycle generator is deferred, are shown in Table 10.6 for our base assumption with Noranda continuing to take electric service from Ameren Missouri and for the case with no Noranda load after May 2020. The table shows that PVRR would be reduced by nearly $3.4 billion if the timing of resources in the preferred plan did not change. It also shows that PVRR would be reduced by $3.6 billion if the combined cycle were deferred beyond the end of the planning horizon.

Table 10.6 Impact of Noranda Load Loss

Plan	PVRR ($Million)
Preferred Plan	61,352
Noranda Contract Expired-CC in 2034	57,966
Noranda Contract Expired-No CC in 2034	57,755

As with the distributed generation case discussed in the previous section, the flexibility of our preferred resource plan allows us to adjust our resource timing to minimize cost impacts, which in this case would be borne by our remaining customers outside of Noranda.

10.4.4 Incremental Wind Additions[11]

Ameren Missouri has also modeled its preferred plan with the addition of 150 MW of wind resources (beyond that already included in the preferred plan) in year 2022 in order to evaluate the cost effectiveness of additional incremental renewable resources. Table 10.7 shows the results of the analysis, which indicates increased cost to customers for the plan with additional wind resources compared to our preferred plan.

Table 10.7 Impact of Additional Wind

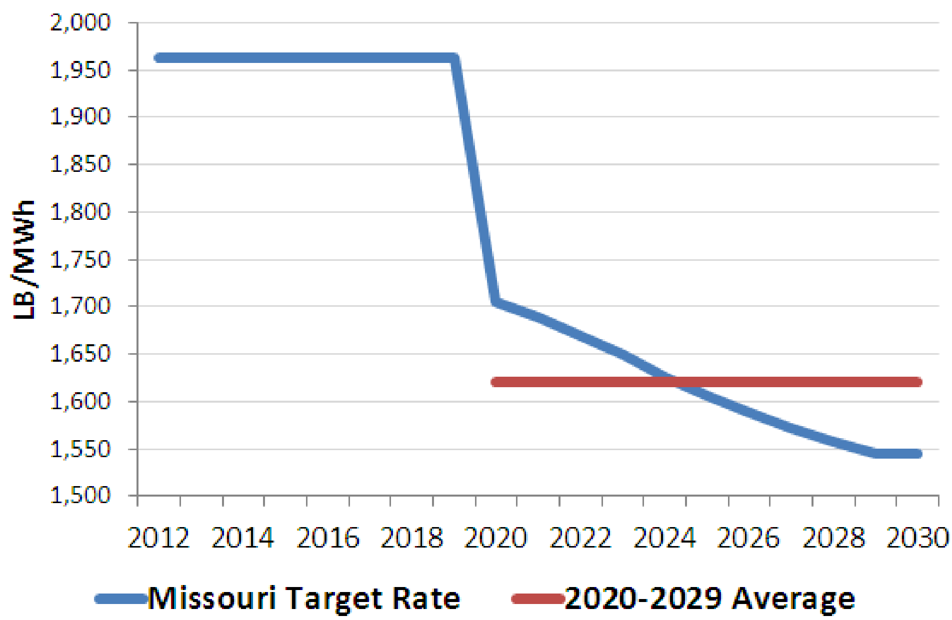
Plan	PVRR ($Million)
Preferred Plan	61,352
Additional Wind	61,455
Difference	102

[11] 4 CSR 240-22.060(4)(E); EO-2011-0271 Order

10.4.5 Greenhouse Gas Regulation

On June 2, 2014, the EPA announced its proposed “Clean Power Plan,” which calls for a 30% reduction in carbon dioxide emissions from existing power plants compared to 2005 levels from existing power plants by 2030, with aggressive interim targets beginning in 2020. These targets are not based on mass carbon emission reductions, but instead are based on rates of carbon emitted from existing plants as derived from 2012 levels. The EPA established different targets for each state, including a 21% reduction for Missouri. Figure 10.3 shows the required reduction and timing of carbon dioxide emission rates proposed by the EPA. As the chart shows, much of the targeted 2030 reduction, 13% of the 21% final target, is required starting in 2020 due to interim targets included in the proposed rule. This means that more than 60% of the 2030 reduction goal must be met by 2020.

Figure 10.3 EPA Target Carbon Dioxide Emission Rates for Missouri



The proposal’s basic formula for setting CO_2 emissions reduction requirements is:

CO_2 emissions from fossil fuel-fired power plants (in pounds)

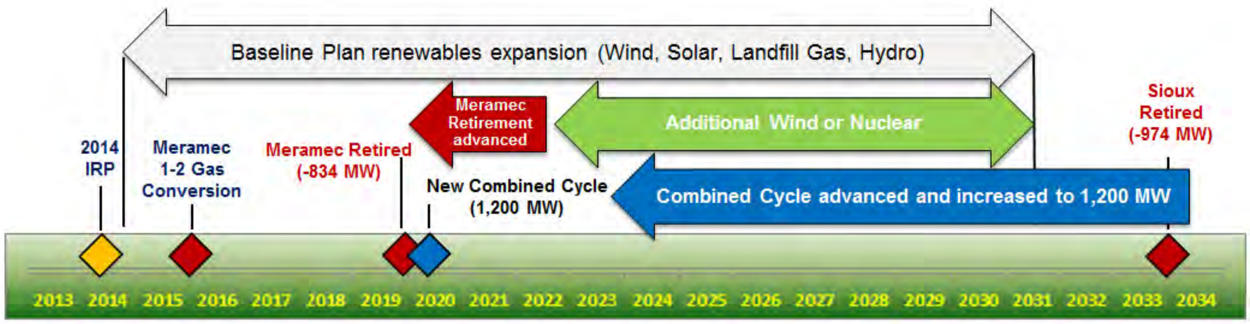
divided by:

Electricity generation from fossil fuel-fired power plants and certain low- or zero-emitting power sources (in MWh)

According to the EPA, this approach "factors in MWh from fossil fuel power plants and other types of power generation, such as renewables, new nuclear and natural gas combined cycle, as well as MWh savings from energy efficiency in the state."

Should the rule be implemented as proposed, Ameren Missouri would have to significantly alter its preferred resource plan in such a way as to lead to much higher capacity reserves by advancing and adding natural gas-fired generation, as early as 2020, and uneconomically dispatching those resources, which would not otherwise be needed until 2034 to meet customer demand and reserve margin requirements for reliability. Figure 10.4 illustrates the changes that could have to be made to Ameren Missouri's preferred resource plan to comply with the proposed regulations.

Figure 10.4 Impacts of GHG Regulations on Preferred Resource Plan



The changes include 1) advancing the retirement of Meramec by three years to the end of 2019, 2) constructing a 1,200 MW combined cycle generation facility to be operational by the beginning of 2020, 3) altering the operation of the new combined cycle and existing coal resources such that gas generation runs more (about twice what it would run otherwise) and coal generators run less than they would under current methods for economic dispatch in MISO, and 4) constructing additional wind (or possibly nuclear) resources in the 2022-2030 timeframe. Making these changes would result in additional costs to customers of approximately $4 billion over the 15 year period starting in 2020 while achieving roughly the same level of annual carbon dioxide emission reductions a few years earlier than under our preferred plan.

Ameren is advocating for changes to the EPA's proposed rules that will allow Ameren Missouri to execute its Preferred Resource Plan and achieve the overall objective of the Clean Power Plan to reduce carbon emissions by 30 percent below 2005 levels over a slightly longer period of time. Specifically, Ameren proposes that EPA:

1. Eliminate the aggressive interim emission reduction targets and give states, who possess intimate knowledge of their system needs, the flexibility to adopt interim milestones as appropriate

Schedule MM-S10

2. Treat unreplaced retired coal units as a zero-emitting resource (similar to how customer energy efficiency programs are treated)
3. Give states the flexibility to extend the compliance date to allow the orderly retirement of coal plants as states implement their transition plans

Comments to the rule are due December 1, 2014, and EPA expects to issue a final rule in June 2015. States are required to develop plans to implement the rule by mid-2016, with the possibility of a one or two year extension. Legal challenges to the rule are expected and could in turn cause significant planning and operational challenges in developing and executing plans to comply with EPA's proposed interim targets starting in 2020. The changes we are advocating would alleviate these planning and operational challenges in addition to saving our customers $4 billion.

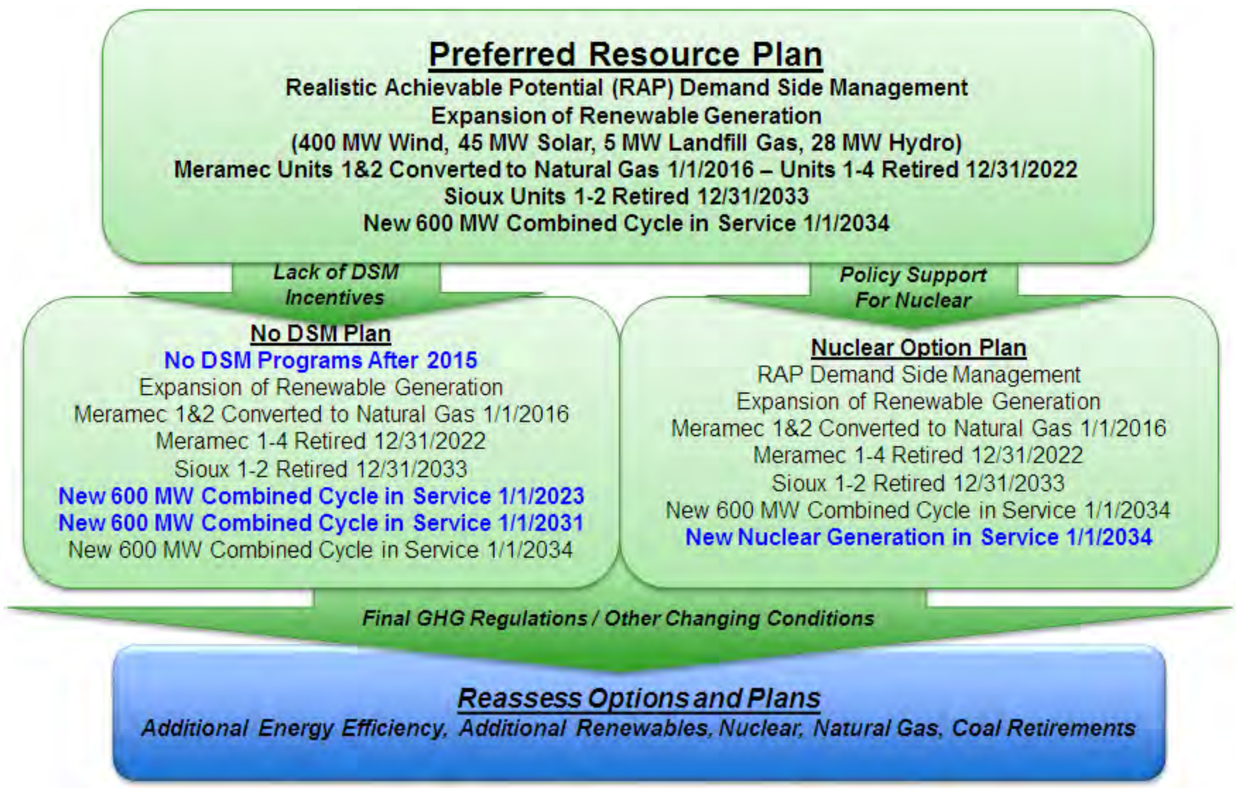
10.4.6 Optionality for New Generation

As the contingency cases described earlier illustrate, it is important to maintain options and flexibility to ensure Ameren Missouri can meet its customers' energy needs in a safe, reliable, and environmentally responsible manner at a reasonable cost. Our analysis has shown that renewables, gas-fired combined cycle, and nuclear generation continue to be attractive options for meeting our customers' future energy needs. It is therefore important to ensure that we can exercise these options when needed and in response to changing circumstances. This includes continuing to evaluate opportunities for developing additional renewable energy resources, evaluating potential sites for new gas-fired generation, and taking actions to maintain an option for future nuclear generation and the associated economic development benefits that would be realized for the state of Missouri. As the discussion of greenhouse gas regulation demonstrates, options for cleaner and dependable resources are also critical for ensuring compliance with such regulations while maintaining safe, reliable, and cost-effective service to customers.

10.5 Resource Acquisition Strategy[12]

Our resource acquisition strategy has three main components. First is the Preferred Resource Plan which is discussed in more detail in Section 10.5.1. The second component of the resource acquisition strategy is contingency planning. Under no ranges or combinations of outcomes for the critical uncertain factors, would the Preferred Resource Plan be inappropriate. Figure 10.5 shows the Preferred Resource Plan as well as several contingency options and the events that could lead to a change in our preferred plan. The final component of the resource acquisition strategy is the implementation plan which includes details of major actions over the next three years, 2015-2017.

Figure 10.5 Preferred Plan and Contingency Plans



[12] 4 CSR 240-22.070(1); 4 CSR 240-22.070(1)(A) through (D); 4 CSR 240-22.070(2);
4 CSR 240-22.070(4); 4 CSR 240-22.070(4)(A) through (C);
4 CSR 240-22.070(7); 4 CSR 240-22.070(7)(A) through (C)

10.5.1 Preferred Plan

As discussed in Section 10.3, our Preferred Resource Plan includes RAP energy efficiency and demand response programs, roughly 500 MW of new renewable generation, and a new 600 MW combined cycle energy center in 2034 along with conversion of Meramec Units 1&2 to natural gas-fired operation in 2016, retirement of all Meramec units by the end of 2022, and retirement of Sioux Energy Center at the end of 2033.

Demand Side Resources

The preferred plan includes RAP energy efficiency and demand response programs. Energy efficiency programs under our current three-year MEEIA plan run through 2015. Energy efficiency programs under subsequent MEEIA cycles begin in 2016. Demand response programs begin in 2019 based on our expectation for higher avoided capacity costs in that timeframe. Program spending for the 20-year planning horizon is $1.41 billion. Cumulative peak demand reductions reach 1090 MW by 2034 (not including planning reserve margin), and cumulative energy savings (at the customer meter) total over 23.6 million MWh.

Renewables

Chapter 9 includes a detailed description of renewable resource requirements. In summary, Ameren Missouri will need additional non-solar resources starting in 2019. We also expect to need additional solar resources to continue to meet the RES solar requirements when SRECs transferred to Ameren Missouri from customer-owned solar facilities are no longer available. Beyond those renewable resources included for RES compliance, we have included additional wind and solar resources to advance our objective to transition our generation portfolio to a cleaner and more fuel diverse mix of resources. Our expansion of renewables includes 400 MW of wind, 45 MW of solar, 20 MW of new hydroelectric, 8 MW of upgrades to existing hydroelectric facilities, and 5 MW of additional landfill gas generation.

Supply-Side Resources

The Preferred Resource Plan calls for the conversion of Units 1&2 at our Meramec Energy Center to natural gas-fired operation in early 2016 and retirement of all Meramec units by the end of 2022. It also includes retirement of Sioux Energy Center by the end of 2033 and a 600 MW combined cycle plant near the end of the planning horizon in 2034.

10.5.2 Contingency Plans[13]

Figure 10.5 presents our key contingency options. In the event that Ameren Missouri's interests are not aligned with helping customers use energy more efficiently, as required by MEEIA, we have included a contingency plan that reflects a discontinuation of demand side programs after our current MEEIA cycle programs expire at the end of 2015. The contingency plan therefore also includes the installation of a 600 MW combined cycle facility to be in service in 2023 and another 600 MW combined cycle in 2031 in addition to the generation resources included in our preferred plan. We are also maintaining a contingency option to reflect policy support for new nuclear generation, which would result in the addition of nuclear generation in 2034. Maintaining an option for new nuclear generation also affords us greater flexibility to comply with requirements of greenhouse gas regulations.

10.5.3 Expected Value of Better Information Analysis[14]

After selecting the preferred plan, Ameren Missouri conducted an expected value of better information (EVBI) analysis to assess the performance of its preferred resource plan under the range of values defined for the critical uncertain factors and to inform its on-going research and implementation activities. Table 10.8 displays the results of the EVBI analysis as measured by PVRR. Under almost all critical uncertain factor values, Plan G results in a lower PVRR than the preferred plan. In part, because it is possible that additional cost-effective energy savings could be identified, we will continue to undertake rigorous evaluation of our programs and periodically update our market research to identify additional such opportunities.

Under the high carbon price scenario, Plan L with only additional renewable resources (no further DSM after MEEIA Cycle 1), performs significantly better than the preferred plan. While the addition of such a vast amount of wind generation may not be practical or feasible, the analysis does indicate the potential for greater value for renewable resources under aggressive scenarios for greenhouse gas regulation. We will continue to evaluate opportunities for additional renewable resources as we identify options and candidate sites for our planned renewable additions and as current efforts to regulate greenhouse gas emissions continue to unfold.

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[13] 4 CSR 240-22.070(4)
[14] 4 CSR 240-22.070(3)

Table 10.8 EVBI Analysis Results

	Alternative Resource Plans	PVRR Without Better Info	Coal Retirements			Carbon				Load Growth				Natural Gas Price				Project Cost			Interest Rate & ROE			DSM			Coal Price		
			Low	Base	High	None	Low	Base	High	PWA	Low	Base	High	PWA	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
A	CC-RAP	61,113	59,612	59,551	69,821	59,576	66,484	69,475	74,195	69,821	55,926	59,682	62,910	61,056	61,151	61,179	60,975	60,349	61,084	62,106	60,259	61,124	61,874	61,335	55,439	60,405	57,490	61,223	63,850
B	Nuke2-RAP	62,262	60,813	60,757	70,657	60,780	67,488	70,325	74,823	70,657	57,138	60,879	64,127	62,211	62,380	62,307	61,974	60,613	62,187	64,507	61,296	62,275	63,122	62,484	56,484	61,554	58,639	62,372	64,999
C	SC-RAP	61,060	59,553	59,489	69,813	59,516	66,421	69,464	74,253	69,813	55,859	59,627	62,838	60,997	61,126	61,122	60,916	60,342	61,033	62,000	60,213	61,072	61,815	61,283	55,392	60,353	57,438	61,171	63,797
D	Pumped Hydro-RAP	61,522	60,007	59,943	70,319	59,969	66,910	69,968	74,780	70,319	56,312	60,081	63,291	61,458	61,577	61,586	61,393	60,760	61,494	62,502	60,645	61,533	62,303	61,744	55,811	60,814	57,899	61,632	64,259
E	Wind-SC-RAP	61,338	59,881	59,823	69,791	59,847	66,592	69,456	73,993	69,791	56,206	59,946	63,190	61,287	61,438	61,388	61,080	60,389	61,306	62,546	60,444	61,350	62,135	61,561	55,644	60,631	57,716	61,449	64,075
F	CC-RAP EE only	61,335	59,840	59,782	70,002	59,806	66,716	69,658	74,317	70,002	56,163	59,906	63,150	61,285	61,347	61,407	61,207	60,490	61,305	62,420	60,459	61,347	62,116	61,431	55,702	61,113	57,713	61,446	64,073
G	CC-MAP	60,842	59,360	59,297	69,449	59,323	66,165	69,108	73,758	69,449	55,683	59,425	62,656	60,788	60,909	60,900	60,647	60,078	60,813	61,835	59,990	60,854	61,601	61,192	55,088	60,134	57,220	60,953	63,579
H	Nuke-RAP-Balanced	61,800	60,338	60,276	70,290	60,302	67,067	69,953	74,523	70,290	56,665	60,402	63,639	61,748	61,895	61,851	61,552	60,620	61,752	63,359	60,884	61,812	62,616	62,022	56,064	61,092	58,177	61,911	64,537
I	CC-RAP-Balanced	61,352	59,870	59,807	69,959	59,833	66,673	69,618	74,270	69,959	56,193	59,936	63,166	61,298	61,418	61,411	61,161	60,505	61,322	62,440	60,479	61,364	62,130	61,575	55,657	60,645	57,730	61,463	64,089
J	Nuke-MEEIA1-Balanced	63,935	62,446	62,384	72,575	62,410	69,343	72,234	76,832	72,575	58,794	62,500	65,755	63,897	63,851	64,026	63,892	62,411	63,879	65,908	62,935	63,948	64,825	63,935	58,123	63,935	60,312	64,045	66,672
K	CC-MEEIA1-Balanced	63,357	61,846	61,782	72,135	61,808	68,837	71,788	76,477	72,135	58,193	61,900	65,148	63,319	63,226	63,460	63,391	62,235	63,323	64,754	62,407	63,370	64,203	63,357	57,597	63,357	59,735	63,468	66,094
L	Wind-MEEIA1	66,973	66,403	66,293	70,570	66,339	69,808	70,444	71,706	70,570	63,035	66,317	69,708	67,029	68,360	66,671	64,256	62,635	66,871	72,134	65,437	66,995	68,337	66,973	60,885	66,973	63,351	67,084	69,710
M	CC-MAP-Labadie	64,452	63,500	63,471	69,939	63,483	67,817	69,705	72,761	69,939	59,717	63,621	66,835	64,328	63,624	64,780	65,789	63,158	64,418	66,011	63,526	64,465	65,271	64,802	58,370	63,743	62,360	64,517	66,015
N	CC-MAP-Rush	62,617	61,394	61,353	69,686	61,370	66,948	69,396	73,296	69,686	57,649	61,495	64,714	62,523	62,249	62,811	63,194	61,654	62,587	63,823	61,746	62,629	63,393	62,968	56,703	61,909	59,810	62,708	64,701
O	Nuke2025-RAP-Labadie-Balanced	65,397	64,489	64,457	70,650	64,470	68,645	70,427	73,326	70,650	60,722	64,602	67,821	65,279	64,624	65,710	66,627	63,477	65,331	67,844	64,390	65,411	66,290	65,620	59,334	64,690	63,306	65,463	66,961
P	Nuke2025-RAP-Rush-Balanced	64,018	62,838	62,794	70,853	62,812	68,231	70,573	74,315	70,853	59,109	62,931	66,156	63,929	63,705	64,195	64,487	62,347	63,954	66,202	63,043	64,031	64,886	64,240	58,080	63,310	61,211	64,108	66,102
Q	Nuke-MAP-Balanced	61,431	59,982	59,915	69,863	59,942	66,640	69,528	74,091	69,863	56,308	60,045	63,269	61,375	61,581	61,469	61,118	60,333	61,384	62,897	60,538	61,443	62,226	61,781	55,624	60,722	57,808	61,541	64,168
R	CC-MAP-Balanced	61,081	59,618	59,553	69,588	59,580	66,354	69,251	73,834	69,588	55,950	59,680	62,911	61,030	61,176	61,132	60,833	60,234	61,051	62,169	60,211	61,093	61,857	61,432	55,306	60,373	57,459	61,192	63,818
S	CC-MAP EE only	61,078	59,595	59,532	69,687	59,558	66,402	69,346	73,999	69,687	55,918	59,661	62,891	61,024	61,144	61,136	60,885	60,314	61,049	62,070	60,224	61,089	61,838	61,278	55,376	60,914	57,455	61,188	63,815
	Minimum PVRR among plans		59,360	59,297	69,449	59,323	66,165	69,108	71,706	69,449	55,683	59,425	62,656	60,788	60,909	60,900	60,647	60,078	60,813	61,835	59,990	60,854	61,601	61,192	55,088	60,134	57,220	60,953	63,579
	Plan with Minimum PVRR		G	G	G	G	G	G	L	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G
	Subjective Probability		35%	50%	15%	85%	3%	9%	3%	15%	17%	51%	17%	40%	18%	36%	6%	10%	80%	10%	10%	80%	10%	45%	55%	5%	10%	80%	10%
	Expected Value of Better Info		510	510	510	510	508	510	2,564	510	510	510	510	510	508	511	514	427	509	605	489	510	529	382	568	511	510	510	510

10.5.4 Implementation Plan[15]

As mentioned earlier, the implementation plan outlines the major activities to be completed during the next three years, 2015-2017. Below is a description of those major activities.

Load Analysis and Forecasting Implementation

Ameren Missouri continually works to explore additional data sources and enhanced forecasting and analytical techniques to improve its load analysis processes, and, as of this writing, is in the process of developing and implementing a new sample for its load research program. Ameren Missouri has worked with Enernoc Utility Solutions in 2009 and 2013 to perform extensive primary market research and anticipates continuing to engage in periodic collection of primary data to further enhance its understanding of the mix of end-use appliances and equipment in its service territory. More detail on load analysis research activities is provided in Chapter 3.

Demand-Side Resources Implementation

The detailed implementation plan for RAP DSM is presented in Chapter 8 and includes program templates, evaluation strategies, energy and peak savings goals, budgets, and other information for the implementation period. Table 10.9 provides a summary of the annual energy savings and peak reduction goals, as well as annual budgets, for residential and business programs.

Table 10.9 DSM Implementation Plan Summary

	2016	2017	2018	Total
Residential EE Programs net energy savings (MWh)	58,505	45,691	61,472	165,668
Business EE Programs net energy savings (MWh)	46,252	91,927	122,536	260,715
Total estimated net energy savings (MWh) at meter	104,757	137,617	184,008	426,382
Residential EE Programs net demand reduction (MW)	14	9	13	36
Business EE Programs net demand reduction (MW)	13	28	37	78
Estimated net demand reduction (MW) at meter	27	37	50	114
Residential EE Programs annual costs ($ millions)	$21.81	$18.61	$22.96	$63.38
Business EE Programs annual costs ($ millions)	$14.60	$30.23	$39.36	$84.19
Estimated costs (Program costs in millions)*	$36.41	$48.84	$62.32	$147.57

*Note: The Company may choose to equalize expenditures for each year after finalizing implementation plans with its implementation contractors.

[15] 4 CSR 240-22.070(6); 4 CSR 240-22.070(6)(A) through (D)

Demand-Side Resources Cost Recovery and Incentives

Ameren Missouri continues to implement its first cycle of approved MEEIA programs, which run through 2015. Ameren Missouri expects to file a request with the Commission in the fourth quarter of 2014 for approval of demand-side programs and associated cost recovery and incentive mechanisms to be implemented in 2016-2018. Upon approval, Ameren Missouri will proceed with contractor onboarding and implementation planning.

Combined Cycle

While the preferred resource plan includes new combined cycle generation near the end of the planning horizon, in 2034, our contingency planning indicates a need to prepare for the possibility of needing new generation much sooner. This may be as a result of triggering a contingency option related to DSM cost recovery and incentives or to comply with greenhouse gas regulations. To prepare for such contingency options, Ameren Missouri will be evaluating potential sites for new combined cycle generation.

Nuclear

To preserve the nuclear resource option, Ameren Missouri continues nuclear development activities as necessary to ensure that this option remains viable in the projected needed timeframes. This includes maintaining the existing application for a new nuclear unit on the US NRC docket with the review suspended, interface with vendors developing new small modular light water reactor technologies, and a continued review and evaluation of large light water reactors with passive safety features.

Renewables

Our preferred resource plan includes the addition of new solar generation in 2016, expansion of our existing landfill gas-fueled Maryland Heights Renewable Energy Center in 2018, and new wind resources beginning in 2019. Ameren Missouri will be engaging in activities during the implementation period to support the construction of the new solar generation in 2016, including bid solicitation, contractor selection, applying for a certificate of convenience and necessity, and construction. We will also be continuing to evaluate the feasibility and timing for expansion at Maryland Heights and evaluating potential sites and options for wind generation.

Meramec

Ameren Missouri will be taking steps to convert Meramec Units 1&2 to natural gas-fired operation by early 2016. Because the units were originally designed with the option of operating on natural gas fuel, the work necessary to ensure reliable operation on natural gas is expected to be minimal and cost less than $2 million.

Environmental

Ameren Missouri will continue to monitor changes in environmental regulations and options for compliance. In the near term, we will complete work needed to comply with MATS.

Voltage Control Pilot Project

Ameren Missouri has initiated a Voltage Control Pilot Project to evaluate Volt/Var Optimization effectiveness and to evaluate Conservation Voltage Reduction on selected distribution power lines. Distributed control programming and operational testing are expected to be completed during 2014-2015.

Competitive Procurement Policies[16]

Ameren Missouri assigns a Project Manager to lead the activities necessary to ensure the successful completion of its acquisition and development of supply-side resources. In general, a project team comprised of a Project Manager and various lead engineers will identify all items to be procured and will coordinate with the Strategic Sourcing and Purchasing departments within Ameren to ensure proper contract structures are considered and used for each procurement activity. A Contract Development Team (CDT) is assembled and assists in collecting material and labor estimates based on the overall project design. Strategic Sourcing, CDT and the project team work to set up a number of components as Ameren stock items that are the basis for ordering materials. A detailed procurement matrix is developed to identify the major purchases that are anticipated to be required as part of the project. Material purchases make use of stock items established by the CDT. Where material has not been established as a stock item, the preferred approach is to solicit and obtain at least three quotations from a group of preferred Ameren vendors wherever possible to ensure the most competitive pricing for the material.

In the case of utilizing engineering, procurement and construction contracts (EPC), competitive bids are acquired from multiple vendors capable of meeting the requirements of the project. For the planned 2016 solar project, for example, the EPC contract will be fixed fee-based and the procurement of all components will be in the bid price and therefore under the full responsibility of the contractor.

Ameren Missouri will be following Ameren's Project Oversight Process, which is provided in Appendix C, for monitoring the progress made implementing its Preferred Resource Plan.[17]

[16] 4 CSR 240-22.070(6)(E)
[17] 4 CSR 240-22.070(6)(G)

10.5.5 Monitoring Critical Uncertain Factors[18]

Ameren Missouri will be monitoring the critical uncertain factors that would help determine whether the Preferred Resource Plan is still valid and whether contingency options should be pursued. Below is a description of how Company decision makers will be monitoring the factors most relevant to future resource decisions.

Climate Policy

Ameren Missouri senior management and the Environmental Services Group will continue to monitor and evaluate developments on efforts to regulate greenhouse gas emissions. With EPA scheduled to announce its final rule for existing power plants in June 2015, Ameren Missouri will continue to be engaged at both the federal and state level.

Gas Prices

The President and CEO of Ameren Missouri is updated at least annually by Corporate Planning on trends and drivers of natural gas prices as part of the update on the drivers of forward commodity prices. Ameren Missouri senior management may, in its sole discretion, request more frequent updates to discuss significant changes in natural gas prices.

Load Growth

Corporate Planning will update Ameren Missouri's capacity position as needed based on the latest assumptions regarding load growth. Any significant changes in resource needs, whether timing or size, will be communicated to Ameren Missouri senior management. Corporate Planning will also reassess, at least annually, its assumptions for load growth in the Eastern Interconnect, which is a critical dependent uncertain factor included in our power price scenario modeling.

Coal Prices

Corporate Planning will work with Ameren Missouri's Fuels organization to monitor coal prices, with updates at least annually and as needed.

Project Costs

Corporate Planning, with support from other groups and as directed by Ameren Missouri senior management, will monitor trends in capital costs for all of the candidate supply-side resource options and environmental compliance retrofits with careful attention to those included in the preferred and contingency resource plans. Any significant changes will be communicated to Ameren Missouri senior management.

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[18] 4 CSR 240-22.070(6)(F)

Demand-Side Resource Impacts and Cost

Corporate Planning will continue to evaluate the cost-effectiveness of its DSM programs internally and through the evaluation process. To further enhance our ability to ensure the continued cost effectiveness of our demand side programs, Ameren Missouri will 1) annually adjust its estimate of annual load reductions from its DSM potential study to incorporate the most recent EM&V measure impact energy savings estimates and 2) seek program design changes to account for emerging baseline energy savings constructs that could affect available potential as well as program cost effectiveness. Any major deviations from planning assumptions like participation rates, technology costs, and customer opt-out will be communicated to Ameren Missouri senior management.

Interest Rates and Financial Metrics

Corporate Planning and Treasury will continue to evaluate the impact of interest rates and various financial metrics on revenue requirements consistent with maintaining investment grade credit ratings. This evaluation will include an analysis of the level of interest rates and financial metrics that would trigger consideration of a contingency plan.

10.6 Compliance References

10. Strategy Selection

Highlights

- *Ameren Missouri continues to execute on a plan that is focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio in a responsible fashion over the next 20 years to ensure we provide service to our customers that is safe, reliable and environmentally responsible at a reasonable cost.*
  - *Our plan includes a dramatic increase in the amount of wind and solar generation in our portfolio, with 700 MW of new wind resources in the next three years and 100 MW of new solar resources in the next ten years.*
  - *Our plan also includes continued customer energy efficiency program offerings, introduction of customer demand response programs, and retirement of approximately half of our coal-fired generating capacity, which will be reaching the end of its useful life.*
  - *Our plan allows us to continue to rely on our existing, low-cost and dependable nuclear generation.*
- *Our plan allows us to achieve carbon dioxide emission reductions of 35% from 2005 levels by 2030, 50% by 2040 and 80% by 2050.*
- *Our implementation plan for the next three years includes steps necessary to add 700 MW of wind to our portfolio, approval and implementation of energy efficiency and demand response programs beyond our current 3-year plan, and actions to preserve contingency resource options and enable us to quickly respond to changing needs and conditions while continuing to ensure safe, reliable and cost-effective service to our customers.*
- *Ameren Missouri will continue to monitor critical uncertain factors to assess their potential impacts on our preferred plan, contingency plans and implementation.*

Ameren Missouri has selected its preferred resource plan and contingency plans in accordance with its planning objectives and practical considerations that inform our decision making. Our selection process consists of several key elements:

✓ Establishing planning objectives and associated performance measures to develop and assess alternative resource plans

✓ Creating a scorecard based on our planning objectives and performance measures to evaluate the degree to which various alternative resource plans would satisfy our planning objectives

Schedule MM-S11

- ✓ Critically analyzing the most promising alternative resource plans to ensure that we select a plan that best balances competing objectives

In addition, Ameren Missouri has subjected its preferred resource plan to testing under several scenarios that represent events that, while not necessarily considered probable, could have a significant impact on our resource needs and the performance of our preferred resource plan. These include 1) the addition of significant customer demand associated with an aluminum smelter, and 2) compliance with regulation of emissions of greenhouse gases (GHG) by existing power plants.

We have established an implementation plan for 2018-2020 that allows us to begin implementing the resource decisions embodied in our preferred resource plan and to preserve contingency options to allow us to effectively respond to changing needs and conditions while continuing to ensure safe, reliable and cost-effective electric service to our customers.

10.1 Planning Objectives

The fundamental objective of the resource planning process in Missouri is to ensure delivery of electric service to customers that is safe, reliable and efficient, at just and reasonable rates in a manner that serves the public interest. This includes compliance with state and federal laws and consistency with state energy policies.[1] Ameren Missouri considers several factors, or planning objectives, that are critical to meeting this fundamental objective. Planning objectives provide guidance to our decision making process and ensure that resource decisions are consistent with business planning and strategic objectives that drive our long-term ability to satisfy the fundamental objective of resource planning. Following are the planning objectives, established in the development of our 2011 IRP, that continue to inform our resource planning decisions.

Cost (to Customers): Ameren Missouri is mindful of the impact that its future energy choices will have on cost to its customers. Therefore, minimization of present value of revenue requirements is our primary selection criterion.[2]

Costs alone do not and should not dictate resource decisions. Our other planning objectives are discussed below.

Customer Satisfaction: Ameren Missouri is dedicated to continuing to improve customer satisfaction. While there are many factors that can be measured, for practical reasons Ameren Missouri focused primarily on measures that can be significantly

[1] 4 CSR 240-22.010(2); 4 CSR 240-22.010(2)(A); EO-2017-0073 1.N
[2] 4 CSR 240-22.010(2)(B)

Schedule MM-S11

impacted by resource decisions: 1) rate impacts – levelized average rates and 2) customer preferences – cleaner energy sources and demand-side programs that provide customers with options to manage their usage and costs.

Environmental & Resource Diversity: Ameren Missouri, like other electric utilities in Missouri, produces the majority of the energy it generates from coal. Ameren Missouri continues to be focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio.

Financial/Regulatory: The continued financial health of Ameren Missouri is crucial to ensuring safe, reliable and cost-effective service for customers in the future. Ameren Missouri will continue to need the ability to access large amounts of capital for investments needed to comply with renewable energy standards and environmental regulations and invest in demand and/or supply side resources to meet customer demand and reliability needs. Measures of expected financial performance and creditworthiness are evaluated along with potential risks.

Economic Development: Ameren Missouri is committed to support the communities it serves beyond providing reliable and affordable energy. Ameren Missouri assesses the economic development opportunities, for its service territory and for the state of Missouri, associated with our resource choices. We do this by examining the potential for direct job growth, which in turn promotes additional economic activity.

Table 10.1 summarizes our planning objectives and the primary measures used to asses our ability to achieve these objectives with our alternative resource plans.

Table 10.1 Planning Objectives and Measures[3]

Planning Objective Categories	Measures
Cost	Present Value of Revenue Requirements
Customer Satisfaction	Customer Preferences, Levelized Rates
Environmental & Resource Diversity	Resource Diversity, CO_2 Emissions, Probable Environmental Costs
Financial/Regulatory	ROE, EPS, FCF, Financial Ratios, Stranded Cost Risk, Transaction Risk, Cost Recovery Risk
Economic Development	Direct Job Growth (FTE-years)

[3] 4 CSR 240-22.060(2); 4 CSR 240-22.060(2)(A)1 through 7

10.2 Assessment of Alternative Resource Plans

Ameren Missouri used a scorecard to evaluate the performance of alternative resource plans with respect to our planning objectives and measures described above. The scorecard and measures include both objective and subjective elements that together represent the trade-offs between competing objectives. It is important to keep in mind that the scorecard is a tool for decision makers and does not, in and of itself, determine the preferred resource plan. The selection of the preferred resource plan is informed by the scorecard and by a more critical analysis of the relative merits of alternative resource plans, including an assessment of any risks or other constraints.

10.2.1 Scoring of Alternative Resource Plans[4]

To score each of the alternative resource plans, we employed a standard approach to scoring for each planning objective on a 5-point scale and determined a composite score by applying a weighting to each planning objective. As Cost is the primary selection criterion, it was given the greatest weight – 30% -- just as it was in the scoring performed for our 2011 and 2014 IRPs.[5] Economic Development carried a weight of 10%. Each of the other three planning objectives – Customer Satisfaction, Environmental & Resource Diversity, and Financial/Regulatory – carried a weight of 20%. The scoring approach for each planning objective is as follows:

Cost – The 18 alternative resource plans were separated into five groups according to probability weighted average PVRR results from the risk analysis discussed in Chapter 9. The lowest cost group of plans were given a score of 5, the next lowest cost group a score of 4, and so on, with the highest cost group of plans receiving a score of 1.

Customer Satisfaction – Alternative resource plans were evaluated based on levelized annual average rates for a portion of the score. As was done with the PVRR results, the alternative resource plans were separated into five groups according to the probability-weighted average levelized annual average rate results produced from our risk analysis. The plans resulting in the lowest rates were given a score of 5, the next lowest rate group a score of 4, and so on, with the highest rate group of plans receiving a score of 1. Plans that yielded a score greater than 3 for rates were given 3 points in the overall scoring for Customer Satisfaction. Plans that yielded a score of 3 were given 2 points. In addition, plans which include continued energy efficiency programs (RAP or MAP) were given a point. Also, plans which included demand response programs were given an additional point. Plans that include significant reductions in emissions, either

[4] 4 CSR 240-22.010(2)(C); 4 CSR 240-22.010(2)(C)1; 4 CSR 240-22.010(2)(C)2; 4 CSR 240-22.010(2)(C)3; 4 CSR 240-22.070(1); 4 CSR 240-22.070(1)(A) through (D)

[5] 4 CSR 240-22.010(2)(B)

as a result of early coal retirements or to achieve emission reduction targets, were given an additional point. Finally, plans that include significant additional renewable generation sources beyond those needed to comply with legal mandates were given an additional point.

Environmental & Resource Diversity – Alternative resource plans were awarded points for each plan attribute contributing to greater resource diversity and/or environmental impact in terms of emission reductions. Plans were awarded one point each for each of the following:

- ✓ Inclusion of demand-side programs
- ✓ Addition of nuclear generation
- ✓ Addition of combined cycle gas generation (1 point per 600 MW)
- ✓ Addition of significant renewables (beyond those needed to comply with legal mandates)
- ✓ Addition of storage resources
- ✓ Early retirement of coal generation (1 point per 1,200 MW)

Financial/Regulatory – Scoring for Financial/Regulatory is based on a default score of 5 with deductions for risks and financial impacts that may detrimentally affect Ameren Missouri's ability to continue to access lower cost sources of capital. Plans that would result in relatively lower free cash flow were reduced by one point. Plans were also reduced by one point each for potential risks associated with:

- ✓ Lack of any DSM programs
- ✓ Significant risk of not achieving energy efficiency targets
- ✓ Nuclear construction costs (2 point deduction)
- ✓ Retirement and replacement of additional coal units beyond Meramec and Sioux (1 point deduction for every 1,200 MW of additional retirement)

Economic Development – Alternative plans were scored based on direct job creation, including construction and ongoing operation. Estimates for direct job creation were developed using the Jobs and Economic Development Impact (JEDI) Model, developed by Marshall Goldberg of MRG & Associates under contract with the National Renewable Energy Laboratory, or more specific estimates where available (e.g., nuclear).

Construction and operating jobs were translated into full-time equivalent years (FTE-years). Alternative plans were ranked based on FTE-years and divided into five groups based on relative rank. The group of plans resulting in the highest FTE-year values were given a score of 5 points each, the next highest FTE-year group a score of 4, and so on, with the lowest FTE-year group of plans receiving a score of 1.

Table 10.2 Alternative Resource Plan Scoring Results

Description	Overall Assessment
R - RAP-35% CO2 Reduction	4.30
A - RAP	3.90
P - Meramec Retired 2020	3.90
Q - RES Compliance only	3.90
B - RAP EE only	3.60
M - Rush Island Retired 2024	3.60
N - Labadie Retired 2024	3.60
O - Meramec 2020-Labadie 2024	3.60
D - MAP	3.40
E - MAP EE only	3.00
F - MAP DR only	3.00
C - RAP DR only	2.70
L - No DSM-Solar	2.50
K - No DSM-Wind&SC	2.40
G - No DSM-CC	2.30
I - No DSM-Pumped Storage	2.30
H - No DSM-SC	2.10
J - No DSM-Nuclear	1.40

Table 10.2 shows the composite scores for each of the 18 alternative resource plans. The full scorecard with scores for each planning objective for each alternative resource plan is shown in Appendix A.

Based on the scoring results, the alternative resource plans were separated into three tiers – Top, Mid, and Bottom. Plans with scores greater than 3.6 were placed in the Top Tier. Plans with scores between 2.8 and 3.6 were placed in the Mid-Tier. Plans with scores below 2.8 were placed in the Bottom Tier. All Top Tier plans include energy efficiency and demand response at the realistic achievable potential (RAP) level.

10.2.2 DSM Portfolio Considerations

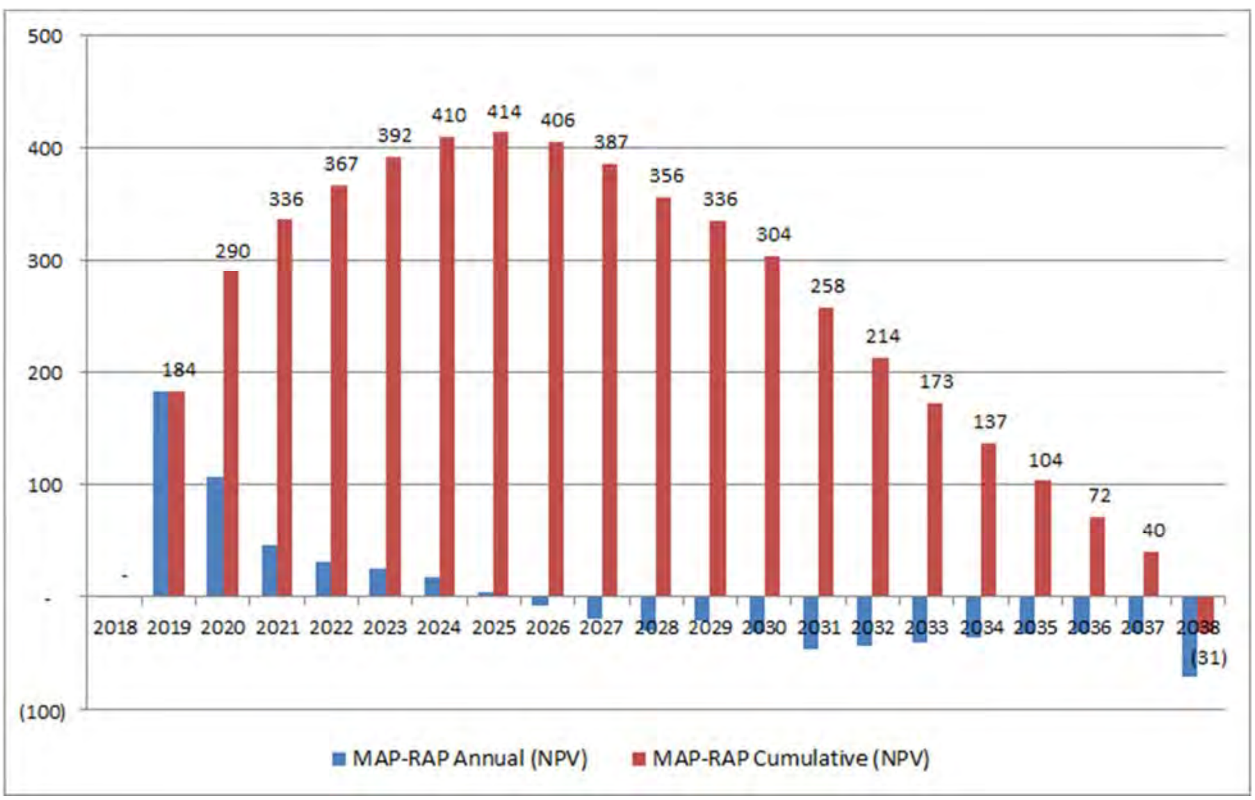
While MAP DSM results in lower total customer costs than RAP DSM over the 30 years evaluated in our risk analysis, it is important to further evaluate the performance of MAP relative to RAP, in particular because MAP is defined as the hypothetical upper boundary of achievable demand-side potential, assuming ideal conditions for implementation. To further investigate the relative merits of RAP and MAP DSM portfolios, we evaluated:

- ✓ The year-by-year relative net benefits for RAP and MAP
- ✓ A "Mid DSM" portfolio between RAP and MAP

Year-by-Year Net Costs/Benefits

Implementation of the MAP energy efficiency portfolio would require a program budget for that is nearly double the budget needed to implement the RAP portfolio, although MAP reflects cumulative energy savings that are only roughly 40% greater than those for RAP. We analyzed the year-by-year revenue requirement impacts of the RAP plan (Plan A) and the MAP plan (Plan D), including all costs and benefits. Figure 10.1 shows the annual and cumulative revenue requirement differences between the two plans.

Figure 10.1 Year-by-Year PVRR Differences for RAP and MAP Plans



Schedule MM-S11

As the chart shows, the MAP plan results in higher overall costs than the RAP plan through 2025. While the MAP plan results in lower overall costs starting in 2026, the cumulative increase in costs for the MAP plan reaches $414 million in 2025 and persists until 2038, beyond the last year of the twenty-year planning horizon. The greater net benefits of MAP relative to RAP increase significantly after the end of the planning horizon as captured in the end effects.

Portfolios between RAP and MAP

To further evaluate the economics of DSM portfolios and to assist us in addressing the policy goal of MEEIA to achieve all cost-effective demand-side savings, we evaluated the possibility of a DSM portfolio that results in savings that are between those represented by RAP and MAP. Because market research exists only to support the development of RAP and MAP portfolios, we must estimate the costs and savings for any other portfolio assumptions.

We started by estimating the costs and savings for a portfolio that lies midway between the RAP and MAP portfolios, called the “Mid DSM” portfolio as discussed in Chapter 8. We then constructed a test plan including this portfolio and supply side resources necessary to meet load and reserve requirements. The plan was evaluated using the same ranges of assumptions used to evaluate alternative resource plans in our risk analysis. The results of the analysis, with a comparison of comparable plans including RAP and MAP portfolios (Plans A and D), is shown in Table 10.3. As the table shows, the PVRR results for the Mid DSM portfolio are roughly midway between the results for plans with RAP and MAP DSM portfolios.

Table 10.3 PVRR Comparison of RAP and MAP

DSM Portfolio	PVRR
RAP	54,429
MAP	53,892
Mid	54,165

While it is possible to repeat this process, estimating other portfolios between RAP and MAP at different points on a continuum between the two portfolios, it would not provide additional insight into the merits of these various portfolios. Based on the results of our analysis of the Mid DSM portfolio, we would expect such additional portfolios to produce results that are similarly predictable. We would also expect the year-by-year analysis to produce similarly predictable results, showing a net advantage for RAP through 2025 on an annual basis and through 2037 on a cumulative basis.

Pursuing the Policy Goal of MEEIA

As stated previously, the stated goal of MEEIA is to achieve all cost-effective demand-side savings by aligning utility incentives with helping customers to use energy more efficiently. Ameren Missouri has demonstrated its commitment to pursuing this goal by implementing the largest utility energy efficiency program in Missouri history. And while we believe this is a goal worth pursuing, it cannot be quantified with any degree of accuracy for the next twenty years. Rather, it is a goal that will constantly be shaped and reshaped through continuous implementation, evaluation, research, testing and readjustment.

As noted earlier, Ameren Missouri has conducted a DSM Potential Study, prepared by a nationally recognized independent contractor team. The primary objective of the study was to assess and understand the long-term technical, economic, and achievable potential for all Ameren Missouri customer segments. Assuming regulatory treatment that reflects the requirements of MEEIA, RAP represents all cost-effective energy efficiency because, by definition, it represents a forecast of likely customer behavior under realistic program design and implementation.

10.3 Preferred Plan Selection[6]

In selecting its Preferred Resource Plan, Ameren Missouri decision makers[7] relied on the planning objectives discussed earlier in this chapter and the considerations reflected in the scoring and comparison of DSM portfolios highlighted in the previous section. As was noted previously, the Top Tier plans identified through scoring include the RAP DSM portfolio as well as renewables, including three plans that go beyond the renewable requirements of the RES. These define the key options for consideration in the selection of the preferred resource plan.

DSM Portfolio[8] – RAP and MAP DSM portfolios both result in reduced total costs to customers compared to plans with no DSM beyond the current MEEIA Cycle 2 program. The decision between the two must involve a consideration of risk and reward from the perspective of both customers and Ameren Missouri. Based on our analysis of the year-by-year cost differences between RAP and MAP, and an understanding of the increased level of risk in achieving MAP relative to RAP, Ameren Missouri has chosen to include the RAP portfolio in its preferred resource plan.

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[6] 4 CSR 240-22.010(2)(C); 4 CSR 240-22.010(2)(C)1; 4 CSR 240-22.010(2)(C)2
4 CSR 240-22.010(2)(C)3; 4 CSR 240-22.060(3)(A)5; 4 CSR 240-22.070(1); 4 CSR 240-22.070(1)(A) through (D)

[7] Names, titles and roles of decision makers are provided in Appendix B.

This is not to say that there couldn't be additional potential energy savings that can be realized. Indeed, our uncertainty range for the RAP portfolio includes potential upside. However, we must consider the immediate cost impact to all customers of a large increase in DSM expenditures (approximately $250 million per year for MAP vs. $135 million per year for RAP) and the significant uncertainty of the relative long-term benefits. We must also consider that the path for demand-side programs is not "locked in" for twenty years.

Including RAP DSM in our preferred resource plan allows us to continue to offer highly cost-effective programs to customers at a reasonably aggressive level of annual spending while also allowing the potential for increased savings if our experience and expectations indicate they could be achieved in a cost-effective manner. Identifying such opportunities will depend on the results of program implementation and periodic updates of our market research.

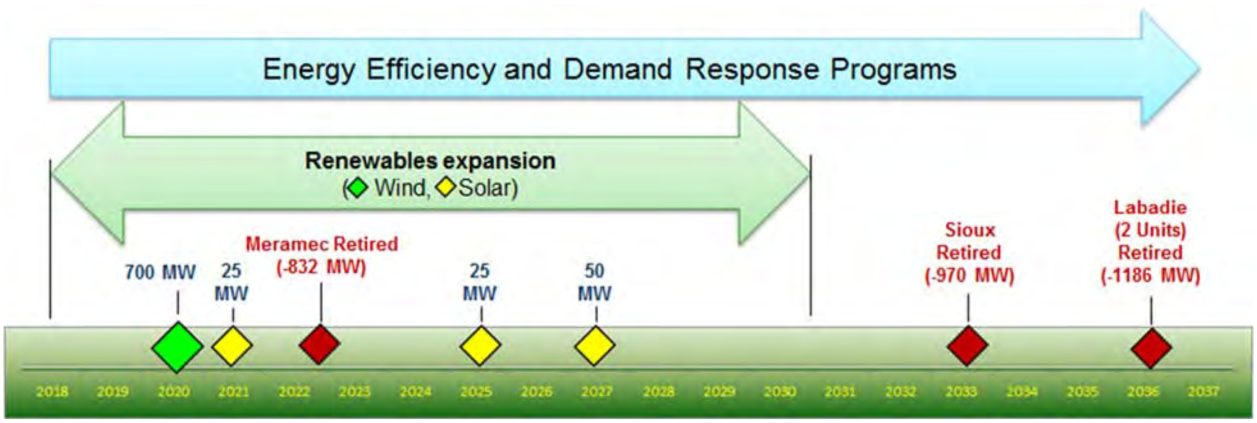
Renewable Resources – One of Ameren Missouri's planning objectives is to transition our generation portfolio to one that is cleaner and more fuel diverse in a responsible fashion. Compliance with the Missouri RES is reflected in all of our alternative resource plans. This includes approximately 734 MW of wind and solar generation. An additional 66 MW of solar results in a relatively modest increase in PVRR under current assumptions. Because costs for solar resources are expected to continue to decline, it is possible that these additional resources could be added at no additional cost, or perhaps a savings to customers, by the time implementation is considered. We have therefore included additional solar generation in our preferred resource plan to bring our renewable generation additions to 800 MW. It is also possible that additional wind resources beyond those included in our plan could be beneficial to customers. Implementation of our planned wind additions will provide us with an opportunity to identify additional potentially beneficial projects.

Meramec Retirement – We evaluated two plans with early retirement of Meramec at the end of 2020 rather than at the end of 2022 – Plans O and P. As described in Chapter 9, our risk analysis results demonstrated that the cost of plan O, which also includes early retirement of Labadie, is more than a billion dollars higher than that for the preferred plan. The cost of plan P is about $49 million higher than that for plan A, which differs only in the retirement date for Meramec, on a probability weighted basis. As our EVBI analysis shows, the cost of plan P is consistently higher than that for plan A across all values of the critical uncertain factors.

Carbon Dioxide Emissions – We evaluated a plan (plan R) that targets additional reductions in CO_2 emissions to achieve a 35% reduction from 2005 levels by 2030. This plan differs from plan A only in this regard and results in costs that are about $52 million higher. The additional costs are expected to be incurred in 2030-2033 and are based on our current IRP assumptions. Targeting greater levels of CO_2 emission reductions is expected to help spur innovation in the optimization of fleet operations, leading to potential efficiencies that may result in net savings to customers in the long run.

The plan that embodies these key choices is listed in Table 10.2 as "Plan R". It includes RAP energy efficiency and demand response programs, 800 MW of new renewable generation, retirement of all Meramec units by the end of 2022, retirement of Sioux Energy Center at the end of 2033, and retirement of two of the four units at Labadie Energy Center at the end of 2036. It also includes CO_2 emission reductions of 35% by 2030 and supports achievement of our long-term goal of an 80% reduction by 2050. Figure 10.2 shows the preferred resource plan and its key elements.

Figure 10.2 Preferred Resource Plan



10.4 Contingency Planning[9]

Because any assumptions about the future are subject to change, we must be prepared for changing circumstances by evaluating such potential circumstances and options for providing safe, reliable, cost-effective and environmentally responsible service to our customers. We have identified several cases which could significantly impact the performance of our preferred resource plan. These include cases that may result in 1) significantly higher demand, and 2) altered costs and feasibility of continuing to operate existing generating units.

10.4.1 DSM Cost Recovery and Incentives

As stated previously, MEEIA provides for cost recovery and incentives for utility-sponsored demand-side programs to align utility incentives with helping customers to

[9] 4 CSR 240-22.070(4)

Schedule MM-S11

use energy more efficiently. In early 2016, the Missouri Public Service Commission (Commission) approved our second cycle of MEEIA programs and supporting cost recovery and incentives. Our preferred resource plan is based on the expectation that supporting cost recovery and incentives will continue to be approved in the future. If such alignment is not achieved, it may be necessary for Ameren Missouri to change its preferred resource plan.

Ameren Missouri expects to file a request with the Commission for approval of a new portfolio of demand-side programs in the first quarter of 2018. Costs are expected to be recovered through our Rider Energy Efficiency Investment Charge (Rider EEIC). In our request, we will also seek recovery of costs associated with the so-called "throughput disincentive."

In addition to recovery of program costs and addressing the throughput disincentive, MEEIA also mandates that utilities be provided with timely earnings opportunities that serve to make investments in demand-side resources equivalent to investments in supply-side resources. Ameren Missouri will seek such incentives in its upcoming MEEIA filing.

10.4.2 Addition of Large Customer Load

Ameren Missouri's largest customer in recent years has been the aluminum smelter now owned by Magnitude 7 Metals in New Madrid, Missouri. The smelter historically used roughly 4,200 GWh of electricity annually with a peak demand of approximately 500 MW. The smelter suffered damage to its potlines in 2016 and has significantly reduced it electric usage since that damage occurred. To evaluate the impact on our preferred plan of a return to full operation of the smelter and its impact on our need for resources under the preferred plan, we evaluated a capacity position included this demand. We found that the addition of load would not result in the need for new supply side resources during the planning horizon.

10.4.3 Greenhouse Gas Regulation

As described in Chapter 5, the EPA's previously proposed "Clean Power Plan" (CPP) continues to be subject to a stay issued by the U.S. Supreme Court in early 2016. As a result, many states (including Missouri) suspended any significant further action to implement the rule unless and until the stay is lifted. While much uncertainty remains, we have evaluated the potential effect of implementation of the rule in its final form prior to the stay on the performance of our preferred resource plan. In doing so, we assumed a mass-based compliance regime for the state of Missouri. Table 10.4 shows the PVRR results for the preferred plan with and without application of the CPP limits. The cost of the preferred plan would be expected to increase by about $55 million as a result of applying the CPP limits.

Table 10.4 PVRR Comparison With and Without CPP Limits

Plan	PVRR ($Million)
Preferred Plan	54,481
CPP	54,536

10.4.4 Optionality for New Generation

As the contingency cases described earlier illustrate, it is important to maintain options and flexibility to ensure Ameren Missouri can meet its customers' energy needs in a safe, reliable, and environmentally responsible manner at a reasonable cost. Our analysis has shown that renewables and gas-fired combined cycle continue to be attractive options for meeting our customers' future energy needs. It is therefore important to ensure that we can exercise these options when needed and in response to changing circumstances. This includes continuing to evaluate opportunities for developing additional renewable energy resources and evaluating potential sites for new gas-fired generation. As the discussion of greenhouse gas regulation demonstrates, options for cleaner and dependable resources are also critical for ensuring compliance with such regulations while maintaining safe, reliable, and cost-effective service to customers.

10.5 Resource Acquisition Strategy[10]

Our resource acquisition strategy has three main components. First is the Preferred Resource Plan which is discussed in more detail in Section 10.5.1. The second component of the resource acquisition strategy is contingency planning. Under no ranges or combinations of outcomes for the critical uncertain factors, would the Preferred Resource Plan be inappropriate. Figure 10.3 shows the Preferred Resource Plan as well as contingency options and the events that could lead to a change in our preferred plan. The final component of the resource acquisition strategy is the implementation plan which includes details of major actions over the next three years, 2018-2020.

[10] 4 CSR 240-22.070(1); 4 CSR 240-22.070(1)(A) through (D); 4 CSR 240-22.070(2);
4 CSR 240-22.070(4); 4 CSR 240-22.070(4)(A) through (C);
4 CSR 240-22.070(7); 4 CSR 240-22.070(7)(A) through (C)

Figure 10.3 Preferred Plan and Contingency Plans

10.5.1 Preferred Plan

As discussed in Section 10.3, our Preferred Resource Plan includes RAP energy efficiency and demand response programs, 800 MW of new renewable generation, retirement of all Meramec units by the end of 2022, retirement of Sioux Energy Center at the end of 2033, and retirement of two of the four units at Labadie Energy Center at the end of 2036.

Demand Side Resources

The preferred plan includes RAP energy efficiency and demand response programs. Energy efficiency programs under our current three-year MEEIA plan run through February 2019. Program spending for the 20-year planning horizon (after the current cycle of MEEIA programs) is over $3 billion. Cumulative peak demand reductions exceeding 2,000 MW by 2037 (not including planning reserve margin), and cumulative energy savings (at the customer meter) total nearly 56 million MWh.

Renewables

Chapter 9 includes a detailed description of renewable resource requirements. In summary, Ameren Missouri will need additional RECs or non-solar resources starting in 2019. We also expect to need additional solar resources to continue to meet the RES

Schedule MM-S11

solar requirements when SRECs transferred to Ameren Missouri from customer-owned solar facilities are no longer available. Beyond those renewable resources included for RES compliance, we have included additional solar resources to advance our objective to transition our generation portfolio to a cleaner and more fuel diverse mix of resources. Our expansion of renewables includes 700 MW of wind and 100 MW of solar generation.

Supply-Side Resources

The Preferred Resource Plan calls for the retirement of all Meramec units by the end of 2022. It also includes retirement of Sioux Energy Center by the end of 2033 and retirement of two of the four units at Labadie Energy Center at the end of 2036.

10.5.2 Contingency Plans[11]

Figure 10.3 presents our key contingency options. In the event that Ameren Missouri's interests are not aligned with helping customers use energy more efficiently, as required by MEEIA, we have included a contingency plan that reflects a discontinuation of demand side programs after our current MEEIA cycle programs expire at the end of February 2019. The contingency plan therefore also includes the installation of a 600 MW combined cycle facility to be in service in 2034 and another 1,200 MW of combined cycle generation in 2037.

10.5.3 Expected Value of Better Information Analysis[12]

After selecting the preferred plan, Ameren Missouri conducted an expected value of better information (EVBI) analysis to assess the performance of its preferred resource plan under the range of values defined for the critical uncertain factors and to inform its on-going research and implementation activities. Table 10.5 displays the results of the EVBI analysis as measured by PVRR. Under almost all critical uncertain factor values, Plan D results in a lower PVRR than the preferred plan. In part, because it is possible that additional cost-effective energy savings could be identified, we will continue to undertake rigorous evaluation of our programs and periodically update our market research to identify additional such opportunities.

[11] 4 CSR 240-22.070(4)
[12] 4 CSR 240-22.070(3)

Table 10.5 EVBI Analysis Results

Alternative Resource Plans		PVRR Without Better Info	Coal Retirements			Carbon		Load Growth			Natural Gas Price				DSM			Coal Price		
			Low	Base	High	None	Base	Low	Base	High	PWA	Low	Base	High	Low	Base	High	Low	Base	High
A	RAP	54,429	53,431	54,830	54,816	53,431	54,823	53,375	54,527	55,187	54,281	54,535	54,617	54,166	54,067	54,404	54,992	52,633	54,484	55,787
B	RAP EE only	54,740	53,745	55,141	55,126	53,745	55,133	53,526	54,861	55,593	54,560	54,864	54,951	54,503	54,438	54,719	55,212	52,944	54,795	56,098
C	RAP DR only	57,158	56,034	57,610	57,595	56,034	57,602	55,774	57,311	58,085	56,929	56,931	57,551	57,254	57,099	57,154	57,250	55,362	57,213	58,516
D	MAP	53,892	52,931	54,276	54,266	52,931	54,271	53,113	53,961	54,462	53,788	54,084	54,011	53,486	53,236	53,846	54,914	52,095	53,946	55,249
E	MAP EE only	54,534	53,577	54,916	54,906	53,577	54,911	53,469	54,639	55,283	54,376	54,755	54,691	54,171	53,978	54,495	55,399	52,738	54,588	55,892
F	MAP DR only	56,641	55,519	57,096	57,072	55,519	57,084	55,399	56,777	57,476	56,437	56,417	57,003	56,725	56,541	56,634	56,798	54,845	56,696	57,999
G	No DSM-CC	57,679	56,551	58,127	58,122	56,551	58,124	56,119	57,856	58,709	57,414	57,450	58,112	57,797	57,679	57,679	57,679	55,883	57,734	59,037
H	No DSM-SC	57,532	56,401	57,985	57,973	56,401	57,979	55,972	57,711	58,557	57,264	57,316	57,959	57,657	57,532	57,532	57,532	55,736	57,587	58,890
I	No DSM-Pumped Storage	58,250	57,129	58,702	58,682	57,129	58,692	56,695	58,428	59,268	57,982	57,990	58,692	58,414	58,250	58,250	58,250	56,453	58,304	59,607
J	No DSM-Nuclear	63,924	62,974	64,296	64,302	62,974	64,299	62,351	64,107	64,949	63,650	64,136	64,175	63,779	63,924	63,924	63,924	62,128	63,979	65,282
K	No DSM-Wind&SC	59,042	58,069	59,418	59,433	58,069	59,425	57,467	59,222	60,075	58,771	59,218	59,312	58,880	59,042	59,042	59,042	57,246	59,096	60,399
L	No DSM-Solar	57,947	56,878	58,373	58,364	56,878	58,369	56,385	58,129	58,962	57,674	58,094	58,218	57,864	57,947	57,947	57,947	56,151	58,002	59,305
M	Rush Island Retired 2024	55,450	54,692	55,764	55,736	54,692	55,750	54,106	55,626	56,267	55,186	55,125	55,895	55,735	55,089	55,425	56,014	54,049	55,496	56,483
N	Labadie Retired 2024	55,869	55,177	56,155	56,130	55,177	56,142	54,215	56,123	56,759	55,487	55,393	56,458	56,505	55,507	55,844	56,432	54,636	55,911	56,767
O	Meramec 2020-Labadie 2024	55,918	55,224	56,204	56,180	55,224	56,192	54,221	56,155	56,904	55,562	55,412	56,490	56,563	55,556	55,893	56,482	54,722	55,957	56,801
P	Meramec Retired 2020	54,478	53,478	54,880	54,866	53,478	54,873	53,382	54,559	55,332	54,357	54,554	54,649	54,225	54,117	54,453	55,042	52,719	54,530	55,821
Q	RES Compliance only	54,406	53,407	54,808	54,793	53,407	54,800	53,348	54,506	55,165	54,256	54,505	54,598	54,151	54,044	54,381	54,969	52,610	54,461	55,764
R	RAP-35% CO_2 Reduction	54,481	53,494	54,880	54,862	53,494	54,871	53,422	54,582	55,239	54,330	54,541	54,687	54,269	54,120	54,456	55,045	52,734	54,535	55,801
Minimum PVRR among plans			52,931	54,276	54,266	52,931	54,271	53,113	53,961	54,462	53,788	54,084	54,011	53,486	53,236	53,846	54,914	52,095	53,946	55,249
Plan with Minimum PVRR			D	D	D	D	D	D	D	D	D	D	D	D	D	D	D	D	D	D
Subjective Probability			28%	35%	37%	28%	72%	20%	60%	20%	40%	19%	32%	8%	10%	80%	10%	10%	80%	10%
Expected Value of Better Info			563	605	596	563	600	308	621	777	542	457	677	783	883	610	131	638	588	552

Schedule MM-S11

10.5.4 Implementation Plan[13]

As mentioned earlier, the implementation plan outlines the major activities to be completed during the next three years, 2018-2020. Below is a description of those major activities.

Demand-Side Resources Implementation

Our approach to implementation of demand side programs is presented in Chapter 8. It includes our planned approach for soliciting bids from potential vendors and collaborating with stakeholders to define the demand-side portfolio, budgets and targets for our next MEEIA plan.

Demand-Side Resources Cost Recovery and Incentives

Ameren Missouri continues to implement its second cycle of approved MEEIA programs, which run through February 2019. Ameren Missouri expects to file a request with the Commission in the first quarter of 2018 for approval of demand-side programs and associated cost recovery and incentive mechanisms to be implemented during a six-year program cycle beginning in 2019.

Supply-Side Contingency

While the preferred resource plan does not include new combined cycle generation, our contingency planning indicates a need to prepare for the possibility of needing new generation during the planning horizon. This may be as a result of triggering a contingency option related to DSM cost recovery and incentives or to address increases in customer demand associated with electrification. To prepare for such contingency options, Ameren Missouri will continue evaluating potential sites for new combined cycle generation.

Renewables

Our preferred resource plan includes the addition of new wind generation by the end of 2020 and new solar generation in 2022, 2025 and 2027. Ameren Missouri will be engaging in activities during the implementation period to support the development of the new wind generation by the end of 2020, including bid solicitation, contractor selection, applying for a certificate of convenience and necessity, and construction. We will also be continuing to evaluate potential sites and options for solar generation.

[13] 4 CSR 240-22.070(6); 4 CSR 240-22.070(6)(A) through (D)

Meramec

Ameren Missouri will be taking steps to retire the units at Meramec Energy Center by the end of 2022. This includes the construction of any necessary transmission infrastructure and required notifications to MISO.

Environmental

Ameren Missouri will continue to monitor changes in environmental regulations and options for compliance. In the near term, we will complete work needed to comply with regulations for Coal Combustion Residuals (CCR), Effluent Limitation Guidelines (ELG) and 316(a) and (b).

Competitive Procurement Policies[14]

Ameren Missouri assigns a Project Manager to lead the activities necessary to ensure the successful completion of its acquisition and development of supply-side resources. In general, a project team comprised of a Project Manager and various lead engineers will identify all items to be procured and will coordinate with the Strategic Sourcing and Purchasing departments within Ameren to ensure proper contract structures are considered and used for each procurement activity. A Contract Development Team (CDT) is assembled and assists in collecting material and labor estimates based on the overall project design. Strategic Sourcing, CDT and the project team work to set up a number of components as Ameren stock items that are the basis for ordering materials. A detailed procurement matrix is developed to identify the major purchases that are anticipated to be required as part of the project. Material purchases make use of stock items established by the CDT. Where material has not been established as a stock item, the preferred approach is to solicit and obtain at least three quotations from a group of preferred Ameren vendors wherever possible to ensure the most competitive pricing for the material. Competitive bids are acquired from multiple vendors capable of meeting the requirements of the project. Ameren Missouri will be following Ameren's Project Oversight Process, which is provided in Appendix C, for monitoring the progress made implementing its Preferred Resource Plan.[15]

10.5.5 Monitoring Critical Uncertain Factors[16]

Ameren Missouri will be monitoring the critical uncertain factors that would help determine whether the Preferred Resource Plan is still valid and whether contingency options should be pursued. Below is a description of how Company decision makers will be monitoring the factors most relevant to future resource decisions.

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[14] 4 CSR 240-22.070(6)(E)
[15] 4 CSR 240-22.070(6)(G)
[16] 4 CSR 240-22.070(6)(F)

Schedule MM-S11

Climate Policy

Ameren Missouri senior management and the Environmental Services Group will continue to monitor and evaluate developments on efforts to regulate greenhouse gas emissions as well as state and industry efforts aimed at reducing greenhouse gas emissions.

Gas Prices

The President and CEO of Ameren Missouri is updated at least annually by Corporate Planning on trends and drivers of natural gas prices as part of the update on the drivers of forward commodity prices. Ameren Missouri senior management may, in its sole discretion, request more frequent updates to discuss significant changes in natural gas prices.

Load Growth

Corporate Planning will update Ameren Missouri's capacity position as needed based on the latest assumptions regarding load growth. Any significant changes in resource needs, whether timing or size, will be communicated to Ameren Missouri senior management. Corporate Planning will also reassess, at least annually, its assumptions for load growth in the Eastern Interconnect, which is a critical dependent uncertain factor included in our power price scenario modeling.

Coal Prices

Corporate Planning will work with Ameren Missouri's Fuels organization to monitor coal prices, with updates at least annually and as needed.

Demand-Side Resource Impacts and Cost

Ameren Missouri will continue to evaluate the cost-effectiveness of its DSM programs internally and through the evaluation process. Any major deviations from planning assumptions like participation rates, technology costs, and customer opt-out will be communicated to Ameren Missouri senior management.

10.6 Compliance References

10. Strategy Selection

Highlights

- *Ameren Missouri is embarking on a transformation of its generation portfolio over the next twenty years while also considering portfolio implications through 2050.*
  - *Our plan includes our largest ever expansion of renewable wind and solar generation, bringing us to 3,100 MW of wind and solar by 2030 and 5,400 MW by 2040. This allows us to begin providing clean renewable energy to our customers now and mitigate significant risks associated with changes in energy policy, including policies that establish a price on carbon dioxide ("CO_2") emissions.*
  - *Our plan also includes continued customer energy efficiency and demand response program offerings, expansion of customer programs for renewable energy, and retirement of over three-fourths of our coal-fired generating capacity by 2040, which will be reaching the end of its useful life.*
  - *Our plan supports more aggressive reductions in CO_2 emissions, resulting in a 50% reduction by 2030 from 2005 levels and an 85% reduction by 2040, with a goal of achieving Net Zero CO_2 emissions by 2050.*
- *Our implementation plan for the next three years includes steps necessary to add an additional 1,200 MW of wind and solar generation to our portfolio by 2025, approval and implementation of energy efficiency and demand response programs beyond our current plan, and actions to preserve contingency resource options and enable us to quickly respond to changing needs and conditions while continuing to ensure safe, reliable and cost-effective service to our customers.*
- *Ameren Missouri will continue to monitor critical uncertain factors to assess their potential impacts on our preferred plan, contingency plans and implementation. These include prices for CO_2 and natural gas and costs for implementing customer demand-side programs.*
- *We will also continue to monitor prices for coal, costs for renewable generation, needs for transmission network infrastructure, and development of carbon-free resources such as large-scale long-cycle battery energy storage, hydrogen-based generation and storage, new nuclear technologies, and generation with carbon capture and sequestration.*

Ameren Missouri has selected its preferred resource plan and contingency plans in accordance with its planning objectives and practical considerations that inform our decision making. Our selection process consists of several key elements:

- ✓ Establishing planning objectives and associated performance measures to develop and assess alternative resource plans
- ✓ Creating a scorecard based on our planning objectives and performance measures to evaluate the degree to which various alternative resource plans would satisfy our planning objectives
- ✓ Critically analyzing the most promising alternative resource plans to ensure that we select a plan that best balances competing objectives

We have established an implementation plan for 2021-2023 that allows us to begin implementing the resource decisions embodied in our preferred resource plan and to preserve contingency options to allow us to effectively respond to changing needs and conditions while continuing to ensure safe, reliable, and cost-effective electric service to our customers.

10.1 Planning Objectives

The fundamental objective of the resource planning process in Missouri is to ensure delivery of electric service to customers that is safe, reliable and efficient, at just and reasonable rates in a manner that serves the public interest. This includes compliance with state and federal laws and consistency with state energy policies.[1] Ameren Missouri considers several factors, or planning objectives, that are critical to meeting this fundamental objective. Planning objectives provide guidance to our decision making process and ensure that resource decisions are consistent with business planning and strategic objectives that drive our long-term ability to satisfy the fundamental objective of resource planning. Following are the planning objectives, established in the development of our 2011 IRP, that continue to inform our resource planning decisions today.

Cost (to Customers): Ameren Missouri is mindful of the impact that its future energy choices will have on cost to its customers. Therefore, minimization of present value of revenue requirements is our primary selection criterion.[2]

Costs alone do not and should not dictate resource decisions. Our other planning objectives are discussed below.

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[1] 20 CSR 4240-22.010(2); 20 CSR 4240-22.010(2)(A);
[2] 20 CSR 4240-22.010(2)(B)

Customer Satisfaction: Missouri is dedicated to continuing to improve customer satisfaction. While there are many factors that can be measured, for practical reasons Ameren Missouri focused primarily on measures that can be significantly impacted by resource decisions: 1) rate impacts – levelized average rates, 2) supply and service reliability, 3) customer preferences for renewable energy sources and demand-side programs that provide customers with options to manage their usage and costs, 4) availability of programs that allow customers to source more of their energy needs from renewable resources, and 5) reductions in energy center emissions.

Portfolio Transition (formerly Environmental & Resource Diversity): Ameren Missouri, like other electric utilities in Missouri, produces the majority of the energy it generates from coal. Ameren Missouri continues to be focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio. We therefore evaluate alternative resource plans based on the degree and pace of the transition from fossil generation sources to cleaner sources of energy.

Financial/Regulatory: The continued financial health of Ameren Missouri is crucial to ensuring safe, reliable and cost-effective service for customers in the future. Ameren Missouri will continue to need the ability to access large amounts of capital for investments needed to comply with renewable energy standards and environmental regulations, invest in demand and/or supply side resources to meet customer demand, provide reliable service, and execute our portfolio transition. Measures of expected financial performance and creditworthiness are evaluated along with potential risks.

Economic Development: Ameren Missouri is committed to support the communities it serves beyond providing reliable and affordable energy. Ameren Missouri assesses the economic development opportunities, for its service territory and for the state of Missouri, associated with our resource choices. We do this by examining the potential for direct job growth for both construction and operation of resources, which in turn promotes additional economic activity.

Table 10.1 summarizes our planning objectives, the primary measures used to assess our ability to achieve these objectives with our alternative resource plans, and the weighting applied to each objective for scoring the alternative resource plans.

Table 10.1 Planning Objectives and Measures[3]

Planning Objective Categories	Measures	Weighting
Cost	Present Value of Revenue Requirements	30%
Customer Satisfaction	Customer Preferences, Levelized Rates	20%
Portfolio Transition	Resource Diversity, CO_2 Emissions, Probable Environmental Costs	20%
Financial/Regulatory	Free Cash Flow, Financial Ratios, Stranded Cost Risk, Transaction Risk, Cost Recovery Risk	20%
Economic Development	Direct Job Growth (FTE-years)	10%

These planning objectives are consistent with Ameren's overall sustainability efforts. In early May 2020, Ameren Corporation released its corporate sustainability report – Our Sustainability Story: Customers at the Center. The report details Ameren's commitment to sustainability and environmental stewardship and offers a comprehensive view of the actions taken on key environmental, social, and governance ("ESG") matters. In the report Ameren addresses a range of topics, including:

- ✓ Addressing significant immediate and long-term needs of our communities, which include wide-ranging support during the COVID-19 pandemic as well as ongoing energy assistance support, philanthropy and apprenticeships.
- ✓ Plans to significantly increase renewable energy in our generation portfolio while reducing carbon and other greenhouse gas emissions.
- ✓ Improving reliability by investing in rate-regulated energy infrastructure while, at the same time, keeping electric rates more stable and affordable for customers.
- ✓ Actions we have taken to enhance our robust risk management and governance with respect to ESG matters.

10.2 Additional Alternative Resource Plans

Upon completion of the integration and risk analysis described in Chapter 9, additional alternative resource plans were identified to evaluate additional specific paths for the addition of renewable energy resources and to evaluate various DSM portfolios in the context of early retirement of the Sioux and Rush Island Energy Centers. Table 10.2 shows the additional plans that were developed and passed through the same risk

[3] 20 CSR 4240-22.060(2); 20 CSR 4240-22.060(2)(A)1 through 7

Schedule MM-S12

analysis described in Chapter 9 and applied to the alternative resource plans listed in Table 9.4. This brings the number of alternative resource plans to 28.

These additions are based in part on the conclusions described in Chapter 9, in section 9.7. First, our risk analysis demonstrated that adding significant levels of wind and solar resources resulted in a reduction in total costs to customers. While these investments would provide benefits to all customers, some customers are seeking to source their energy needs from renewable sources more quickly or at levels greater than that available to all customers. This desire on the part of some customers may be based in part on explicit renewable energy or greenhouse gas reduction goals. To evaluate the potential for investments to specifically serve those customers interested in additional renewable energy under a Renewable Subscription offering, we have added a plan, Plan V shown in Table 10.2, for analysis. We have also added a potential contingency plan, Plan W, which includes investments for the Renewable Subscription program but no further DSM investment beyond our currently approved program plan.[4]

Table 10.2 Additional Alternative Resource Plans

Plan Name		DSM	Renewables	New Supply Side	Coal Retirements/ Modifications
V	Sioux-Rush Early Retirement - Renewable Subscription	RAP	Renewable Expansion with Renewable Subscription	CC 2043	Sioux Dec-2028 Rush Island Dec-2039
W	Sioux-Rush Early Retirement - No DSM - Renewable Subscription	-	Renewable Expansion with Renewable Subscription	CC 2037, 2x2040, 2043	Sioux Dec-2028 Rush Island Dec-2039
X	Sioux-Rush Early Retirement - Renewables when needed	RAP	Renewables When Needed for Capacity	CC 2043	Sioux Dec-2028 Rush Island Dec-2039
Y	Sioux-Rush Early Retirement - Grain Belt Express	RAP	Renewable Expansion with Grain Belt Acceleration	CC 2043	Sioux Dec-2028 Rush Island Dec-2039
Z	Sioux-Rush Early Retirement - DOPE1 DSM	RAP	Renewable Expansion	CC 2040, 2043	Sioux Dec-2028 Rush Island Dec-2039
AA	Sioux-Rush Early Retirement - DOPE2 DSM	RAP	Renewable Expansion	CC 2040, 2043	Sioux Dec-2028 Rush Island Dec-2039
BB	Sioux-Rush Early Retirement - MAP	RAP	Renewable Expansion	-	Sioux Dec-2028 Rush Island Dec-2039

In addition, a potential opportunity exists with respect to a planned high voltage direct current ("HVDC") transmission line project which could deliver renewable energy from western Kansas to Missouri. The Grain Belt Express ("GBX") HVDC transmission project

[4] EO-2020-0047 1.K

could deliver 1,000 MW of renewable energy to our service territory. To evaluate the potential value of this project, we have added a plan, Plan Y, which includes an investment by Ameren Missouri in 1,000 MW of transmission capacity along with the acceleration of investments represented in our Renewable Expansion portfolio described in Chapter 9.

We have also added Plan X, which includes the same total capacity of wind and solar additions as the Renewable Expansion portfolio described in Chapter 9, but adds the wind and solar resources when there is an explicit need for capacity. The wind and solar additions for Plans V-Y are shown in Table 10.3.

Table 10.3 Renewable Additions for Plans V-Y

Renewable Additions		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Renewable Expansion	Wind	700	-	-	300	-	-	-	300	-	-	300	-	300	-	300	-	300	-	200	-	2,700
	Solar	-	30	20	-	250	-	400	-	300	400	-	300	-	300	-	300	-	400	-	-	2,700
Renewable Exp. w/ Subscription	Wind	700	-	-	400	-	-	-	300	-	-	200	-	300	-	300	-	300	-	200	-	2,700
	Solar	-	30	20	500	250	-	400	-	200	300	-	200	-	200	-	200	-	400	-	-	2,700
Renewable Exp. With GBX	Wind	700	-	-	1,000	-	-	-	-	-	-	-	-	200	-	300	-	300	-	200	-	2,700
	Solar	-	30	20	-	250	-	400	-	300	400	-	300	-	300	-	300	-	400	-	-	2,700
Renewables When Needed	Wind	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,000	2,700
	Solar	-	30	20	-	-	75	-	-	-	-	-	75	-	-	-	-	-	-	-	2,500	2,700

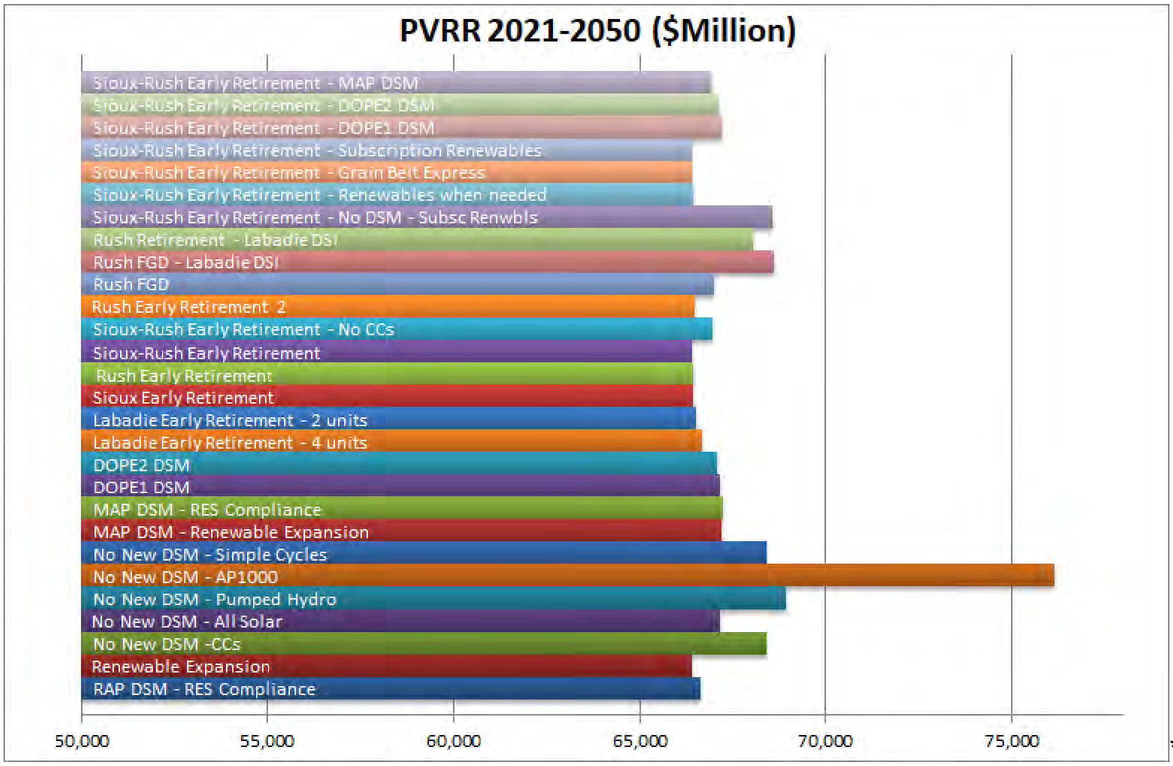
The second objective of the additional alternative resource plans is to evaluate the performance of various DSM portfolios in the context of early retirement of Sioux and Rush Island. Plans Z, AA and BB were added to evaluate the DSM portfolios DOPE 1, DOPE 2, and MAP, respectively. We performed our risk analysis for all 28 alternative resource plans using the same approach described in Chapter 9. Table 10.4 shows the PVRR results for the additional plans compared to the results for the reference plan, Plan P. Figures 10.1 and 10.2 show the PVRR and levelized rates for all alternative resource plans, including these additional plans.

Table 10.4 Comparison of Results for Additional Plans

Plan Description		PVRR ($MM)	Lev. Rate (c/kwh)
P	Sioux-Rush Early Retirement	66,412	15.82
V	Sioux-Rush Early Retirement - Renewable Subscription	66,391	15.81
W	Sioux-Rush Early Retirement - No DSM - Renewable Subscription	68,549	15.08
X	Sioux-Rush Early Retirement - Renewables when needed	66,431	15.82
Y	Sioux-Rush Early Retirement - Grain Belt Express	66,408	15.81
Z	Sioux-Rush Early Retirement - DOPE 1	67,255	15.51
AA	Sioux-Rush Early Retirement - DOPE 2	67,183	15.37
BB	Sioux-Rush Early Retirement - MAP	67,048	16.51

Schedule MM-S12

*****Figure 10.1 Probability-Weighted PVRR Results[5]**



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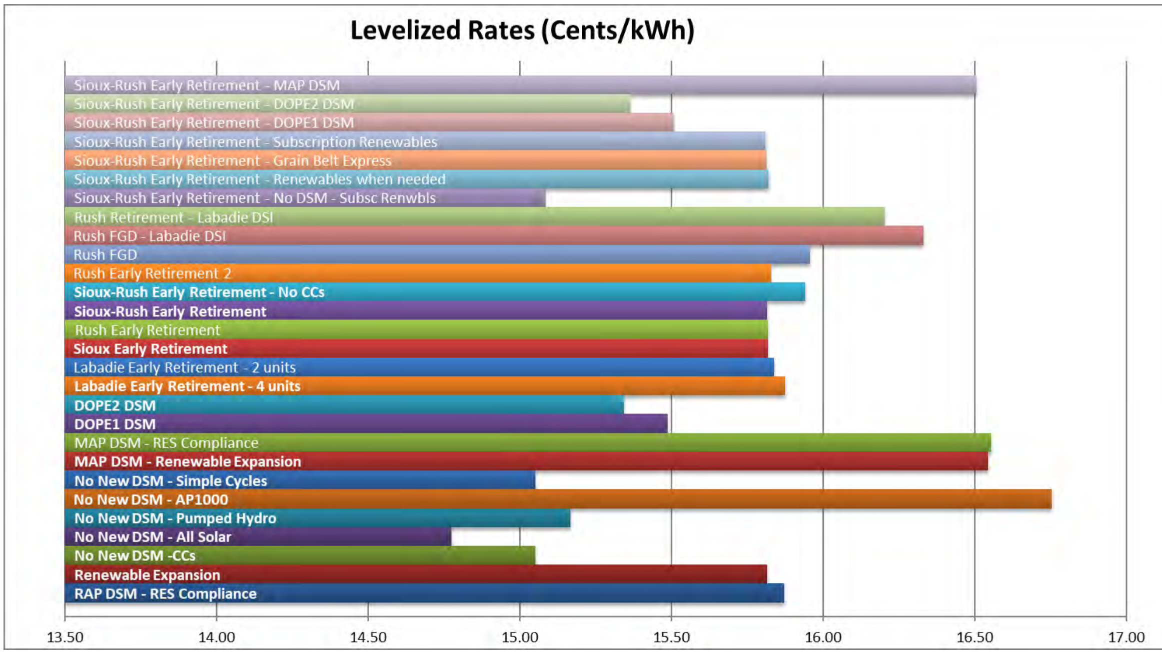
[5] Plans include RAP-level DSM unless otherwise noted.

Schedule MM-S12

Figure 10.2 Probability-Weighted Levelized Rate Results***



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10.3 Assessment of Alternative Resource Plans

Ameren Missouri uses a scorecard to evaluate the performance of alternative resource plans with respect to our planning objectives and measures described above. The scorecard and measures include both objective and subjective elements that together represent the trade-offs Ameren Missouri's management considers in balancing these competing objectives. It is important to keep in mind that the scorecard is a tool for decision makers and does not, in and of itself, determine the preferred resource plan. The selection of the preferred resource plan is informed by the scorecard and by a more critical analysis of the relative merits of alternative resource plans, including an assessment of any risks or other constraints.

10.3.1 Scoring of Alternative Resource Plans[6]

To score each of the alternative resource plans, we employed a standard approach to scoring for each planning objective on a 5-point scale and determined a composite score by applying the weightings shown in Table 10.1 to each planning objective. As Cost is the primary selection criterion, it was given the greatest weight – 30% -- just as it was in the

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[6] 20 CSR 4240-22.010(2)(C); 20 CSR 4240-22.010(2)(C)1; 20 CSR 4240-22.010(2)(C)2; 20 CSR 4240-22.010(2)(C)3; 20 CSR 4240-22.070(1); 20 CSR 4240-22.070(1)(A) through (D)

Schedule MM-S12

scoring performed for all of our IRP filings since 2011.[7] The scoring approach for each planning objective is as follows:

Cost – The 28 alternative resource plans were separated into five groups according to probability weighted average PVRR results from the risk analysis discussed in Chapter 9. The lowest cost group of plans were given a score of 5, the next lowest cost group a score of 4, and so on, with the highest cost group of plans receiving a score of 1.

Customer Satisfaction – Alternative resource plans were evaluated based on levelized annual average rates for a portion of the score. As was done with the PVRR results, the alternative resource plans were separated into five groups according to the probability-weighted average levelized annual average rate results produced from our risk analysis. The plans resulting in the lowest rates were given a score of 5, the next lowest rate group a score of 4, and so on, with the highest rate group of plans receiving a score of 1. Plans that yielded a score greater than 3 for rates were given 3 points in the overall scoring for Customer Satisfaction. Plans that yielded a score of 3 were given 2 points. Plans were given one additional point for each of the following:

- ✓ Inclusion of demand-side programs
- ✓ Early retirement of coal generation
- ✓ Addition of significant renewables (beyond those needed to comply with legal mandates)
- ✓ Inclusion of customer programs for renewable energy

Portfolio Transition – Alternative resource plans were awarded points for each plan attribute contributing to greater resource diversity and/or environmental impact in terms of emission reductions. Plans were awarded one point each for each of the following:

- ✓ Inclusion of demand-side programs
- ✓ Addition of nuclear generation
- ✓ Early retirement of coal-fired generation (1 point per 2 large units)
- ✓ Addition of significant renewables (beyond those needed to comply with legal mandates)
- ✓ Addition of storage resources

[7] 20 CSR 4240-22.010(2)(B)

- ✓ Acceleration of renewable transition

Financial/Regulatory – Scoring for Financial/Regulatory is based on a default score of 5 with deductions for risks and financial impacts that may detrimentally affect Ameren Missouri's ability to continue to access lower cost sources of capital. Plans that would result in relatively lower free cash flow were reduced by one point. Plan scores were also reduced by one point each for potential risks associated with:

- ✓ Lack of any DSM programs
- ✓ Risks associated with delays in implementing energy efficiency measures
- ✓ Nuclear construction and operating risks
- ✓ Risks associated with the addition of gas-fired generation
- ✓ Risks associated with major environmental retrofits
- ✓ Risks associated with recovery of coal-fired generation investment
- ✓ Risks associated with access to low-cost capital

Economic Development – Alternative plans were scored based on direct job creation, including construction and ongoing operation. Estimates for direct job creation were developed using the Jobs and Economic Development Impact ("JEDI") Model, developed by Marshall Goldberg of MRG & Associates under contract with the National Renewable Energy Laboratory, or more specific estimates where available (e.g., nuclear). Construction and operating jobs were translated into full-time equivalent years (FTE-years). Alternative plans were ranked based on FTE-years and divided into five groups based on relative rank. The group of plans resulting in the highest FTE-year values were given a score of 5 points each, the next highest FTE-year group a score of 4, and so on, with the lowest FTE-year group of plans receiving a score of 1.

Table 10.5 Alternative Resource Plan Scoring Results[8]***

Plan	Description	Composite Score
V	Sioux-Rush Early Retirement - Renewable Subscription	4.90
Y	Sioux-Rush Early Retirement - Grain Belt Express	4.70
P	Sioux-Rush Early Retirement	4.50
M	Labadie Early Retirement - 2 units	4.30
N	Sioux Early Retirement	4.30
O	Rush Early Retirement	4.20
Q	Sioux-Rush Early Retirement - No CCs	4.20
R	Rush Early Retirement 2	4.00
X	Sioux-Rush Early Retirement - Renewables when needed	3.90
BB	Sioux-Rush Early Retirement - MAP	3.80
L	Labadie Early Retirement - 4 units	3.80
B	Renewable Expansion	3.70
Z	Sioux-Rush Early Retirement - DOPE 1	3.50
AA	Sioux-Rush Early Retirement - DOPE 2	3.40
W	Sioux-Rush Early Retirement - No DSM - Renewable Subscription	3.20
S	Rush FGD	3.10
H	MAP DSM - Renewable Expansion	3.00
J	DOPE1 DSM	2.90
U	Rush Retirement - Labadie DSI	2.90
K	DOPE2 DSM	2.80
A	RAP DSM - RES Compliance	2.70
T	Rush FGD - Labadie DSI	2.60
I	MAP DSM - RES Compliance	2.50
D	No New DSM - All Solar	2.20
E	No New DSM - Pumped Hydro Storage	2.20
G	No New DSM - Simple Cycle Gas	1.80
C	No New DSM -Combined Cycle Gas	1.70
F	No New DSM - AP1000 Nuclear	1.60

***

Table 10.5 shows the composite scores for each of the 28 alternative resource plans. The full scorecard with scores for each planning objective for each alternative resource plan is shown in Appendix A. Based on the scoring results, the alternative resource plans were separated into three tiers – Top, Mid, and Bottom. Plans with scores greater than 4.0 were placed in the Top Tier. Plans with scores between 3.0 and 4.0 were placed in the Mid-Tier. Plans with scores below 3.0 were placed in the Bottom Tier. All Top Tier plans include energy efficiency and demand response at the realistic achievable potential (RAP) level.

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[8] Plans include RAP-level DSM unless otherwise noted.

Schedule MM-S12

10.3.2 Renewable Resource Expansion

One of the key conclusions from our evaluation of alternative resource plans is that the inclusion of a sustained long-term expansion of renewable energy resources is beneficial across all of our planning objectives. It steadily transforms our portfolio to one that is cleaner and more diverse while enhancing customer affordability and providing much needed clean energy jobs for our communities and the state of Missouri. It also does something to help ensure our ability to accomplish these goals – it mitigates risks inherent in our existing portfolio as we manage the transition away from fossil fuels while relying on the reliability and economic benefits they continue to provide.

Resource planning has traditionally focused on the balance of generating capacity with customer demand and reserve margin requirements. While that remains important, transforming our generation portfolio requires that we carefully consider all the implications of how we effectuate that transformation. This includes the following considerations, which are discussed in more detail in this section:

1. **Ameren Missouri will need energy resources as coal-fired generation is retired even as capacity resources remain sufficient to meet demand and reserve margin requirements.**

2. **The large-scale expansion of renewable resources provides significant risk mitigation to Ameren Missouri's portfolio, particularly with respect to changes in climate policy.**

3. **Ameren Missouri's coal-fired fleet continues to provide value to customers in order to provide reliable, affordable energy even as it faces significant risks to long-term operations.**

4. **There is a growing need for renewable resources in both the near term and the long term and potential that the need could be further spurred by changes in energy policy.**

5. **A large expansion of renewable generation must include consideration of practical limitations, including the potential for financing constraints.**

6. **Initiating renewable resource builds in the nearer term provides the opportunity to realize tax incentives for customers.**

Ameren Missouri's Need for Energy Resources

Ameren Missouri's existing generation fleet has a total net capability of 10,142 MW. Of this, half is coal, 12% is nuclear, 8% is hydroelectric and other renewables, and 30% is gas or oil fired peaking generation. In contrast, coal currently provides approximately

Schedule MM-S12

70% of the energy produced by our fleet, with nuclear providing roughly 25% and renewables providing another 5%. Gas and oil fired resources provide less than 1% of the energy produced by our existing fleet. As coal-fired resources are retired or as their level of production decreases as a result of changes in operating efficiencies, CO_2 prices, other market conditions, regulatory constraints, or other factors, new energy resources will be needed to supplement the remaining generation. While the peaking generation will continue to provide capacity to meet peak demand and reserve margin needs, it will not be able to make up for the loss of coal-fired energy on its own. In fact, it is likely the production levels from these coal-fired energy assets will remain relatively low as they are dispatched in the Midcontinent Independent System Operator ("MISO") market and as they are operated in compliance with environmental permit constraints. The continued availability of these affordable coal-fired energy assets does allow Ameren Missouri to maintain reliability as increasing amounts of renewable energy are integrated into the system to meet customer needs.

Figure 10.3 Energy Comparison for Selected Plans – Low CO_2 Price

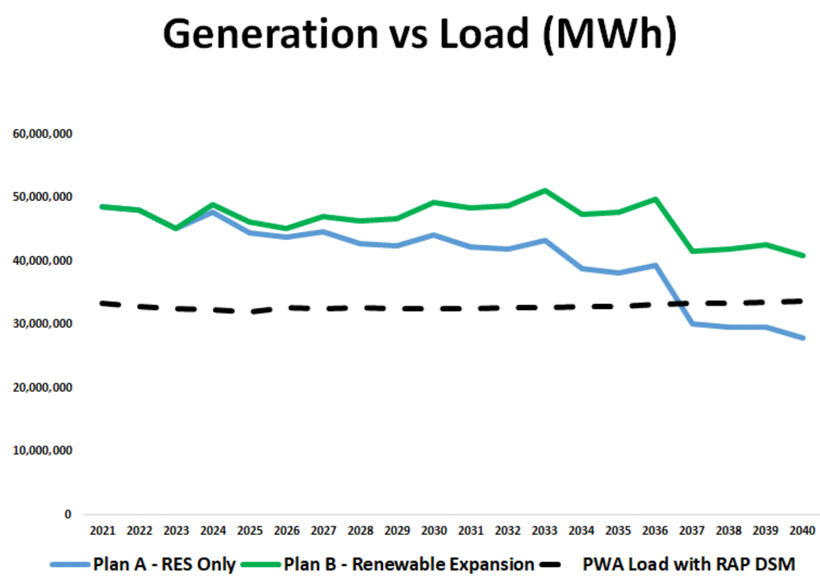
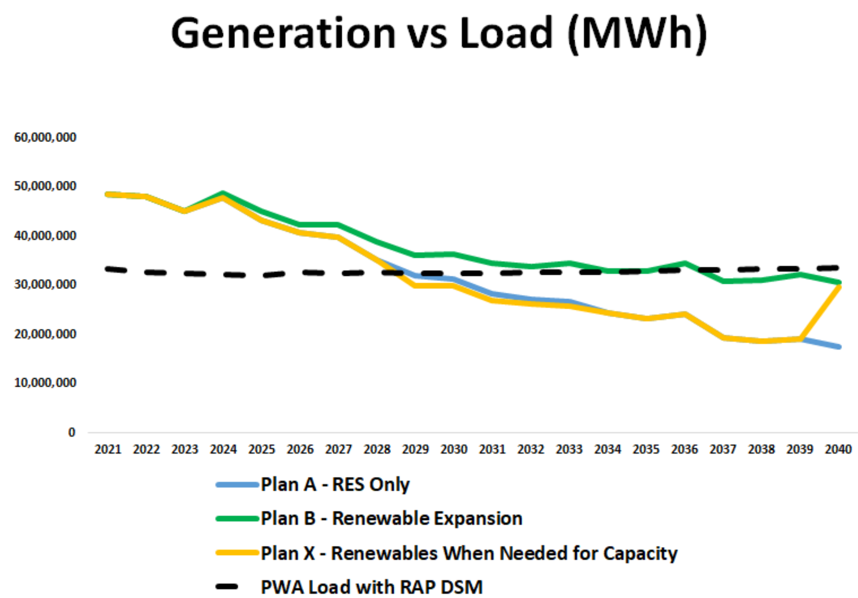


Figure 10.3 shows a comparison of the energy production from several of our alternative plans under our Low CO_2 price scenario. Figure 10.4 shows a similar comparison of energy production for several alternative plans under our High CO_2 price scenario, which results in reduced levels of generation from coal resources (and also gas to a much lesser extent) compared to the levels of production under the Low CO_2 price scenario. The chart shows that for Plan 2 (RAP – RES Compliance), which does not include a large renewable buildout, Ameren Missouri would be generating less energy than its customers use by 2030 and that this shortfall would grow to over one-third of total load by 2040. Any acceleration of coal energy center retirements further exacerbates this issue.

Taken together, the charts in Figures 10.3 and 10.4 highlight a key consideration in the approach to our renewable resource expansion. There is significant uncertainty regarding the level of production from our existing fleet of resources. Differences in future CO_2 prices is only one source of this uncertainty, but it helps to highlight the broader issue. Other sources of uncertainty include natural gas prices, power prices, environmental regulation, and potential changes in climate policy. All of these and perhaps others could impact coal-fired resources and result in a much earlier need for new energy generation. Waiting until such needs are certain may result in suboptimal solutions and potential higher costs to customers. It could also result in an unintended but necessary reliance on fossil-fueled generation like natural gas combined cycle, deferring or displacing some renewable resource additions.

Figure 10.4 Energy Comparison for Selected Plans – High CO_2 Price



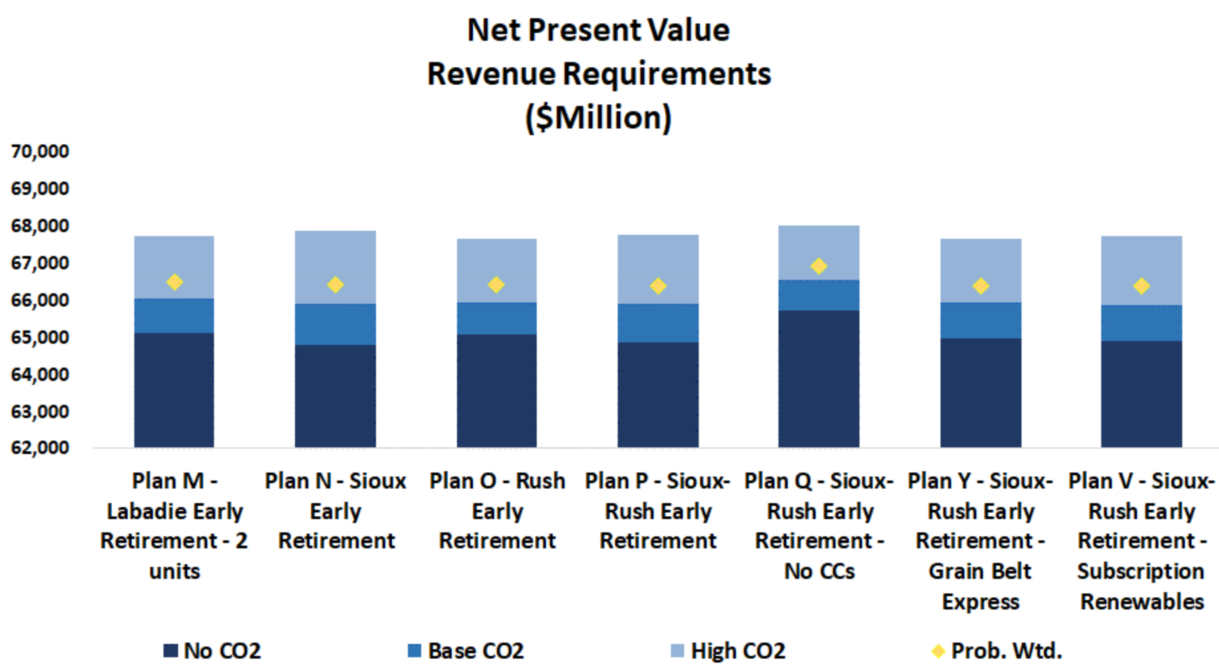
Risk Mitigation Benefits of Renewable Expansion

Our analysis shows that higher CO_2 prices have a beneficial impact on the economics of renewable resources and a detrimental effect on the economics of coal-fired resources. The impact on coal is somewhat obvious in that the CO_2 prices impose a cost directly on the energy production from coal generators. It is this cost imposed on coal and gas generators that also manifests itself in power market prices, as illustrated in Chapter 2. The higher the CO_2 price, the higher the power price. Wind and solar generation, along with other non-carbon-emitting generating sources like hydro and nuclear, therefore see a benefit from CO_2 prices through the revenue they receive in the market. In contrast, the absence of a CO_2 price results in maximal benefits to coal-fired generation and minimal benefits to renewables, nuclear and hydro.

Schedule MM-S12

By expanding the share of renewable resources in our portfolio, we increase the balance of resources that from an economic perspective perform better as CO_2 prices rise and resources whose performance diminishes as CO_2 prices rise. This is not unlike the diversification of personal investments like those many hold in retirement funds like a 401(k) plan. By investing in a variety of resources, each of which perform well under different conditions, the overall risk of the portfolio can be mitigated. To illustrate this effect in the context of resource planning, we can simply examine how various alternative resource plans perform under different levels of CO_2 price. Figure 10.5 shows the PVRR results for several plans with different levels of renewable energy resources under the three different scenarios for CO_2 price used in our risk analysis.

Figure 10.5 PVRR Results for Selected Plans by CO_2 Price Scenario



As the chart in Figure 10.5 shows, the steady addition of wind and solar resources provides risk mitigation around the range of CO_2 prices used for risk analysis, with costs to customers under the No CO_2 price scenario being slightly higher than without the steady buildout and significantly lower under the high CO_2 price scenario. This is in addition to the risk mitigation highlighted by the discussion of energy needs above. Specifically, the steady addition of renewable resources mitigates risk with respect to numerous factors that could impact the production of coal-fired resources, including market prices for energy, environmental regulations and other energy policies.

Continuing Value of Ameren Missouri's Coal-fired Fleet

Ameren Missouri's coal-fired generators are among the most efficient and cost-effective in MISO. They, along with our nuclear and hydro resources, provide around-the-clock

Schedule MM-S12

capability that serves as a foundation for reliable energy supply to our customers. While the challenges associated with coal-fired generation continue to increase, Ameren Missouri has found innovative ways to maintain affordability of reliable operations while meeting or exceeding current environmental standards. Our alternative resource plan demonstrates the ongoing viability of our Labadie and Rush Island Energy Centers as we prepare to manage our Meramec and Sioux Energy Centers to the ends of their useful lives during this decade.

The primary factor in our analysis influencing the long-term viability of Labadie and Rush Island is CO_2 prices. While high CO_2 prices would negatively affect the economics of these units, we are able to monitor climate policy developments and adjust our plans accordingly as future policies become clearer. In the meantime, we can continue to rely on these units to provide reliable energy in order to integrate increasing amounts of renewable energy, as well as to provide the resultant economic benefits to customers. As a result, we have an opportunity to build out a significant portfolio of cleaner and more diverse renewable resources that enhance customer affordability, mitigate the risks of CO_2 prices, and mitigate the risks of a potential urgent need for capacity that might otherwise need to be satisfied by gas-fired resources.

Customer and Policy Drivers of the Need for Renewable Resources

Customers are expressing an increasing preference for energy supplied by renewable resources. One way to meet this growing demand is to offer programs that allow customers to increase the share of their energy needs that is supplied by renewable resources. In addition to such programs, there has also been a growing sentiment that greater levels of renewable generation should be available to all customers. This is the sentiment that drove the adoption of Missouri's RES in 2008. Ameren Missouri will soon have the resources necessary to comply with the full requirement of the RES upon completion of 700 MW of wind generation projects in Missouri.

Because of the success of Missouri's RES and the still growing demand for renewable energy resources, policymakers and advocates are continuing to push for energy policies to promote clean and renewable energy resources. This includes the potential for a federal Clean Energy Standard ("CES") and an increase in the requirements for the Missouri RES in future years. Both policies could drive a further expansion of renewable resources.

Figure 10.6 Percentage of Retail Sales Served by Renewable Energy

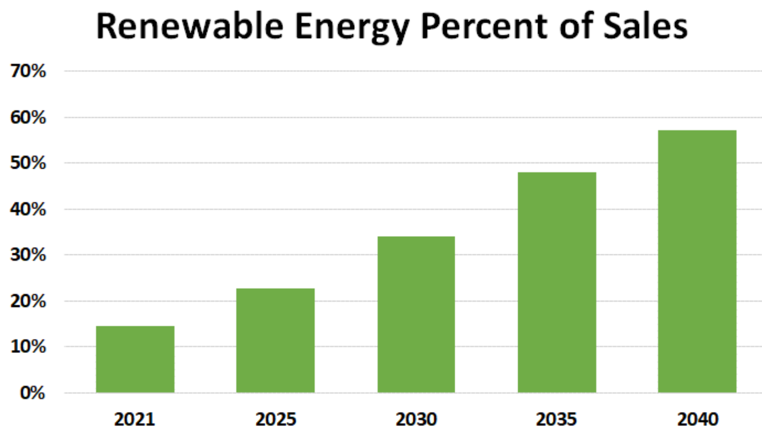


Figure 10.6 shows the percentage of customer sales generated by renewable resources with our Renewable Expansion portfolio. Should explicit policies requiring greater percentages of renewable resources than the current RES requires be enacted, this portfolio would better position Ameren Missouri to meet such requirements.

Practical Considerations for Large-Scale Renewable Expansion

It is one thing to set forth a plan to meet customer energy needs for the next twenty years. It is quite another thing to execute plans and construct the renewable energy resources to serve those needs. So while we have some time to build out the entire renewable resource portfolio, there are practical considerations that must be taken into account when embarking on the kind of portfolio transformation that Ameren Missouri believes is necessary to best meet our customers' future energy needs. These include practical limitations on project permitting, development and construction, environmental studies, the need for new transmission infrastructure to deliver renewable energy, and the ability to finance project construction. By spreading out the build of renewable resources, we mitigate practical project construction risks associated with the beneficial transformation of the generation portfolio and preserve flexibility to address these and possibly other potential roadblocks that may hamper resource acquisition.

As we have seen in recent years, the development, approval, and construction of renewable resources presents unique challenges. These include complications associated with permitting requirements, acquisition of land leases, and securing necessary regulatory approvals. Spreading out the addition of renewable resources allows us to maintain flexibility, reliability, and affordability in our acquisition and integration of those resources without the pressure of a clear and imminent capacity need.

Likewise, the need for transmission infrastructure can present unique and project-specific challenges that flexibility can help to overcome. As we saw with the planned Brickyard Hills wind project, the costs for transmission network upgrades associated with new

Schedule MM-S12

projects can change dramatically depending on the capacity of the existing transmission network to accommodate additional wind generation and the amount of wind generating capacity seeking interconnection through the queue in a given Regional Transmission Organization ("RTO"). This could easily be true for large-scale solar projects as well, which are likely necessary to achieve the level of solar resources called for in our plan. By pursuing a steady buildout of wind and solar generation, we maintain flexibility to be selective and opportunistic with respect to projects for a host of reasons, including costs for necessary transmission system upgrades.

Another key consideration is Ameren Missouri's ability to raise the necessary capital to fund project construction. Ameren Missouri seeks to maintain sufficient credit metrics to ensure access to capital markets to fund not only renewable resource acquisition but also grid modernization and a number of other investments necessary to ensure safe, reliable and affordable service to our customers. We have evaluated the performance all of our alternative resource plans with respect to these credit metrics and have included the results in Chapter 9. We also included consideration of these credit metrics in our scorecard assessment of alternative resource plans as part of our Financial/Regulatory planning objective.

Table 10.6 Credit Metrics for Selected Plans vs. Target Metrics

Plan Description		FFO/Debt	FFO Interest Coverage
	Target Credit Metrics	25.0%	6.30
P	Sioux-Rush Early Retirement	23.9%	6.91
V	Sioux-Rush Early Retirement - Renewable Subscription	23.9%	6.89
X	Sioux-Rush Early Retirement - Renewables when needed	19.3%	6.46

Table 10.6 shows the credit metrics for three plans compared to our target credit metrics. These represent the minimum results for the period 2030-2040 for funds from operations ("FFO") to total debt and FFO to interest expense. As the table shows, the credit metrics for Plan X, in which renewable additions are included only when needed for capacity are significantly lower than those for Plans P and V, in which renewable additions are added throughout the planning horizon. Most notably, the FFO/Debt metric for Plan X is well below our target for this metric. While metrics for individual years during the 20-year planning horizon may not indicate a credit challenge, the degree to which the metrics vary from other plans provides an indication that such challenges may be more likely.

Capturing the Value of Available Tax Credits

Current tax law includes production tax credits ("PTC") for wind generation and additional investment tax credits ("ITC") for solar generation. Ameren Missouri has captured significant value for customers with the wind projects currently nearing completion through the PTC. Continuing our buildout of renewable energy projects allows us the opportunity to capture significantly more value from PTC and ITC for wind and solar projects in the next several years.

Weighing the Considerations Together

In accounting for the foregoing considerations and in conjunction with our rigorous risk analysis of alternative resource plans, we conclude that a continued buildout of renewable wind and solar resources throughout the planning horizon yields significant real and potential benefits for our customers with limited downside. It provide us with valuable risk mitigation regarding CO_2 prices and other factors, and valuable flexibility in managing the transformation of our generation portfolio.

10.3.3 DSM Portfolio Considerations

While RAP DSM results in lower total customer costs than the other portfolios evaluated (MAP, DOPE 1, DOPE 2), it is important to also consider the potential risks associated with these portfolios. The DOPE portfolios are designed to target specific capacity needs in particular years based on a given schedule for retirement of coal-fired generation. However, we know that for a host of reasons these retirement dates may change. As is clear from our full risk analysis described earlier in this chapter, the acceleration of retirement of the Sioux and Rush Island Energy Centers appears to result in benefits to customers. This was a driving reason for the addition of Plans Z, AA, and BB. While the inclusion of either of the DOPE portfolios results in the deferral of combined cycle generation under our existing coal energy center retirement schedule, changing the retirement date for Rush Island to 2039 results in the first addition of combined cycle gas generation in 2040 rather than in 2043. Targeting capacity deferrals in specific years may result in missed opportunities for supply-side deferrals if conditions change and accelerate the need for capacity. Table 10.7 demonstrates a flaw with attempts to precisely time demand savings as contemplated with either of the two DOPE portfolios. Both DOPE portfolios resulted in higher PVRR when stress tested against changes in coal retirements. This result highlights the value of continuous deployment of demand-side resources in terms of both PVRR and risk mitigation.

Table 10.7 DSM Portfolio Sensitivity to Coal Retirements

PVRR Difference $Million	Sioux-Rush Island Retirement Regular	Sioux-Rush Island Retirement Early
MAP-RAP	788	636
DOPE1-RAP	757	843
DOPE2-RAP	685	771
DOPE1-MAP	(30)	207
DOPE2-MAP	(103)	135

Pursuing the Policy Goal of MEEIA

The stated goal of MEEIA is to achieve all cost-effective demand-side savings by aligning utility incentives with helping customers to use energy more efficiently. Ameren Missouri has demonstrated its commitment to pursuing this goal by implementing the largest utility energy efficiency program in Missouri history. And while we believe this is a goal worth pursuing, it cannot be quantified with any degree of accuracy for the next twenty years. Rather, it is a goal that will constantly be shaped and reshaped through continuous implementation, evaluation, research, testing and readjustment.

As noted earlier, Ameren Missouri has conducted a DSM Potential Study, prepared by a nationally recognized independent contractor team. The primary objective of the study was to assess and understand the long-term technical, economic, and achievable potential for all Ameren Missouri customer segments. Assuming regulatory treatment that reflects the requirements of MEEIA, RAP represents all cost-effective energy efficiency because, by definition, it represents a forecast of likely customer behavior under realistic program design and implementation.

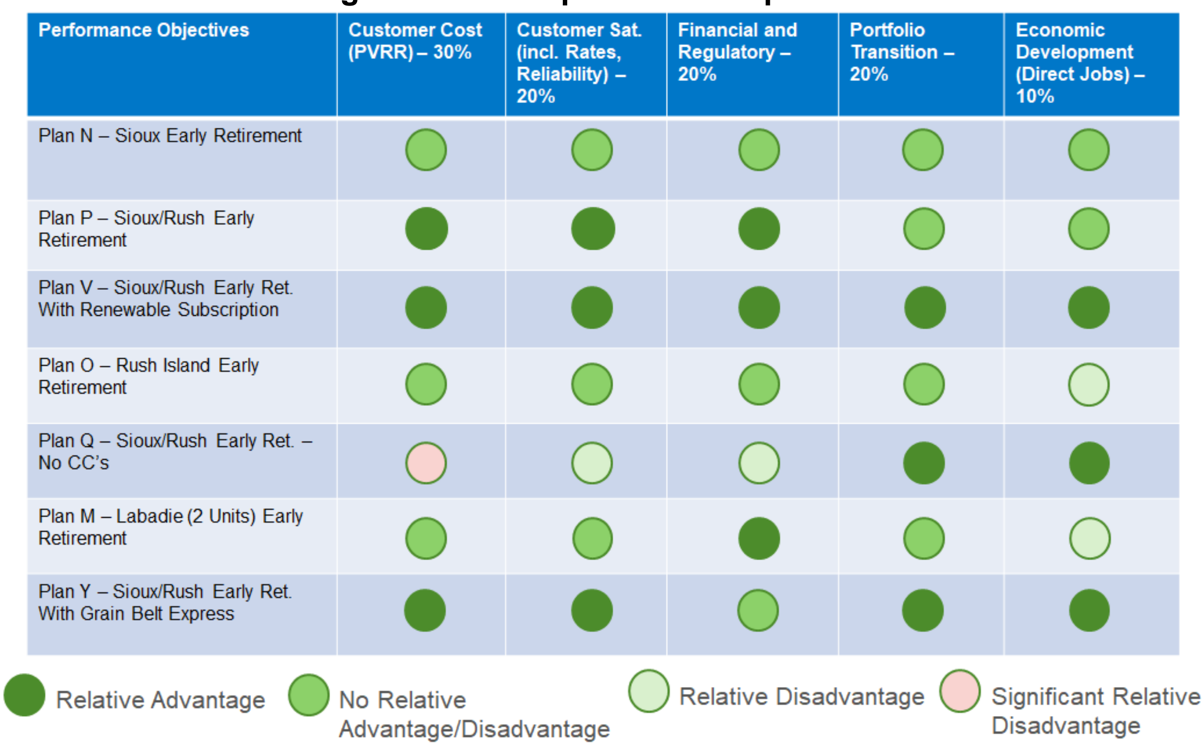
10.3.4 Electrification

As discussed in Chapter 3, the load forecasts used to evaluate alternative resource plans reflect a range of assumptions for electrification of transportation and other sectors. While these assumptions are used for evaluation of all plans, it is worth noting that electrification can play a significant role in the reduction of greenhouse gas emissions and in lowering customer rates. Ameren Missouri has shared cost-benefit analyses in proceedings before the MPSC. Based on these analyses and based on our continuing analysis of efficient electrification costs, we expect that there are many technologies and programs whose adoption will prove to be cost-effective. Ameren Missouri will build on this analysis in proposing future programs designed to accelerate adoption of efficient electrification which benefits all our customers. While Ameren Missouri has not yet modeled other potential benefits from efficient electrification, such as reduced carbon emissions from the transportation sector, we are confident that such benefits exist.

10.4 Preferred Plan Selection[9]

In selecting its Preferred Resource Plan, Ameren Missouri decision makers[10] relied on the planning objectives discussed earlier in this chapter and the considerations reflected in the scoring and comparison of DSM portfolios highlighted in the previous section. As was noted previously, the Top Tier plans identified through scoring include the RAP DSM portfolio, early retirement of coal-fired generation and a significant expansion of renewables. These define the key options for consideration in the selection of the preferred resource plan.

Figure 10.7 Comparison of Top Tier Plans



To facilitate the selection of the preferred plan, an additional assessment was made of the top tier resource plans. Figure 10.7 presents the comparison of the top tier plans based on further assessment of Ameren Missouri's planning objectives. By isolating the top tier plans, we can assess their relative advantages with more specificity. This also means that the ratings applied in the scorecard in Table 10.4 does not constrain this comparison. Following is a description of the consideration of each planning objective for the top tier plans.

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[9] 20 CSR 4240-22.010(2)(C); 20 CSR 4240-22.010(2)(C)1; 20 CSR 4240-22.010(2)(C)2 20 CSR 4240-22.010(2)(C)3; 20 CSR 4240-22.060(3)(A)5; 20 CSR 4240-22.070(1); 20 CSR 4240-22.070(1)(A) through (D)

[10] Names, titles and roles of decision makers are provided in Appendix B.

PVRR – Table 10.7 summarizes the results for the top tier plans, including PVRR. Based on these results, Plans P, V and Y were rated as having a relative advantage compared to the other plans. Plans M, N, and O were rated as having no relative advantage. Plan Q was rated as having a significant relative disadvantage because its PVRR result is over $400 million higher than the next most costly plan among the top tier plans.

Table 10.7 Results for Top Tier Plans[11]

Plan Description		PVRR ($MM)	Lev. Rate (c/kwh)	2030 Rate (c/kwh)
N	Sioux Early Retirement	66,425	15.82	15.13
P	Sioux-Rush Early Retirement	66,412	15.82	15.10
V	Sioux-Rush Early Retirement - Renewable Subscription	66,391	15.81	15.08
O	Rush Early Retirement	66,425	15.82	15.82
Q	Sioux-Rush Early Retirement - No CCs	66,942	15.94	15.23
M	Labadie Early Retirement - 2 units	66,507	15.84	15.67
Y	Sioux-Rush Early Retirement - Grain Belt Express	66,408	15.81	14.99

Customer Satisfaction – Plans P, V, and Y were judged to have a relative advantage due to their relative low rate impacts in both the near term (through 2030) and the long term, the advancement of retirements for multiple coal energy centers, and in the case of Plans V and Y, the expansion of customer renewable programs. Plan Q was judged to have a relative disadvantage due to long-term rate impacts and uncertainty regarding the reliability of the portfolio given its increased reliance on wind, solar and battery storage. The other plans were judged to have no relative advantage or disadvantage.

Financial and Regulatory – Plans P, V, and M were judged to have a relative advantage given the acceleration of retirement for multiple coal-fired energy centers. Plans N and O were judged to have no relative advantage or disadvantage because they include accelerated retirement of one coal-fired energy center. Plan Y was also judged to have no relative advantage or disadvantage – while it does include accelerated retirement of multiple coal-fired energy centers, risks associated with the regulatory approval process offset that advantage. Plan Q was judged to have a relative disadvantage based on the potential challenges of regulatory approvals and risks of a potential need for other resources to ensure reliability.

Portfolio Transition – Plans V, Q, and Y were judged to have a relative advantage given the comparative acceleration of renewable resource additions. All other plans were judged to have no relative advantage or disadvantage.

Economic Development – Plans V, Q, and Y were judged to have a relative advantage based on the accelerated deployment of renewable resources. Plans O and M were

[11] Plans include RAP-level DSM unless otherwise noted.

judged to have a relative disadvantage based on the earlier elimination of jobs at coal-fired energy centers. Plans N and P were judged to have no relative advantage or disadvantage.

Along with these objectives, we have considered the costs and benefits of the specific components that define an integrated resource plan. These include consideration of DSM programs, the addition of renewable energy resources, and the retirement of existing generation resources, particularly coal-fired generation. These components define the transformation of our portfolio that we believe best achieves and balances the objectives discussed above.

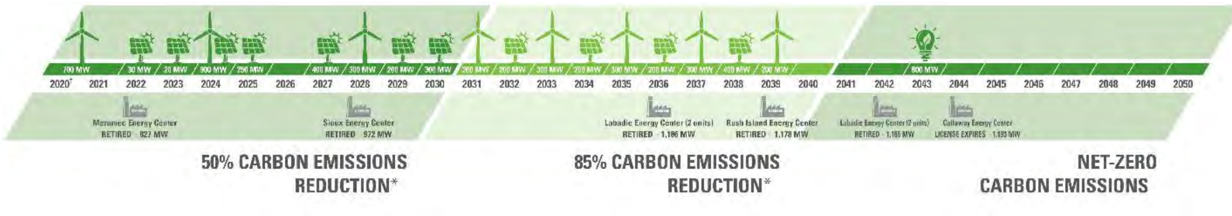
DSM Portfolio – Including RAP DSM in our preferred resource plan allows us to continue to offer highly cost-effective programs to customers at a reasonably aggressive level of annual spending while also allowing the potential for increased savings if our experience and expectations indicate they could be achieved in a cost-effective manner. Identifying such opportunities will depend on the results of program implementation and periodic updates of our market research.

Renewable Resources – One of Ameren Missouri's planning objectives is to transition our generation portfolio to one that is cleaner and more fuel diverse in a responsible fashion. For the reasons set forth in section 10.3.2, we believe that the appropriate course of action is to begin the transition to greater levels of renewable energy today. Doing so will address both near-term and long-term risks and ensure flexibility in the face of uncertainty and changing conditions. These could include changes in environmental regulations, coal generation economics, and changes in policy that require or can be satisfied by the addition of renewable energy resources.

Coal Retirements – We evaluated various alternatives for earlier retirement of coal-fired generation. Advancing the retirement of Sioux Energy Center to 2028 and Rush Island Energy Center to 2039 yields benefits in terms of customer costs while also addressing risks associated with potential policy changes and changes in market conditions that affect coal generation economics. Making these changes now will ensure we can address recovery of the cost of these investments in way that is consistent with our objective to ensure affordability. These changes also help to accelerate our transition to a cleaner generation portfolio and allow us to realize even greater reductions in CO_2 emissions than those we announced with the filing of our 2017 IRP. At the same time, the managed drawdown of our coal-fired fleet helps us to ensure reliability of supply to our customers as we significantly expand our renewable portfolio.

Based on our consideration of all these objectives and factors and consideration of the results of our thorough analysis of a wide range of options, we have selected Plan V as our preferred resource plan. Figure 10.8 shows the major resource additions and retirements defined by Plan V.

Figure 10.8 Preferred Resource Plan



* Reductions are presented as of the end of the period indicated and based off of 2005 levels. Wind and solar additions, energy center retirements by end of indicated year.
† Projects expected to be substantially complete in 2020, fully in service in early 2021.

10.5 Contingency Planning[12]

Because any assumptions about the future are subject to change, we must be prepared for changing circumstances by evaluating such potential circumstances and options for providing safe, reliable, cost-effective and environmentally responsible service to our customers. We have identified several cases which could significantly impact the performance of our preferred resource plan.

10.5.1 DSM Cost Recovery and Incentives

As stated previously, MEEIA provides for cost recovery and incentives for utility-sponsored demand-side programs to align utility incentives with helping customers to use energy more efficiently. In early 2019, the Missouri Public Service Commission ("Commission") approved our third cycle of MEEIA programs and supporting cost recovery, and incentives. Our preferred resource plan is based on the expectation that supporting cost recovery and incentives will continue to be approved in the future. If such alignment is not achieved, it may be necessary for Ameren Missouri to change its preferred resource plan. We have therefore included a contingency plan, Plan W, for this circumstance.

Ameren Missouri expects to file a request with the Commission for approval of a new portfolio of demand-side programs that would become effective starting in 2023. Costs are expected to be recovered through our Rider Energy Efficiency Investment Charge ("Rider EEIC"). In our request, we will also seek recovery of costs associated with the so-called "throughput disincentive."

In addition to recovery of program costs and addressing the throughput disincentive, MEEIA also mandates that utilities be provided with timely earnings opportunities that serve to make investments in demand-side resources equivalent to investments in supply-side resources. Ameren Missouri will seek such incentives in its upcoming MEEIA filing.

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12 20 CSR 4240-22.070(4)

Schedule MM-S12

10.5.2 Renewable Subscription Program

Our preferred plan includes approval of a new Renewable Subscription Program to offer commercial and industrial customers and communities the means by which they can source more of their electric energy needs from renewable resources. Should this program not be approved by the MPSC, we would plan to pursue a renewable resource expansion without that program. We have included a contingency plan, Plan P, for this circumstance.

10.5.3 Environmental Retrofits

We evaluated several potential options for addressing the need for environmental retrofits. While the need for such retrofits is uncertain, and while the alternative resource plans we have evaluated do not cover all potential outcomes, they do provide some insight into the relative benefits of different approaches to address the potential need. ***<u>**Plans R, S, T, and U reflect specific potential outcomes and demonstrate the relative costs of retrofit vs. retirement. The ultimate disposition of the current litigation will require careful consideration based on the specific details of the Appellate Court's judgment**</u>.***

10.6 Resource Acquisition Strategy[13]

Our resource acquisition strategy has three main components. First is the Preferred Resource Plan which is discussed in more detail in Section 10.6.1. The second component of the resource acquisition strategy is contingency planning. Figure 10.9 shows the Preferred Resource Plan as well as contingency options and the events that could lead to a change in our preferred plan. The final component of the resource acquisition strategy is the implementation plan which includes details of major actions over the next three years, 2021-2023.

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[13] 20 CSR 4240-22.070(1); 20 CSR 4240-22.070(1)(A) through (D); 20 CSR 4240-22.070(2); 20 CSR 4240-22.070(4); 20 CSR 4240-22.070(4)(A) through (C); 20 CSR 4240-22.070(7); 20 CSR 4240-22.070(7)(A) through (C)

Schedule MM-S12

Figure 10.9 Preferred Plan and Contingency Plans

10.6.1 Preferred Plan

As discussed in Section 10.3, our Preferred Resource Plan includes RAP energy efficiency and demand response programs, 5,400 MW of wind and solar generation by 2040, retirement of all Meramec units by the end of 2022, retirement of Sioux Energy Center at the end of 2028, retirement of two of the four units at Labadie Energy Center at the end of 2036, and retirement of Rush Island Energy Center at the end of 2039.

Demand Side Resources

The preferred plan includes RAP energy efficiency, distributed energy resource and demand response programs. Energy efficiency programs under our current MEEIA plan run through 2022. Program spending for the 20-year planning horizon (after the current cycle of MEEIA programs) is over $2.5 billion. Cumulative peak demand reductions exceeding 1,900 MW by 2040 (not including planning reserve margin), and cumulative energy savings (at the customer meter) total 50 million MWh.

Renewables

We are embarking on a transformation of our generation portfolio, and one of the key components of that transition is the significant expansion of renewable wind and solar generation resources, with a total of 5,400 MW of wind and solar generation by 2040 and 3,100 MW by 2030. In contrast to our 2017 IRP, these resource additions are not driven by the requirements of the Missouri RES. Instead, they reflect an understanding that these renewable energy resources will be necessary to ensure the energy supply that our

Schedule MM-S12

customers need and do so in a way that is environmentally responsible and ensures affordability for our customers. Included in these renewables are planned solar generation paired with energy storage (solar plus storage) that can provide generation-related benefits together with distribution system reliability benefits, as also discussed in Chapter 7.

Supply-Side Resources

The Preferred Resource Plan calls for the retirement of all Meramec units by the end of 2022, retirement of Sioux Energy Center by the end of 2028, retirement of two of the four units at Labadie Energy Center at the end of 2036, and retirement of the Rush Island Energy Center at the end of 2039.

10.6.2 Contingency Plans[14]

Figure 10.5 presents our key contingency options. In the event that Ameren Missouri's interests are not aligned with helping customers use energy more efficiently, as required by MEEIA, we have included a contingency plan that reflects a discontinuation of demand side programs after our current MEEIA cycle programs expire at the end of 2022. The contingency plan therefore also includes the installation of an ~800 MW combined cycle facility to be in service in 2037 and another ~1,600 MW of combined cycle generation in 2040. In the event our proposed Renewable Subscription program is not approved, we have included a contingency plan that reflects a renewable resource expansion without the program.

10.1 Expected Value of Better Information Analysis[15]

After selecting the preferred plan, Ameren Missouri conducted an expected value of better information ("EVBI") analysis to assess the performance of its preferred resource plan under the range of values defined for the critical uncertain factors and to inform its on-going research and implementation activities. Table 10.8 displays the results of the EVBI analysis as measured by PVRR. Under most critical uncertain factor values, the preferred plan results in the lowest PVRR. Plans A, B, L, and O result in the lowest PVRR under certain values for critical uncertain factors. Only for no CO_2 prices, does the PVRR difference from the preferred plan exceed \$100 million, or less than 0.2% of total revenue requirements.

[14] 20 CSR 4240-22.070(4)
[15] 20 CSR 4240-22.070(3)

Schedule MM-S12

***Table 10.8 EVBI Analysis Results

	Alternative Resource Plans	PVRR Without Better Info	Carbon Price			Natural Gas Price			Load Growth			DSM		
			None	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
A	RAP DSM - RES Compliance	66,647	63,769	65,316	68,111	66,000	66,071	66,186	65,051	66,174	66,735	65,781	66,043	66,494
B	Renewable Expansion	66,410	64,191	65,363	67,404	66,068	65,876	65,580	64,891	66,014	66,575	65,621	65,883	66,333
C	No New DSM -CCs	68,395	65,906	67,207	69,466	67,879	67,786	67,674	66,791	67,915	68,476	67,802	67,802	67,802
D	No New DSM - All Solar	67,143	65,026	66,159	68,085	66,873	66,633	66,244	65,652	66,775	67,336	66,663	66,663	66,663
E	No New DSM - Pumped Hydro	68,922	66,403	67,713	70,046	68,392	68,321	68,233	67,322	68,445	69,006	68,333	68,333	68,333
F	No New DSM - AP1000	76,139	73,717	74,882	76,833	75,579	75,360	75,028	74,379	75,503	76,063	75,390	75,390	75,390
G	No New DSM - Simple Cycles	68,402	65,923	67,220	69,503	67,898	67,810	67,698	66,814	67,937	68,498	67,825	67,825	67,825
H	MAP DSM - Renewable Expansion	67,197	65,133	66,236	68,145	66,944	66,707	66,338	65,728	66,851	67,412	66,166	66,667	67,885
I	MAP DSM - RES Compliance	67,238	64,471	65,964	68,666	66,657	66,691	66,739	65,675	66,799	67,359	66,113	66,614	67,832
J	DOPE1 DSM	67,167	64,844	66,075	68,208	66,772	66,615	66,379	65,626	66,749	67,310	66,430	66,594	67,185
K	DOPE2 DSM	67,094	64,745	65,983	68,142	66,680	66,532	66,311	65,542	66,665	67,226	66,379	66,518	67,008
L	Labadie Early Retirement - 4 units	66,657	65,025	65,809	67,180	66,159	66,172	66,202	65,161	66,284	66,845	65,891	66,153	66,603
M	Labadie Early Retirement - 2 units	66,507	64,611	65,560	67,228	66,063	65,992	65,882	64,991	66,114	66,675	65,721	65,982	66,433
N	Sioux Early Retirement	66,425	64,274	65,392	67,370	66,062	65,894	65,637	64,906	66,029	66,590	65,636	65,898	66,348
O	Rush Early Retirement	66,425	64,569	65,450	67,183	65,989	65,911	65,815	64,914	66,037	66,598	65,644	65,906	66,356
P	Sioux-Rush Early Retirement	66,412	64,382	65,401	67,294	66,027	65,890	65,698	64,900	66,023	66,584	65,630	65,892	66,342
Q	Sioux-Rush Early Retirement - No CCs	66,942	65,256	66,082	67,575	66,720	66,441	66,029	65,470	66,593	67,154	66,200	66,462	66,912
R	Rush Early Retirement 2	66,470	64,663	65,506	67,188	66,000	65,961	65,919	64,957	66,081	66,642	65,687	65,949	66,400
S	Rush FGD	67,011	64,830	65,983	67,981	66,666	66,485	66,204	65,498	66,622	67,183	66,228	66,490	66,941
T	Rush FGD - Labadie DSI	68,582	66,504	67,647	69,412	68,214	68,080	67,836	67,083	68,206	68,767	67,813	68,075	68,525
U	Rush Retirement - Labadie DSI	68,040	66,337	67,171	68,619	67,548	67,555	67,551	66,542	67,665	68,226	67,272	67,534	67,984
V	Sioux-Rush Early Retirement - Subscription Renewables	66,391	64,393	65,393	67,253	66,022	65,871	65,661	64,883	66,006	66,567	65,613	65,875	66,326
W	Sioux-Rush Early Retire - No DSM - Renewable Subscription	68,549	66,315	67,429	69,478	68,016	67,965	67,948	66,968	68,092	68,652	67,979	67,979	67,979
	Minimum PVRR among plans		63,769	65,316	67,180	65,989	65,871	65,580	64,883	66,006	66,567	65,613	65,875	66,326
	Plan with Minimum PVRR		A	A	L	O	V	B	V	V	V	V	V	V
	Subjective Probability		15%	50%	35%	32%	56%	12%	20%	60%	20%	10%	80%	10%
	Expected Value of Better Info		624	77	73	33	0	82	0	0	0	0	0	0

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10.6.3 Implementation Plan[16]

As mentioned earlier, the implementation plan outlines the major activities to be completed during the next three years, 2021-2023. Below is a description of those major activities.

Demand-Side Resources Implementation

Ameren Missouri continues to implement its third cycle of approved MEEIA programs, which run through 2022. Ameren Missouri expects to file a request with the Commission in 2021 for approval of demand-side programs and associated cost recovery and incentive mechanisms to be implemented beginning in 2023. Such a proposal will be consistent with the preferred resource plan which includes the RAP portfolio.

Supply-Side Contingency

While the preferred resource plan does not include new combined cycle generation, our contingency planning indicates a need to prepare for the possibility of needing new combined cycle generation during the planning horizon. This may be as a result of triggering a contingency option related to DSM cost recovery and incentives or to address increases in customer demand associated with electrification. To prepare for such contingency options, Ameren Missouri will continue evaluating potential sites for new combined cycle generation. At the same time we will monitor and support efforts to develop dispatchable zero-carbon resources consistent with our goal of achieving Net Zero CO_2 emissions by 2050.

Renewables[17]

Our preferred resource plan includes the addition 1,200 MW of new wind and solar generation by the end of 2025, some of which will be used to serve customers under our planned Renewable Subscription program, and some of which will consist of solar plus storage projects as also addressed in Chapter 7. Ameren Missouri will be engaging in activities during the implementation period to support the development of the new wind and solar generation, including bid solicitation, contractor selection, applying for certificates of convenience and necessity, and construction. A request for proposal process for wind and solar resources is already underway.

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[16] 20 CSR 4240-22.070(6); 20 CSR 4240-22.070(6)(A) through (D)
[17] EO-2020-0047 1.K

Schedule MM-S12

Meramec and Sioux

Ameren Missouri will be taking steps to retire the units at Meramec Energy Center by the end of 2022 and Sioux Energy Center by the end of 2028. This includes the construction of any necessary transmission infrastructure and required notifications to MISO.

Competitive Procurement Policies[18]

Ameren Missouri assigns a Project Manager to lead the activities necessary to ensure the successful completion of its acquisition and development of supply-side resources. In general, a project team comprised of a Project Manager and various lead engineers will identify all items to be procured and will coordinate with the Strategic Sourcing and Purchasing departments within Ameren to ensure proper contract structures are considered and used for each procurement activity. A Contract Development Team ("CDT") is assembled and assists in collecting material and labor estimates based on the overall project design. Strategic Sourcing, CDT and the project team work to set up a number of components as Ameren stock items that are the basis for ordering materials. A detailed procurement matrix is developed to identify the major purchases that are anticipated to be required as part of the project. Projects make use of stock items where appropriate. Where material has not been established as a stock item, the CDT determines potential vendors, collects quotes, and scores the potential vendor to make the best selection. Ameren Missouri will be following Ameren's Project Oversight Process, which is provided in Appendix C, for monitoring the progress of projects that fulfill its Preferred Resource Plan.[19]

10.6.4 Monitoring Critical Uncertain Factors[20]

Ameren Missouri will be monitoring the critical uncertain factors that would help determine whether the Preferred Resource Plan is still valid and whether contingency options should be pursued. Below is a description of how Company decision makers will be monitoring the factors most relevant to future resource decisions.

Climate Policy

Ameren Missouri senior management and the Environmental Services Group will continue to monitor and evaluate developments on efforts to regulate greenhouse gas emissions as well as state and industry efforts aimed at reducing greenhouse gas emissions.

[18] 20 CSR 4240-22.070(6)(E)
[19] 20 CSR 4240-22.070(6)(G)
[20] 20 CSR 4240-22.070(6)(F)

Schedule MM-S12

Natural Gas Prices

Ameren Missouri evaluates natural gas prices at least annually, included as part of its IRP annual update process.

Demand-Side Resource Cost

Ameren Missouri will continue to evaluate the cost-effectiveness of its DSM programs internally and through the evaluation process. Any major deviations from planning assumptions like participation rates, technology costs, and customer opt-out will be communicated to Ameren Missouri senior management.

In addition to monitoring the critical uncertain factors, we will continue to monitor trends in energy and environmental policy, technology development, and resource cost trends, among other factors. We will also continue to monitor trends that affect customer demand including electrification, adoption of customer-owned DER, and efficiency trends, as well as underlying economic trends like population growth and economic growth.

10.7 Compliance References

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Schedule MM-S13

Agenda

Transmission & Distribution Analysis

Transmission Planning

- Combination of Ameren Missouri "bottom-up" reliability analysis and MISO "top-down" economic and public policy planning.
- Culminates in the annual MISO Transmission Expansion Plan (MTEP), which is approved by the independent MISO Board of Directors.
  - In 2022 MISO BOD approved the LRTP tranche 1 projects as part of MTEP21
    - MISO LRTP Tranche 2 efforts continue
  - Significant rise in wind/ solar generator interconnections
- Ameren Missouri's Focus:
  - Providing continued safe and reliable service to customers.
  - Allocates its limited capital resources on generation, transmission, and distribution projects needed to meet this obligation.
    - Improvements to its aging infrastructure
    - Improvements to address increasing or shifting customer load
    - Mandated transmission upgrades (e.g., for NERC compliance)

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Transmission & Distribution Analysis

Transmission System- Use and Application of Advanced Technologies

- Meramec STATCOM:
  - First Missouri dynamic VAR device in-service 2022
    - Produces steady state VARS for voltage control
    - Produces dynamic VARs for transient voltage recovery
    - Actively eliminates harmonics from the system
    - Injecting negative sequence current for relay polarization
- Variable Reactor
  - Allows for large shunt reactors to be used for voltage control, but with a small voltage bump.
  - Dynamic in nature, can change real-time with the grid
- Modern Substation Design:
  - Battery monitoring to eliminate single points of failure and enhance compliance
  - Using fiber and IEC61850 to reduce the number of panels, reducing wiring, eliminate control switches and lockouts and reducing the overall control building size
  - Incorporating enhanced EMP protection

Transmission & Distribution Analysis

Transmission System- Use and Application of Advanced Technologies

- Substation Scanning
  - Allows for virtual field visits, enhancing scoping and safety
  - Drafting using 3D drafting software and smart wiring

- Artificial Intelligence:
  - Analyzes photos from Unmanned Aerial Systems devices for woodpecker damage
  - Presently learning to analyze other problems such as:
    - Structure damage
    - Bird nests
    - Objects in the right of way

Distribution Overview

Smart Energy Plan

Designed to drive customer benefits, modernize the electric grid and ensure stable and predictable rates

Senate Bill 745, passed in 2022, is an expansion and extension of the successful Senate Bill 564 to continue helping customers. This plan continues the construction of smart energy infrastructure that will drive job creation and economic development across Missouri through at least 2028.

Key Elements of the Smart Energy Plan

- $9.9B in electric investments from 2023 to 2027
  - Requires 25% of annual investment be in Grid Modernization
  - Allows up to 6% of capital for smart meter program
  - Encourages renewable energy by providing up to $28M in solar rebates to customers, and requiring a minimum $14M investment in Ameren Missouri owned solar (complete)
- Supports economic development and provides job creation

SEP Capital Project Evaluation: Distribution

- Ameren Missouri continuously assesses the feasibility and cost effectiveness of potential upgrade and modernization projects.
- Due to the age of our grid and recent trends in localized load growth, the majority of approved projects focus on system reliability, modernization, and resiliency.
- In 2022, Ameren Missouri with key stakeholders developed project evaluation methodologies and frameworks to justify their six Energy Delivery SEP categories of investments.
- A centralized Distribution Planning team annually assess load growth and shift trends to ensure grid upgrades meet the needs of customers today and into the future.

Distribution Overview

Distribution Grid Modernization Highlights

Investment Category	Category Plan (2019-2028)	Expected Customer and Operational Benefits
Smart Meter Program (SMP)	Upgrade approximately 1.2M electric meters by 2024; these meters allow us to offer a suite of expanded rate options that give customers the power to choose a rate that fits their lifestyle. In addition, they provide two-way communication that can more quickly pinpoint and restore outages.	Provide customers more precise energy usage data and quicker restoration after outages.
Substations	175+ new or upgraded substations; a foundational asset in supplying energy to customers, targeting those hat are aged, operationally challenged, or capacity limited. Distribution substations with critical components beyond their expected life serve over 700k of our ~1.2M customers.	Continue to provide reliable service through reductions in the frequency and duration of outages and improved operating flexibility.
Underground Cable Upgrades	Upgrade 800 miles of existing aging underground cables with modern cables encased by protective conduit to safely connect our customers to the key "last mile" segment of the grid. Over 2,900 miles of our underground system already exceed their expected life.	Reduction in the frequency and duration of outages.
System Hardening	Upgrade 500 miles of the sub-transmission system, including strengthened wood or composite poles, upgraded fiberglass cross-arms, and new conductor. Around 36% of our sub-transmission circuits have a majority of assets beyond their expected life.	Hardening to better withstand the impact of severe weather events; reductions in the frequency and duration of outages.
Private LTE (PLTE)	Our plan is initially to deploy private Long-Term Evolution ("PLTE") transmitters to approximately 50 sites in he greater St. Louis metropolitan area to provide uniform PLTE coverage.	This expansion will provide a uniform, private cellular network to operate additional smart devices and provide better real- ime system operational information.
Distribution Automation	Deploy over 2,350 smart and automated switching devices to reroute power until a line is fixed, improving reliability.	DA switches and control systems drive reliability improvement up to 40% for the circuits on which they are installed.

Distribution Overview

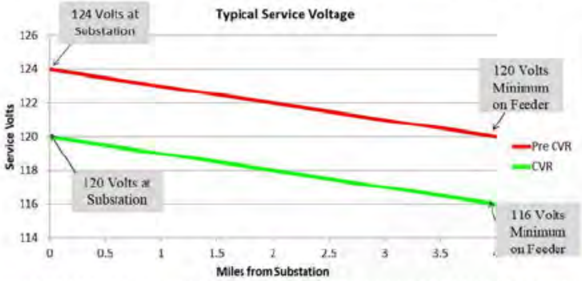
EPRI (Electric Power Research Institute) is currently studying the costs and benefits for Ameren Missouri to employ Conservation Voltage Reduction (CVR)

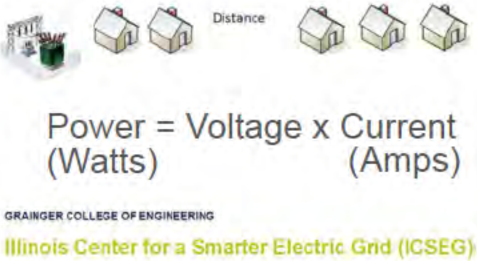
Conservation Voltage Reduction (CVR)

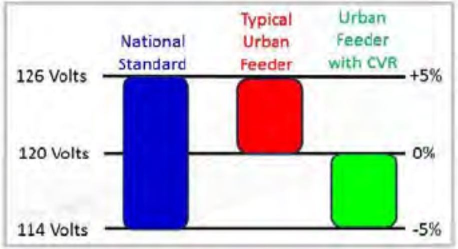
- Process of operating near the lower voltage threshold at the customer delivery point.
- Can be used as a means to achieve energy savings, if system attributes are favorable.

EPRI will estimate possible cost and savings potential of CVR for Ameren Missouri

- Evaluate the load make up of AMO customers
- Analyze possible voltage control equipment/methods
- Study to be completed in late Summer/early Fall '23







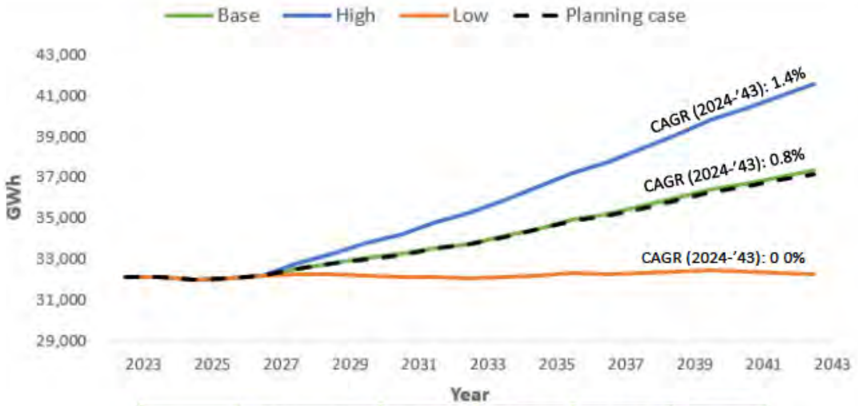
Load Forecast Scenarios and High-Level Summary

Ameren MISSOURI

- The forecast scenarios do not include saving potentials from *future* Ameren sponsored Energy Efficiency (EE) programs
- *Without* considering higher potentials of customer owned distributed energy resources and efficient electrification, Ameren's system load is expected to grow at annual compound growth rate (CAGR) of 0.2% between 2024 and 2043*
- The Planning case scenario forecasts Ameren's system load to grow at a CAGR of 0.8% between 2024 and 2043
  - The Base case scenario forecasts CAGR of 0.8% between 2024 and 2043
  - The High load growth scenario forecasts CAGR of 1.4% between 2024 and 2043
  - The Low load growth scenario forecasts CAGR of 0.0% between 2024 and 2043
- Distributed Energy Resources (DER), Energy Efficiency and Efficient Electrification will have significant impacts on load growth
  - PV and storage, driven largely by declining technology costs, can put between approx. 350MWs (low solar adoption scenario) and approx. 1,400 MWs (High solar adoption scenario) of demand at risk by 2043.
    - The Base case scenario assumes approx. 700 MWs of solar capacity by 2043
    - Impacts from MEEIA 2 and 3 Net impact from approved MEEIA programs is ~1,966 GWh in 2043
  - Higher potential from efficient electrification helps in mitigating demand losses from EE and DER programs. Ameren Missouri's base case load forecast scenario projects approx. ~4,868 GWh of additional energy in 2043.
    - *High adoption case*: Approx. 8,426 GWh of additional sales in 2043
    - *Low adoption case:* Approx. 963 GWh of additional sales in 2043

**No additional Solar and electrification beyond 2027*

Energy Forecast Scenarios



	Scenario	Res	Com	Ind	System
CAGR (2024-43)	Base	1.0%	0.4%	1.5%	0.8%
	High	1.9%	0.7%	1.6%	1.4%
	Low	0.0%	-0.1%	0.4%	0.0%
	Planning Case	1.0%	0.4%	1.3%	0.8%

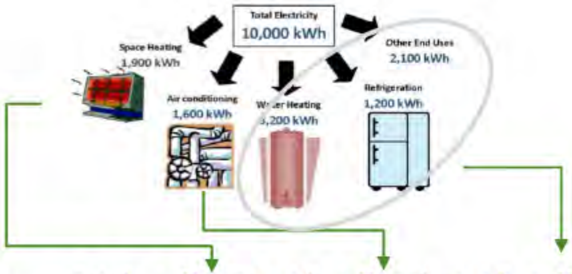
Key Insights

- **Base case** scenario reduces sales by 700 GWh due to DER (solar), and adds 4,868 GWh due to Efficient Electrification by 2043. CAGR between 2024 and 2043 is 0.8%
- **High case** scenario reduces sales by 350 GWh due to DER, and adds 8,426 GWh of energy from Efficient Electrification by 2043. CAGR between 2024 and 2043 is 1.4%
- **Low case** scenario reduces sales by 1,400 GWh due to DER, and adds 963 GWh of energy from Efficient Electrification by 2043. CAGR between 2024 and 2043 is 0.0%

Reference EPRI Study

Forecasts are developed using either Statistically Adjusted End-use (SAE) or Econometric models

SAE Modeling Framework



$$AvgUse_{y,m} = a + b_h * XHeat_m + b_c * XCool_m + + b_o * XOther_m + e_m$$

- *Market saturation of end uses such as AC, Heating, and Others (refrigeration/cook top/lighting etc)*
- *Thermal efficiency or appliance efficiency*
- *Economic variables (Income, household size)*
- *Electricity price*
- *Heating/Cooling degree days*
- *Billing days*

Reference EIA, Itron, EPRI

Modeling Philosophy

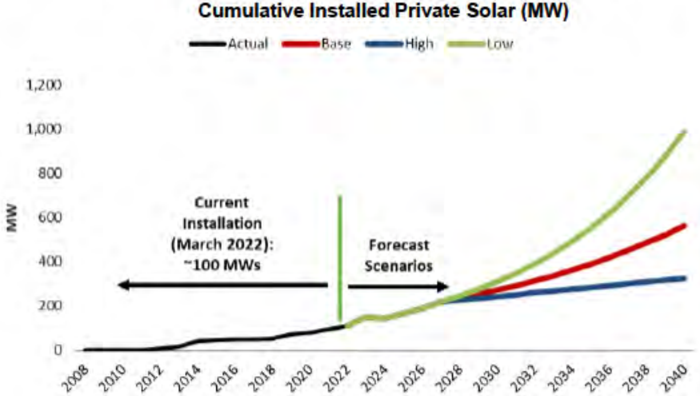
- Combines end use information to econometric approach
- SAE models are designed to disaggregate an average customer's total annual energy consumption into end uses such as (space) heating, cooling (air conditioning), water heating, refrigeration, and so on.
- Seems like linear model, but the multiplicative interactions between parameters make the models intrinsically non—linear
- Res/Com models are developed based on SAE philosophy
- Time variables such as month etc can be used, but preferred not to be used!

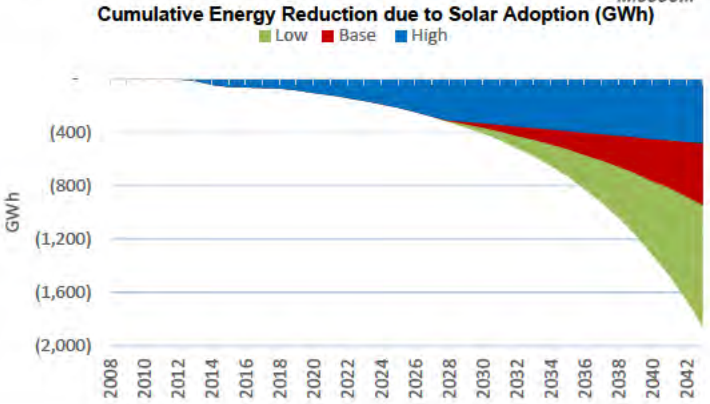
Important factors influencing scenarios are DER, Energy Efficiency, Efficient Electrification

2043 view

Reference EPRI

Customer owned PV adoption is expected to increase as the cost declines



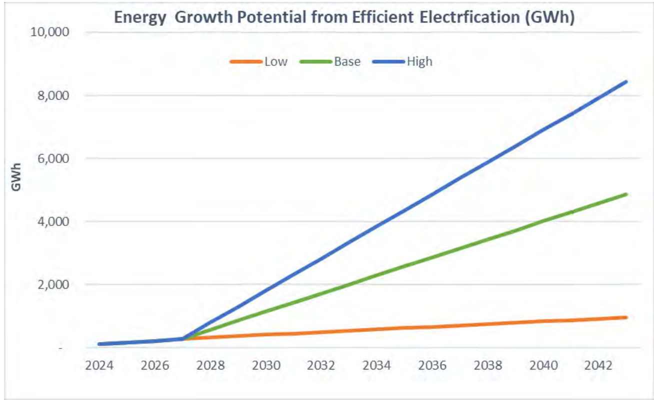


Scenario Assumptions:

- Solar PV can reduce between approx. 350 GWh (high load growth) and 1,400 GWh (low load growth) of energy by 2043
  - Base case scenario assumes approx. 700 GWh of energy reduction

Reference Internal view

Higher potential for efficient electrification will lead to load growth in all the scenarios



- Long term efficient electrification potential includes both on-road and off-road potentials based on state-wide study conducted by EPRI
- Projected increases in load from electrification were estimated using the Economy, Greenhouse Gas, and Energy Model developed and maintained by the Electric Power Research Institute (EPRI)
- Key assumption: Customers have free choice to choose the technologies – electric or non-electric that make the most sense to them
- Final electric demand and load shapes are developed taking into consideration electricity demand responses, policy changes impacting end-use energy consumption and technological improvements

Reference EPRI

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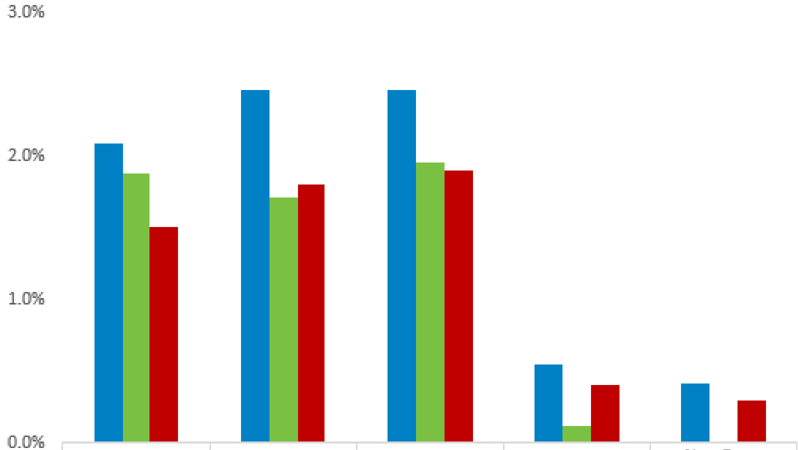
Economic Drivers



	Manuf GDP	Retail GDP	Education GDP	Households	Non-Farm Employment
USA (2024-2043)	2.1%	2.5%	2.5%	0.6%	0.4%
2023 IRP (2024-2043)	1.9%	1.7%	2.0%	0.1%	0.0%
2020 IRP (2020-2040)	1.5%	1.8%	1.9%	0.4%	0.3%

Source: Moody's Analytics, Federal Reserve

Schedule MM-S13

Residential and commercial customer counts expected to grow

While residential and commercial customer counts are expected to grow, albeit slightly below historical growth rates, Industrial customer counts will continue to decline during the planning years

Customer Growth CAGR

Year	Residential	Commercial	Industrial
2009-2022	0.3%	0.7%	-1.8%
2024-2043	0.1%	0.7%	-0.2%

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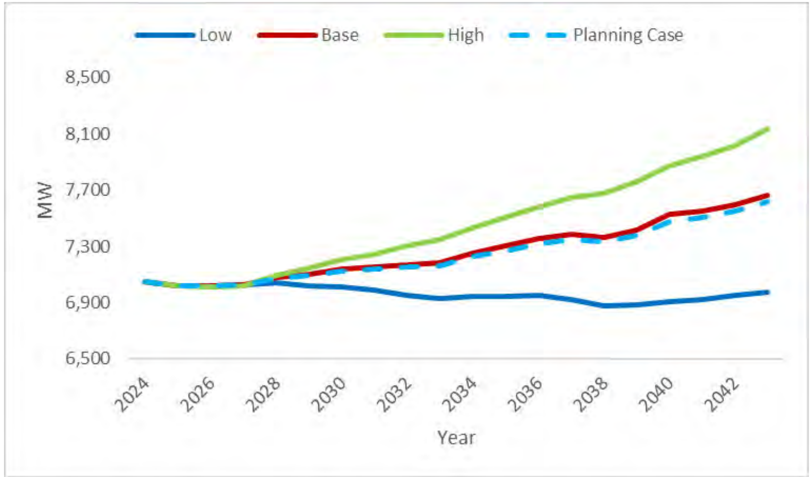
Peak Forecast Scenarios



	Base	High	Low	Planning
CAGR 2024-2033	0.2%	0.5%	-0.2%	0.2%
CAGR 2024-2043	0.4%	0.8%	-0.1%	0.4%

Schedule MM-S13

Demand-Side Resource Analysis

Energy Efficiency Market Potential Results

Cumulative Annual Percentage of Forecasted Sales in 2043				
	Ameren MPS			DOE MPS
	Residential	C&I	Combined	Combined
Maximum Achievable Potential	17%	22%	19%	25%
Realistic Achievable Potential	14%	16%	15%	16%

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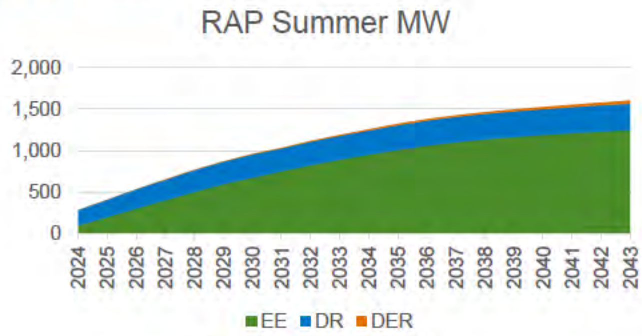
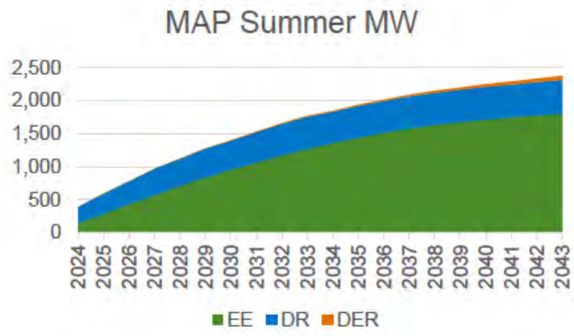
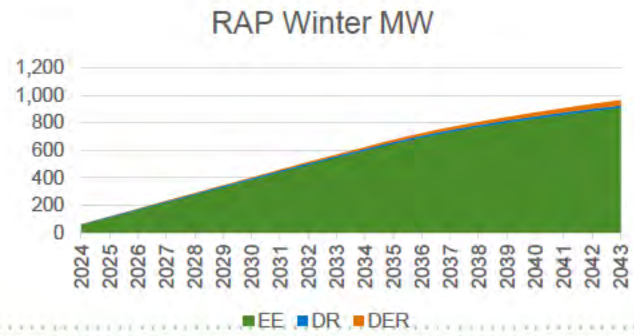
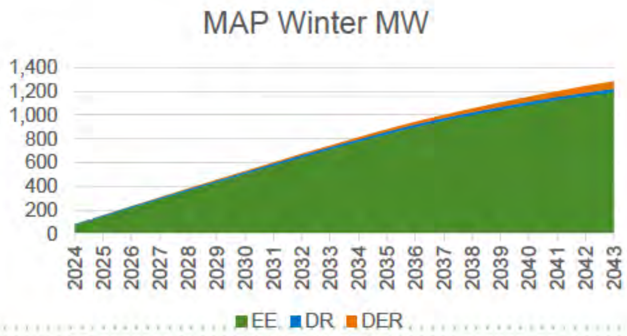
Demand-Side Resource Analysis

MW Potential





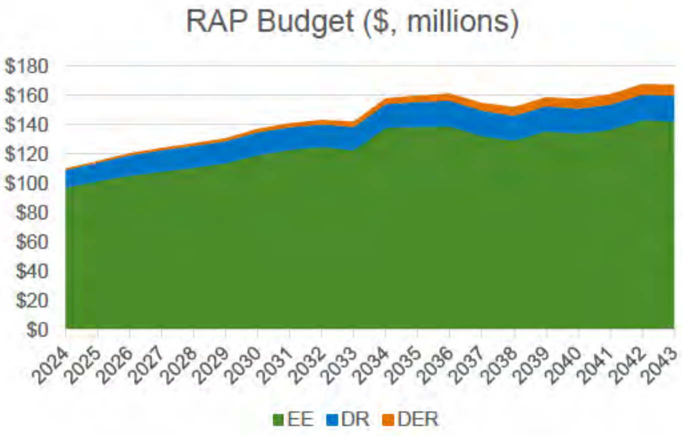


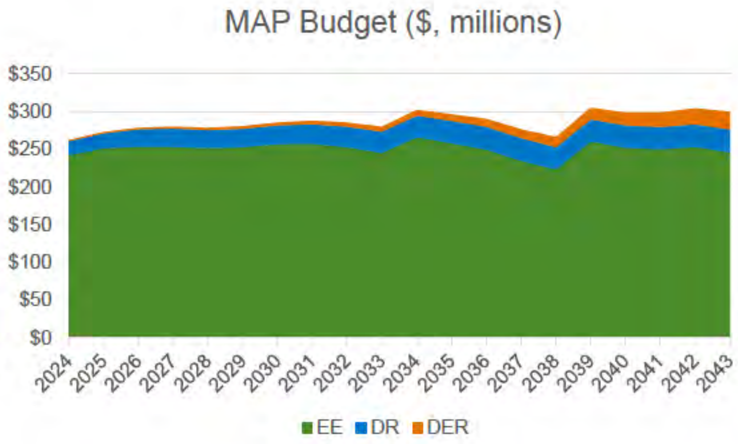


Schedule MM-S13

Demand-Side Resource Analysis

RAP and MAP Budget





Demand-Side Resource Analysis

Load Flexibility Analysis

Residential DR - Impact/Cost Comparison of Program RAP vs. Load Flex					
	2024	2025	2026	2033	2043
Base Case					
Summer MW	47	54	63	98	141
Winter MW	5	6	7	12	17
Annual Costs ($ millions)	$ 3.2	$ 3.2	$ 3.7	$ 4.7	$ 7.0
Load Flex Scenario					
Summer MW	47	54	63	98	141
Winter MW	10	24	44	67	73
Annual Costs ($ millions)	$ 3.3	$ 3.6	$ 4.6	$ 6.1	$ 8.4

Business DR - Impact/Cost Comparison of Program RAP vs. Load Flex					
	2024	2025	2026	2033	2043
Base Case					
Summer MW	125	137	152	173	158
Winter MW	0	0	0	0	0
Annual Costs ($ millions)	$ 8.9	$ 9.4	$ 10.4	$ 11.3	$ 10.5
Load Flex Scenario					
Summer MW	125	137	152	173	158
Winter MW	113	122	132	150	138
Annual Costs ($ millions)	$ 14.3	$ 15.2	$ 16.7	$ 18.4	$ 17.0

- Residential and business demand response demonstrated the largest potential to add incremental winter MW savings at the lowest cost when compared to other program types
- Residential energy efficiency has strong potential for winter MW savings due to heating season measures becoming more cost effective, however the cost to achieve these savings is more substantial
- Impacts from business energy efficiency and DER were relatively minor

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Supply-Side Resource Analysis

New Resource Characteristics

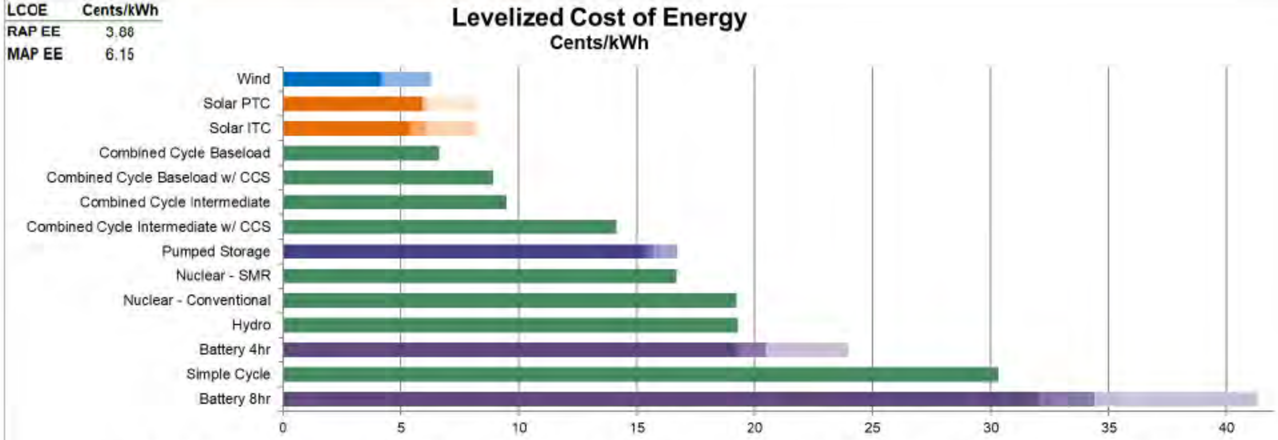
Resource Option	Net Plant Output (MW)	Overnight Capital Cost ($/kW)	First Year Fixed O&M Cost ($/kW)	First Year Variable O&M Cost ($/MWh)	Assumed Annual Capacity Factor (%)	Heat Rate (Btu/kWh)
Wind	-	$1,979	$36	-	42%	N/A
Solar	-	$1,925	$14	-	26%	N/A
CC	1,200	$1,115	$62	$2.67	40% / 80%	6,148
CC with 98.5% CCS	1,135	$2,096	$107	$4.11	40% / 80%	7,138
SC	230	$885	$8	$5.22	5%	9,895
Nuclear (Conventional)	1,100	$9,859	$151	$3.64	94%	10,443
Nuclear (SMR)	864	$8,183	$122	$3.86	94%	11,991
Hydro	50	$5,586	$99	-	40%	N/A
Pumped Storage	600	$1,891	$4	$3.63	25%	N/A
Battery (4 hour)	-	$1,717	$33	-	17%	N/A
Battery (8 hour)	-	$3,373	$50	-	17%	N/A

Transmission interconnection costs not added yet except for renewables.

Supply-Side Resource Analysis

New Resource Levelized Cost of Energy

LCOE	Cents/kWh
RAP EE	3.88
MAP EE	6.15



Note: Wind costs are shown with and without PTC. Solar costs are shown with (including 10% adder) and without PTC, and 40%, 30% and no ITC (assuming tax credit transfer at 95% and no normalization). Battery and pumped storage costs are shown with 40%, 30% and no ITC.

Supply-Side Resource Analysis

LCOE Component Analysis

Potential Resource	Levelized Cost of Energy (¢/kWh)								
	Capital	Fixed O&M	Variable O&M	Fuel	Resource Specific Cost	CO_2	SO_2	NO_X	Total Cost
Wind[1]	5.03	1.26	0.00	--	-2.13	--	--	--	**4.16**
Solar[1]	7.42	0.80	--	--	-2.09	--	--	--	**6.14**
Combined Cycle:	1.74	1.13	0.34	2.73	--	0.65	0.00	0.02	**6.61**
Combined Cycle: with CCS	3.27	1.85	0.51	3.17	--	0.10	0.00	0.02	**8.93**
Storage: Pumped Hydro[2,3]	8.87	0.27	0.48	--	6.05	--	--	--	**15.68**
Nuclear: SMR[4]	12.07	1.95	0.51	1.99	0.19	--	--	--	**16.71**
Nuclear: AP1000[4]	14.70	2.44	0.48	1.42	0.20	--	--	--	**19.23**
Hydro	15.32	3.97	0.00	--	--	--	--	--	**19.29**
Storage: Li-Ion Battery (4h)[2,3]	13.08	2.64	0.00	--	4.76	--	--	--	**20.47**
Simple Cycle: Greenfield F Class	21.76	2.37	0.66	4.40	--	1.05	0.00	0.10	**30.34**
Storage: Li-Ion Battery (8h)[2,3]	25.69	3.96	0.00	--	4.76	--	--	--	**34.40**

1. Resource Specific Cost: Full PTC
2. Resource Specific Cost: Battery Charging/Pump Cost
3. 30% ITC
4. Resource Specific Cost : Decommissioning Fund

CTG Retirements/Oil Backup

- Four oil-fired older CTG's with a total capacity of ~220 MW
  - High average heat rate, inefficient compared to modern turbines
  - Availability of spare parts is questionable, and the leads time for obtaining spare parts is unknown.
  - The general equipment health and reliability is deteriorating
  - IRP assumption for retirements: Mexico, Moberly, Moreau, Fairgrounds - 2029
  - Detailed condition assessment to be completed before retirement
- Restoration of oil-fired backup capability at Peno Creek and Kinmundy Energy Centers
  - Nominal O&M expense (~$10 million)
- Evaluating addition of oil backup for Audrain Energy Center (~$200 million)

RES Compliance

- On February 8, 2023, Ameren Missouri was issued a CCN for the 200 MW-AC Huck Finn Solar Project.
  - Expected to come online late 2024
  - RECs from Huck Finn Solar will help replace the expiring Pioneer Prairie Wind PPA
- Ameren Missouri may have additional RES compliance needs beyond the addition of Huck Finn Solar
  - Will continue to monitor compliance position, considering resource output and system load, to determine if additional RES-specific renewables are needed
  - Will continue to ensure compliance portfolios stay within the 1% rate impact limitation in each 10-year term

AMO Key RES Compliance Resources

Facility	Resource Type	Est. Annual Output (MWh)	Eligible for 1.25x MO Adder
Keokuk	Hydroelectric	738,833 – 1,017,277	No
High Prairie REC	Wind	945,033 – 1,351,200	Yes
Atchison REC	Wind	866,400 – 1,099,600	Yes
Huck Finn	Solar	411,979 – 466,207	Yes

Environmental Assumptions
Air

- Reference Case based on:
  - Status quo operation of all energy centers
  - Compliance with certain (current) and uncertain (proposed/potential) standards
- CSAPR (Good Neighbor) 2023 Update
  - CSAPR changes will reduce NOx Ozone Season allowance allocations to Ameren EGUs beginning in the 2023 Ozone Season
    - Compliance for 2023 Ozone Season will necessitate use of existing SnCR systems at Sioux
  - Ameren Missouri currently evaluating compliance scenarios; additional control equipment (SCRs)
- MATS Rule 2023 Update
  - On April 5, 2023, EPA released a proposal to tighten certain aspects of the MATS Rule
  - Specifically of importance to Ameren Missouri are stricter fine PM requirements
  - Additional controls or compliance measures are not yet known – analyses currently underway
  - Industry comments on the proposed rule forthcoming, after detailed review

Environmental Assumptions

Water

- Reference Case based on:
  - Status quo operation of all energy centers
  - Compliance with certain (current) and uncertain (proposed / potential) standards
- Clean Water Act
  - 316(a) – Thermal Discharges
    - Reissued Labadie permit uses thermal modeling approach.
  - 316(b) – Entrainment and Impingement Of Aquatic Organisms
    - Evaluation indicates that coarse mesh screens with fish buckets and fish friendly wash and return systems are the best solution; implementation in progress at Labadie
  - Effluent Limitations Guidelines Revisions
    - Installation of wastewater treatment and dry ash handling at Labadie, Rush Island and Sioux energy centers is complete
    - ELG compliance coordinated with Coal Combustion Residual (CCR) rule compliance
    - FGD wastewater at Sioux is closed-loop with no discharge

Environmental Assumptions

Solid Waste

- Reference Case based on:
  - Status quo operation of all energy centers
  - Compliance with certain (current) and uncertain (proposed / potential) standards
- Coal Combustion Residual (CCR)
  - We have taken significant actions that are consistent with federal and state regulations
  - All CCR Rule former ash storage basins have been closed at Rush Island, Sioux, and Labadie
  - Majority of former ash storage basins at Meramec have been closed; remainder to be closed in 2023 & 2024
  - Groundwater monitoring confirms that the CCR units do not represent a risk to public health or the environment
  - Novel groundwater treatment systems in place at Rush Island & Sioux; Labadie in design phase
  - Operation of solid waste landfills at Labadie and Sioux

Environmental Assumptions

Mitigation Costs

Facility	Environmental Mitigation	Regulation	In-Service Year	Cost (incl. AFUDC) $ Million	O&M $ Million
Labadie	Landfill Cell	CCR	2033	11	-
	Traveling Screens	CWA 316	2025	24	0.5 *
	Groundwater Improvement	CWA	2025	26	1.4 α
	NOx Control	CSAPR	2025	0.3	
	SCR	CSAPR	2027	400	5.0
Labadie	Total Environmental			461	7
Rush Island	NPDES Permitting	CWA 316 (b)	2023	0.4	-
Rush Island	Total Environmental			0.4	0
Sioux	Landfill Cell Closure	CCR	2022	9	-
	Landfill Cell	CCR	2022	8	-
	Aquatic Life	CWA 316 (b)	2026	8	-
	Groundwater Improvement	CWA	2024	3	0.7 α
	NOx Control	CSAPR	2024	1	
Sioux	Total Environmental			18	0.7
TOTAL	Total Environmental			**479**	**7.6**

* One time expense in 2024

α Average annual over lifetime

Scenario Development

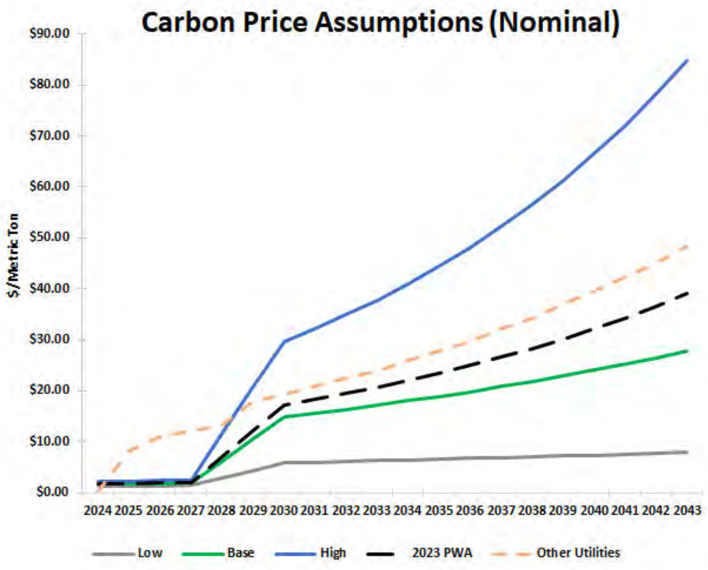
Scenario Variables

- Similar approach to past IRP filings
- Key variables that drive power prices
  - Climate/environmental policy with CO_2 prices as the driver variable
  - Natural gas prices
  - Load growth for Eastern Interconnect was evaluated during the process but was determined to have minimal impact on power prices and was therefore not included as a driver of power prices.
    - Continued price parity between coal and efficient natural gas and an expected decline in coal generation minimizes the impact of supply-demand balance changes
- Variable ranges define a probability distribution – high and low values should not be considered maximums and minimums, respectively

Scenario Development

Climate/Environmental Policy

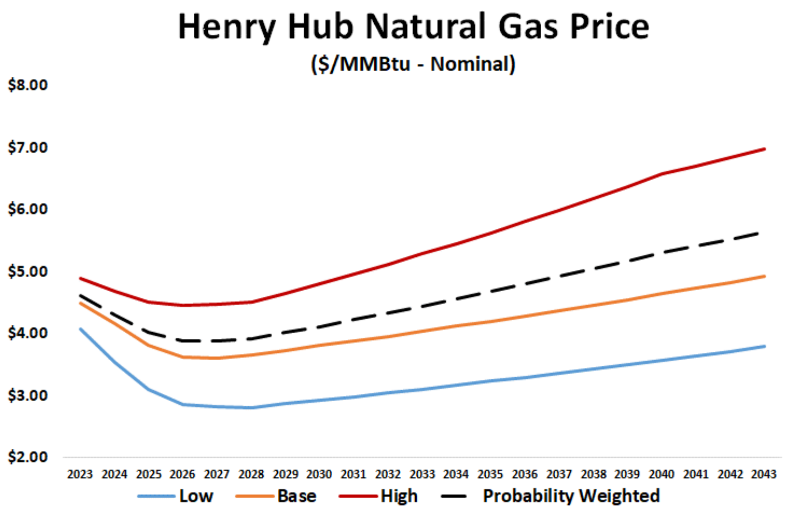
- CO_2 emission price assumptions reflect potential combinations of implicit and explicit pricing and potential implementation at various levels (e.g., federal, state, RTO)
- Key considerations:
  - Federal incentives (incl. Inflation Reduction Act)
  - Climate policy goals (e.g., Net Zero 2050)
  - Potential environmental regulation
- Sources reviewed:
  - EIA AEO 2022
  - World Bank 2022 Carbon Pricing Trends
  - World Energy Outlook 2021
  - U.S. Social Cost of Carbon
  - Other Utility IRPs (AEP, CMS, Entergy, PacifiCorp, Xcel)



Scenario Development

Natural Gas Prices

- Key considerations:
  - Future supply and production costs (dry gas, tight oil, shale gas)
  - Future demand (incl. industrial, power generation, LNG exports)
  - Potential regulation (e.g., methane leakage, fracking restrictions)
- Sources reviewed:
  - EIA 2022 AEO
  - Platt's long-range forecast
  - Recent NYMEX price curves
  - J.P. Morgan production break-even costs



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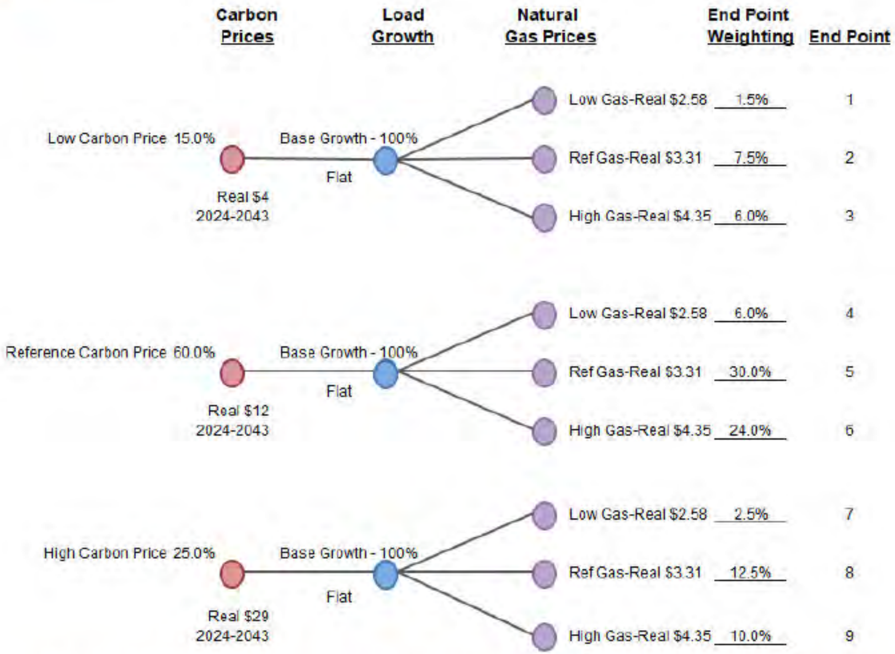
Scenario Development

Probability Tree

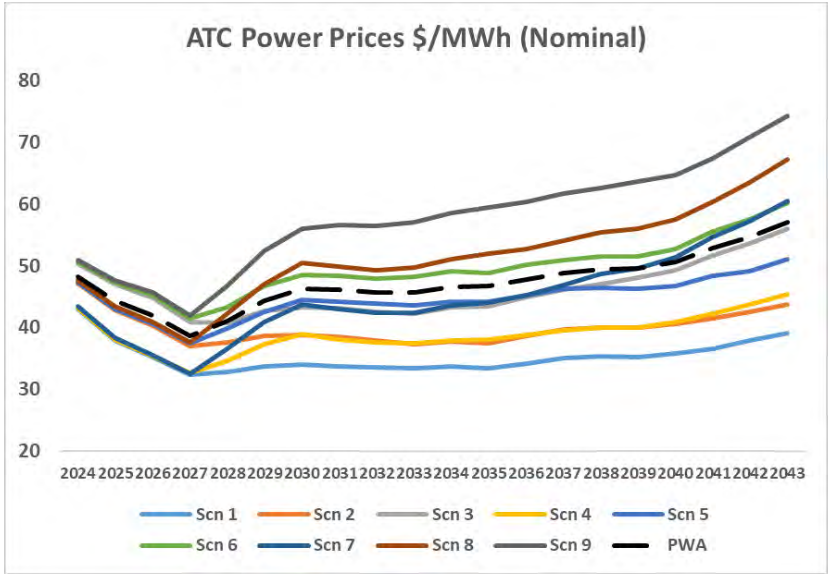


Probabilities are preliminary

Scenario Development

Power Market Prices

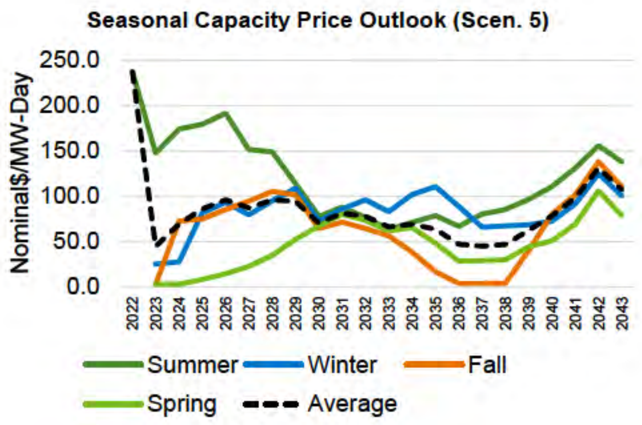
- CRA modeled energy curves using Aurora for each combination of scenario variables
  - Natural Gas Prices
  - Climate/Environmental Policy
- Hourly prices were developed for MISO Zone 5 (primarily Ameren Missouri)

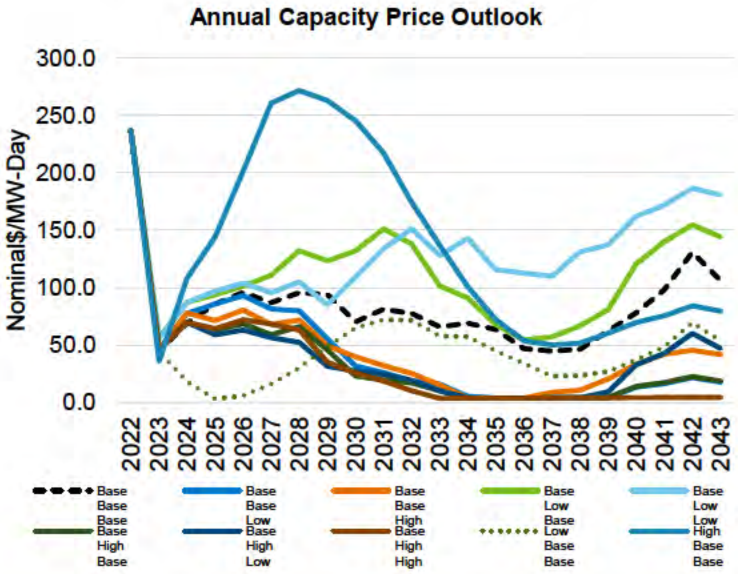


Scenario Development

Capacity Market Prices

- CRA developed capacity prices for each power price scenario for each MISO season using their proprietary capacity market model





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Avoided Costs

- **Avoided Transmission and Distribution Costs**: Estimated the average transmission and distribution cost of serving the load and applied the condition/reliability factor.
- **Avoided Capacity Costs**: CONE for MISO Zone 5
- **Avoided Energy Costs**: Probability weighted average of the market price for electricity of 9 distinct scenarios

Avoided Cost	Transmission $/kW-yr	Distribution $/kW-yr	Generation $/kW-yr	Energy $/MWh
2024	$1.5	$21	$89	$48
2025	$1.5	$22	$91	$44
2026	$1.6	$23	$93	$42
2027	$1.6	$23	$95	$39
2028	$1.6	$23	$96	$41
2029	$1.7	$24	$98	$44
2030	$1.7	$24	$100	$46
2031	$1.7	$25	$102	$46
2032	$1.8	$25	$104	$46
2033	$1.8	$26	$107	$46
2034	$1.8	$26	$109	$47
2035	$1.9	$27	$111	$47
2036	$1.9	$28	$113	$48
2037	$1.9	$28	$115	$49
2038	$2.0	$29	$118	$49
2039	$2.0	$29	$120	$50
2040	$2.1	$30	$122	$51
2041	$2.1	$30	$125	$53
2042	$2.1	$31	$127	$55
2043	$2.2	$32	$130	$57

Integrated Resource Plan and Risk Analysis

Key Assumptions

	PRM UCAP	Wind	Solar
Summer	7.4%	18.1%	50.0%
Fall	14.9%	23.1%	50.0%
Winter	25.5%	40.3%	5.0%
Spring	24.5%	23.0%	50.0%

- Seasonal accreditation (SAC) values
- Solar-wind ELCC from SERVM for long-term SAC
  - 30% for winter wind, 40% for summer solar by 2040
- New resources in service when capacity would be less than 0 MW
- Evaluating potential for additional resource needs to address extreme weather conditions

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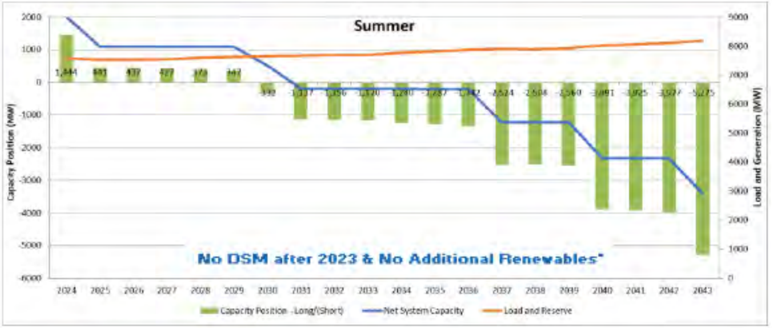
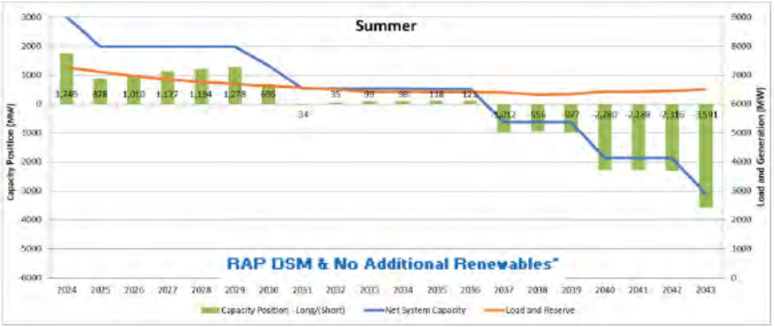
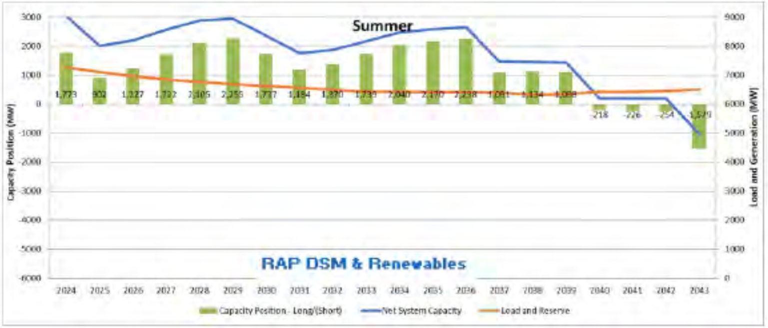
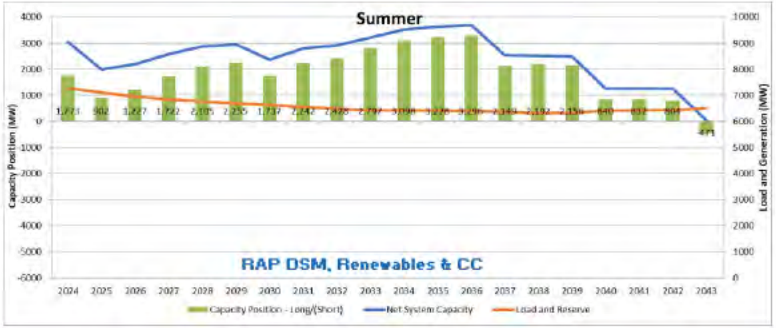
Preliminary Capacity Position









*No additional renewables after Huck Finn and Boomtown solar projects

Preliminary Capacity Position

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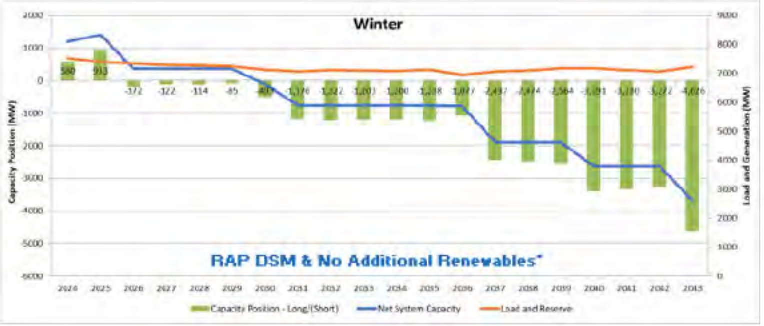

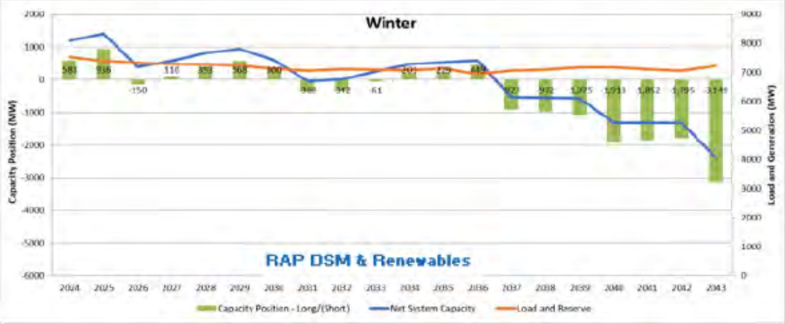

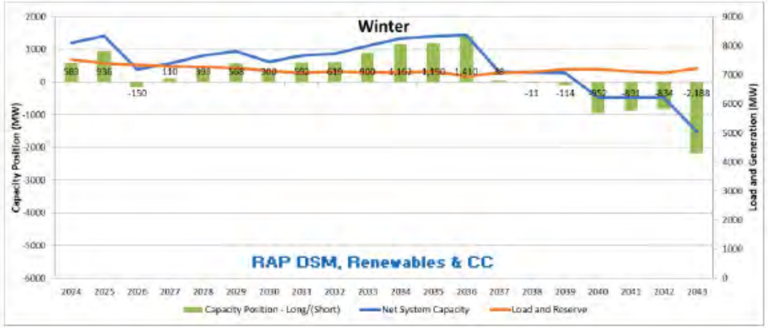

*No additional renewables after Huck Finn and Boomtown solar projects

Alternative Resource Plans

	20 CSR 4240-22.060 (3) (A) 1-5 (A) ....The utility shall examine cases that—	Ameren Missouri Approach
1.	Minimally comply with legal mandates for demand-side resources, renewable energy resources, and other mandated energy resources. This constitutes the compliance benchmark resource plan for planning purposes;	Only renewable energy mandate RES with 1% cap
2.	Utilize only renewable energy resources, up to the maximum potential capability of renewable resources in each year of the planning horizon, if that results in more renewable energy resources than the minimally-compliant plan. This constitutes the aggressive renewable energy resource plan for planning purposes;	More aggressive renewables deployment than RES
3.	Utilize only demand-side resources, up to the maximum achievable potential of demand-side resources in each year of the planning horizon, if that results in more demand-side resources than the minimally compliant plan. This constitutes the aggressive demand-side resource plan for planning purposes;	DSM - MAP
4.	In the event that legal mandates identify energy resources other than renewable energy or demand-side resources, utilize only the other energy resources, up to the maximum potential capability of the other energy resources in each year of the planning horizon, if that results in more of the other energy resources than the compliance benchmark resource plan. For planning purposes, this constitutes the aggressive legally-mandated other energy resource plan;	No other legal mandates N/A
5.	Optimally comply with legal mandates for demand-side resources, renewable energy resources, and other targeted energy resources. This constitutes the optimal compliance resource plan, where every legal mandate is at least minimally met, but some resources may be optimally utilized at levels greater than the mandated minimums;	No other legal mandates N/A

Alternative Resource Plans

- IRP rule requires utilization of <u>only</u> renewable energy resources in at least one alternative resource plan.

DSM	Retirements	Other New Supply-Side Resource
RAP EE & DR MAP EE & DR Load Flexibility - RAP Load Flexibility - MAP None after MEEIA Cycle 3	Rush Island 2025 Sioux 2030 Labadie 2036, 2042 Labadie 2036, 2039 Labadie 2036	Combined Cycle Combined Cycle w/ CCS Simple Cycle Pumped Storage Nuclear (SMR) Solar Wind Batteries

Candidate Uncertain Factors

- Critical uncertain factors already included in the scenarios:
  - Natural gas price
  - Carbon price

Uncertain Factor
Load Growth
Fuel Prices Coal Nuclear
Project Costs
Project Schedule
Fixed and Variable O&M
Forced Outage Rates
Emissions Prices
DSM Load Impacts & Costs
Return on Equity
Interest Rates

Risk Analysis

- Sensitivity Analysis
  - Low and high values in addition to base
  - Will be run on the most likely scenario:

    Base CO_2 Price – Base Natural Gas – Base Load Growth
  - Factors that significantly change the ranking of alternative resource plans will be determined ‘critical’

- Risk Analysis
  - Full probability tree for all alternative resource plans
  - All performance metrics will be estimated to evaluate performance of plans

Planning Objectives, Performance Measures and Metrics

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- Expect to use the following “Planning Objectives” and associated measures in the selection of the Preferred Resource Plan:
  - Environmental and Resource Diversity – Generation Mix, Carbon Emissions, SO_2 Emissions, NO_X Emissions
  - Financial/Regulatory – ROE, EPS, Free Cash Flow, Stranded Cost Risk, Transaction Risk, Recovery Risk (separately evaluated credit metrics – FFO/Interest and FFO/Debt)
  - Customer Satisfaction – Average Rates, Largest Single Year Rate Increases
  - Economic Development – Direct Job Growth (no indirect or induced)
  - Cost – PVRR (primary selection criterion as required by PSC rules)
- Planning objectives, measures and metrics are consistent with prior IRP filings

Next Steps

- Share draft reports for 20 CSR 4240-22.030–20 CSR 4230-22.050 – May
- Determine uncertain factor ranges – May
- Perform integrated resource plan and risk analyses – May-July
- Finalize reporting for filing by October 1st

Q&A

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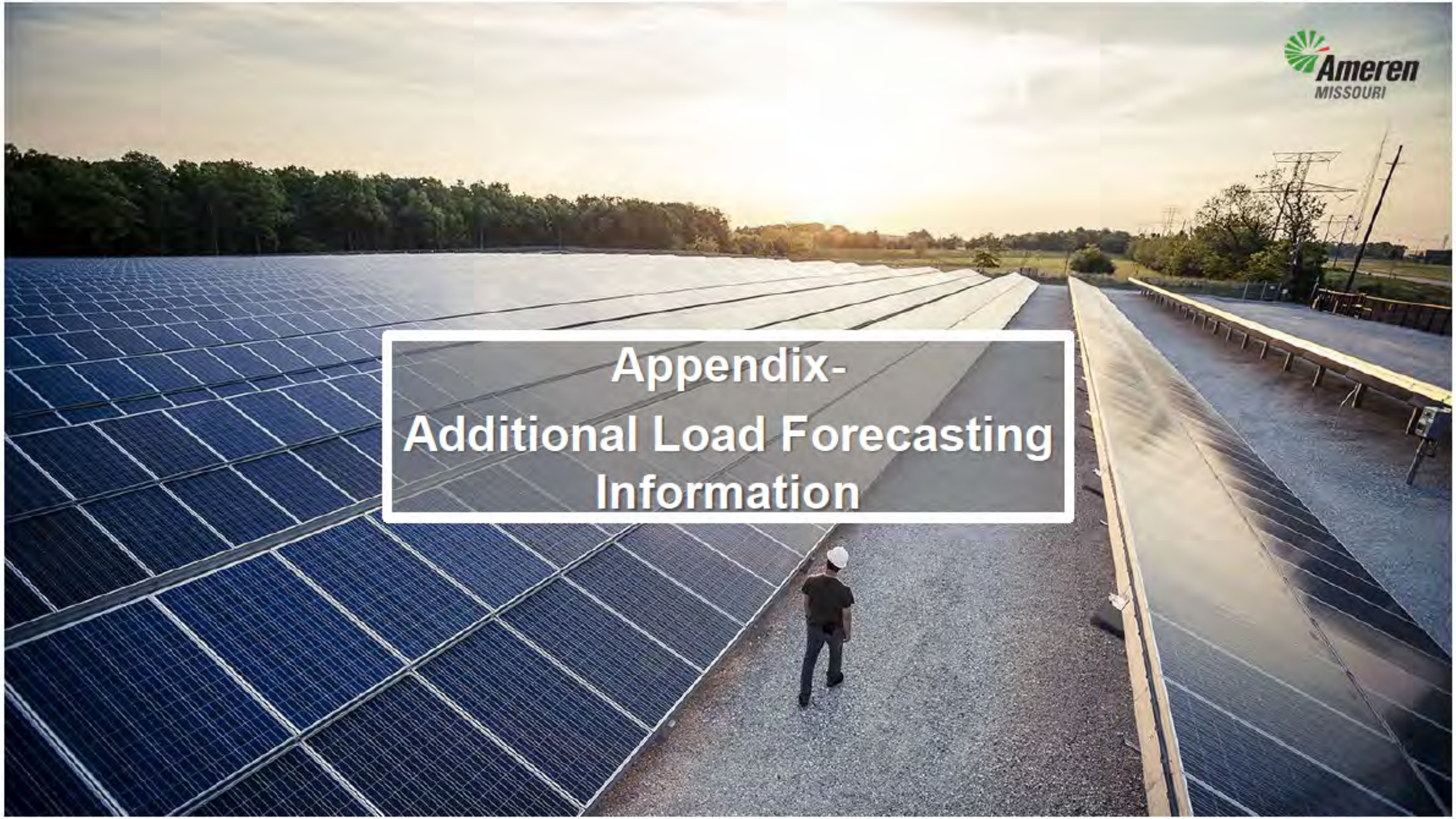


Schedule MM-S13

Average residential usage continues to decline for next 10 years and then flattens out

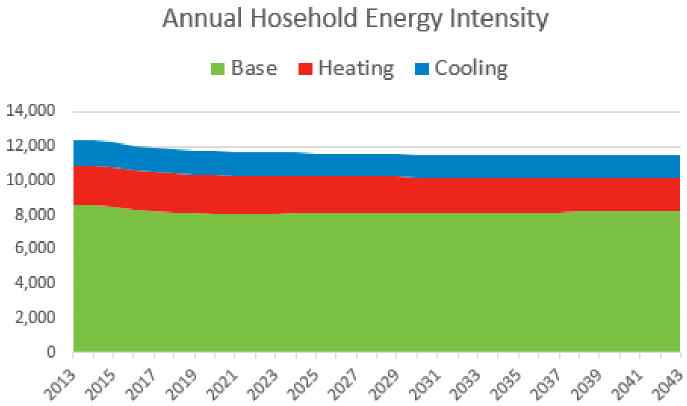
Changes in End-use intensity

- This forecast uses information from Annual Energy Outlook published by EIA and Itron.

Residential:

- **Base-use intensity** starts out flat between 2023 and 2033 and begins to increase slightly between 2033-2043.
- **Cooling intensity**: Cooling intensity continues to decline for next five years and then flattens out. Intensities are positive in the later years as CAC efficiency flattens out and households continue to migrate from room air conditioning to central air conditioning.
- **Heating intensity:** Intensity projections continue to increase slightly for most part of the planning years due to efficiencies in head pumps.
- **Miscellaneous Intensity**: Miscellaneous intensity grows at an annual compound rate of approx. 0.5% during the forecast horizon.

Reference: EIA, Itron



CAGR	Base Use	Heating	Cooling	Misc	Total
2013-2023	-0.6%	-0.6%	-0.5%	1.9%	-0.6%
2023-2033	0.0%	-0.8%	-0.4%	0.8%	-0.2%
2033-2043	0.2%	-0.7%	0.2%	0.3%	0.0%
2023-2043	0.1%	-0.7%	-0.1%	0.5%	-0.1%

Energy Forecast Scenarios: Summary

Residential

- **Base case** scenario reduces energy usage by ~423 GWh of solar, but adds ~2,368 GWh of energy from efficient electrification by 2043. 20 Year forecast CAGR is 1.0%
- **High case** scenario reduces energy usage by ~212 GWh of solar, but adds ~2,500 GWh of energy from efficient electrification by 2043. 20 Year forecast CAGR is 1.9%
- **Low case** scenario reduces energy usage by ~847 GWh of solar, but adds ~120 GWh of energy from efficient electrification by 2043. 20 Year forecast CAGR is 0.0%

	Base	High	Low
CAGR (2024-43)	1.0%	1.9%	0.0%

Commercial

- **Base case** scenario reduces energy usage by ~246 GWh of solar, but adds ~711 GWh of energy from efficient electrification by 2040. 20 Year forecast CAGR is 0.4%
- **High case** scenario reduces energy usage by ~123 GWh of solar, but adds ~2,005 GWh of energy from efficient electrification by 2040. 20 Year forecast CAGR is 0.7%
- **Low case** scenario reduces energy usage by ~492 GWh of solar, but adds ~33 GWh of energy from efficient electrification by 2040. 20 Year forecast CAGR is -0.1%

	Base	High	Low
CAGR (2024-43)	0.4%	0.7%	-0.1%

Industrial

- **Base case** scenario reduces energy usage by ~31 GWh of solar but adds ~1,789 GWh of energy from efficient electrification by 2040. 20 Year forecast CAGR is 1.5%
- **High case** scenario reduces energy usage by ~15 GWh of solar, but adds ~2,033 GWh of energy from efficient electrification by 2040. 20 Year forecast CAGR is 1.6%
- **Low case** scenario reduces energy usage by ~61 GWh of solar, but adds ~809 GWh of energy from efficient electrification by 2040. 20 Year forecast CAGR is 0.4%

	Base	High	Low
CAGR (2024-43)	1.5%	1.6%	0.4%

3. Load Analysis and Forecasting

Highlights

- *Ameren Missouri expects energy consumption to grow 0.8% annually and peak demand to grow 0.4% annually for the planning case over the next 20 years including potential impacts from electrification and behind the meter solar generation.*
- *Economic growth, naturally occurring energy efficiency and customer adoption of distributed energy resources such as solar and efficient electrification of end-uses are key drivers of future growth in our base case forecast.*

Ameren Missouri has developed a range of load forecasts consistent with the scenarios outlined in Chapter 2. These load forecasts provide the basis for estimating Ameren Missouri's future resource needs and provide hourly load information used in the modeling and analysis discussed in Chapter 9. In addition, the Statistically Adjusted End-use forecasting tools and methods used to develop the forecasts provide a solid analytical basis for testing and refining the assumptions used in the development of the potential demand-side resource portfolios discussed in Chapter 8.[1] The energy intensity of the future economy and the inherent energy efficiency of the stock of energy using goods are explored throughout the analysis to arrive at reasonable estimates of high, base, and low load growth.

3.1 Energy Forecast

This chapter describes the forecast of Ameren Missouri's energy, peak demand, and customers that underlies the analysis of resources undertaken in this IRP. In order to account for a number of combinations of possible economic and policy outcomes, three different forecast scenarios, a high load growth scenario, low load growth scenario, and base case scenario were prepared. Based on the subjective probabilities of these scenarios identified by Ameren Missouri, a fourth case was developed to represent the planning case for the study. The planning case forecast projects Ameren Missouri's retail sales to grow by 0.8% annually between 2024 and 2043, and retail peak demand to grow by 0.4% per year.

[1] 20 CSR 4240-22.030(1)(A)

As with any forecast of energy, there are several underlying assumptions. Expectations for economic growth underlying the load forecast are based on Moody's Analytics' forecast of economic conditions in the Ameren Missouri service territory. Expectations about future energy market conditions, such as fuel prices and the impact on electricity prices of different environmental policy regimes are based on interviews with internal Ameren subject matter experts.

Since the last IRP filing, Ameren Missouri has implemented significant energy efficiency programs, which has significantly reduced overall energy consumption year over year. This forecast assumes significant savings from company sponsored energy efficiency programs under Missouri Energy Efficiency Investment Act (MEEIA). Savings from MEEIA Cycle 2 programs and MEEIA Cycle 3 programs are forecasted through 2043. This IRP forecast assumes 2043 will cumulatively have implemented 1,966 GWh of energy savings. As mandated by SB 564, Ameren Missouri will provide $23 million in incentives between 2018 and 2024 resulting in approximately 100 MWs of customer owned renewable, if the rebates are fully subscribed. Base case scenario assumes that the customer owned renewable generation capacity would increase during the planning years, reaching 700 MWs by 2043. Customer owned renewable generation capacity is assumed to reach as high as 1,400 MWs by 2043 in low load growth scenario and 350 MWs by 2043 in high load growth scenario.

Compared to Ameren Missouri's last IRP, which was filed in 2020, the growth rate of the forecasts is lower in the base, low, and planning scenario, but higher in the high scenario. The growth rate in the high scenario increased due to additional adoption of Electric Vehicles by 2043. Ameren Missouri's current initiatives on efficient electrification programs are expected to increase total consumption by 285 GWh between 2022 and 2027. An efficient electrification study conducted by EPRI shows significant potential for adoption of electric vehicles and other efficient electrification technologies by 2043 raising the overall electric consumption by approximately 4,868 GWh in the base case scenario. Forecasts for the high load growth scenario assumes approximately 8,426 GWh and forecasts for low growth scenario assumes approximately 963 GWh of additional load from efficient electrification.

It should be noted that in the development of this forecast, expectations of improving energy efficiency of end use equipment and appliances is reflected only to the extent that it is due to market conditions, federal standards, or past and current cycles of energy efficiency programs Ameren Missouri has implemented under the MEEIA program. The third cycle of MEEIA programs is included in the load forecast because it is already planned and approved and is being implemented by the company. Future energy efficiency programs are the subject of Chapter 8, and the impacts of those programs will be included according to their role in the various candidate resource plans discussed in Chapter 9.

3.1.1 Historical Database[2]

Ameren Missouri tracks its historical sales[3] and customer counts by revenue class (Residential, Commercial, and Industrial), and also by rate class (Small General Service, Large General Service, Small Primary Service, and Large Primary Service).[4] Ameren Missouri uses these rate classes as the sub-classes for forecasting, both because the data is readily accessible from the billing system and because it provides relatively homogeneous groups of customers in terms of size. Historical billed sales are available for all rate and revenue classes back to January 1995 and calendar month sales and class demand data[5] is available beginning with July 2003. At the time of the preparation of the load forecast for this IRP, historical sales were known through March of 2022.[6] Except as noted later in this chapter, any data presented for 2022 or beyond is forecasted data and data from 2021 and earlier is actual metered or weather normalized sales data. Historical energy consumption and customer count data will be provided in the final filing.

Ameren Missouri routinely weather normalizes the observed energy consumption of its customers to remove the impact of weather variations. The process for weather normalizing sales is described in section 3.3, and weather normalized historical consumption from 2004 forward will also will be provided in the final filing. Appendix A includes weather normalization model statistics for various rate-revenue classes. Workpapers that include use per unit energy sales and demand data for all classes will be provided in the final filing. In each case, the unit included in the analysis is the customer count for the class.[7] Customer count is selected because it is a measured value for each class that is accessible and meaningful in all cases.

3.1.2 Forecast Vintage Comparison

Independent variables[8]

Section 20 CSR 4240-22.030(6)(C)3 of the Missouri IRP rules require a comparison of prior projections of all independent variables used in the energy usage and peak load forecasts made in at least the last 10 years to actual historical values and to projected values in the current IRP filing. Actual historical values for each independent variable for a period of at least the last 20 and up to 40 or more years are acquired by Ameren Missouri from Moody's Analytics, along with forecasts of each variable for the entire planning horizon.[9]

[2] 20 CSR 4240-22.030(1)(B)
[3] 20 CSR 4240-22.030(2)(B)1
[4] 20 CSR 4240-22.030(2)(A)
[5] 20 CSR 4240-22.030(2)(B)2
[6] 20 CSR 4240-22.030(2)(F)
[7] 20 CSR 4240-22.030(2)(C)1
[8] 20 CSR 4240-22.030(6)(C)3
[9] 20 CSR 4240-22.030(6)(C)1

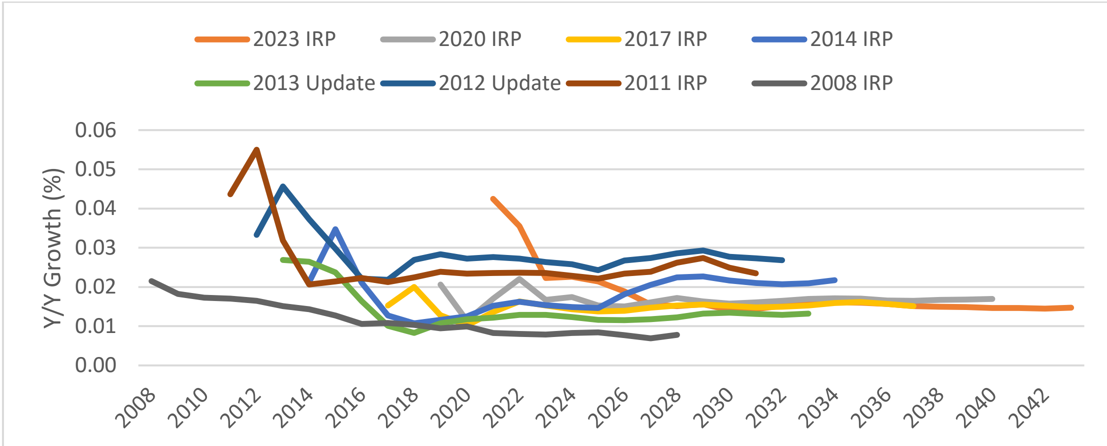
The following discusses only the independent variables used in the energy usage forecasts. The peak forecast is derived from using the output from the energy forecast and modeling historical peaks as the Y variable. The growth rates in peak demand are driven by the energy forecasts for each class and end use as described later in this chapter, so the same economic variables used in the energy forecast are also being used to forecast the peak loads.

The prior projections involved in addressing this requirement are from the 2008 IRP, the 2011 IRP, the 2012 Annual Update, the 2013 Annual Update, the 2014 IRP, the 2017 IRP, and the 2020 IRP. Besides these prior projections, projections for this 2023 IRP are included. Sales volume shown for the 2023 IRP includes the actuals for years up to 2021 and projections starting from 2024.

In some cases, the data vendor may have changed the 'base year' for the independent variables' values. In addition, between certain IRPs, Ameren Missouri has changed its methodology for weighting county level variables into a service territory indicator, so the absolute level of the values for the same year among various vintages may be significantly different. However, the key is the growth rate or trend in these values, so each table is expressed in terms of the year over year growth rate and is accompanied by a chart showing the same, which overcomes the problem of sometimes relying on different bases for some of the variables.

For the residential energy forecast, independent variables used in these forecasts were Households, Population, and Personal Income. For the commercial and industrial energy forecasts, independent variables used in these forecasts were total GDP and GDP for several sectors of the economy, including Manufacturing, Retail Trade, Information Services, Financial Services, Education/Health Services, total non-farm employment, and manufacturing employment. Service territory GDP variables from each archived forecast are shown below in Figure 3.1. The growth rates for each of the variables discussed above will be shown in chart and tabular form in the final filing.

Figure 3.1: Ameren Missouri Service Territory GDP Forecasts from Prior IRPs

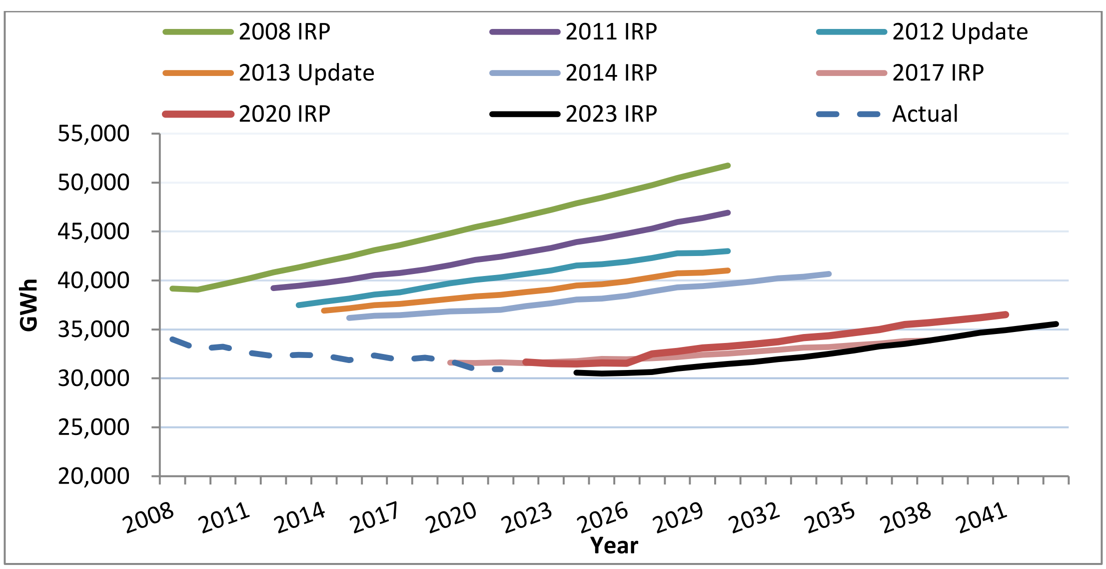


Forecasts[10]

Section 20 CSR 4240-22.030(6)(C)4 requires a comparison of prior projections of energy and peak demand made in at least the last 10 years to the actual historical energy and peak demands and to projected values in the current IRP filing.

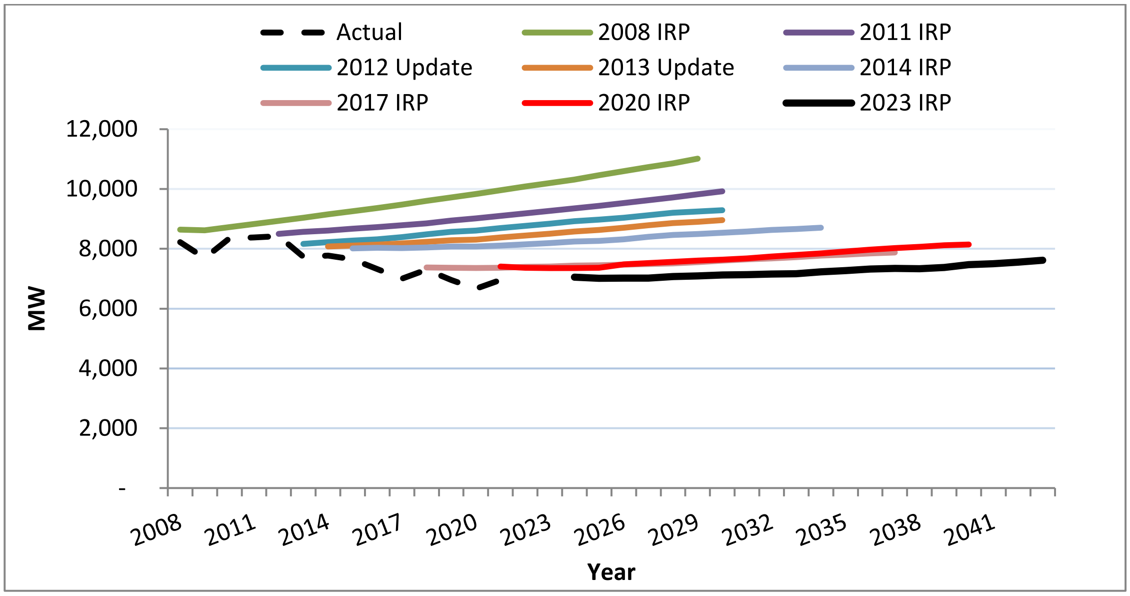
Figures 3.2 and 3.3 below show previous forecasts of energy and peak demand, including those for the 2008 IRP, 2011 IRP, 2012 Update, 2013 Update, the 2014 IRP, the 2017 IRP, the 2020 IRP, the 2023 IRP, and actual historical values. The data from these charts will be presented in tabular form in the final filing.

Figure 3.2: Ameren Missouri Actual Historical Energy Sales and Past IRP Energy Forecasts



[10] 20 CSR 4240-22.030(6)(C)4

Figure 3.3: Ameren Missouri Actual Historical Peak Demand and Past IRP Peak Demand Forecasts



As is evident from the forecasts in the tables, the projections of both energy consumption and peak demand have decreased quite significantly over time. This is due to three factors. First, increases in the efficiency of end uses of electricity has reduced electric consumption relative to the earlier projections. As an example, the Energy Independence and Security Act of 2007 included an efficiency standard for light bulbs that significantly reduces the energy consumption associated with lighting. This and other standards, as well as the energy efficiency programs under the MEEIA program that have already been implemented by Ameren Missouri have served to reduce the rate of growth in energy and peak demand below what they otherwise would have been. Secondly, Ameren Missouri anticipates a significant increase in customer-owned solar and other distributed sources of energy over next 20 years, which negatively impacts both the energy and peak forecast. Ameren Missouri's base case forecast reflects ~700 MW of installed customer owned solar generation capacity within its terrirtory by 2043. Finally, past IRP forecasts included sales to one of the largest aluminum smelting facilities in the country at the time amounting to more than 10% of annual sales when the customer operated at its full capacity. Ameren Missouri does not serve this customer any longer. This customer was the only entity in the Large Transmission Service class and hence, forecasts pertaining to Large Transmission Service class has been excluded in the forecast scenarios developed for the 2020 IRP. Sales and Peak Demand in the 2023 IRP also saw a decrease due to the COVID-19 pandemdic. Sales in 2020 decreased by ~3% compared to 2019, and have not yet fully recovered to pre-pandemdic levels. Sales are not expected to return to 2019 levels until 2029.

Schedule MM-S14

Based on a state wide study conducted by Electric Power Research Institute (EPRI), Ameren Missouri has also assumed a significant increase in the adoption of electric vehicles and efficient electrification of end uses in its territory over next 20 years. Adoption of such technologies is assumed to increase at an annual rate of approximately 22% over the planning horizon.

3.1.3 Service Territory Economy

The Ameren Missouri electric service territory is comprised of 59 counties primarily in eastern and central Missouri. It should be noted, however, that although Ameren Missouri serves customers in 59 counties, it does not necessarily serve every electric customer in each of those counties. The level of sales is highly correlated with the behavior of the economy in the service territory.

Historically, the Ameren Missouri service territory has been characterized by slower population growth than the U.S. as a whole due to demographic and migration factors. In that respect, the service territory's economy is not terribly different from most other Midwestern states and metropolitan areas. Like much of the Midwest, the region's economy was based on manufacturing for many years, but over the past several decades the share of the territory's employment in manufacturing has been declining while employment in services, particularly health care, has grown. So although the service territory still has a higher than average share of employment in manufacturing, it is no longer the employment growth engine it once was. The allocation of service territory employment by NAICS sector is shown in Figure 3.5; a list of some of the largest employers in the service territory is shown in Table 3.1.

The territory's major employers are spread across a number of different industries, but the region's single biggest employer is a hospital system, BJC Healthcare. Two other healthcare systems and three universities are among the largest employers in the territory, highlighting the importance of health and education services to both the growth and level of employment, as well as to electricity sales.

As noted above, the service territory economy has grown at a slightly slower pace than the U.S. as a whole because of slower population growth. In addition to the trend of slower population growth, the St. Louis region did not experience the boost from the housing bubble that some other markets did.

The service territory economy also contains several nationally known financial firms, including Wells Fargo and Edward Jones.

Figure 3.4: U.S. and Missouri Population Change

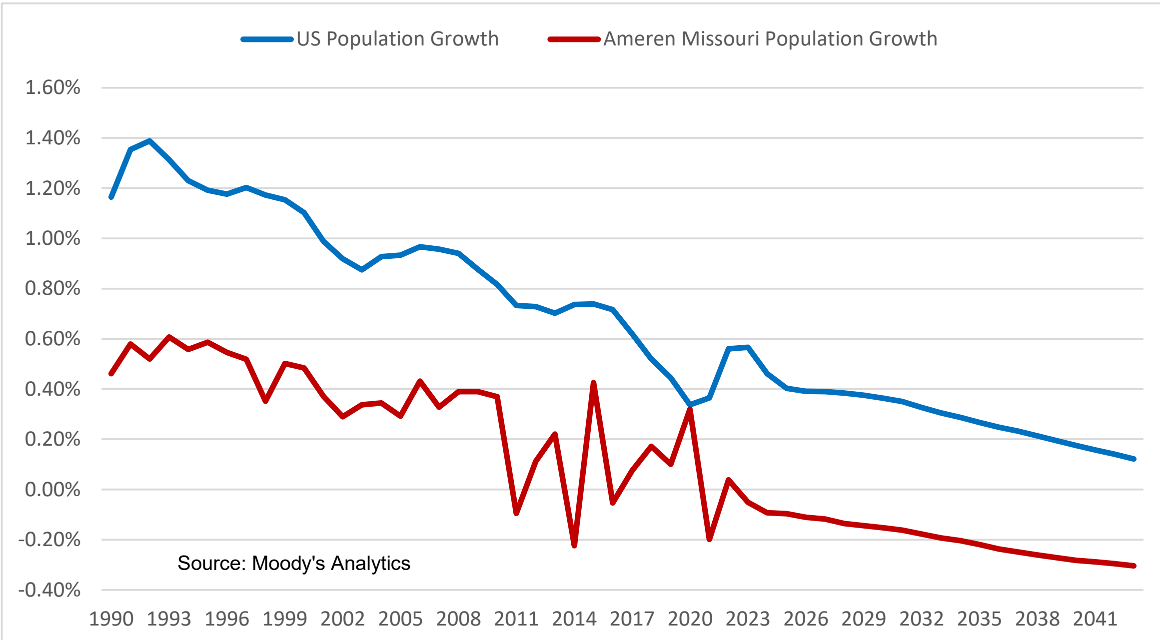
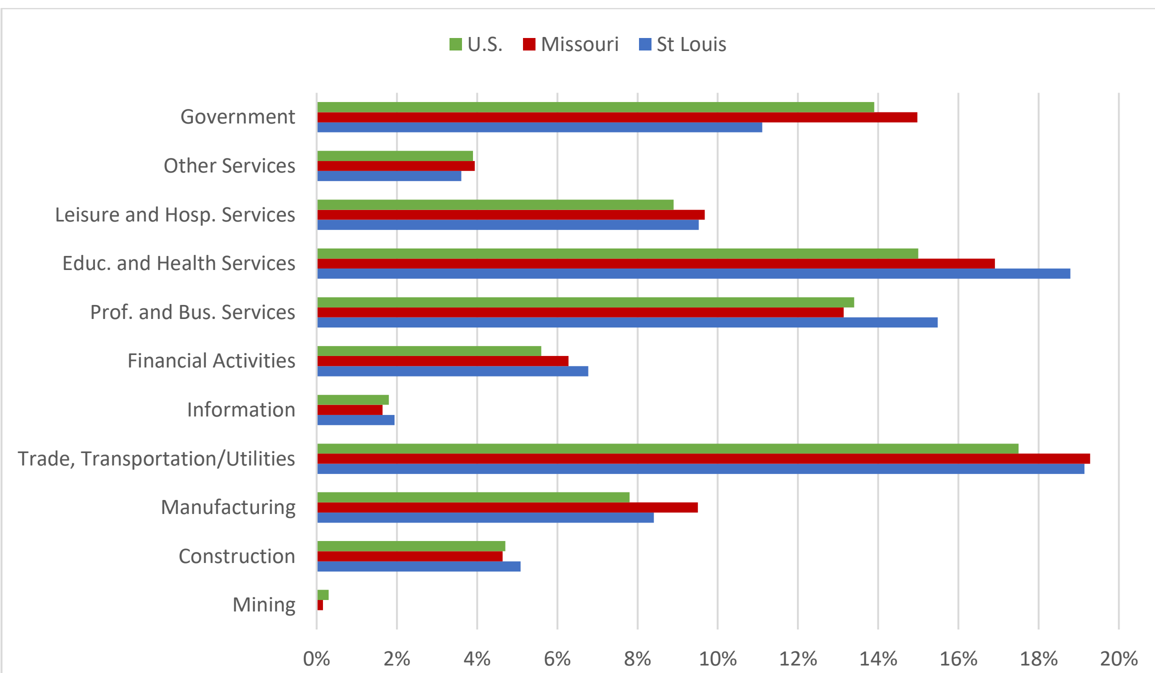


Figure 3.5: U.S. and Ameren Missouri Service Territory Employment by Industry

Source: BLS, Moody's Analytics



Schedule MM-S14

Table 3.1: Major Employers in Ameren Missouri Service Territory

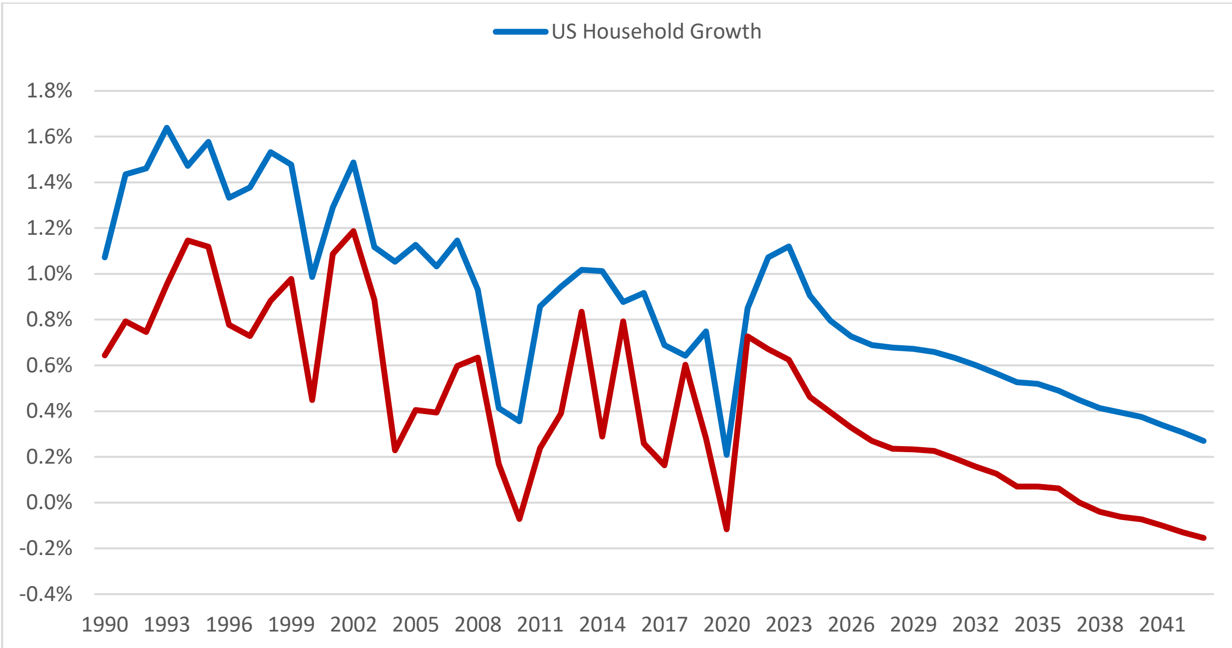
Rank	Employer	Industry	Number of Employees
1	BJC Healthcare	Education or Health Services	28,516
2	Mercy Health Care	Education or Health Services	23,011
3	Wal-Mart Stores, Inc.	Retail Trade	22,290
4	Washington University in St. Louis	Education or Health Services	17,442
5	Boeing Defense, Space & Security	Boeing Defense, Space & Security	14,566
6	SSM Health Care System	Education or Health Services	13,500
7	Scott Air Force Base	Federal Government	13,000
8	Archdiocese of St Louis	Other Services	10,460
9	Schnuck Markets Inc.	Retail Trade	9,956
10	AT&T	Information	9,000
11	McDonald's Corporation	Retail Trade	7,550
12	St Louis University	Education or Health Services	7,311
13	Washington University Physicians	Education or Health Services	7,222
14	Edward Jones	Financial Activities	6,100
15	Imo's Pizza	Retail Trade	5,515
16	Enterprise Holdings	Trans./Warehouse/Utilities	5,500
17	Express Scripts Inc.	Financial Activities	5,323
18	Wells Fargo	Financial Activities	5,000
19	Walgreens	Retail Trade	4,740
20	Target Corp.	Retail Trade	4,675

Source: Moody's Analytics

Since the great recession of the past decade, Ameren Missouri's service territory economy continued to recover in a manner like the U.S. economy's recovery, although at a slower pace than that of the U.S. recovery. This is evident from the chart of the U.S. and Service Territory GDP Growth shown in Figure 3.7, in which the red line for Ameren Missouri growth follows a pattern like that of the U.S. but is below the blue line for the U.S. GDP growth.[11] During 2020, GDP saw a decrease due to the COVID-19 Pandemic, but GDP saw a recovery in 2021 after the government started lifting COVID-19 restrictions.

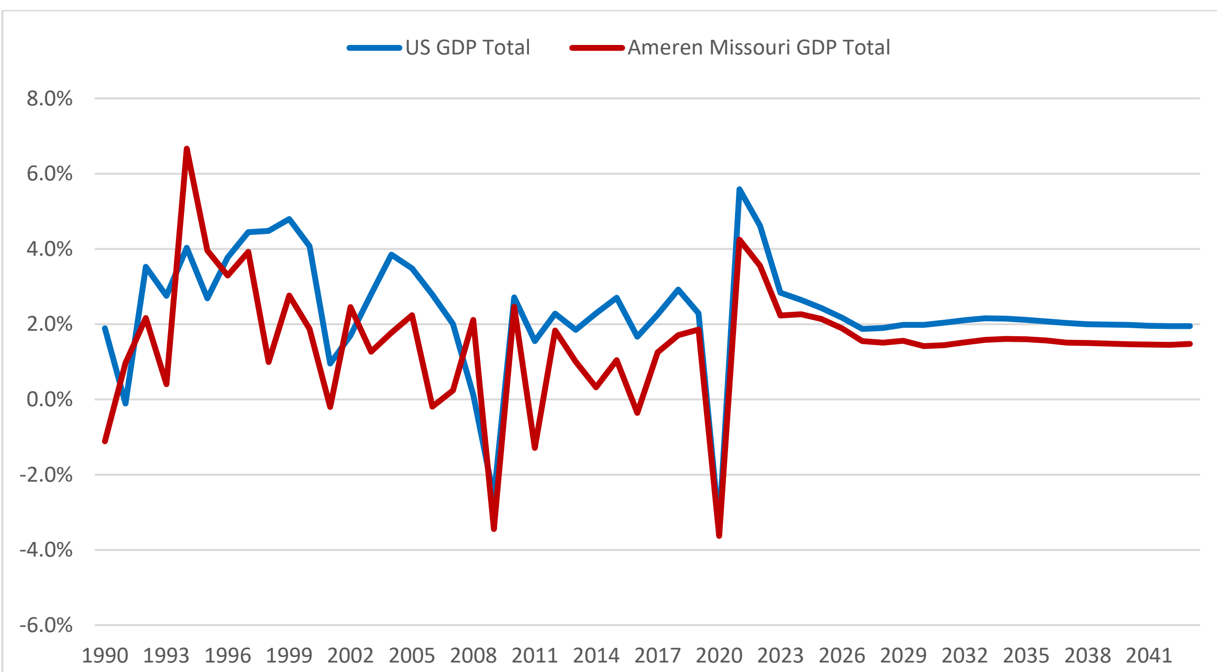
[11] 20 CSR 4240-22.030(7)(B)3

Figure 3.6: Growth in U.S. and Ameren Missouri Households[12]



Source: Moody's Analytics

Figure 3.7: U.S. and Service Territory GDP Growth[13]



[12] 20 CSR 4240-22.030(2)(D)3
[13] 20 CSR 4240-22.030(2)(D)3

Schedule MM-S14

3.1.4 Economic Drivers

Several economic indicators were used as independent variables (independent variables in the forecasting models are often referred to as "drivers) in our energy forecasting process.[14]

- For the residential class, income, population, and the number of households in the service territory were used as drivers. These drivers are consistent with drivers used in all recent IRP forecasts.[15]
- For the four classes of commercial sales (small general service, large general service, small primary service, large primary service), GDP for one or more of six sectors of the economy were used as drivers. Those six sectors were Retail Trade, Information Services, Financial Services, Education/Health Services, Leisure, and Other Services, and these six sectors account for almost all the non-manufacturing and non-government entries in the top employers list in Table 3.1 shown above. These drivers are consistent with drivers used in all recent IRP forecasts except to the extent that a different sector may have been included for a particular rate class as compared with a previous forecast, but only if the analysis of historical correlation of that driver to the historical loads indicated a better relationship between the two.[16]
- For the four classes of industrial sales (same classes as in commercial listed above), one or more of the following drivers were used: GDP, Manufacturing GDP, Employment, and Manufacturing Employment. These variables are consistent with past load forecast drivers for the industrial class. Table 3.2 illustrates these drivers and their expected growth over the IRP planning horizon.
- As in prior IRPs and IRP Annual Updates, the economic forecasting firm Moody's Analytics was the source for the forecasts of these economic drivers. Moody's Analytics is a highly reputable firm in the macroeconomic forecasting arena with a specialized competency in doing this work, and Ameren Missouri has extensive history with using its forecasts and has consistently found them to be credible. Their forecasts are done for individual counties, and Ameren Missouri aggregates those counties that make up its service territory. The forecasting models used by Moody's are proprietary and not available to Ameren Missouri.[17]

[14] 20 CSR 4240-22.030(5)(A)
[15] 20 CSR 4240-22.030(6)(A)1A
[16] 20 CSR 4240-22.030(6)(A)1B
[17] 20 CSR 4240-22.030(7)(B)1;20 CSR 4240-22.030(7)(B)2

Table 3.2 Growth Rates of Selected Economic Drivers

	2024-2043 Compound Growth Rate
Households	0.10%
Population	-0.21%
Real Personal Income	3.70%
GDP Retail	1.68%
GDP Info	2.60%
GDP Financial	1.22%
GDP Education /Health	1.92%
GDP Leisure	1.81%
GDP Other Services	-0.24%
GDP Total	1.56%
GDP Manufacturing	1.84%
Employment Total	0.00%
Manufacturing Employment	-1.11%

3.1.5 Energy Forecasting

This forecast of Ameren Missouri energy sales was developed with traditional econometric forecasting techniques, as well as a functional form called Statistically Adjusted End-Use (SAE). In the SAE framework, variables of interest related to economic growth, the price of electricity, and energy efficiency and intensity of end-use appliances, are combined into a small number of independent variables, which are used to predict the dependent variable (typically energy sales or sales per customer by class). The SAE framework was used to forecast energy sales in the company's residential general service rate class, and for all four of its commercial rate classes. The discussion below details the process followed for developing the models, inputs, assumptions, and parameters used in forecasting.

Statistically Adjusted End-Use (SAE)

The advantage of the SAE approach is that it combines the benefits of engineering models and econometric models. Engineering models, such as REEPS, COMMEND, and INFORM model energy sales with a bottom-up approach by building up estimates of end use energy consumption by appliance type, appliance penetration, and housing unit or business type. These models are good at forecasting energy because they can be used to estimate the effects of future changes in saturations or efficiency levels of equipment and appliances, which may be driven by policy, economics, or consumer preferences,[18] even if the changes are not present in observable history. In a traditional econometric model, it can be difficult

[18] 20 CSR 4240-22.030(5)(C)

to model precisely how the changing appliance efficiency standards will affect sales if the standards have been unchanged during the estimation period.

Econometric models, however, are estimated against a relatively long period of time rather than calibrated to sales from a single year, and it is therefore easier to detect and correct any systematic errors or biases in the forecasting model. For that reason, a system that combines the bottom-up approach of engineering models with an econometric approach should produce more accurate forecasts.[19] The SAE approach allows us to do that for our residential and commercial class sales. For the industrial classes, we used an econometric approach that was influenced by the SAE approach.

The SAE framework used in this load analysis and forecasting work[20] was developed by Itron, a consulting firm Ameren Missouri has worked with for many years, and implemented by Ameren Missouri forecasting personnel.[21] In it there are specific end uses for which saturation and efficiency must be estimated, as well as a miscellaneous category. The residential end uses are heating, cooling, water heating, cooking, two refrigeration's (primary and secondary), freezers, dishwashing, clothes washing, clothes drying, television, lighting, and miscellaneous.[22] Furnace fans are consolidated with the space heating end use due to the fact that in the SAE regression, they are analyzed using a common driver: heating degree days. Personal computers, plug loads and other loads from various forms of electrification are also consolidated due to the availability of data from the U.S. Energy Information Administration (EIA) as packaged by Itron, and due to the fact that these end uses constitute many small devices for which gathering accurate historical appliance stock data beyond what Itron has analyzed from the EIA would be challenging at best.[23] Also, as discussed later in this chapter, self-generation resulting from solar photovoltaic systems is treated essentially as a negative end use and modeled explicitly in the load for each class.[24] Similarly, electric vehicle charging and other types of efficient electrification were considered as end use, contributing additional load. For the commercial class, the end uses are heating, cooling, ventilation, water heating, cooking, refrigeration, lighting, office equipment, and miscellaneous.[25] The combination of Itron's analysis and past and future Market Potential Studies provide a framework for maintaining the appropriate end use data for future IRPs.[26]

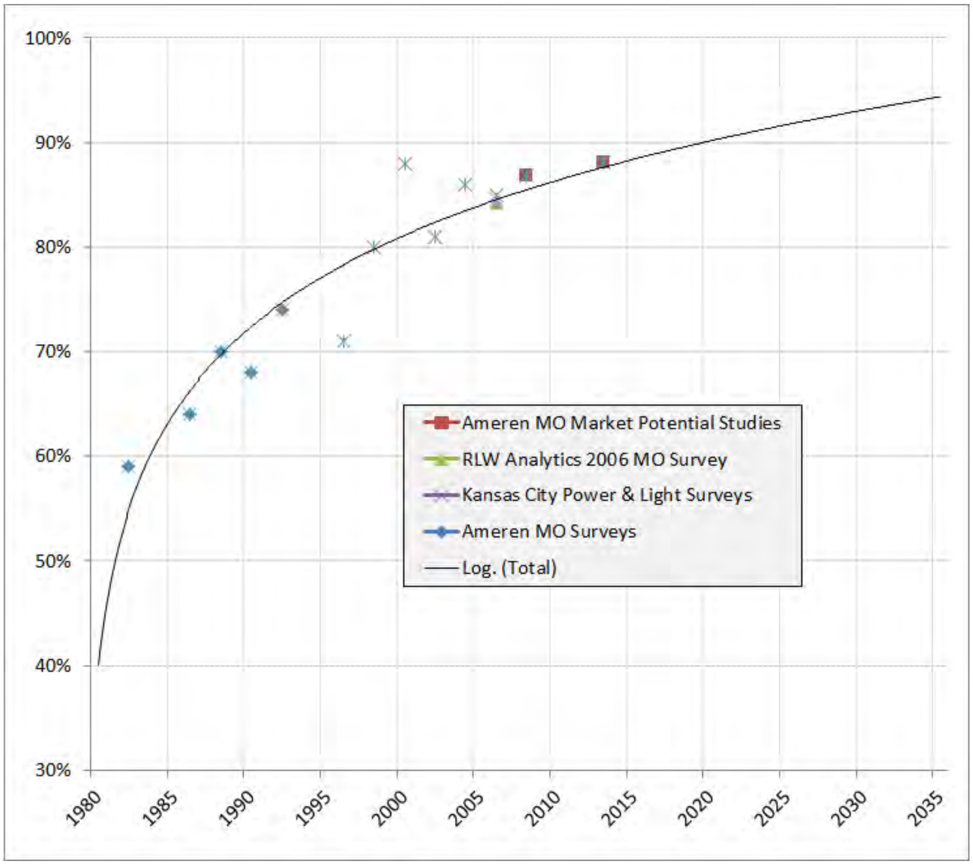
[19] 20 CSR 4240-22.030(5)(B)
[20] 20 CSR 4240-22.030(6)(B)
[21] 20 CSR 4240-22.030(6)(A)3
[22] 20 CSR 4240-22.030(4)(A)1A
[23] 20 CSR 4240-22.030(4)(A)2A
[24] 20 CSR 4240-22.030(4)(A)2B
[25] 20 CSR 4240-22.030(4)(A)1B
[26] 20 CSR 4240-22.030(4)(A)2C

To predict future changes in the efficiency of the various end uses for the residential class, Ameren Missouri relied on analysis of EIA's Annual Energy Outlook forecast performed by Itron and the past Market Potential Studies. Both of these sources rely on stock accounting logic that projects appliance efficiency trends based on appliance life and past and future efficiency standards. These models account for the impacts of all currently effective laws and regulations regarding appliance efficiency, along with life cycle models of each appliance.[27] The life cycle models are based on the decay and replacement rates, which are necessary to estimate how fast the existing stock of any given appliance turns over and newer more efficient equipment replaces older less efficient equipment. The underlying efficiency data is based on estimates of energy efficiency from the EIA, or other primary market research data and secondary sources determined to be relevant to Ameren Missouri's service territory. The EIA estimates the efficiency of appliance stocks and the saturation of appliances at the national level and for the Census Regions, while Ameren's market potential study focusses specifically on Ameren Missouri's service territory.

The saturation trends for the end use appliances from EIA for the Census Region were generally discarded in the residential analysis in favor of more locally relevant information. The primary source for up-to-date saturation information was the Ameren Missouri Market Potential Study surveys.[28] These studies were conducted in order to provide primary data for Ameren Missouri's energy efficiency and demand side management programs. An historical and forecasted time series of appliance saturations are necessary for the SAE forecasting models that capture long term trends and changes in appliance and equipment ownership. The two surveys done in conjunction with the market potential studies provide a good starting point for developing these trends. Additional information was utilized to fully develop them across more years.

[27] 20 CSR 4240-22.030(7)(A)2
[28] 20 CSR 4240-22.030(4)(B)1

Figure 3.8: Air Conditioning Saturation, Survey Data Points and Fitted Curve[29]



Three other sources of survey information were used to complement Ameren Missouri's market potential study surveys and make the process of developing the saturation trend time series easier and more accurate. One was a series of surveys conducted by Ameren Missouri (then Union Electric Company) of its service territory households between 1982 and 1992. Next, a series of surveys of its households conducted by Kansas City Power and Light between 1996 and 2006, and published in its public IRP documents was used. The geographic proximity of KCP&L to Ameren Missouri contributes to its greater similarity compared to the entire West North Central Census Region, and the demographic make-up has greater similarity. Therefore, it is a preferable source of secondary data to the EIA information. Finally, information from a statewide survey of Missouri households conducted by RLW Analytics in 2006 was also incorporated. The Ameren Missouri market potential studies were conducted in 2009 and 2013, so a set of observations spanning the period between 1982 and 2013 was ultimately available. The approach used to develop the complete time series of saturation data for the historical and forecast period was to plot the points from all four survey sources and then fit a curve through the points. This methodology

[29] 20 CSR 4240-22.030(2)(D)3

took advantage of all of the best information available and resulted in what is almost certainly a more accurate representation of the Ameren Missouri customer base than the regional EIA data. Figure 3.8 is a graph of this process for residential central air conditioning. In this case, one can see how this approach allows the incorporation of different survey data, and also allows us to incorporate a trend in saturation that is reasonable – in this case growth at a decreasing rate. In the example above for central air conditioning, this methodology predicted a saturation of 93.1% in 2030 and at least 95.5% in 2043.

At the time of this forecast work, Ameren Missouri's market potential study was being conducted. After successful implementation of energy efficiency programs under MEEIA since 2012, it is expected to have higher saturation of certain end use stocks such as air conditioners. Since the study results were not available at the time of this forecast work, this forecast partially relied on the previous market potential studies.

Appliance saturation and efficiency data is an obvious and important explanatory variable in modeling electricity sales, but there are other important variables that need to be included. Other logical predictors of electricity sales include the number of households in the service territory, income, and weather. Although this sales forecast is based on 30 year normal weather, actual historical weather and actual observed loads are used to estimate model coefficients.

In the SAE framework, elasticities with respect to price and income are determined exogenously and included in the calculation of the independent variables.[30] The estimation of price and income elasticities is a complicated subject, and especially with regard to price elasticity, there is a great deal of literature on the subject. One paper that was reviewed identified 36 different studies with 123 estimates of short run residential price elasticity, and those estimates ranged from -2.01 to -0.004.[31]

Ameren Missouri’s approach to estimating elasticity parameters for each model was to start with a figure that was close to a central tendency from the literature reviewed where possible, incorporating recommendations from the consultant firm Itron where necessary to supplement the available information. After determining an appropriate starting point, the elasticity parameters were then adjusted up or down by small amounts to determine whether model statistics improved from the change. The elasticities used in the base case load forecast models were values that minimized the model mean absolute percent error (MAPE) over the estimation period.[32] The price elasticity in the base case load growth

[30] 20 CSR 4240-22.030(7)(A)1; 20 CSR 4240-22.060(4)(D)
[31] Espey, James A. and Molly Espey. “Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities.” Journal of Agricultural and Applied Economics, 36, 1 (April 2004):65-81.
[32] Differences between the base, high, and low load growth scenarios are discussed in section 3.1.6

residential model is -0.13. This is similar to the elasticity values used in prior Ameren Missouri IRPs.

Each model used a different economic driver, or a set of economic drivers. In the SAE model framework for residential sales, household income and the number of people per household in the service territory act as drivers for use per customer.

The functional framework of the SAE model is:[33]

$$Use\ per\ customer = B1 * ((cooling\ use) * (cooling\ index)) + B2 * ((heating\ use) * (heating\ index)) + B3 * ((other\ use) * (other\ index))^{34}$$

In each term the “index” variable captures past and future trends in appliance saturation and efficiency. This variable is characterizing changes over time in the stock of end use appliances within the service territory. The “use” variable is a combination of variables that characterize the utilization of those appliances, including household income, the number of people per household, heating & cooling degree days, and the relevant elasticities. As would be expected, income has a positive correlation with consumption (i.e. as people have more money they tend to consume more), price has a negative correlation (the higher the price of electricity the less people tend to use) and heating and cooling degree days have a positive correlation with usage (as the weather gets more extreme, more energy is required to condition the space in the home to a comfortable level). The specific form of cooling use, for example, is:

$$Cooling\ use = (persons\ per\ household\ \hat{}\ persons\ per\ household\ elasticity\ of\ use\ per\ customer) * (household\ income\ \hat{}\ household\ income\ elasticity\ of\ use\ per\ customer) * (electricity\ price\ 1\ year\ moving\ average\ \hat{}\ price\ elasticity\ of\ use\ per\ customer) * (index\ of\ cooling\ degree\ days)$$

The heating and other use variables are similar, except that the heating use variable includes heating degree days instead of cooling degree days, and the other use variable does not include a weather term.

The coefficients B1, B2, and B3 are estimated with ordinary least squares (OLS) regression. One advantage of the SAE approach is that it produces very high t-statistics for each variable relative to most econometric models. In the base case residential model, for example, the t-statistics for the heating, cooling, and other variables are 44.01, 51.42, and 45.89 respectively. The residential model also included an additional interaction variable

[33] 20 CSR 4240-22.030(6)(A)2
[34] 20 CSR 4240-22.030(4)(A)4

between xCool and Shoulder months. T-stat for this interaction variable is ~-2.00. The adjusted R-squared for that model is 0.98 with Mean Absolute Percentage Error (MAPE) of 2.29%.

For this IRP iteration a "COVID-19" variable was added to the SAE equation for the Residential and Commercial class. This variable was multiplied to the Heat, Cool, and Other End Uses. The variable was constructed as a binary variable and ranged from 0 to 2. A unit greater than 1 represents that load increased due to COVID-19, and a unit less than 1 means load decreased due to COVID-19. Residential load had a positive impact due to increased work from home, and Commercial had a negative impact caused by lockdowns and capacity requirements. The Covid variable is only applicable for the time March 2020 to December 2028. After 2028, Ameren Missouri assumes no impact due to COVID-19.

The SAE framework was also used for the four classes of commercial electricity sales: small general service (SGS), large general service (LGS), small primary service (SPS), and large primary service (LPS).

The functional form of the commercial SAE model is:

$$\begin{aligned} Use \;=\; & B1 * \big((cooling\ use) * (cooling\ index)\big) + B2 * \big((heating\ use) * (heating\ index)\big) \\ & + B3 * \big((other\ use) * (other\ index)\big) \end{aligned}$$

The coefficients B1, B2, and B3 were estimated with OLS regression.

The SAE approach used to forecast sales for the commercial rate classes is very similar to that used in the residential model. As with the residential class, the “index” variable includes past and forecasted data on appliance efficiency and saturation, while the “use” variable includes an economic driver, electricity prices, weather, and the appropriate elasticities. The end use index variables in the commercial SAE model also include consideration of the mix of building types in the rate class and associated estimates of electric intensity that we matched to our customer base with data from the Ameren Missouri Market Potential Study.

One difference between the commercial class SAE models and the residential SAE model is that in the residential model the SAE function is used to forecast use per customer, and a separate regression model predicts the number of customers. Total MWh sales in the residential class are the product of the result of the customer model and the SAE model. In the case of the commercial class, we are forecasting MWh sales with the SAE models rather than use per customer.

Econometric

The four industrial rate classes were forecasted without including estimates of appliance saturation or efficiency that distinguish the SAE models from more traditional econometric

Schedule MM-S14

models. The four industrial rate classes, SGS, LGS, SPS, and LPS lack the homogeneity necessary to make the SAE approach useful without having a robust history of primary customer information. Across households, appliance use and saturation is fairly homogeneous, and even within the commercial class there is some homogeneity, especially within building types. However, the industrial customers are much less homogenous. The way that a brewery, for example, uses electricity is likely to be quite different from the way that an aircraft manufacturer uses electricity, and the way an aircraft manufacturer uses electricity is likely to be quite different from a cement factory. Additionally, the SAE framework which has been utilized for the residential and commercial classes requires a significant history of end use information to identify end use trends, and such history is not readily available from any internal studies or external sources that have been identified. Ameren Missouri has collected a significant amount of primary data on these customers as a part of DSM market potential studies in 2009 and 2013, but has not used that data to perform end use forecasting for the reasons described above.[35] As additional studies are done, enough history may be developed to consider an end use approach, but the heterogeneous nature of the large industrial customers may still be an overriding factor in determining that econometric forecasts are preferable.

In order to produce a forecast of energy that is reasonable and is able to incorporate future changes in the economic environment and electricity prices, it is necessary to include a price term, a price elasticity parameter, an economic driver, and some elasticity with respect to the economic driver in a sales model. The SAE framework does this very well, but as noted above that form is not currently appropriate for Ameren Missouri's industrial class sales. In a typical econometric model this would be done by including price and an economic driver in the model as independent variables. The regression estimated coefficients would then serve as de facto elasticities.

In the case of Ameren Missouri's industrial sales data, however, that approach does not always work, so a slightly different approach was used. Price in particular is problematic because real prices trended flat to down over much of the historical estimation period of the sales models, and the period of time with price increases is largely overshadowed by the significant economic disruptions of the 2007-2009 recession. The result is that models with each factor input as standalone independent variables tend to produce coefficients for the price term that are either statistically insignificant, practically insignificant (i.e., a positive sign on the price coefficient), or both. A modification was chosen that combined price, output, and their respective elasticities into one composite independent variable.

The functional form was different from, but inspired by, the SAE framework:

[35] 20 CSR 4240-22.030(4)(A)1C; 20 CSR 4240-22.030(4)(A)3

$$Sales = B1 * (economic\ driver \hat{}\ economic\ driver\ elasticity) * (price\ \hat{}\ price\ elasticity) * index\ of\ billing/calendar\ days\ in\ the\ month + B2 * (CDD\ index) + B3 * (HDD\ Index)$$

Price, output, and their elasticities were combined into one term. As was the case with the SAE residential and commercial models, estimating elasticity was a challenge, because estimates of elasticity in electricity consumption vary widely. Initial elasticities were chosen that reflected a mid-point of estimates from the literature. Through an iterative process elasticities were chosen that minimized the MAPE over the sample period. A measure of billing or calendar days was added to the variable, to better reflect the changes in the volume of energy used in a month driven simply by the varying number of days of consumption that each month includes.

The composite independent variable didn't include a weather term. In each rate class, an index of CDD and HDD were added as separate independent variables. In each of the four cases, the weather terms remained in the model if they were both practically and statistically significant.

Other Forecasting Considerations – Historical DSM Impacts

There are a few minor changes in methodology that bear noting. First is the treatment of historical DSM program impacts on the load. At the time that the forecast work was executed for the 2014 and 2017 IRPs, Ameren Missouri's DSM programs under the MEEIA were relatively new. Since that time, Ameren Missouri has implemented programs that have achieved significant energy savings across almost all customer classes. Care must be taken not to "double-count" energy efficiency program impacts when using a methodology like SAE that accounts for efficiency trends on its own. Ameren Missouri's approach to this problem for the 2023 IRP was to "add back" the savings from the programs to the observed loads and create time series of dependent variable in the forecast models.[36] The forecast models were then executed based on the reconstituted loads (dependent variable). The estimates of the savings associated with historical programs are deducted from the forecast model outputs to create the future load projections. This approach makes sense in that the SAE end use driver variables were based off regional and secondary data about the stock of end using equipment in the service territory that would not have accounted for the specific impacts of our own programs.

It should also be noted that the anticipated savings of Ameren Missouri's third cycle of energy efficiency programs under the MEEIA programs are also subtracted from the load forecast projections. These programs are already being implemented and are not the subject of any decision making resulting from this IRP, and therefore these savings are

[36] 20 CSR 4240-22.030(6)(C)2

Schedule MM-S14

considered as a given that they will occur. All future DSM impacts beyond MEEIA cycles 2 and 3 (i.e., programs approved for implementation through December 2023) are excluded from the base forecast and are the subject of the DSM chapter of this IRP study.

Other Forecasting Considerations – Weather[37]

As in the past IRP forecasts, SAE models are typically built using three explanatory variables representing cooling, heating and other loads. However, for some classes, an additional explanatory variable was added to some of the models to reflect the fact that the customers in that class either use their heating or cooling equipment differently during different times of the year, or that there is a non-linearity in their weather response. This additional explanatory variable is constructed as interaction between month/season and one of the three primary variables in SAE model construction. This is especially applicable in a class where some subset of customers start cooling at one temperature, but another subset does so at a higher temperature. This additional term in the forecast equation captures these seasonal and non-linear weather effects. Additionally, the degree day break points are evaluated to ensure best model fit to the weather and load relationships. Table 3.3 below shows the degree day breakpoints used for heating and cooling for each class. To the extent that there are two values in the table, a non-linear response was detected and there will be an extra term in the forecasting equation. For the 2023 IRP, Ameren Missouri used a normal weather definition based on the years 1992-2021.

Table 3.3 Degree Day Break Points Used in Energy Modeling

Class	HDD	CDD
Residential	60	65
ComSGS	50	60
ComLGS	50	60
ComSPS	50	50
ComLPS	N/A	50

Other Forecasting Considerations – Customer Owned Solar PV

Over the past couple of years, there has been an increasing penetration of customer owned solar photovoltaic generating systems in Ameren Missouri's service territory especially with incentives mandated in SB 564. Generation from these systems appears to the utility as a reduction in demand for electricity. To capture the impact on demand for power supplied by the utility, we have incorporated an offset of load by using a projection of customer-owned generation in this forecast.

The rebate that Ameren Missouri offered to customers pursuant to applicable Missouri law drove a rapid increase in solar installations in recent years. The total amount paid for

[37] 20 CSR 4240-22.030(5)(A); 20 CSR 4240-22.030(2)(D)2

rebates were subsequently capped by regulatory agreement. In this forecast, we assumed that solar installations would continue at their current pace until 2024, during which time distributed solar is expected to begin to reach parity with utility rates, beginning with larger customers. Ameren Missouri expects the customer-owned solar to increase at a compound annual growth rate of approximately 8.6% between 2024 and 2043 (base case scenario). In this case, the cumulative installed customer-owned solar capacity is expected to reach approximately 145 MW in 2024, if SB 564 mandated rebates are fully subscribed and 700 MW by 2043 in Ameren Missouri's territory. The high load growth scenario assumes low adoption of customer owned solar (approximately 350 MW of cumulative installed customer owned solar capacity by 2043), and the low load growth scenario assumes high adoption of customer owned solar (approximately 1,400 MW of cumulative installed customer owned solar capacity by 2043) (Figure 3.9).

Figure 3.9: Cumulative Installed Private Solar (MW)

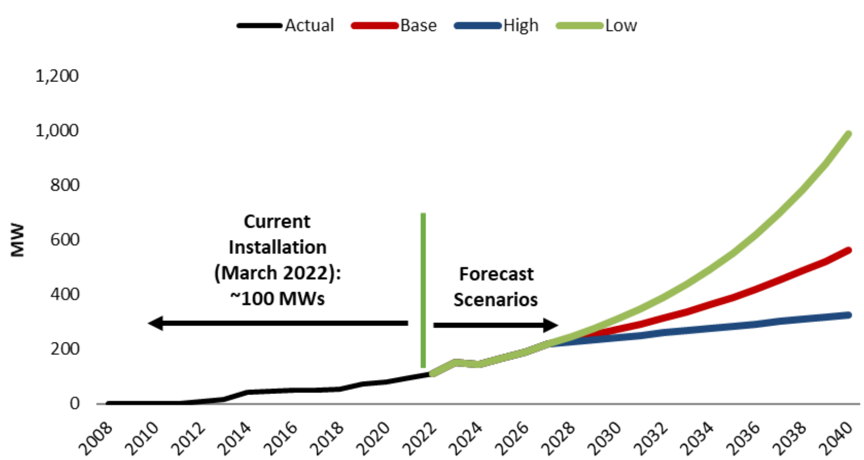
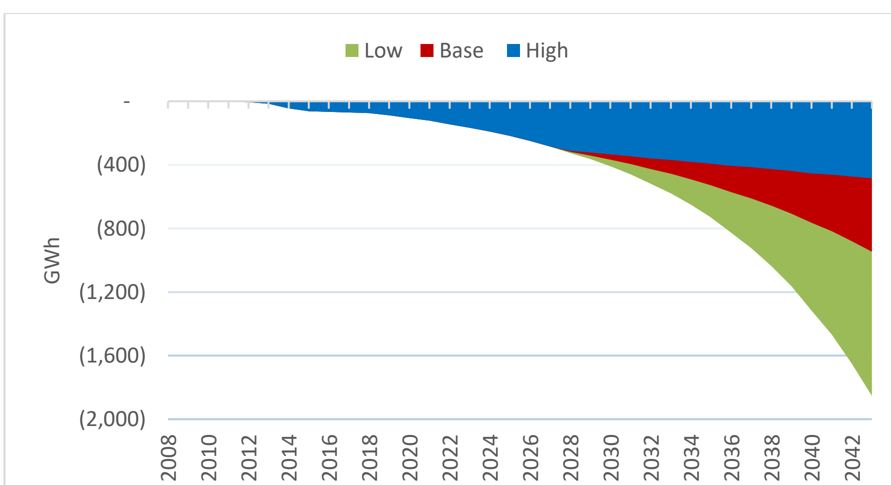


Figure 3.10: Cumulative Energy Reduction due to Solar Adoption (GWh)



Schedule MM-S14

Other Forecasting Considerations – Efficient Electrification[38]

At the time of the IRP 2020 publication, Ameren Missouri worked with EPRI to identify cost-effective and resilient strategies to produce and use clean energy. The two year work plan laid out research to identify efficient electrification opportunities in Missouri and specifically in Ameren's service territory. Based on this detailed statewide study, EPRI provided an initial estimation of potential impacts of efficient electrification on various end uses. This forecast includes projections of additional energy consumption from efficient electrification during the planning horizon. After discussions with internal EPRI members, it was concluded that the 2020 study was still valid for the 2023 IRP. Ameren Missouri's load forecast for the 2023 IRP incorporates the results from the 2020 study for the base and low load growth assumptions along with its current business targets for the years 2024 to 2027. For the High load Growth Scenario, the EPRI forecast was modified to include a larger EV adoption rate. The High load scenario now assumes by 2050 all 2.5 million vehicles in Ameren Missouri's service territory will be Electric. A brief description of the scope of the 2020 EPRI study has been provided below.

The EPRI study consisted of four tasks: Energy System Assessment, Environmental Assessment, High-level Transmission Assessment, and Electrification Potential and Implementation Plan. Additional details for each task are provided below.

- ***Task 1: Energy System Assessment (2020-2050)***

The U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) modeling system has been adapted in this task to conduct an integrated analysis of potential development paths for the energy system in Missouri.[39] US-REGEN has a national scope with flexible regional disaggregation based on state or sub-state-level data. US-REGEN combines a detailed capacity expansion and dispatch model of the electric sector with a detailed end-use model that includes a high resolution of economy-wide energy use, as well as a representation of upstream non-electric energy activities. For each scenario evaluated, the electric model is solved out to 2050, in five year time steps, to meet electric load at lowest economic costs. The end-use model is solved over the same time horizon, with iteratively updated electricity prices and hourly load shapes based on the changing end-use mix. A version of the model that evaluates Missouri as one of the 16 regions is being used to evaluate a series of Ameren-specified scenarios.

- ***Task 2: Environmental Assessment (2020-2050)***

US-REGEN outputs include projections of greenhouse gas (GHG) emissions namely carbon dioxide (CO_2) and methane (CH_4) and air pollution from the energy system. Estimated energy system CO_2 and CH_4 emissions changes include emissions associated with fossil resource energy development, extraction, distribution, and use. Changes in air

[38] 20 CSR 4240-22.030(7)(A)5
[39] US-REGEN Model documentation: http://eea.epri.com/models.html

emissions will be estimated for each scenario broken down by sector and geography to illustrate how electrification strategies could impact emissions over time and space.

Detailed air quality modeling is being conducted for the U.S. lower-48 to explore the implications of a set of high electrification and low electrification scenarios. The air quality analysis includes economy-wide emissions of air pollutants—including SO_2, NO_x, VOC, NH_3, CO and primary particulate matter—which are calculated by the US-REGEN model and examines the implications for ozone, PM2.5 and other air quality measures.

- ***Task 3: High Level Transmission Assessment (2020-2050)***

The results from Task 1, Energy System Assessment (supply side), details on the electric sector power generation mix and capacity, and demand side changes to overall energy demand and load shapes across the end-use sector of buildings, industry, and transportation form the basis of the high-level transmission assessment in Task 3. The transmission assessment will focus on enhancing the safety, reliability, and resiliency of bulk power and distribution system infrastructure consistent with the achieving the goals defined in the analysis scenarios.

The assessment in this task was conducted to understand the qualitative impacts on transmission needs in the state with particular attention to the following:

a) Assessment of potential ability of the system to incorporate increased loads based on knowledge of existing system
b) Description of operational implications of new loads and the new system resources required to meet those loads
c) Guidance for utility internal follow-up study of these issues

- ***Task 4: Electrification Potential and Implementation Plan***

Incorporate the state-level results from Tasks 1, 2, and 3 into strategic, utility-specific guidance for the implementation of electrification programs to realize the economic and environmental benefits projected in the state-level analyses. This included energy technology assessments over the industrial, commercial, residential, and transportation sectors covering both energy-efficiency achievable potentials and opportunities for electrification. The final analysis includes: a utility-specific assessment of electric technologies, location-specific and across all customer classes, and a strategic vision and assessment for near- and long-term emerging technologies and their benefits and impacts. The resulting Customer Electrification Potential Model is used to guide near term program design as well as long-term strategic planning. The model is designed to incorporate other relevant data from prior analyses conducted by Ameren

Ameren Missouri's Customer Electrification Potential Model incorporates the best available data, organized by:

- Technology categories within the four customer classes

- Locational distribution of key technologies within the utility service territory
- Projected adoption of both current and emerging technologies from present day to 2050

The Technology Pipeline will be updated over time to include detailed analysis for technologies with high impact and high potential to deliver customer and societal benefits across the timeframe of the project, including:

- Evaluation of Electric Technology Characteristics: Changes in cost and performance over time; identification of energy and non-energy benefits
- Detailed analysis for high-impact, high-potential technologies, including:
  - Electric transportation (light, medium, and heavy-duty), material handling, airports, and rail and other transit terminals.
  - Residential and commercial space and water heating.
  - High impact industrial electrification opportunities.
  - High impact emerging technologies: Indoor agriculture, additive manufacturing, and others.
- Strategic vision and assessment for near and long-term emerging technologies and their benefits and impact
- Detailed System Impact: Hourly load shapes developed for each technology. Assessment of customer and grid flexibility for each technology

Implementation scenarios will be prioritized for utility specific opportunities and customer requirements, and will continue to leverage existing EPRI tools, including the Electrification Knowledge Base and the Technology Readiness Guide.

Projected increases in load from electrification for Ameren Missouri were estimated using the US Regional Economy, Greenhouse Gas, and Energy Model, an energy-economy model developed and maintained by the Electric Power Research Institute. US-REGEN analyses were the basis of the EPRI's U.S. National Electrification Assessment (USNEA), which explored the potential for efficient electrification across the U.S. for four core scenarios – two with and two without federal climate policy. Utilities in 14 states are conducting electrification assessments with the model. A central feature in the USNEA and in the runs made for Missouri is the assumption that customers have free choice to choose the technologies – electric or non-electric that make the most sense to them.

There are three cases defined for the Ameren IRP: The Low, Base and High Electrification scenarios. All use the same basic structure for the models as discussed earlier, but make changes to the input assumptions. The Low and Base case scenarios assume a low forecast of natural gas prices (developed by Ameren) and zero carbon price. In the High Electrification case, high natural gas price is used, as well as a countrywide, economy-wide carbon price. Additionally, for the Low Electrification case, the share of electric vehicle (EV) and other electrification is restricted to grow at a constant rate. In the base case, a $5,000 cost adder is added to the estimated future cost of electric vehicles, to account for the fact that battery prices may not fall as fast as EPRI projections. In addition, the study had assumed that autonomous vehicles are not developed. Finally, the High Electrification case uses the default assumptions from the EPRI NEA (except for Ameren's gas and CO_2 prices). The imposition of an economy-wide carbon tax tends to increase electrification, however, in some sectors, electrification decreases between the Base and High cases, because the much higher deployment of electric vehicles, fueled by the relative decrease in EV costs between the two scenarios as well as the economy-wide carbon price increases the cost of electricity, which reduces the incentive to electrify in other sectors. In order to ensure that the High Electrification case represents a true maximum potential for electrification, each sector's maximum load from across all the scenarios is used to construct the electric load in the High Electrification case. For the 2023 IRP, the team further increased EV adoption in the High Electrification case to show expected electrification if the region were on track to fully electrify on-road vehicles by 2050.

Other Forecasting Considerations – Electric Vehicle Adoption[40]

The IRP 2023 electrification forecast combines the current business plan and long term efficient electrification potential estimates from EPRI. All three scenarios utilize Ameren Missouri's internal five-year budget electrification projections through 2027. Beyond 2027, the low adoption scenario bypasses the economic choice mechanism in US-REGEN and assumes that the share of electric vehicles continues to increase at recent historical rates. The medium adoption scenario assumes that the purchase price of electric vehicles does not decline as rapidly as in the default assumptions, and the high electrification scenario has default assumptions and also assumes the Ameren Missouri service territory is on track to see full electrification of all 2.5 million on road vehicles by 2050. Figure 3.12 shows the projected share of electric vehicles from 2024-2043 in terms of total on road vehicles.

[40] 20 CSR 4240-22.030(7)(A)5; EO-2020-0047 1.B

Schedule MM-S14

Figure 3.12: Shares of Electric Vehicles by Number of Vehicles

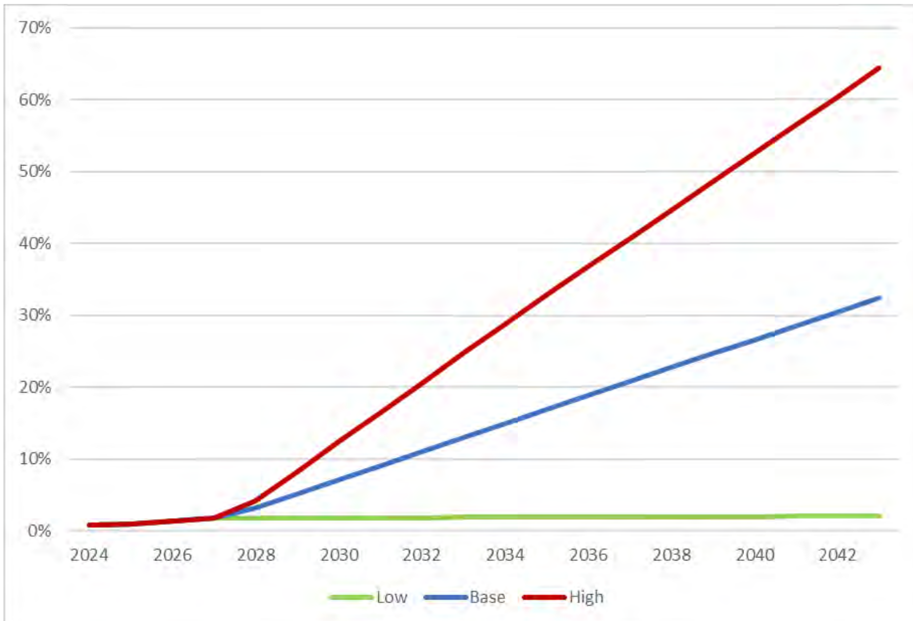
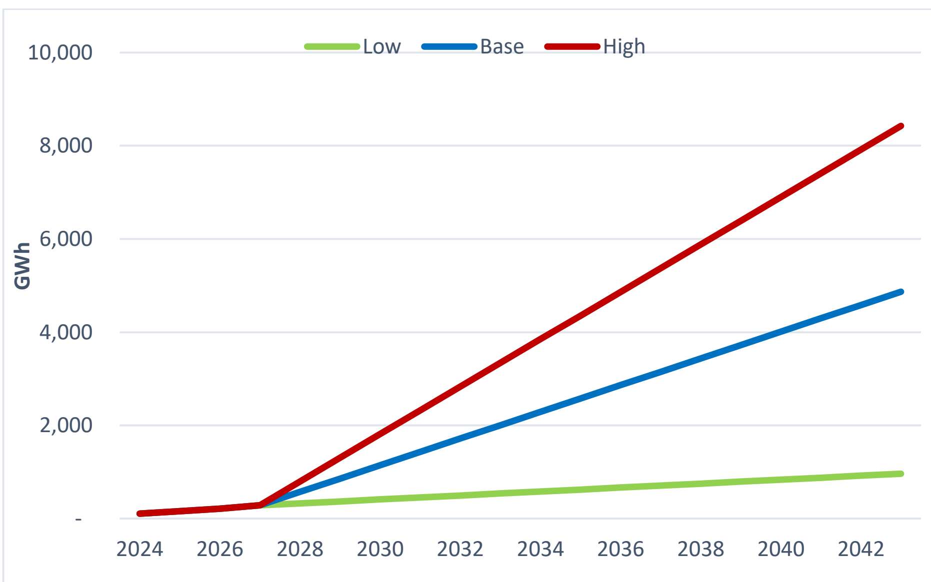


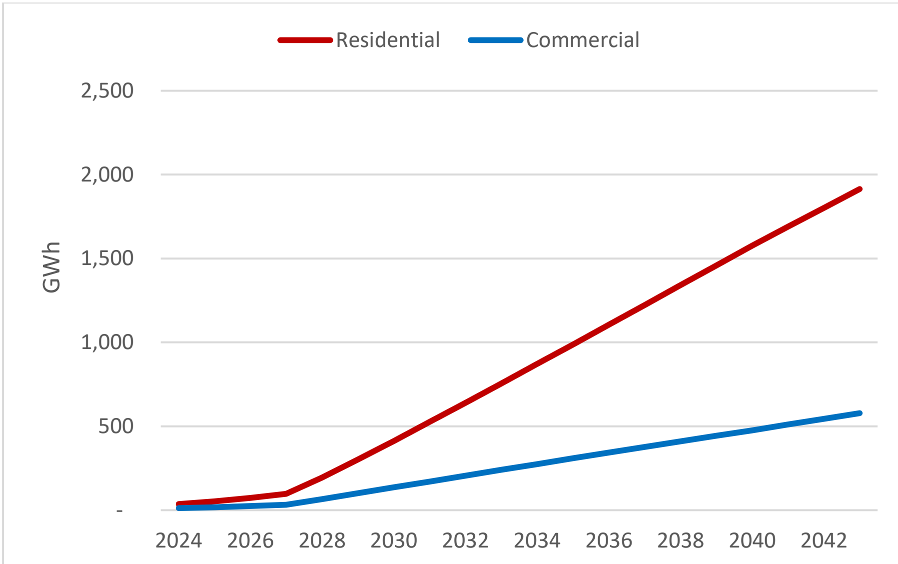
Figure 3.13 shows long term electrification projections used in different load forecasting scenarios. Figure 3.14 shows long term load growth projection from light duty electric vehicles adopted for residential and commercial classes.

Figure 3.13: Long-term electrification projection



Schedule MM-S14

Figure 3.14: Long-term Load Growth from Electric Vehicle Adoption in Base Case Scenario



Other Customer Class Forecasts

There are two other classes of energy sales which fell into neither the SAE nor econometric form of forecasting. Those two were Street Lighting and Public Authority (SLPA), and Dusk to Dawn lighting (DTD). SLPA and DTD sales are both functions of the light in a day and other seasonal factors such as time of the year. With the adoption of LED technologies, sales in the lighting categories are expected to decline. Hence, the projected sales in lighting categories are modeled as a function of the light bulb replacement with LED technologies along with a seasonal shape. This forecast assumes that all the streetlights will be replaced with LED by 2027.

Ameren Missouri's current business plan dictates to replace lightbulbs once they stop functioning and therefore, there is no pre-determined schedule for the LED installations. It's assumed that the annual kWh reduction due to LEDs will be similar year over year. Therefore, this forecast utilizes the kWh reduction in annual kWh sales in lighting classes from April 2021 to March 2022. After the annual reduction in lighting load was established, a monthly shape was applied to derive the monthly energy for the lighting classes.

Customer History and Forecasts

Forecasts of customer counts were produced at the rate class level; however, those forecasts were aggregated to revenue class for documentation purpose. In each case, an econometric approach was used with customers modeled as a function of an appropriate driver for that customer class, such as households, employment, or GDP.[41] The customer

[41] 20 CSR 4240-22.030(3)(A)

Schedule MM-S14

models may include dummy variables, end shift variables, or trends to capture the fact that customer growth and driver growth diverged over that part of the historical model estimation period to incorporate unusual effects of economic recession in 2008-2009 into the customer count growth. The models may also include auto-regressive and moving average terms as well as combinations of multiple of the aforementioned modeling approaches to smooth out the customer forecast in some cases.

3.1.6 Sensitivities and Scenarios[42]

The nature of the forecasting models used in this IRP forecast is such that the dependent variable (energy sales) is sensitive to changes in the independent variables as well as to the parameter estimates used to represent elasticity. This is a feature of econometric and SAE models, but it is worth mentioning here because it means that the forecast of energy sales is sensitive to changes in any one of the driver variables. The forecast of residential sales is sensitive to changes in households, electricity prices, income, population, and changes in appliance saturation and efficiency. Commercial and industrial sales are sensitive to changes in service territory GDP, employment, and electricity prices.

In this IRP, three different scenarios were modeled that stemmed from the combinations of assumptions about load growth, economic factors, customer owned renewable generation, electric vehicles and electrification of end uses. While the renewable generation forecasts were based on discussions with Ameren subject matter experts, the electrification projections were developed in consultation with EPRI. The scenario development process is discussed in Chapter 2.

In order to forecast high, base and low load growth scenarios, Ameren Missouri forecast team first developed energy forecast for various classes without including long-term projections of customer owned renewables and efficient electrification of end uses as described in previous sections. This added with various levels of customer owned renewables and efficient electrification provided base, high and low load growth forecast scenarios. Table 3.4 summarizes the key assumptions used to develop base, high and low load growth scenarios. In all the cases, the forecasts remain the same until 2027 and changes after that due to changing assumptions on solar and electrification to create different scenarios.

[42] 20 CSR 4240-22.030(8); 20 CSR 4240-22.030(8)(A)

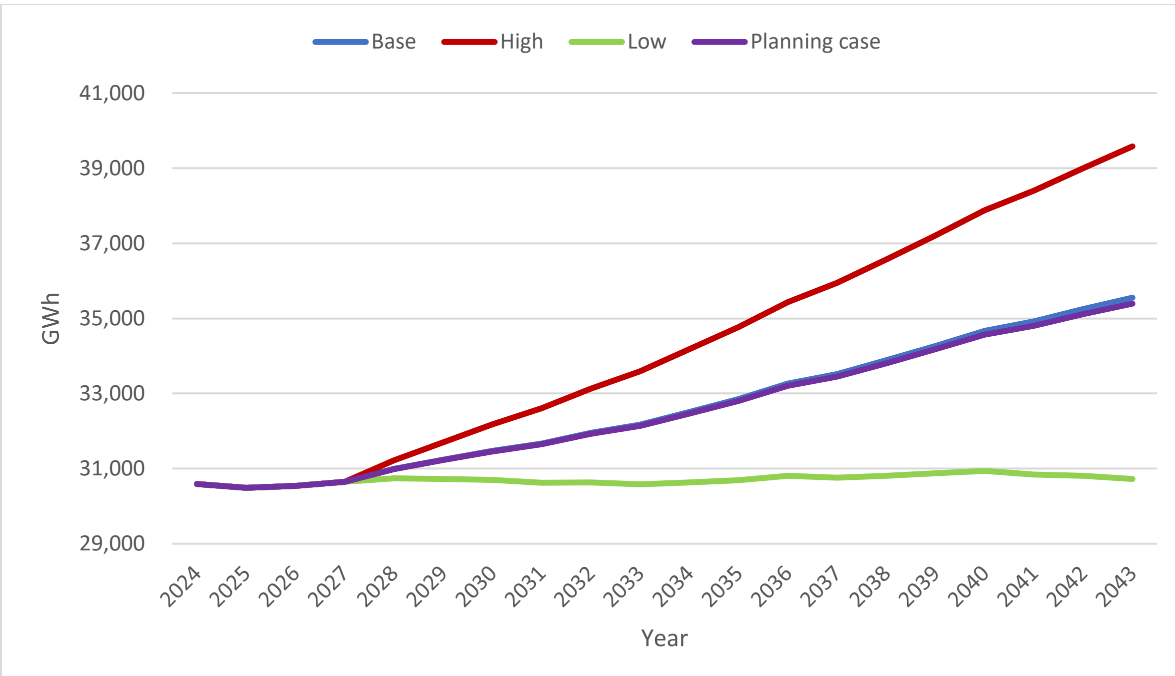
Table 3.4: Scenario Driver and Parameter Differences

	High Load Growth Assumptions (Low Solar and High Electrification)	Base Load Growth Assumptions	Low Load Growth Assumptions (High Solar and Low Electrification)
Res	• Solar adoption (20 year CAGR): 5.7% • EV adoption (20 year CAGR): 28.2%	• Price elasticity: -0.13 • Household size elasticity: 0.20 • Income elasticity: 0.40 • Solar adoption (20 year CAGR): 9.5% • Electrification (20 year CAGR): 23.2%	• Solar adoption (20 year CAGR): 13.4% • EV adoption (20 year CAGR):13.1%
Com	• Solar adoption (20 year CAGR): 4.1% • Electrification (20 year CAGR): 26.0%	• SGS Output 0.30, Price -0.17 • LGS Output 0.06, Price -0.11 • SPS Output 0.19, Price -0.06 • LPS Output 0.40, Price -0.06 • Solar adoption (20 year CAGR): 7.8% • Electrification (20 year CAGR): 22.4%	• Solar adoption (20 year CAGR): 11.7% • Electrification (20 year CAGR): 12.4%
Ind	• Solar adoption (20 year CAGR): 4.9% • Electrification (20 year CAGR): 21.0%	• SGS Output 0.75, Price -0.22, Output Weight 0.15 • LGS Output 0.60, Price -0.10, Output Weight 0.70 • SPS Output 0.25, Price -0.10, Output Weight 0.30 • LPS Output 0.05, Price -0.04, Output Weight 0.90 • Solar adoption (20 year CAGR): 8.7% • Electrification (20 year CAGR): 20.8%	• Solar adoption (20 year CAGR): 12.6% • Electrification trend (20 year CAGR): 11.0%

Schedule MM-S14

Statistical models built with assumptions provide us with energy forecasts for the corresponding scenarios. System energy forecasts are obtained by adding all individual class level energy forecasts. Comparisons of annual system energy forecasts associated with three scenarios are shown below in Figure 3.15.

Figure 3.15: Total Energy Sales Forecast by Scenario



3.1.7 Planning Case Forecast

The three scenarios described in section 3.1.6 describe the range of likely outcomes for load growth over the planning horizon. The single forecast that represents the expected value of load growth over the planning horizon is referred to as the planning case. This forecast is needed in order to have a base expectation against which candidate resource plans can be developed, as discussed in Chapter 9. The integration modeling is actually performed using each forecast scenario, but the plans were created in order to maintain an appropriate amount of capacity given expectations in the planning case.

The calculation of the planning case forecast is a fairly simple exercise. The subjective probabilities of each scenario, as determined by the subject matter experts for the various uncertain factors, were used to weight the different scenarios and thus determine a probability weighted average load. The planning case does not have its own set of forecast models with case specific drivers, but instead is derived from the modeling results for the three independently generated scenarios.

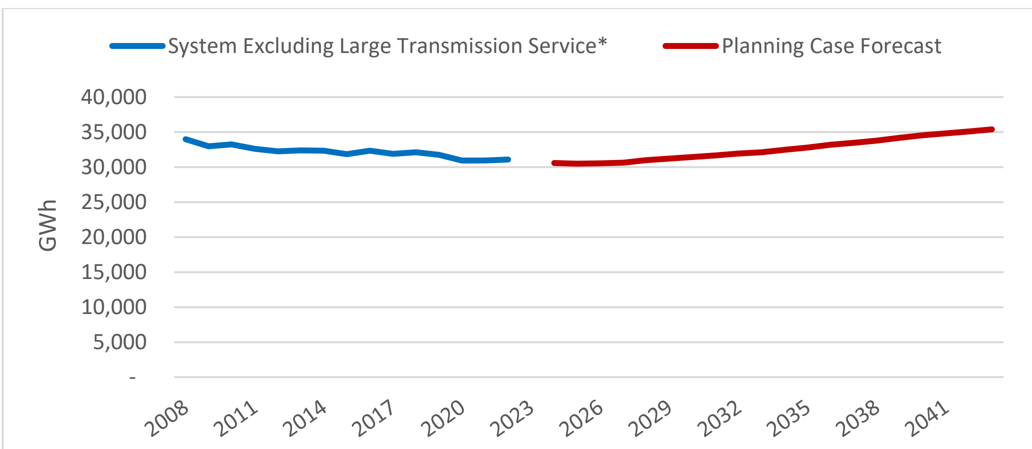
Schedule MM-S14

For this IRP analysis, 60% probability was assigned to base case scenario and 20% probability was assigned to each of high and low growth scenarios. Planning case forecast was developed using these probability weights.

3.1.8 Forecast Results

For the planning case, total retail energy sales are expected to grow at 0.8% compound annual rate between 2024 and 2043. In the last decade, total retail sales declined primarily due to the naturally occurring and company sponsored energy efficiency programs and a decline in consumption by the aluminum smelter. Sales dipped sharply in 2009 and went through an uneven period of recovery following the recession. Post-recession recovery was also offset by naturally occurring and company sponsored energy efficiency programs. Despite projecting steady economic growth over the near term period, loads are forecast to remain essentially flat because of the impact of efficiency standards and programs. As mentioned earlier, the load forecast scenarios only incorporate savings from MEEIA 3 cycles through the program year ending in December 2023.[43]

Figure 3.16: Planning Case energy sales forecast



**Historical sales have been adjusted to reflect that Ameren Missouri does not serve any customer in Large Transmission rate class at this time.*

The severe recession that the U.S. experienced depressed service territory electricity sales. Residential sales fell by 0.9% in 2009, commercial sales fell by 1.0%, and Industrial sales, exclusive of large smelter customer, fell by 13.6%. Energy efficiency programs under MEEIA (Cycle 1, 2 and 3) have incrementally reduced sales by ~1% in each of its program years. As the economy recovered from the severe recession, Ameren Missouri's residential and commercial customer count began growing at a historically slow, yet steady pace. Over the past three years, Ameren Missouri's customer counts in residential and commercial classes have grown steadily between 0.5 and 1% year over year. However, the savings

[43] 20 CSR 4240-22.030(7)(A)3

Schedule MM-S14

from energy efficiency programs have diminished any sales growth achieved as a result of this customer growth. Also, after experiencing significant economic growth for past several years, Ameren Missouri's economic projections expect a slowdown in the economy in the near term. Additionally, the implementation of LED technologies in the lighting classes reduces sales to the lighting categories significantly over four years. (Figure 3.16).

Table 3.5: Planning Case (2024-2043) Annual Sales Growth by Class

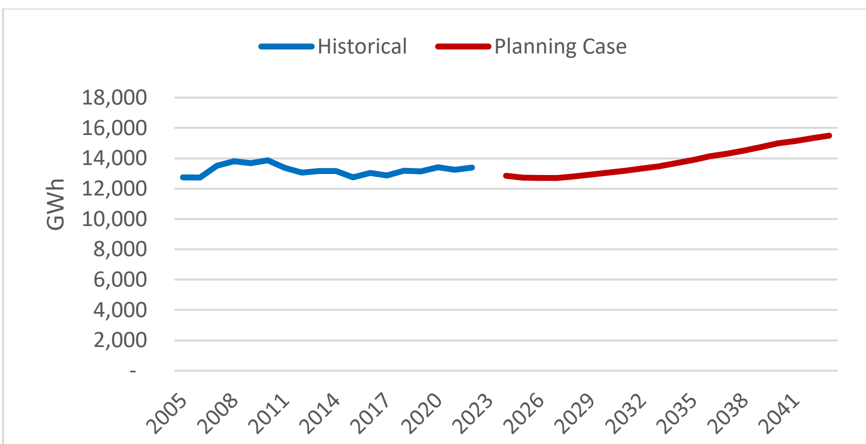
Year	Residential	Commercial	Industrial	Lighting	Total
2024	-0.6%	0.4%	0.5%	-1.8%	0.0%
2025	-1.0%	0.0%	0.7%	-1.8%	-0.3%
2026	-0.1%	0.2%	0.8%	-1.9%	0.2%
2027	0.0%	0.6%	0.9%	-1.9%	0.4%
2028	0.9%	1.0%	2.3%	0.0%	1.1%
2029	0.9%	0.3%	1.9%	0.0%	0.8%
2030	0.9%	0.2%	1.8%	0.0%	0.7%
2031	0.9%	0.0%	1.5%	0.0%	0.6%
2032	1.3%	0.3%	1.5%	0.0%	0.9%
2033	1.0%	0.1%	1.4%	0.0%	0.7%
2034	1.5%	0.5%	1.3%	0.0%	1.0%
2035	1.5%	0.5%	1.3%	0.0%	1.0%
2036	1.8%	0.6%	1.3%	0.0%	1.2%
2037	1.2%	0.1%	1.2%	0.0%	0.7%
2038	1.5%	0.6%	1.2%	0.0%	1.1%
2039	1.5%	0.6%	1.2%	0.0%	1.1%
2040	1.7%	0.6%	1.2%	0.0%	1.1%
2041	1.0%	0.1%	1.2%	0.0%	0.7%
2042	1.2%	0.4%	1.3%	0.0%	0.9%
2043	1.1%	0.3%	1.2%	0.0%	0.8%

One seemingly trivial feature of our sales modeling affecting sales growth is leap day. In each of our models, the number of calendar days in the month is included as an explanatory variable; either on its own or combined with another. Each leap year is one day, or 0.27% longer than normal, and that extra day is in a month when we typically experience meaningful heating load. That causes sales growth in every leap year to be slightly higher than it otherwise would be, and growth in each year that follows a leap year to be slightly lower. This isn't noticeable in Figure 3.17, but is noticeable in Table 3.5. The impact of leap years on sales is in one sense trivial, and doesn't meaningfully affect capacity planning, which is of course the central goal of the IRP. It is, however, a logical and observable result of the detailed modeling used in the forecasting process.

Residential

Between 2006 and 2016, residential class weather normalized sales grew at a compound annual rate of 0.24%. This period was characterized by three distinctly different trends, however. From 2006 through 2008, residential load grew at a robust pace of around 4.1%. Beginning around the time of the 2007-2009 recession, followed by the years when Ameren Missouri’s energy efficiency program spending ramped up, trajectory of residential load flattened considerably. The economic impacts of the recession and post-recession recovery coincided with increasing energy efficiency program impacts during this period. The result is load characterized by years that have been either close to flat in terms of load growth or even declining in some years. Residential load between 2005 and 2012 changed at a compound annual rate of 0.36%. The period beginning with 2013 exhibited slow, yet steady year over year customer growth. However, Ameren Missouri also started the first cycle of MEEIA programs in 2013, which had incrementally reduced energy sales by approximately 1% during each of its program years. Customer count in residential class has been growing modestly in the past three years. Sales growth due to customer growth between 2013 and 2022 was diminished by naturally occurring and company sponsored energy efficiency programs. Residential Sales grew in 2020 by 2.0% due to the COVID-19 pandemic and an increase in telework. This trend is like the trends seen in other utilities and nationwide.

Figure 3.17: Planning Case Forecast of Residential Energy Sales



In the planning case forecast, residential load is anticipated to grow at a compound annual rate of 1.0% between 2024 and 2043.

The number of residential customers is expected to grow at a compound average rate of 0.08% between 2024 and 2043. Compared to historical standards, customer growth has been rather modest since the recovery from the recession years of 2008-2009. Ameren Missouri's residential customer count grew at a compound annual rate of 0.3% between 2009 and 2022. The forecast assumes that the residential customer count will continue the slow, yet steady growth over the planning horizon at an annual compound growth rate of 0.1%.

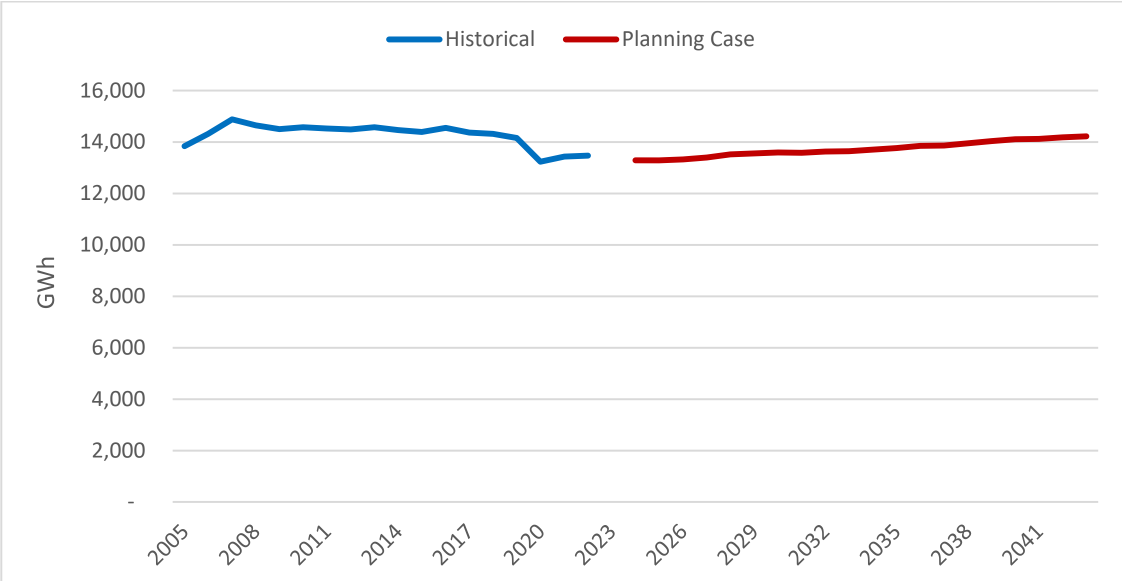
Use per customer growth in the residential class is expected to remain modestly declining for the first few years of the forecast horizon. Again, customer owned distributed energy resources, efficiency standards of appliances and MEEIA programs hold average customer consumption down during this time. Use per customer increases slowly as already approved standards transform the stock of end use appliances and equipment and more electrification takes hold at the end use level.

Commercial

Prior to the COVID-19 pandemic, Ameren Missouri commercial class sales have been the fastest growing segment of sales over the period of historical review for this IRP, partially reflecting the shift away from manufacturing toward health and education services in the service territory economy, and partially because of the growth of new types of commercial load such as data centers. Between 2004 and 2012, weather normalized sales grew at a compound annual rate of 1.0%. Like residential sales, commercial sales were impacted by the recession and have grown more slowly than the previous historical trend since 2009 due to naturally occurring and company sponsored energy efficiency programs. During 2020, Ameren Missouri Commercial Sales decreased 6.6% due to remote work, government lockdowns, and capacity restrictions on businesses. Since 2020, Commercial sales have seen a recovery, but are still below 2019 levels.

Three different factors contributed to the load growth prior to 2020. From 2006 through 2008, commercial load grew at a robust pace of around 1.1%. The recession between 2007 and 2009 combined with Ameren Missouri's energy efficiency programs flattened the trajectory of commercial load considerably. The economic impacts of the recession and post-recession recovery coincided with increases in energy efficiency savings during this time period. Customer count has been growing at a year over year rate slightly below 1% since 2012. However, Ameren Missouri also started the first cycle of MEEIA programs in 2013, which had incrementally reduced energy sales by little less than 1% in each of its program years. As savings from MEEIA programs are fully realized, Ameren Missouri expects customer owned distributed energy resources will increase which will further impact the growth in sales to commercial customers. However, positive impacts from electrification of end uses may stabilize the decline in the sales. Ameren Missouri anticipates commercial sales to grow at a compound annual rate of 0.4% in the planning scenario over next 20 years.

Figure 3.18: Planning Case Forecast of Commercial Class Energy Sales



Industrial

Ameren Missouri industrial class sales have been experiencing a structural decline for more than a decade. Compounding this decline was the significant toll the 2007-2009 recession took on the service territory manufacturing base. The decline in manufacturing activity was not one confined to the Ameren Missouri service territory; national manufacturing severely contracted during the recession as well. However, industrial loads elsewhere recovered at least a significant portion of their losses in the years of slow recovery since the recession. Ameren Missouri's industrial load remained relatively flat to modestly declining in those years.

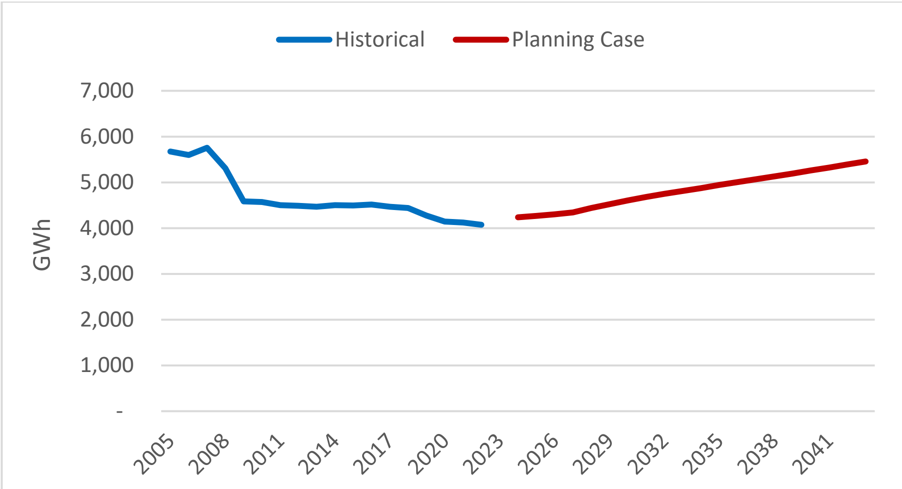
Casualties of this decline in the service territory manufacturing base include the Ford Assembly plant in Hazelwood, Missouri, which closed in 2003, and the Chrysler plant in Fenton Missouri, which closed in 2010. Between 2009 and 2022, Ameren Missouri's industrial sales declined at a compound annual rate of 0.9%. Note that Ameren Missouri's largest single customer by far in the past decade, the aluminum smelter in New Madrid, Missouri, is not included in these industrial load statistics, as this customer is no longer an Ameren Missouri customer.

The planning case forecast calls for industrial sales growth at a compound annual rate of 1.3% between 2024 and 2043, primarily driven by significant potential from efficient electrification. While the overall industrial forecast is directionally positive after the long-term industrial sales decline that has been experienced in the recent years, expected growth without electrification is still flat. In fact, the forecast does not anticipate that the

Schedule MM-S14

industrial sales will reach pre-recession levels at all during the planning horizon without efficient electrification.

Figure 3.19: Planning Case Forecast of Industrial Class Energy Sales



Customer Forecast

The forecasts of customers for the residential, commercial and industrial classes are reasonable given the performance of customer growth over the prior decade. The historical growth rates shown in Table 3.6 below are impacted by the 2007-2009 recession, which caused declines or at least a significant slowing of growth for all classes. Going forward, we expect the modest growth that has developed since the recession ended to continue to accelerate for a few years, before the forces associated with demographic and economic trends begin to slow the growth in customer counts.

Table 3.6: Customer Growth Rates

Year	Residential	Commercial	Industrial
2009-2022	0.3%	0.7%	-1.8%
2024-2043	0.1%	0.7%	-0.2%

Lighting and Other

We anticipate reduction in energy consumption in the Dusk-to-Dawn lighting classes due to expected conversion to LED technologies. Once all the light bulbs are converted into LEDs by 2027, there is no anticipated change in the consumption level during the planning horizon. Overall compound annual growth rate (CAGR) is -0.3% in lighting classes during the planning horizon.

3.2 Peak and Hourly System Load Forecast

The peak demand forecast is of critical importance to the IRP. The demand on the system at the hour of peak drives the need for generating capacity. While the need for energy influences the optimal mix of generation resources, the timing and amount of capacity additions are most directly tied to peak demand.

The system load forecast, as in years past, is done on a bottom up basis. This means that the load is forecasted by aggregating customer class loads and their associated transmission and distribution losses in order to represent all energy consumed on the system. As in prior IRP forecasts, there is an additional level of granularity in this forecast stemming from the fact that the bottom up forecast is being built from the level of the end-use load when possible rather than just the customer class load. The energy forecast is prepared on an end use basis for the residential and commercial classes as described previously. Each end use that has an energy forecast also has an accompanying load profile to shape it into an hourly forecast. These individual end use forecasts are aggregated to the class level. Where end-use energy forecasts are not available, particularly in the industrial class, class level profile models based off of load research data are used to shape the hourly forecast. Class level forecasts based on the aggregated end uses or class level models have appropriate loss factors applied to them and are then added to create the system level forecast. The maximum load hour from the system load forecast for each year becomes the annual forecast peak load.

3.2.1 Historical Peak and System Load

Ameren Missouri's historical database of actual and weather normalized class and system demands is maintained back to July 2003.[44] Actual hourly system data is available back to the beginning of January 2001. Earlier data for both class demands and system loads does exist, but is not applicable to the Missouri jurisdiction only. Prior to 2005, Ameren Missouri served the Metro East load in Illinois. For the periods described above, the data was able to be disaggregated into its Missouri and Illinois components. For earlier data, the detail needed to perform this disaggregation was no longer available at the time of the Metro East transfer.

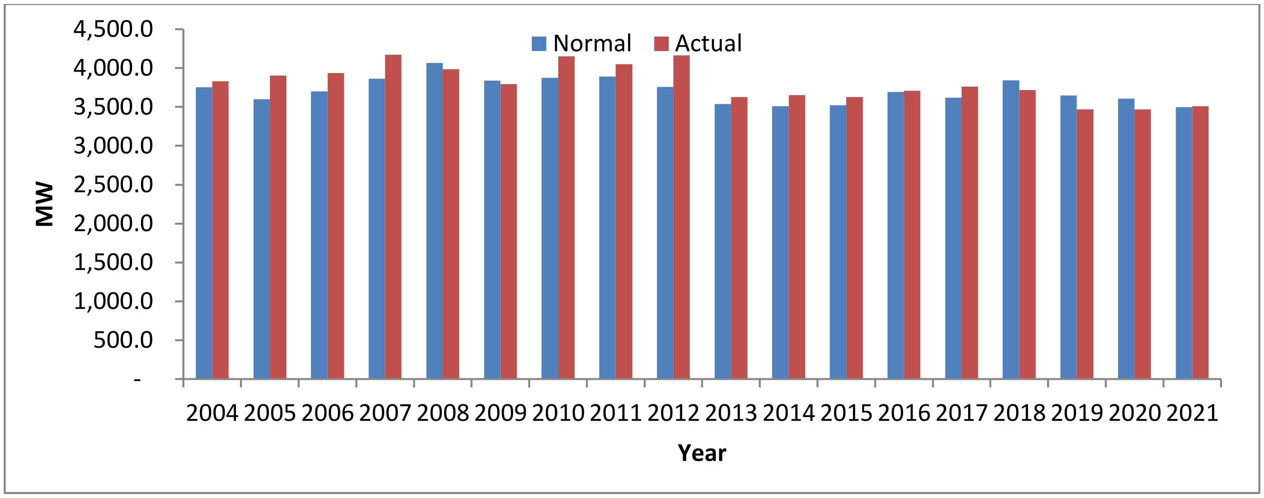
All class demand data is based on Ameren Missouri's load research program. As a part of the load research process, hourly class demands are calibrated to the observed system load to ensure that all energy consumed on the system is attributed to classes appropriately.

[44] 20 CSR 4240-22.030(2)(B)3

Schedule MM-S14

The annual coincident peak demand, on a weather normalized basis, for the residential class from the year 2004 to 2016 declined at a compound annual rate of 0.1%. Between 2008 and 2021, residential class demand declined at a compound annual rate of 1.2%. The class load dropped from a weather normalized 4,065 MW in 2008 to 3,497 MW in 2021 (at generation, i.e., inclusive of transmission and distribution losses). On an actual basis (not weather normalized), the residential class load reached its highest level on August 15, 2007, when the temperature in St. Louis reached 105 degrees Fahrenheit. On that day, the highest hourly integrated residential demand at the time of system peak was 4,174 MW.

Figure 3.20: Residential Coincident Peak Demand (MW)



For the commercial class, the annual coincident peak demand declined at 0.6% per year, from a weather normalized 2,983 MW in 2008 to 2,748 MW in 2021 (at generation, i.e., inclusive of transmission and distribution losses). On an actual basis, the commercial class load reached its highest level in 2011, with an hourly integrated demand of 3,127 MW.

The industrial class annual coincident peak demand declined on a weather normalized basis from the year 2008 to 2021 by approximately 1.9% per year. The normalized class demand increased modestly between 2004 (859 MW) and 2005 (934 MW), but fell rapidly through the recession of 2007-2009 and ended 2012 at 713 MW. Industrial peak further declined over the next nine years with a 2021 normalized peak load of 626 MW. There was broad based weakness across this class, but a couple of specific large customer closures coupled with energy efficiency programs had a significant impact on such reduction over last decade. For the industrial class, 2007 saw the highest actual coincident peak demand at 940 MW.

Figure 3.21: Commercial Coincident Peak Demand (in MW)

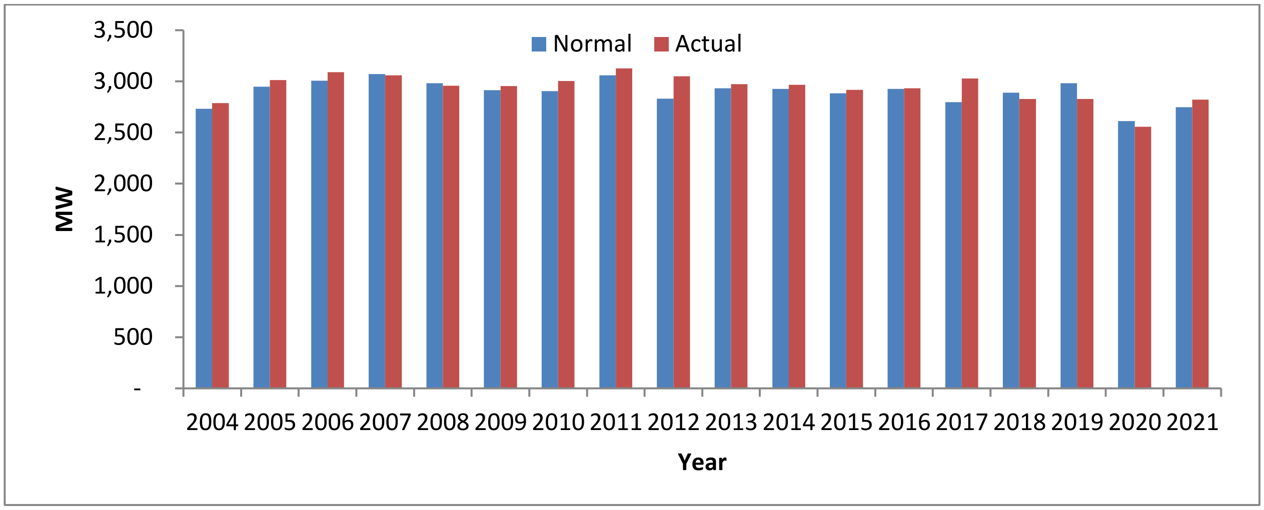
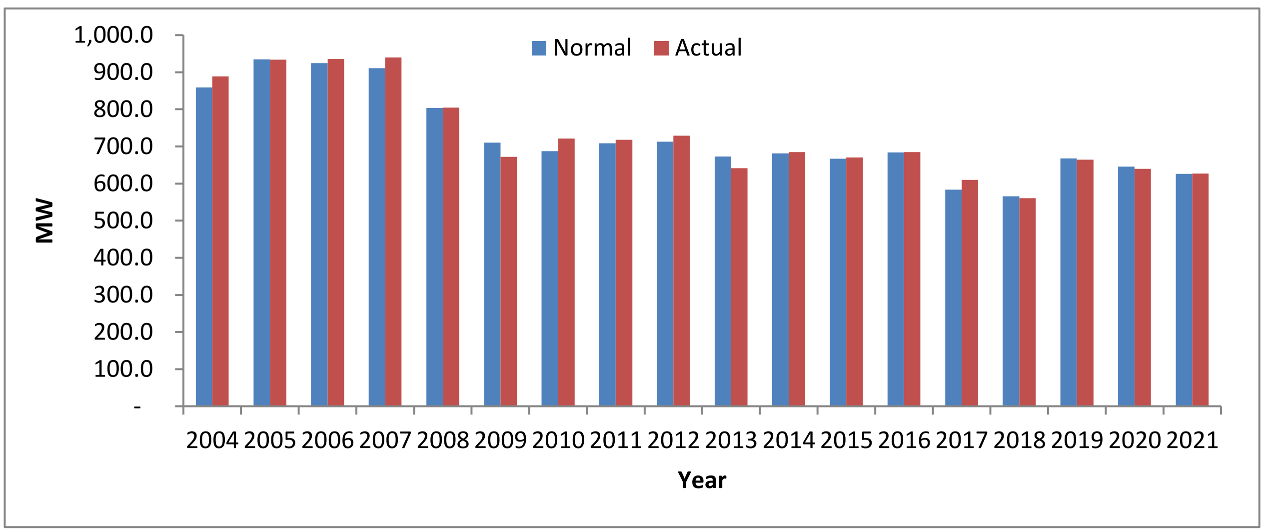


Figure 3.22: Industrial Coincident Peak Demand (MW)



3.2.2 Profile Shapes

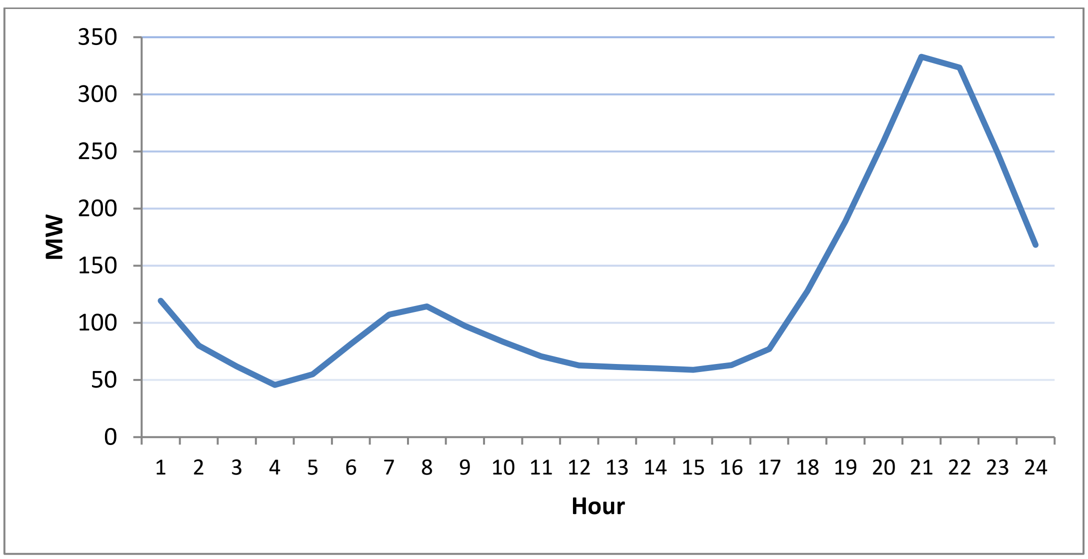
The energy forecast provides a view of how much energy is expected to be used by each category of end use for each customer class where applicable and for each total class where end uses are not contemplated in the energy forecast. The challenge of developing a system peak and hourly forecast comes down to determining when that usage will occur. This problem is well-suited to the application of load research data. For the industrial classes that were forecasted using econometric models (no end-use detail), Ameren Missouri specific load research data is used to determine that pattern of usage.

Schedule MM-S14

For the residential and commercial classes, the energy forecast from the SAE models can be disaggregated into its end-use components relatively easily. Because of various changes in energy efficiency standards for different end uses as well as differences in the natural growth of the stock of each end-use appliance in the service territory, it was hypothesized that a more accurate peak and hourly forecast could be generated by applying specific end-use shapes to this end-use energy forecast.

To illustrate the point, consider the lighting end use. Lighting is most prominently used by residential customers after sunset to illuminate homes in the evening. The summer peak load, which is arguably the most critical component of this forecast, will almost certainly occur late in the afternoon on a summer weekday. At this time, the sun is shining brightly and lighting use is relatively low for residential customers compared to the evening. A typical lighting load shape is shown in Figure 3.23, note the peak at hour 21 and the fact that hour 17 (likely the summer system peak hour) energy is only 23% of the peak.

Figure 3.23: Lighting Load Shape



Because EISA (issued in 2007) included standards to increase the efficiency of most light bulbs used by residential customers, the energy forecast associated with lighting is actually declining fairly significantly relative to other end uses over the planning horizon. If a class level model was used to forecast the residential summer peak, the decline in lighting load would produce a 1 for 1 decline in the summer peak. In other words, if lighting load hypothetically represented 10% of the residential energy usage, and the forecast included a 10% decrease in lighting energy, then the peak load forecast would be 1% lower (10% lighting share * 10% decline in lighting load = 1% decline in total load). However, under the end-use profile framework, lighting may still hypothetically represent 10% of the residential energy consumption, and it may still decline by 10% in a forecast year, but because the lighting profile is at a relatively lower level during the summer peak hours (23% of the peak lighting usage and 63% of the average lighting usage), the lighting contribution to peak will cause something less than a 1% decline in peak load. More of the decline induced by the lighting efficiency gains will be associated with energy usage that occurs later in the evening, not affecting the peak. As this example highlights, by assigning specific end-use profiles to the end-use energy forecast, more realistic load impacts on the peak should result.

Unfortunately, neither Ameren Missouri, nor any other utility of which we are aware, currently collects load research data at the end use level. So for developing load shapes that are applicable to the end use energy forecast, secondary data must be acquired.

Itron's eShapes Database

End-use load research can be a very costly activity. Whereas traditional load research utilizes the existing meter and meter reading infrastructure, end-use load research typically requires the utility to install additional equipment within the premises of the customer and develop a new infrastructure for collecting this data. The cost of it is generally prohibitive, and end-use load research programs are not common today as a result. However, in the 1990's a number of utilities did engage in end-use load research, and the data collected was shared through EPRI.

Itron, an industry leading forecasting and load analysis consulting company, has a product called eShapes, a database of load shapes that apply to loads from various combinations of end use, customer class, and geographic location. The data underlying Itron's eShapes database is proprietary, but has been publicly available for years and is relied upon widely as a high quality set of end-use load shapes. Ameren Missouri has acquired the Itron eShapes database and utilized its load shapes in its peak and hourly load forecasting process.

Load Shape Calibration[45]

Because the data in Itron's eShapes database is secondary data and probably more than a decade old, and more recent and geographically similar data is nearly impossible to come by, Ameren Missouri worked with this data to ensure that it was as applicable to the Ameren Missouri load as possible. For a three year period (2010-2012), the Itron data was utilized to construct Ameren Missouri class level data from the bottom-up. Historical energy sales for 2010-2012 were divided into end uses based on information from the SAE forecasting models. The eShapes profiles for each end use were then scaled so that they represented the estimated energy from those years. The scaled end-use shapes were then aggregated to create a "synthetic" class level load shape. That synthetic load shape was then compared to the Ameren Missouri load research data for the same class to determine whether the

[45] 20 CSR 4240-22.030(4)(B)2; 20 CSR 4240-22.030(1)(C); 20 CSR 4240-22.030(1)(D)

resultant bottom-up shape was an accurate representation of the relevant load. The eShapes profiles were then calibrated to ensure that the load shapes utilized in the final forecast were a good representation of the load for the class.

For the weather sensitive end uses (heating and cooling), it was necessary to build a regression model of the load temperature relationship of the end use in order to make the load shapes applicable to the historical period in question given the weather that occurred. The data used in the model in the case of these end uses did not come directly from the eShapes database, but instead was based on the end-use data simulated for Ameren Missouri by Itron for its 2008 IRP filing. The actual weather from the study years was applied to the model coefficients to produce weather sensitive heating and cooling shapes that are based off of the weather experienced in that year.

The synthetic class load shapes were plotted on graphs against the load research data to allow for visual inspection of the loads side by side. Also an hourly error series was developed by subtracting the load research from the synthetic class load. This error series was examined by averaging it across several time dimensions (hour of the day, day of the week, month) to determine whether there were systematic ways in which the synthetic load profile was varying from the load research data. It quickly became apparent that the average hourly class load shape that had been generated from the end-use data was not consistent with the load shape observed from the load research data. This is not surprising, as again, the end-use load research is secondary data and is removed from its original source in both time and geography. Figure 3.24 shows the average hourly error pattern that was generated in this process for the residential class.

As is apparent in Figure 3.24, the synthetic class load shape was too high during the late morning and evening hours (generating a positive error pattern) and too low in the mid-afternoon hours (generating a negative error pattern). In order to improve the fit of the build-up load, the individual end-use load shapes were adjusted slightly. The overall characteristic of the shape was respected, as the eShapes data is the best information available to discern the usage patterns of these end uses. However, the load factor of each shape was adjusted up or down using the unitized load calculation. An algorithm was set up to vary each end-use load shape within certain parameters judged by the forecasting staff to be reasonable, with the goal of minimizing the sum of the hourly absolute errors in the calculation represented by the chart above. Through this process, using the adjusted end-use load shapes, the hourly pattern in the error was reduced significantly. Below is an example of an end-use load shape both before and after load factor adjustment.

Figure 3.24: Average Hourly Difference-End Use Build Up vs. Load Research

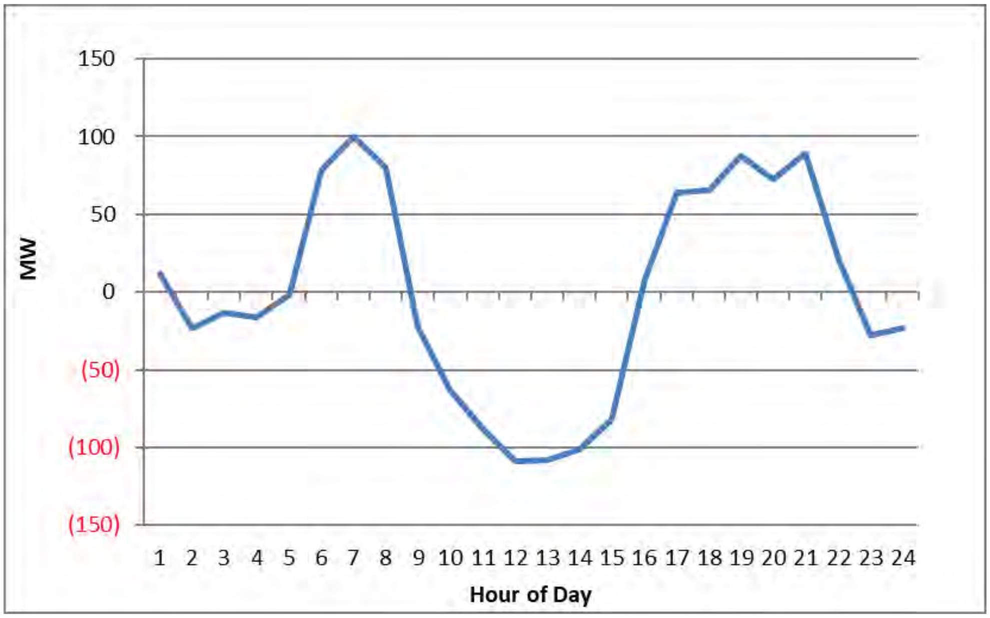
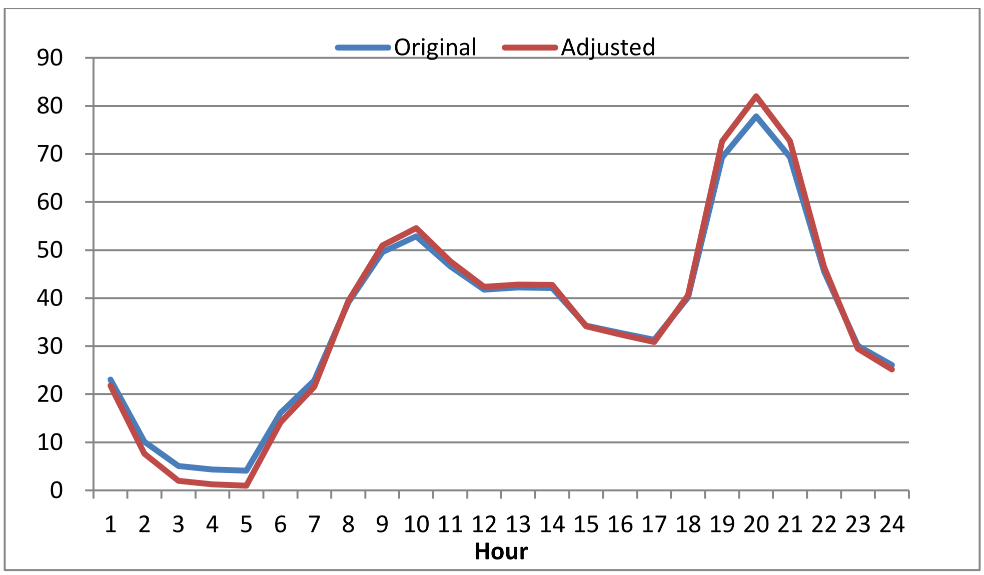


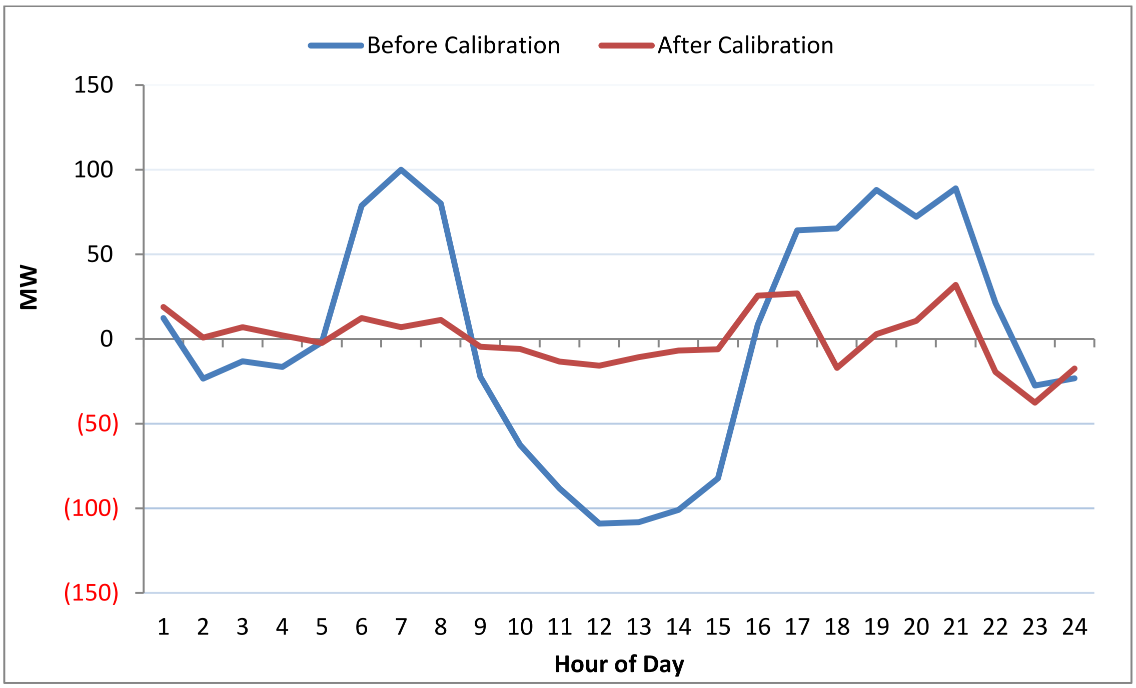
Figure 3.25: Dishwasher Load Shapes



As is visible in the chart of the dishwasher shape, the basic characteristic is retained, but the load factor is reduced in this instance (the peak of the adjusted shape is higher relative to the total energy). Each end use was reviewed and a similar adjustment process applied until the error pattern in the difference series was minimized. The final load shapes for each end use will be included in a chart in the final filing. The pattern of the hourly differences before and after adjustment is shown in Figure 3.26.

While the adjusted load shape still exhibits some differences from the class actual load shape, the magnitude of the differences is clearly reduced by a substantial amount. It would be impossible to make the synthetic load shape have a perfect fit with the load research data while respecting the characteristic shape of each end use. But with reasonable adjustments, the fit was dramatically improved. Where the original load shape had absolute differences that exceeded 100 MW at times, now no hour's difference exceeds 35 MW as shown in Figure 3.26. This innovative process helped bring the secondary data much more in line with the specific characteristics of the Ameren Missouri service territory loads. The forecasting staff reviewed the adjusted load shape for each individual end use to confirm that it was reasonable.

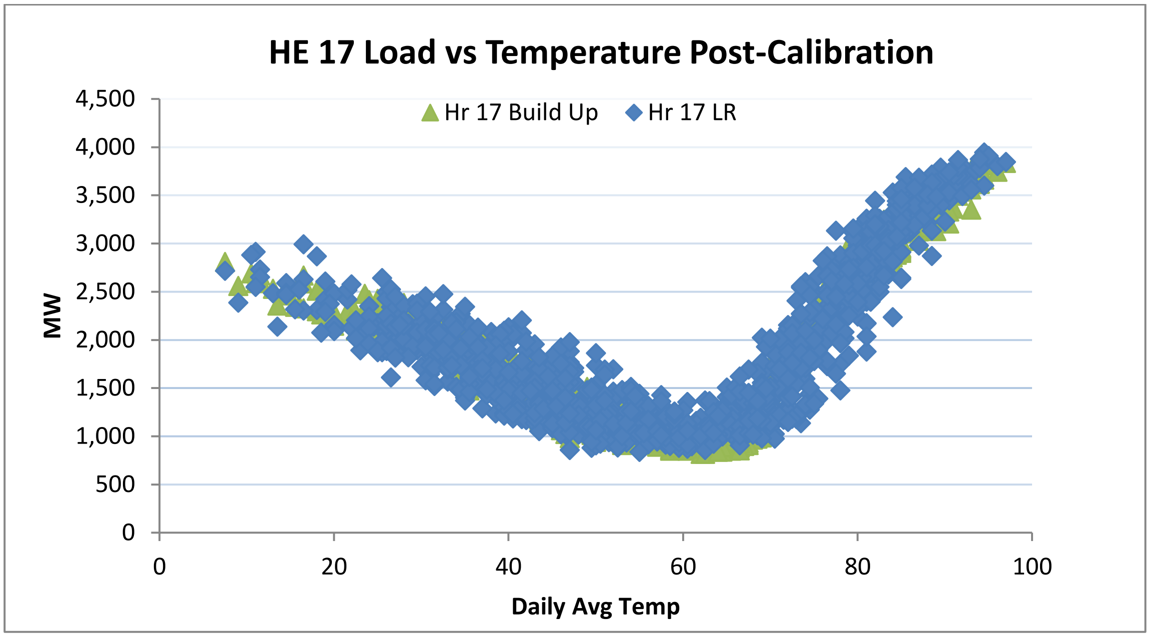
Figure 3.26: Avg. Hourly Difference-End Use Build Up vs. Load Research



The process described above was replicated for the four commercial rate classes to provide end-use load shapes for all classes for which the energy forecast contemplated this level of detail.

Schedule MM-S14

Figure 3.27: Cooling End Use Shape Calibration



An additional level of scrutiny was given to the heating and cooling end use loads, as these are significant contributors to the peak load hours and hence the peak forecast to which Ameren Missouri will plan its capacity needs. Since the system peak typically occurs at hour ended 17 (the hour from 4:00 pm to 5:00 pm) in the summer, we created a scatter plot of HE 17 loads vs. temperature using both the load research data and the synthetic load data. After further adjustment of the cooling load shape, still respecting its basic shape, a high level of agreement between the observed loads and the calculated loads was achieved. The chart shown in Figure 3.27 shows a comparison of the two scatter plots.

3.2.3 Peak Load Forecast

Once the load shapes, both end-use, and class level have been developed, the process of forecasting the peak system loads is straightforward. The most complicated part is developing a planning calendar to base the forecast period profile shapes on and later substituting the actual calendar for this.

Planning Calendar Profile Development

While the forecast is based on normal weather, for future years we cannot know the actual pattern in which the weather will occur. So a reference historical year is selected for forecasting purposes. For this forecast, 2011 was used as the reference year. This historical year (2011) becomes the base for the ordering of the daily normal temperatures across the calendar. So the normal weather will follow the pattern that the actual weather followed within each month of 2011. So for example, the hottest day of August 2011 fell on the 2nd. In our planning calendar case, the hottest weather of August will also fall on the

Schedule MM-S14

2nd. However, when applying normal weather to the planning calendar, if the most extreme weather in the historical year fell on a weekend day, the most extreme normal temperature will be shifted down to the next most extreme day, until it lands on a weekday. Weekdays tend to have the highest loads to begin with due to the business cycles of the commercial and industrial customers. It is therefore important to have peak temperatures on a weekday so that the peak is not under-forecasted by matching the highest residential load with lower levels of commercial and industrial load.

In the planning calendar forecast run, both the weather and the days of the week are forced to follow the pattern of the reference year. For example, August 2nd (2011) was a Tuesday. So for the planning calendar (which will be applied to forecast all future years), August 2nd will remain a Tuesday for modeling purposes in all years. This prevents the peak load from changing simply due to changing combinations of weather and weekday over the forecast horizon. If our peak temperatures were allowed to float to different weekdays over the forecast horizon, the load forecast would change from year to year based on nothing more than the assumed day of the week on which the peak fell. Again, as industrial and commercial load patterns follow those customers' weekly business cycles, it is important to reflect a consistent match between the point in the weekly business cycle and the peak load.

The profile shapes must then be extended over the forecast horizon using the planning calendar assumptions. For the non-weather sensitive end-uses, this is a very easy exercise. The shapes from eShapes are generally comprised of just a weekday and weekend shape for each month of the year. To extend the shapes to the forecast horizon, the weekday shapes and the weekend shapes (as adjusted per the calibration process described previously) are applied to the appropriate days given the month and day of week in the planning calendar.

For the weather sensitive end-uses and classes, the statistical profile models and the reference year weather and calendar patterns are used to project the planning case load shape. For classes that are not modeled with end use detail, the models are based on Ameren Missouri load research data for the class consistent with the weather normalization modeling. For the weather sensitive end-uses, the models are based on the Itron simulated heating and cooling shapes consistent with the load shape calibration process mentioned previously. In the case of both the end use and class level profiles, the daily peak load and daily energy are modeled as a function of temperature and calendar (day of week, month, and season) variables. The models are then simulated using the planning calendar normal temperatures and weekdays

Once both the end-use and class level profiles have been simulated for the planning calendar year, that year is replicated exactly in order to represent the load shape for each year in the forecast horizon for peak modeling purposes.

Actual Calendar Profile Development

While the planning calendar shapes are utilized, as will be discussed further below, to generate a consistent peak forecast from year to year, the final net system hourly load shape will be developed by load shapes based on the actual calendar. In the actual calendar, the temperatures are still mapped to the historical reference year (2011). But in this case, the days of the week are allowed to fall as they actually will in the years in question. So now instead of August 2nd of every year being a Tuesday, in, for example, 2017, August 2nd will be a Wednesday. This way the final hourly loads are realistic relative to that actual calendar that will be used in the forecast. To ensure consistent peaks that do not vary due to changes in the day of the week on which they fall, the peak hour's load for each month is calibrated to the peak forecast from the planning calendar case.

Monthly System Peak Model Development

For this 2023 IRP update, Ameren Missouri developed an end use-based model to forecast the monthly system peak. Ameren Missouri's peak demand forecast methodology adopted for this work captures the underlying end use trends and economic trends. The peak demand forecast model was built based on the historical relationship between the system peak load and end use energy for peak weather conditions. The methodology is a derivation of the SAE energy forecasting techniques where the monthly class level energy forecasts are decomposed into three primary components for most customer classes: heating, cooling, and base load. The basis for the heating, cooling and base load variables extended to the forecast year are derived from the energy forecast models as discussed in section 3.1.5. The cooling and heating variables for peak load were constructed using the weather conditions on the peak day. The base load contribution to the peak demand, which is not influenced by weather conditions, was derived using the share of each end use in the base load at the time of system peak. The system peak model variables, coefficients, and other model statistics are shown in appendix A. The peak forecasting methodology also incorporates impacts of solar and projected electrification described in the respective sections in 3.1.5.

The monthly peak forecast from this process is then combined with the hourly load profiles in the previous section to come up with a class level peak forecast and hourly load forecast.

In order account for reductions in load due to Time of Use rate programs, adjustments were made to the hourly load based upon the methodology from Dr. Ahmad Faruqui, of the Brattle Group prior to his recent retirement, as reflected in his workpapers from the Company's previous rate cases. These TOU options include Evening/Morning Savers,

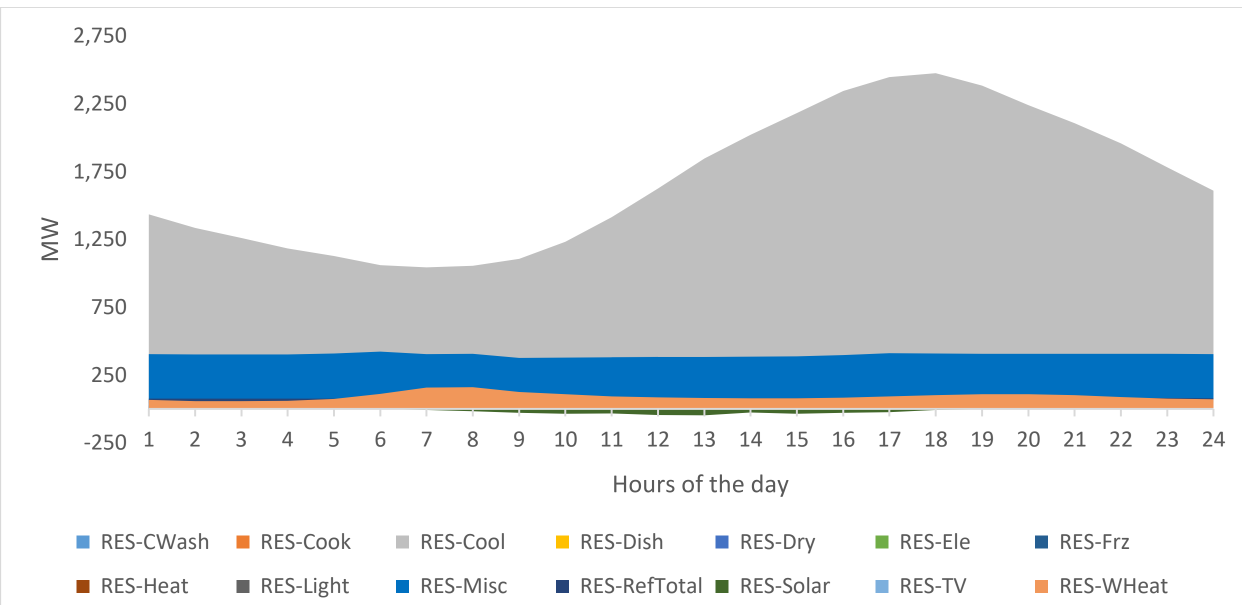
Schedule MM-S14

Overnight Savers, Smart Savers and Ultimate Savers. Definitions of the hours reduced, reduction rate, and participation rate can be found in the TOU section in Appendix A.

Bottom-Up Forecasting

From earlier steps in the forecast process, we have developed class level or end-use energy forecasts, profile models that will generate load shapes for each class and end use, and a monthly system peak forecast from a model. Developing the final peak and hourly forecast is a relatively simple process of bringing these three inputs together. The profile shape for each class and end-use is scaled to the monthly energy from the energy forecast and the monthly system peak forecast. This is a simple mathematical exercise, where a ratio is developed between the energy forecast for each class or end-use and the sum of the hourly profile for that class or end-use within each month of the forecast horizon. That ratio is applied to each hour in the profile so that the hourly load retains the profile shape, but sums across the hours of the month to the forecasted energy level. Figure 3.28 shows an example of the buildup of the residential load for a summer day from the end use components.

Figure 3.28: Residential Summer Day Usage Built-Up by End Use



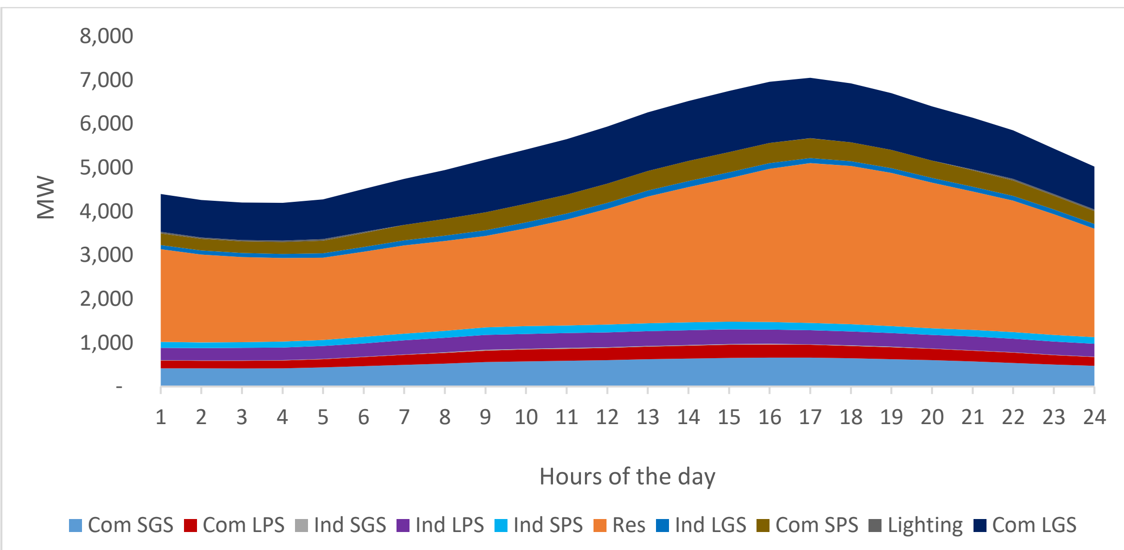
Once each class load has been constructed on an hourly basis (either through direct application of the class profile to the class energy forecast or through the aggregation of the end-use scaled load shapes), transmission and distribution losses are applied. The transmission and distribution losses are based on the Ameren Missouri 2018 loss study performed by its distribution engineers. For purposes of calculating the load for the peak forecast, demand loss rates are utilized. Demand loss rates are the loss rates determined

Schedule MM-S14

by the study to apply to loads at times of peak demand. Typically, this loss rate is higher than average or energy loss rates due to the properties of the system that cause losses to increase both under high load conditions and high temperatures.

The demand loss rates are applied to the profiled loads based on the planning calendar. This is done because the planning calendar was created specifically to develop a consistent peak forecast across time and the demand loss rates are designed specifically for application to peak periods. Each class has the applicable loss rate applied to it based on the voltage level at which its customers are served. When each class' hourly load has been grossed up to represent the amount of energy that must be generated to serve them inclusive of applicable losses, the class loads are summed for each hour. This results in a forecast of the hourly load from which the maximum value for each month can be isolated as the forecasted peak load for that month. Like the build-up of the residential class from end-use data, a graphical representation of the build-up of the system load by class can be seen in Figure 3.29.

Figure 3.29: 2024 Summer System Peak Day Usages Built-Up by Class



3.2.4 Hourly System Load Forecast[46]

After the bottom-up forecast has been generated using the planning calendar, demand loss rate, and the system level peak model that was used to determine the class level peak load forecast, the same process is replicated using the actual calendar information described above and energy loss rates. This hourly system load data is what is actually passed on to the integration analysis.

[46] 20 CSR 4240-22.030(7)(C)

Schedule MM-S14

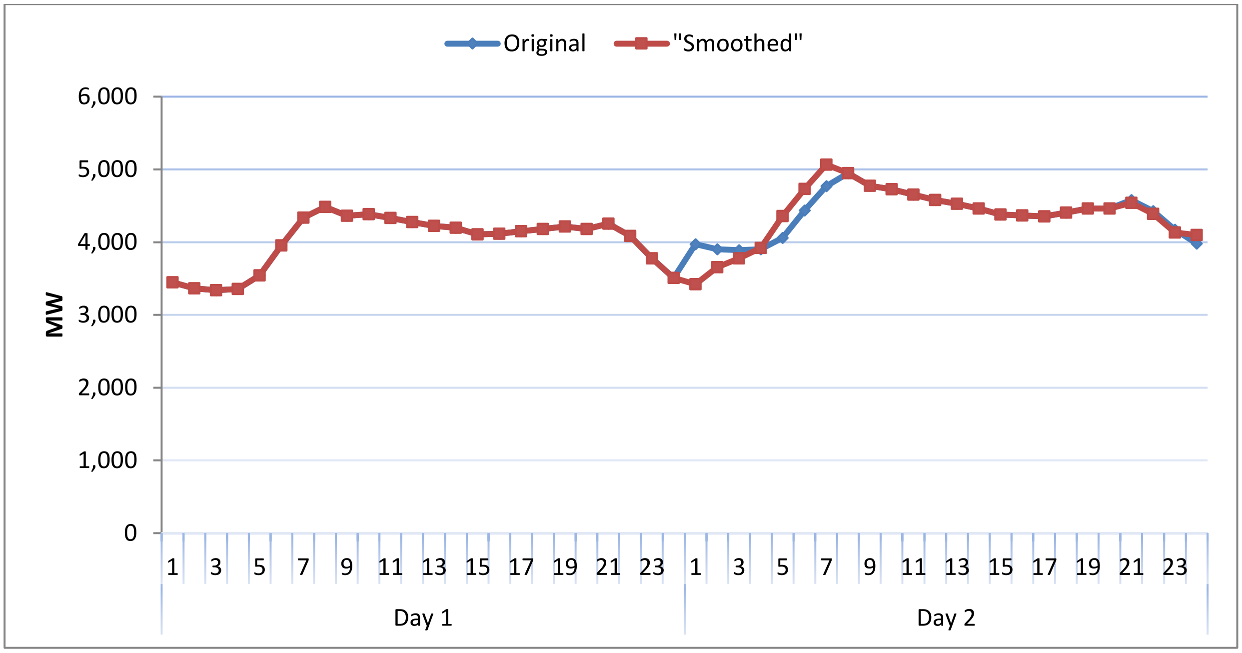
The actual calendar data as described above is used to make the hourly load forecast apply correctly to dates in the future. Since the energy for the forecast horizon is an input to this process and not determined by this process, and since we will use the peak forecast from the planning calendar run, it is no longer necessary to force the days of the week to fall in the same order each year for the sake of consistency. The days can now fall as they will when the years actually occur so that the modeling results are calendar correct.

Also because the peak forecast has been determined in the previous step, energy loss rates can now be utilized instead of demand loss rates. Recall that the demand loss rates were created to determine the level of losses that are occurring on the system at the time of peak. Energy loss rates determine the losses that are incurred across the entire year. These are used to gross up meter level sales to reflect the level of energy that will actually need to be generated in order to meet the demand of Ameren Missouri's customers. The energy loss factors were based on the 2018 loss study mentioned previously.

The process of generating the hourly system forecast begins in exactly the same way as the bottom-up forecasting of the peak does, with the exception of the use of the actual calendar and the energy loss rates. The profile shape for each class and end use where applicable is scaled to the energy forecast, grossed up for losses, and aggregated to the system level. After that has been completed, there are only a couple more steps involved in the creation of the hourly system forecast. First, the annual peak load is calibrated to the peak forecast developed in the planning case (as adjusted per the back-calibration routine). Next, transmission losses are deducted from the forecasted loads. Remember that energy loss rates were used to gross the sales up to the level of load that will have to be generated. The transmission losses are then deducted because of the way that the company interacts with the Midcontinent Independent System Operator's (MISO's) energy markets. Ameren Missouri sells its generation to MISO, and buys power and energy to serve its load from MISO. The difference between generation and load is the volume of off-system sales (net of power purchases) made by the company. However, the load that is purchased from MISO does not include transmission losses. In MISO's market, there is a financial charge for transmission losses, but the physical energy is not purchased by the load serving entity. To reflect this reality, a loss rate is used to back the energy forecast down from the level of energy required to meet customer demand at the generation level to the level of energy needed at the interface between the transmission and distribution system. A loss rate of 2.2% was used to perform this calculation. This rate was based on the actual rate of losses observed on the Ameren Missouri control area based on MISO settlements.

The final step in the process of developing the hourly system loads involves checking for, and if necessary, correcting discontinuities in the load pattern during the overnight hours. Because each day is modeled independently, there are occasions when the transition from hour 24 of one day to hour 1 of the next day exhibits a significant "jump." In the cases where this issue is detected, Ameren Missouri has corrected the situation with a smoothing algorithm. This algorithm maintains the total energy for each day from the original forecast, but reorganizes certain hours so that the load pattern is more realistic. This is important so that the dispatch algorithms in the integration analysis will not be forced to commit units overnight for an artificial jump in load. An example of before and after “smoothed” load can be seen in Figure 3.30.

Figure 3.30: Example of Smoothed Load Shape



Scenarios and Planning Case Forecasts

The energy forecast described in Section 3.1 was modeled under three different scenarios. Each of these scenarios was based on a certain combination of the critical uncertain factors identified in this IRP. The peak and hourly system forecast was also run for each of these scenarios. This was simply a matter of running the class and end-use level energy forecast results from each scenario through the process detailed above. When this process was complete, again similar to the energy forecast, a planning case peak forecast was developed. This forecast was calculated by taking the subjective probabilities assigned to each scenario and using those as weighting factors to average the scenario load forecasts. Again, this mirrors the process for the planning case energy forecast. The planning case peak forecast was passed to integration analysis to develop the capacity position for the IRP. The scenario based load forecasts were also passed to integration so that the candidate resource plans could be tested under all scenarios identified in the IRP.

3.2.5 Forecast Results

The planning case results indicate a forecasted annual peak load growth rate from 2024 through 2043 of 0.4%. For the planning case, the peak load in 2024 is projected to be 7,049 MW, growing to 7,618 MW by 2043. The compound annual growth rates in the various scenarios range from a low of -0.1% (low growth scenario), to 0.8% (high growth scenario).

Figure 3.31: IRP Annual Peak Forecast—Planning Case and Scenarios

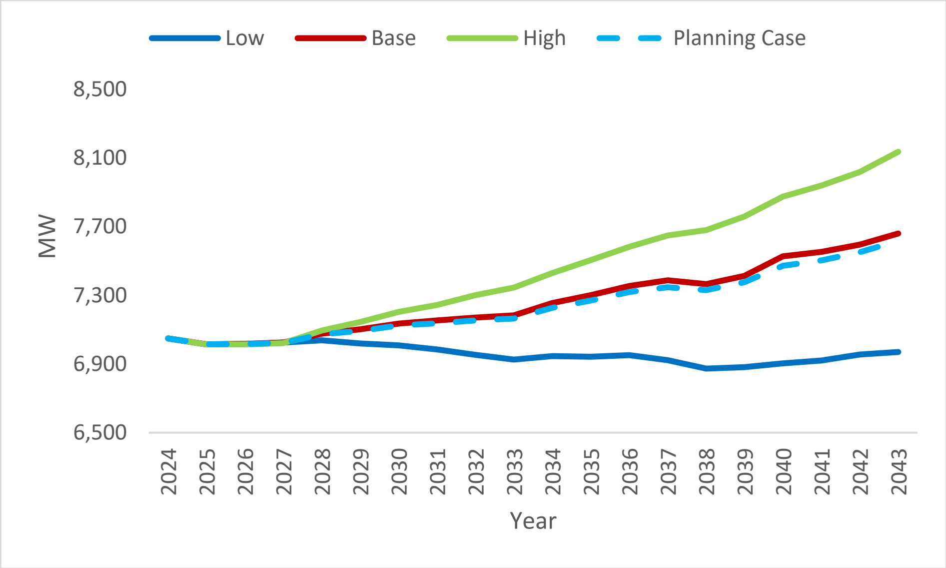
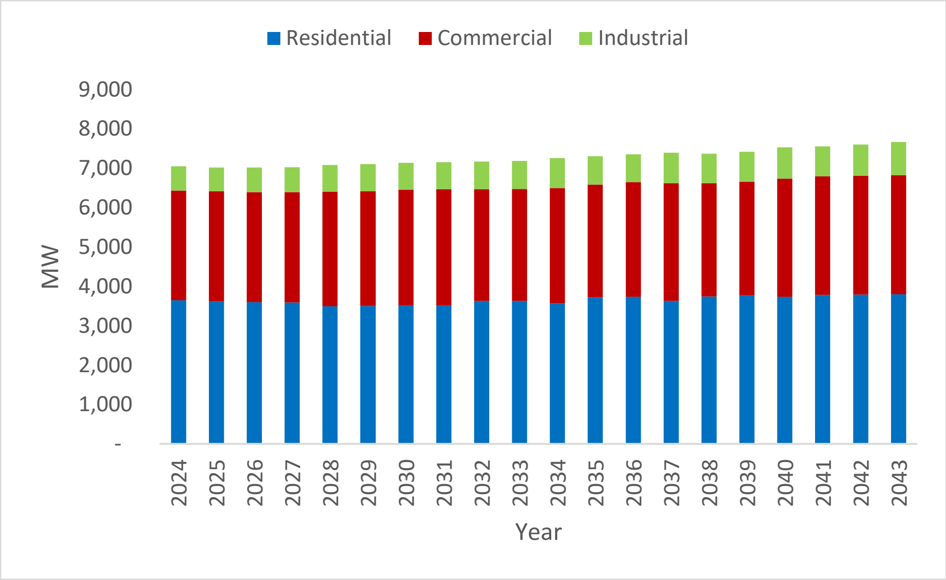


Figure 3.32: Class Contribution to Annual Peak Forecast



Schedule MM-S14

3.2.6 Base Case Peak Demand Forecast

Class and End-Use Peak Demands

The peak contribution of the residential class grows at 0.2% per year from 2024 to 2043, while the commercial class and industrial class peaks are forecasted to grow at a compound annual rate of 0.4% and 1.6% respectively. Although the energy consumption in industrial classes are declining since last decade, it is expected to increase due to efficient electrification.

The end use contributions to the peak load growth within each class varied fairly significantly. For the residential class, the fastest growing end use in the forecast in percentage terms is electric vehicle load. This end use is projected to grow at 22.4% per year. The tables and charts below indicate the end uses that contribute to the peak load for both the residential and commercial classes. The end-use make-up of the peak load is shown for both the first full year of the forecast (2024) and the last year of the forecast (2043).

Table 3.7: Residential End-Use Contribution to Peak

	2024 Peak Contribution (MW)	% of Peak Load (2024)	2043 Peak Contribution (MW)	% of Peak Load (2043)	CAGR
Cooking	38	1.0%	38	1.0%	0%
Cooling	2,793	76.6%	2,662	70.1%	0%
Clothes Washer	13	0.4%	15	0.4%	1%
Dish Washer	6	0.2%	7	0.2%	1%
Electric Dryer	87	2.4%	98	2.6%	1%
Electrification	4	0.1%	196	5.2%	22%
Freezer	40	1.1%	38	1.0%	0%
Heating	-	0.0%	-	0.0%	NA
Lighting	10	0.3%	7	0.2%	-2%
Misc	429	11.8%	487	12.8%	1%
Refrigerator	84	2.3%	82	2.2%	0%
Solar	(27)	-0.7%	(20)	-0.5%	-2%
TV	64	1.8%	82	2.2%	1%
Water Heater	103	2.8%	102	2.7%	0%

Schedule MM-S14

Figure 3.33: Residential Peak Load Composition 2024

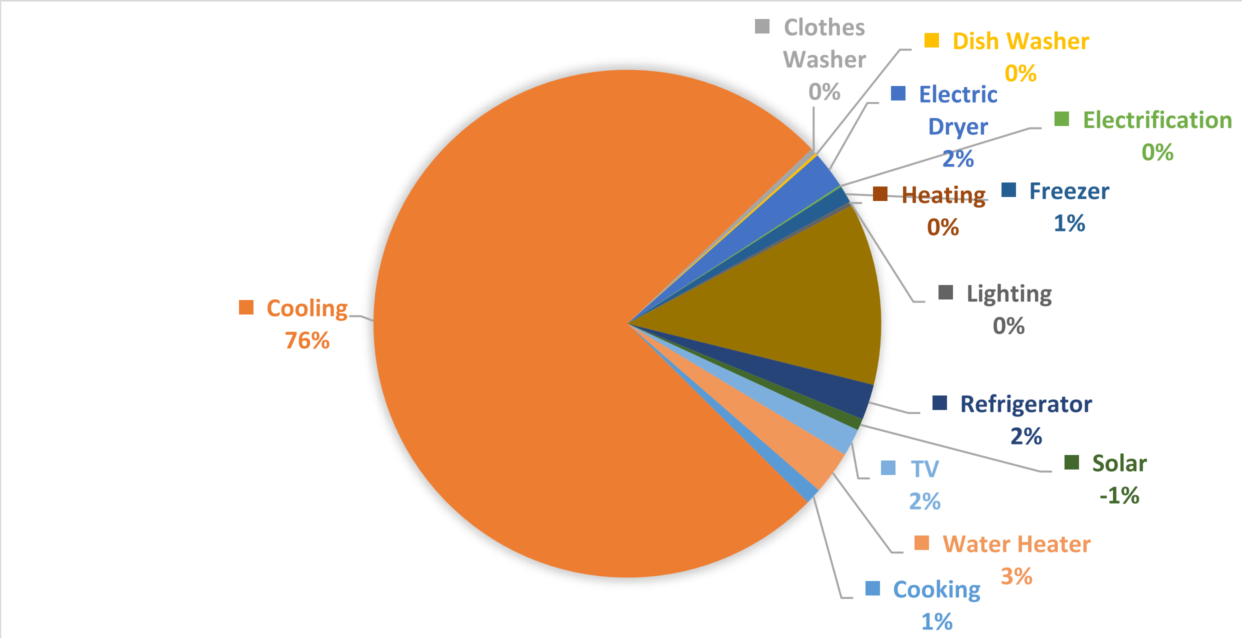
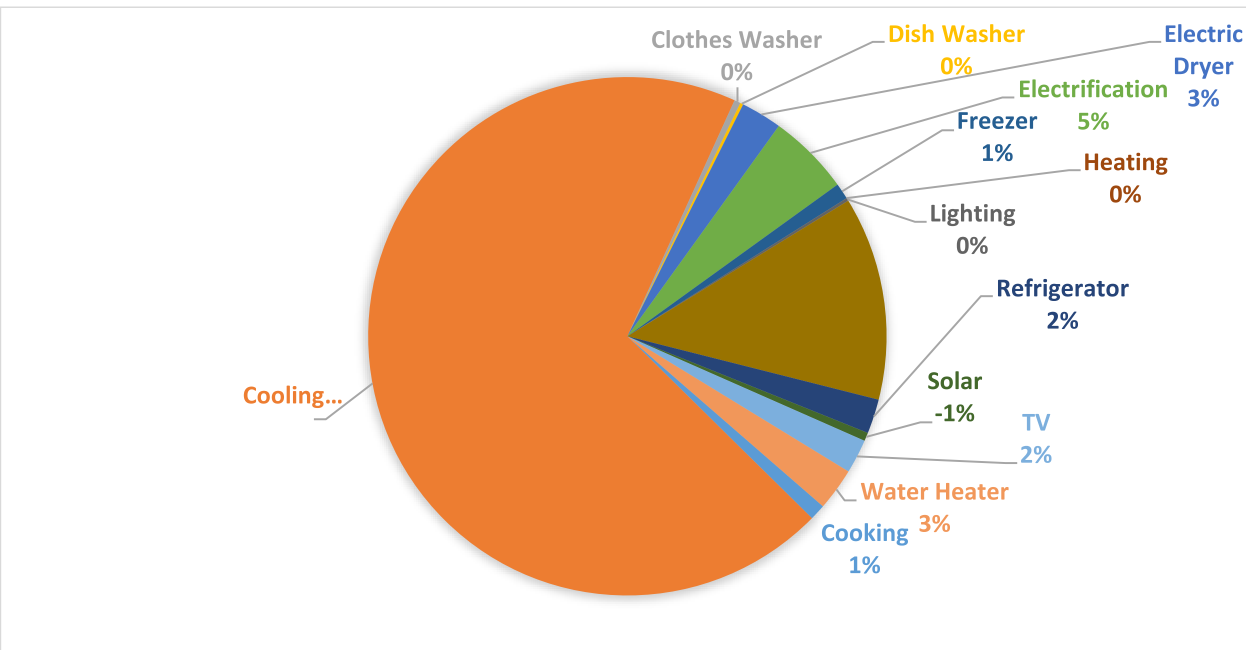


Figure 3.34: Residential Peak Load Composition 2043

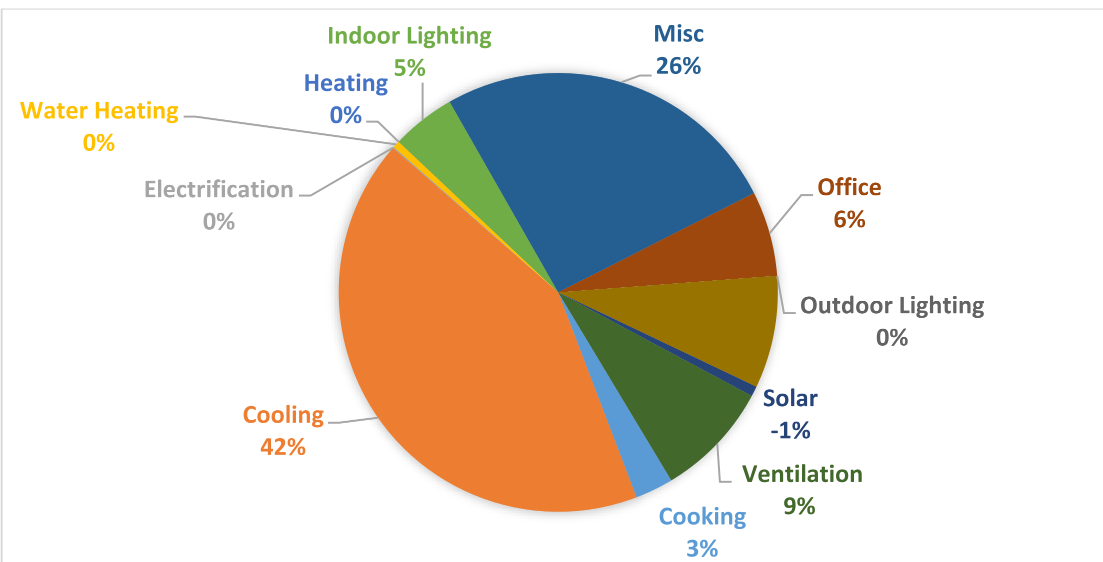


Schedule MM-S14

Table 3.8: Commercial End-Use Contribution to Peak

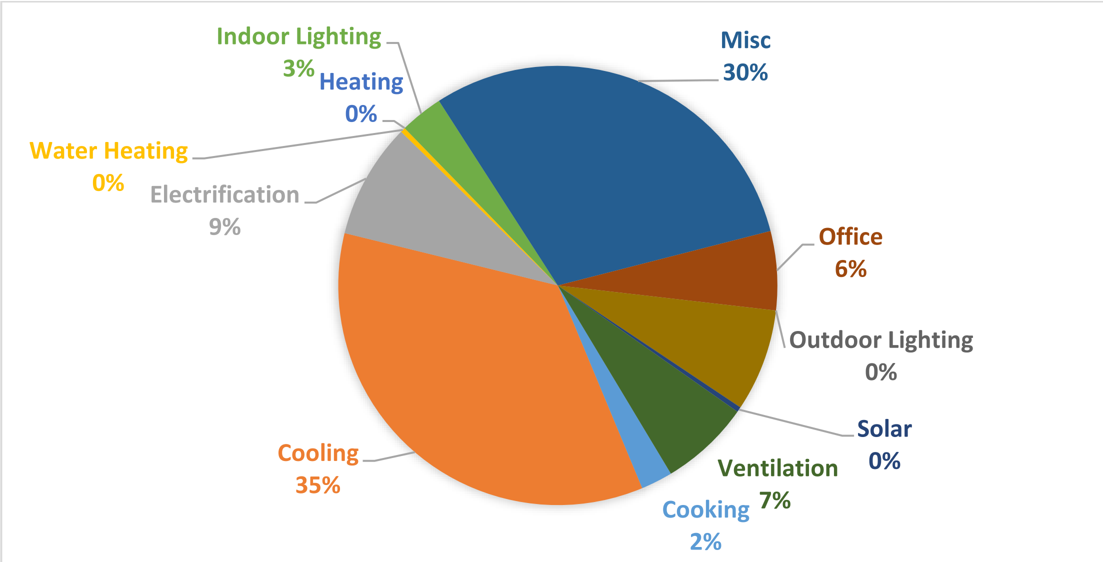
	2024 Peak Contribution (MW)	% of Peak Load	2043 Peak Contribution (MW)	% of Peak Load	CAGR
Cooking	79	3%	71	2%	-0.6%
Cooling	1,194	43%	1,070	35%	-0.6%
Electrification	2	0%	259	9%	27.9%
Water Heating	15	1%	11	0%	-1.4%
Heating	-	0%	-	0%	NA
Indoor Lighting	133	5%	97	3%	-1.7%
Miscellaneous	728	26%	917	30%	1.2%
Office	177	6%	177	6%	0.0%
Outdoor Lighting	0	0%	0	0%	NA
Refrigeration	234	8%	230	8%	-0.1%
Solar	(21)	-1%	(12)	0%	-3.1%
Ventilation	242	9%	202	7%	-0.9%

Figure 3.35: Commercial Peak Load Composition 2024



Schedule MM-S14

Figure 3.36: Commercial Peak Load Composition 2043



3.2.7 Peak Demand – Extreme Weather Sensitivity[47]

The peak demand forecast described above is based on the expectation of normal weather conditions. However, Ameren Missouri must plan its system to provide reliability even under more extreme weather conditions. In order to do this, a reserve margin is maintained. That is to say that Ameren Missouri maintains more generating capacity than is required to meet the forecasted demand in order to account for contingencies including extreme weather conditions. The long-term summer reserve margin utilized in this IRP is 7.4%. So in the capacity position, 7.4% is added to the peak load forecast to determine annual capacity resource requirements. An analysis was undertaken to determine whether this reserve margin is sufficient to cover extreme weather events as they have been observed historically.

In this process, Ameren Missouri identified the highest 10 weekday peak load projections from the month in which the annual peak is forecasted to occur (July) for 2022. From these days, a MW per degree statistic was calculated, that indicates the incremental demand on the system for each degree increase in the daily temperature. This process resulted in an estimate of 146.5 MW of increased system demand per degree.

This estimate was tested using 2024 summer peak data. The 2024 summer peak forecast (from the base case modeling) called for a normal weather (at a two-day weighted average temperature of 89.36 degrees) load of 7,049 MW. Next, Ameren Missouri calculated the expected peak load given two day weighted average temperatures equaling the 90th

[47] 20 CSR 4240-22.030(8)(B); 20 CSR 4240-22.070(1)(D)

Schedule MM-S14

percentile of summer peak temperatures from 1992-2021 and at the absolute maximum temperature observed in that time frame. Additionally, Ameren Missouri tested against a temperature that occurred outside of the 1992-2021 period. Outside this period, the maximum (two day weighted) temperature was 92.17 degrees, occurred in 2022. The peak load corresponding to this temperature was forecasted to reach 7,460 MW, or 5.8% higher than the normal weather forecast. At the 90th percentile temperature, i.e., 92.11 degrees, the load was estimated to reach 7,451 MW, or 5.7% higher than the normal weather peak. In 2012, when Ameren Missouri's service territory experienced historically record high temperature (two day weighted average temperature of 96.67), the corresponding peak load is estimated to be 8,200 MW, 15.2% higher than the normal weather forecast.

In each case except for 2012, the extreme weather produced an effect that was lower than the 7.4% reserve margin, leaving room for additional contingencies, such as a unit outage. For the 90th percentile temperature the weather uncertainty was 2% below the reserve margin available. At the hottest temperature from 1992-2021, the weather uncertainty used about double of the reserve margin available. The heat in 2012 was well beyond the 1 in 10 planning threshold typically used for reliability planning, and even at that level the load increased against the normal weather forecast by only 7% over the 7.9% reserve margin.

Weather Normalization[48]

Weather normalization is an important aspect of load analysis that allows the utility to determine the level of sales that it should be expected to make on an ongoing basis under normal weather conditions. It also allows the utility to quantify the impact of unusual weather on actual sales. Ameren Missouri has developed weather normalization models for various business reasons including to support rate case filings.

The weather normalization process involves the normalization of monthly sales, as well as hourly class level load research. The normalized class level load research also becomes the basis of a "bottom up" approach in weather normalizing net system output. The models used in the current IRP filing are consistent with the models supporting rate case filings that are relevant to the historical period in question. Historical data for 2021 and 2022 has been normalized with the same normal weather used for Ameren Missouri's rate case (ER-2022-0337). Historical data for 2020 has been normalized with the same normal weather used to settle Ameren Missouri's rate case (ER-2021-0240). For historical periods covered by Ameren Missouri's 2020 IRP and earlier, the weather normalized information prepared for and reported in that filing is utilized in this filing as is.

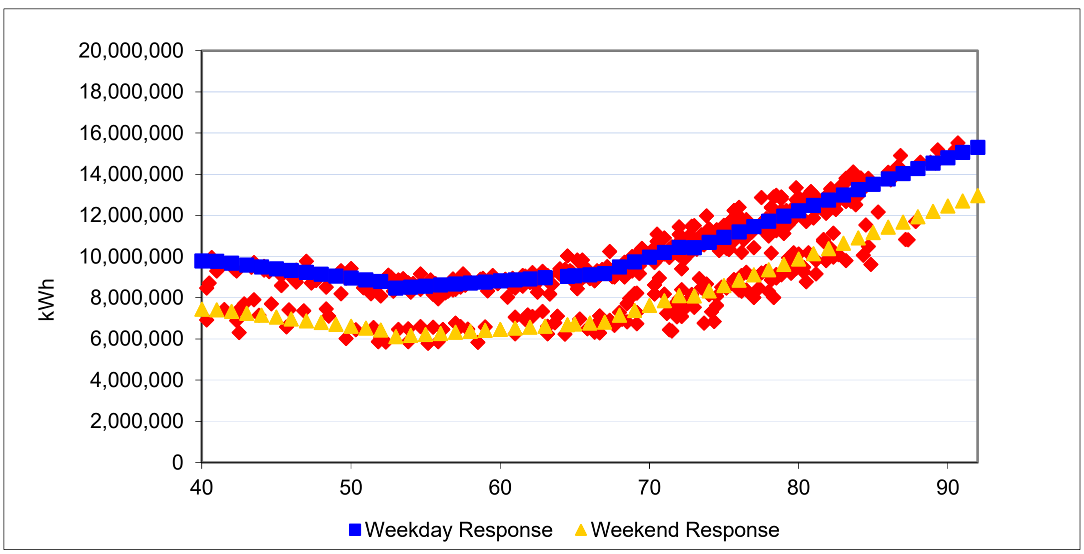
The weather normalization process starts with defining normal weather. As referenced above, Ameren Missouri currently uses actual temperature readings for St. Louis Lambert

[48] 20 CSR 4240-22.030(2)(C)2

Airport from the period 1992-2021 to develop its normal weather conditions, as adjusted for certain changes in the recording equipment at Lambert. Ameren Missouri creates normal temperatures by applying the “rank and average” methodology to temperatures from this time period to accommodate the unique nature of the problem of normalizing energy usage. Application of this procedure is necessary in order to produce realistic levels of normal energy and peak demand later in the process. It is used to ensure that normal temperatures also exhibit a normal amount of variability that would be expected to occur within a year. This method has been utilized routinely in electric rate cases by the Missouri Public Service Commission Staff (Staff) and was used by both Ameren Missouri and Staff in the Company’s most recent rate cases.

The next step in the weather normalization process is to develop load-temperature relationships. Using a software package called MetrixND, daily peak and average loads at the rate and revenue class level are both modeled statistically as a function of calendar and weather variables. These statistical relationships are the basis for the weather adjustments which produce the normalized sales and hourly load research for a given period. These models are developed using various statistically significant weather variables along with various time and economic trend variables if needed as explanatory variables to create a piecewise linear temperature response function.[49] A graphical representation of this modeling approach can be seen in Figure 3.37.

Figure 3.37: MetrixND COMSGS Non-Winter Weather Response



The models are first built using actual weather variables along with other explanatory variables. Then the model coefficients are applied to the normal weather variable to

[49] 20 CSR 4240-22.030(2)(D)2

Schedule MM-S14

generate a normalized version of loads. The difference between the model's estimate of actual and normal loads is the weather impact for the time period in question. This weather impact is applied to the original load value to generate a normalized version of the load in question. The actual model variables and corresponding coefficients are presented in Appendix A.[50] The weather normalized sales results will also be provided in the final filing. For the purposes of normalization of hourly load research, the peak and average energy for each day are normalized as described above. The hourly normal values are then derived using the unitized load calculation described in Section 3.2.2.

3.3 Future Research Projects[51]

Ameren Missouri continually works to improve its load analysis processes to produce more accurate forecasts that provide an increasing depth to our analytical capabilities. The load analysis function is of increasing importance in this era of increasing energy efficiency, both through company sponsored programs and non-utility efforts. To that end we continue to explore additional data sources, and enhanced forecasting and analytical techniques.

Much of this effort is focused on increasing the ways we can segment our data. Whether it be analyzing our commercial class by segmenting the business types, or analyzing our residential and commercial classes by the end use appliances and equipment they operate, our analysis is continually increasing in its level of detail.

NAICS Codes

To facilitate that increasingly detailed analysis, Ameren Missouri recently worked with a vendor to append North American Industrial Classification System (NAICS) codes to its commercial and industrial accounts. Going forward, this data will help us to monitor trends in usage by different types of businesses, and therefore give insights into the causes of changes in the energy intensity of our service territory economy.

End-Use Load Research

Ameren Missouri has been monitoring industry efforts to develop new end use load shape data. We have participated in workshops and discussions within the industry focused on evaluating the ability of Non-Intrusive Load Monitoring devices to disaggregate whole premise load data into its end use components, and will continue to monitor efforts to increase data availability from industry sources in this area. Additionally, the Ameren Missouri load analysis function is working to make sure we are able to leverage any end use metering data collected by EM&V contractors for purposes of energy efficiency program impact evaluation. This data can be a valuable tool to further enhance the

[50] 20 CSR 4240-22.030(2)(C)3
[51] 20 CSR 4240-22.070(6)(A)

Schedule MM-S14

processes described in this chapter for assessing and improving the applicability of end use load shape data to our customers' loads.

Load Research Sample Design

Ameren Missouri's load research sample was designed in the early 2000s. Although the existing sample has continued to perform well in all measurable ways, it will benefit from a refresh as the sample has been in place for a number of years. Ameren Missouri, as of this writing, is in the process of implementing smart meter infrastructure, which will collect interval reading for every customer in the system unless opted out. Once smart meter infrastructure is in place and interval data is collected for every customers in the system, Ameren Missouri will conduct load research based on the data collected from every customer in the smart metering system. This will eliminate much of statistical errors rising from load research process and provide a better in depth understanding of true load profile of Ameren Missouri customers.

3.4 Compliance References

Schedule MM-S14

Chapter 3 – Appendix A

Weather Normalized Energy Models[1]

Residential Weather Normalization Energy Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	81,884,501	2,029,560	40.35	0.00%
DOWBinary.Monday	-1,903,214	233,954	-8.14	0.00%
DOWBinary.Tuesday	-2,048,085	232,467	-8.81	0.00%
DOWBinary.Wednesday	-1,808,305	228,732	-7.91	0.00%
DOWBinary.Thursday	-1,797,965	234,403	-7.67	0.00%
DOWBinary.Friday	-1,760,050	230,841	-7.63	0.00%
DOWBinary.Saturday	-867,956	225,654	-3.85	0.01%
MonthBinary.Jan	4,160,028	316,031	13.16	0.00%
MonthBinary.Feb	3,996,584	323,862	12.34	0.00%
MonthBinary.Mar	1,096,129	277,190	3.95	0.01%
MonthBinary.Apr	-2,335,049	297,999	-7.84	0.00%
MonthBinary.May	-2,978,956	269,815	-11.04	0.00%
MonthBinary.Jul	876,265	294,030	2.98	0.30%
MonthBinary.Aug	636,910	281,343	2.26	2.38%
MonthBinary.Sep	-1,777,380	275,079	-6.46	0.00%
MonthBinary.Oct	-2,132,275	270,313	-7.89	0.00%
MonthBinary.Dec	3,154,991	298,514	10.57	0.00%
ResSplines.AvgT	-2,148,540	233,279	-9.21	0.00%
ResSplines.XColdAvgT	1,342,900	238,164	5.64	0.00%
ResSplines.CoolAvgT	238,371	31,836	7.49	0.00%
ResSplines.MILDAvgT	533,553	69,551	7.67	0.00%
ResSplines.WarmAvgT	959,194	97,208	9.87	0.00%
ResSplines.HotAvgT	564,120	69,253	8.15	0.00%
ResSplines.ShoulderWarm	-360,625	114,931	-3.14	0.18%
US_Holidays.RES_HolidaysX	1,711,395	338,321	5.06	0.00%
GMI_Transform.MO_Residential	140,532	14,587	9.63	0.00%

[1] 20 CSR 4240-22.030(2)(C)3

Schedule MM-S15

Residential Weather Normalization Energy Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	1096
Deg. of Freedom for Error	1070
R-Squared	0.96
Adjusted R-Squared	0.96
F-Statistic	1062.88
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	4.14%
Durbin-Watson Statistic	1.13

Commercial SGS Weather Normalization Energy Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	13,683,219	156,480	87.44	0.00%
DOWBinary.MonFri	960,971	114,698	8.38	0.00%
DOWBinary.TWT	1,129,287	115,704	9.76	0.00%
MonthBinary.Feb	271,633	70,145	3.87	0.01%
MonthBinary.Mar	130,671	67,098	1.95	5.19%
MonthBinary.May	-315,476	72,892	-4.33	0.00%
MonthBinary.Jun	-360,685	62,212	-5.80	0.00%
MonthBinary.Oct	-271,245	65,581	-4.14	0.00%
MonthBinary.Nov	137,405	81,998	1.68	9.42%
COMSGSSplines.AvgT	-139,999	3,492	-40.09	0.00%
COMSGSSplines.CoolAvgT	31,896	9,420	3.39	0.08%
COMSGSSplines.MildAvgT	114,858	15,205	7.55	0.00%
COMSGSSplines.WarmAvgT	114,993	20,497	5.61	0.00%
COMSGSSplines.HotAvgT	119,810	16,744	7.16	0.00%
COMSGSSplines.WkndAvgT	-6,178	1,821	-3.39	0.07%
COMSGSSplines.ShoulderAvgT	-6,132	1,341	-4.57	0.00%
US_Holidays.ComSGS_HolidayX	-596,732	121,284	-4.92	0.00%
GMI_Transform.MO_Workspaces	11,508	2,163	5.32	0.00%
MonthBinary.COVID_April_May2020	-557,561	84,421	-6.61	0.00%

Note: Some of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

ComSGS Weather Normalization Energy Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	711
R-Squared	0.94
Adjusted R-Squared	0.94
F-Statistic	613.29
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	3.87%
Durbin-Watson Statistic	1.01

ComLGS Weather Normalization Energy Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	22,719,487	221,548	102.55	0.00%
DOWBinary.Monday	3,159,894	93,125	33.93	0.00%
DOWBinary.TWT	3,204,393	81,147	39.49	0.00%
DOWBinary.Friday	2,584,051	85,725	30.14	0.00%
DOWBinary.Saturday	622,492	75,228	8.28	0.00%
MonthBinary.May	526,856	91,534	5.76	0.00%
MonthBinary.Jun	-953,001	80,997	-11.77	0.00%
MonthBinary.Oct	839,881	85,731	9.80	0.00%
COMLGSSplines.AvgT	-189,682	6,262	-30.29	0.00%
COMLGSSplines.CoolAvgT	31,889	9,009	3.54	0.04%
COMLGSSplines.WarmAvgT	193,423	9,222	20.98	0.00%
COMLGSSplines.HotAvgT	202,991	11,324	17.93	0.00%
COMLGSSplines.SummerAvgT	31,712	1,454	21.81	0.00%
COMLGSSplines.WkdayWarmAvgT	51,377	4,148	12.39	0.00%
GMI_Transform.MO_Workspaces	33,020	2,561	12.90	0.00%
US_Holidays.July4thHol	-1,302,451	397,110	-3.28	0.11%
US_Holidays.MemorialDay	-2,096,004	407,515	-5.14	0.00%
US_Holidays.LaborDay	-2,328,396	403,637	-5.77	0.00%
US_Holidays.Thanksgiving	-1,333,772	410,505	-3.25	0.12%
MonthBinary.Yr2021_Shift	523,006	47,745	10.95	0.00%

ComLGS Weather Normalization Energy Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	710
R-Squared	0.96
Adjusted R-Squared	0.96
F-Statistic	826.67
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	2.41%
Durbin-Watson Statistic	1.01

ComSPS Weather Normalization Energy Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	7,936,270	85,453	92.87	0.00%
DOWBinary.Friday	-136,196	23,470	-5.80	0.00%
DOWBinary.Saturday	-652,842	27,591	-23.66	0.00%
DOWBinary.Sunday	-729,559	26,591	-27.44	0.00%
COMSPSSplines.AvgT	-34,755	1,954	-17.79	0.00%
COMSPSSplines.CooLAvgT	40,156	2,866	14.01	0.00%
COMSPSSplines.MildAvgT	37,349	10,003	3.73	0.02%
COMSPSSplines.WarmAvgT	26,530	10,591	2.51	1.25%
COMSPSSplines.SummerAvgT	1,099	619	1.78	7.63%
US_Holidays.ComSPS_HolidayX	-137,494	36,659	-3.75	0.02%
GMI_Transform.MO_Workspaces	7,763	959	8.10	0.00%
MonthBinary.Jan	175,829	34,950	5.03	0.00%
MonthBinary.Feb	394,181	37,687	10.46	0.00%
MonthBinary.Apr	-84,959	32,633	-2.60	0.94%
MonthBinary.May	-130,863	33,862	-3.87	0.01%
MonthBinary.Jul	377,206	36,809	10.25	0.00%
MonthBinary.Aug	219,561	36,202	6.07	0.00%
MonthBinary.Sep	157,569	38,303	4.11	0.00%
MonthBinary.Nov	96,575	30,189	3.20	0.15%

Note: One of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

Com SPS Weather Normalization Energy Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	711
R-Squared	0.92
Adjusted R-Squared	0.91
F-Statistic	424.03
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	2.35%
Durbin-Watson Statistic	0.79

Com LPS Weather Normalization Energy Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	3,412,149	40,091	85.11	0.00%
DOWBinary.Saturday	-122,467	17,742	-6.90	0.00%
DOWBinary.Sunday	-160,788	17,781	-9.04	0.00%
MonthBinary.Jan	-332,997	25,846	-12.88	0.00%
MonthBinary.Jul	65,261	27,302	2.39	1.71%
MonthBinary.Aug	120,892	26,378	4.58	0.00%
MonthBinary.Oct	65,689	23,069	2.85	0.45%
MonthBinary.Dec	35,992	23,796	1.51	13.09%
MonthBinary.apr2020	-137,003	31,862	-4.30	0.00%
COMLPSSplines.AvgT	3,849	881	4.37	0.00%
COMLPSSplines.HotAvgT	20,570	3,280	6.27	0.00%
COMLPSSplines.WarmAvgT	18,941	2,145	8.83	0.00%
US_Holidays.ComLPS_HolidayX	-73,241	30,663	-2.39	1.72%
MonthBinary.Customer_Com_Outage	-397,869	39,291	-10.13	0.00%

Note: One of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

Com LPS Weather Normalization Energy Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	716
R-Squared	0.88
Adjusted R-Squared	0.88
F-Statistic	417.978
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	3.31%
Durbin-Watson Statistic	0.58

Ind SGS Weather Normalization Energy Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	322,533	6,257	51.55	0.00%
DOWBinary.Monday	75,369	3,093	24.37	0.00%
DOWBinary.Tuesday	77,520	3,093	25.06	0.00%
DOWBinary.Wednesday	75,696	3,094	24.47	0.00%
DOWBinary.Thursday	75,090	3,093	24.28	0.00%
DOWBinary.Friday	65,726	3,105	21.17	0.00%
DOWBinary.Sunday	-12,561	3,086	-4.07	0.01%
MonthBinary.Feb	7,406	3,767	1.97	4.97%
MonthBinary.May	-10,941	3,457	-3.17	0.16%
MonthBinary.Oct	38,730	3,213	12.06	0.00%
MonthBinary.Nov	69,488	3,361	20.68	0.00%
MonthBinary.Dec	28,347	3,328	8.52	0.00%
INDSGSSplines.AvgT	-3,657	140	-26.08	0.00%
INDSGSSplines.MILDAvgT	2,639	269	9.80	0.00%
INDSGSSplines.WarmAvgT	6,700	401	16.70	0.00%
US_Holidays.IndSGS_HolidayX	-43,287	4,861	-8.91	0.00%
US_Holidays.July4thHol	-55,840	16,607	-3.36	0.08%
MonthBinary.Jul_2020	12,502	4,488	2.79	0.55%
MonthBinary.COVID_IndSGS	-8,280	3,476	-2.38	1.74%

Ind SGS Weather Normalization Energy Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	711
R-Squared	0.85
Adjusted R-Squared	0.85
F-Statistic	227.84
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	8.33%
Durbin-Watson Statistic	1.25

Ind LGS Weather Normalization Energy Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	1,510,923	17,611	85.79	0.00%
DOWBinary.TWT	805,038	21,106	38.14	0.00%
DOWBinary.MonFri	689,700	20,350	33.89	0.00%
MonthBinary.Jan	147,625	25,615	5.76	0.00%
MonthBinary.Feb	95,073	26,588	3.58	0.04%
MonthBinary.May	46,972	26,146	1.80	7.28%
MonthBinary.Jun	139,444	30,760	4.53	0.00%
MonthBinary.Jul	345,825	34,650	9.98	0.00%
MonthBinary.Aug	272,775	31,322	8.71	0.00%
MonthBinary.Sep	207,351	26,781	7.74	0.00%
MonthBinary.Nov	136,368	27,403	4.98	0.00%
INDLGSSplines.HotAvgT	9,778	3,219	3.04	0.25%
GMI_Transform.MO_Workspaces	3,935	821	4.79	0.00%
US_Holidays.NYHol	-639,364	132,869	-4.81	0.00%
US_Holidays.GoodFridays	-933,956	127,458	-7.33	0.00%
US_Holidays.MemorialDay	-1,031,656	134,139	-7.69	0.00%
US_Holidays.LaborDay	-928,377	135,757	-6.84	0.00%
US_Holidays.WedB4Thanks	-397,861	128,922	-3.09	0.21%
US_Holidays.Thanksgiving	-1,169,310	137,451	-8.51	0.00%
US_Holidays.FriAftThanks	-1,080,303	131,934	-8.19	0.00%
US_Holidays.SatAftThanks	-414,986	128,826	-3.22	0.13%
US_Holidays.XMasEve	-755,682	128,174	-5.90	0.00%
US_Holidays.XMasHol	-890,474	133,529	-6.67	0.00%
US_Holidays.XMASAft	-285,207	54,875	-5.20	0.00%
US_Holidays.July4Total	-831,551	93,866	-8.86	0.00%

Note: One of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

Ind LGS Weather Normalization Energy Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	705
R-Squared	0.83
Adjusted R-Squared	0.82
F-Statistic	141.10
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	7.48%
Durbin-Watson Statistic	1.34

Ind SPS Weather Normalization Energy Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	3,305,208	35,233	93.81	0.00%
DOWBinary.Tuesday	155,332	18,949	8.20	0.00%
DOWBinary.Wednesday	166,713	18,904	8.82	0.00%
DOWBinary.Thursday	109,051	18,890	5.77	0.00%
DOWBinary.Saturday	-481,993	18,942	-25.45	0.00%
DOWBinary.Sunday	-665,778	18,970	-35.10	0.00%
MonthBinary.Feb	84,728	25,700	3.30	0.10%
MonthBinary.May	80,096	25,398	3.15	0.17%
MonthBinary.Jun	77,580	33,540	2.31	2.10%
MonthBinary.Jul	85,670	35,940	2.38	1.74%
MonthBinary.Aug	244,663	34,021	7.19	0.00%
MonthBinary.Sep	63,986	27,966	2.29	2.24%
INDSPSSplines.AvgT	-2,709	698	-3.88	0.01%
INDSPSSplines.WarmAvgT	13,637	1,906	7.16	0.00%
MonthBinary.COVIDSPS2	-105,897	24,230	-4.37	0.00%
US_Holidays.IndSPS_HolidayX	-513,906	24,381	-21.08	0.00%

Ind SPS Weather Normalization Energy Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	714
R-Squared	0.84
Adjusted R-Squared	0.84
F-Statistic	254.71
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	3.94%
Durbin-Watson Statistic	0.83

Ind LPS Weather Normalization Energy Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	6,105,449	81,896	74.55	0.00%
DOWBinary.WeekEnd	-335,412	54,689	-6.13	0.00%
DOWBinary.Monday	-175,816	22,845	-7.70	0.00%
MonthBinary.Jan	-140,971	40,570	-3.48	0.06%
MonthBinary.Feb	-354,742	41,863	-8.47	0.00%
MonthBinary.Mar	-157,151	34,263	-4.59	0.00%
MonthBinary.Apr	201,318	42,797	4.70	0.00%
MonthBinary.Jun	102,336	46,936	2.18	2.96%
MonthBinary.Jul	299,325	47,368	6.32	0.00%
MonthBinary.Aug	296,471	42,946	6.90	0.00%
MonthBinary.Sep	95,909	54,880	1.75	8.10%
MonthBinary.Oct	159,989	34,224	4.68	0.00%
MonthBinary.Nov	174,482	36,244	4.81	0.00%
MonthBinary.apr2020	-727,157	59,390	-12.24	0.00%
INDLPSSplines.AvgT	-6,201	1,822	-3.40	0.07%
INDLPSSplines.MildAvgT	14,696	2,949	4.98	0.00%
INDLPSSplines.WarmAvgT	26,669	3,605	7.40	0.00%
INDLPSSplines.WkndAvgT	-3,291	884	-3.72	0.02%
MonthBinary.Customer_Idle	-231,170	39,721	-5.82	0.00%
MonthBinary.LPS_Winter_Storm	-484,652	101,790	-4.76	0.00%
MonthBinary.Sept2020	-143,707	61,810	-2.33	2.04%
MonthBinary.COVIDLPS	-99,322	29,456	-3.37	0.08%

Note: One of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

Ind LPS Weather Normalization Energy Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	691
Deg. of Freedom for Error	669
R-Squared	0.85
Adjusted R-Squared	0.85
F-Statistic	182.20
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	2.65%
Durbin-Watson Statistic	0.90

Weather Normalized Peak Demand Models[2]

Residential Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	3,816,626	165,239	23.10	0.00%
DOWBinary.Sunday	49,334	16,818	2.93	0.34%
MonthBinary.Jan	45,107	26,563	1.70	8.98%
MonthBinary.Feb	60,850	27,310	2.23	2.61%
MonthBinary.Mar	-83,093	24,676	-3.37	0.08%
MonthBinary.Apr	-244,218	24,881	-9.82	0.00%
MonthBinary.May	-252,464	22,885	-11.03	0.00%
MonthBinary.Sep	-104,729	21,836	-4.80	0.00%
MonthBinary.Oct	-223,983	23,640	-9.48	0.00%
MonthBinary.Nov	-138,720	24,136	-5.75	0.00%
ResSplines.AvgT	-84,281	16,710	-5.04	0.00%
ResSplines.MildAvgT	42,961	4,594	9.35	0.00%
ResSplines.xColdAvgT	50,919	16,937	3.01	0.27%
ResSplines.WarmAvgT	37,189	20,573	1.81	7.09%
ResSplines.WkndMildAvgT	2,423	960	2.52	1.18%
ResSplines.HotAvgT	36,248	18,302	1.98	4.79%
MonthBinary.June2019	-80,901	34,183	-2.37	1.81%
GMI_Transform.MO_Residential	4,510	1,235	3.65	0.03%
US_Holidays.RES_HolidaysX	100,129	28,377	3.53	0.05%

Note: One of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

[2] 20 CSR 4240-22.030(2)(C)3

Schedule MM-S15

Residential Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	1096
Deg. of Freedom for Error	1077
R-Squared	0.92
Adjusted R-Squared	0.91
F-Statistic	640.99
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	6.37%
Durbin-Watson Statistic	1.48

Com SGS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	621,877	8,909	69.80	0.00%
DOWBinary.TWT	127,894	4,345	29.44	0.00%
DOWBinary.MonFri	110,701	4,211	26.29	0.00%
MonthBinary.Feb	11,743	5,191	2.26	2.40%
MonthBinary.Mar	14,840	4,591	3.23	0.13%
MonthBinary.May	-39,064	4,679	-8.35	0.00%
MonthBinary.Jun	-35,031	4,988	-7.02	0.00%
MonthBinary.Jul	-16,120	5,227	-3.08	0.21%
COMSGSSplines.AvgT	-5,965	186	-31.99	0.00%
COMSGSSplines.MildAvgT	5,902	1,044	5.66	0.00%
COMSGSSplines.WarmAvgT	8,667	1,361	6.37	0.00%
COMSGSSplines.HotAvgT	7,949	854	9.31	0.00%
COMSGSSplines.WkndMildAvgT	-2,101	226	-9.29	0.00%
COMSGSSplines.ShoulderMildAvgT	-2,119	580	-3.65	0.03%
US_Holidays.ComSGS_HolidayX	-38,175	9,059	-4.21	0.00%
MonthBinary.April2020	-43,286	7,161	-6.05	0.00%
GMI_Transform.MO_Workspaces	1,443	159	9.07	0.00%

Com SGS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	713
R-Squared	0.92
Adjusted R-Squared	0.92
F-Statistic	508.33
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	5.71%
Durbin-Watson Statistic	1.25

Com LGS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	1,076,950	16,216	66.41	0.00%
DOWBinary.MonFri	183,798	5,683	32.34	0.00%
DOWBinary.TWT	205,744	5,891	34.92	0.00%
DOWBinary.Saturday	36,501	5,272	6.92	0.00%
MonthBinary.Jan	-67,948	8,382	-8.11	0.00%
MonthBinary.Feb	-59,882	8,786	-6.82	0.00%
MonthBinary.Mar	-38,488	6,391	-6.02	0.00%
MonthBinary.May	-19,730	5,745	-3.43	0.06%
MonthBinary.Jul	41,390	6,524	6.35	0.00%
MonthBinary.Aug	65,542	6,169	10.62	0.00%
MonthBinary.Sep	73,032	5,965	12.24	0.00%
MonthBinary.Nov	-12,364	6,544	-1.89	5.93%
MonthBinary.Dec	-33,535	7,738	-4.33	0.00%
COMLGSSplines.AvgT	-8,527	273	-31.28	0.00%
COMLGSSplines.MildAvgT	15,336	592	25.91	0.00%
COMLGSSplines.HotAvgT	12,114	852	14.22	0.00%
COMLGSSplines.ShoulderMildAvgT	-4,189	750	-5.59	0.00%
COMLGSSplines.WkndMildAvgT	-3,906	281	-13.91	0.00%
GMI_Transform.MO_Workspaces	2,247	214	10.48	0.00%
MonthBinary.March_10_2021	-106,211	37,338	-2.85	0.46%
MonthBinary.Yr2021_Shift	44,917	3,644	12.33	0.00%

Note: One of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

Com LGS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	682
Deg. of Freedom for Error	661
R-Squared	0.95
Adjusted R-Squared	0.95
F-Statistic	600.52
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	3.22%
Durbin-Watson Statistic	1.47

Com SPS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	314,539	5,249	59.93	0.00%
DOWBinary.Monday	41,754	1,542	27.08	0.00%
DOWBinary.TWT	42,564	1,254	33.95	0.00%
DOWBinary.Friday	37,160	1,536	24.20	0.00%
DOWBinary.Saturday	5,370	1,532	3.51	0.05%
MonthBinary.Feb	7,001	1,784	3.92	0.01%
MonthBinary.May	-12,268	2,121	-5.78	0.00%
MonthBinary.Jun	-9,379	1,770	-5.30	0.00%
MonthBinary.Sep	-5,677	1,915	-2.96	0.31%
MonthBinary.Oct	-9,897	2,294	-4.31	0.00%
COMSPSSplines.ColdAvgT	906	211	4.30	0.00%
COMSPSSplines.AvgT	-1,270	178	-7.16	0.00%
COMSPSSplines.HotAvgT	1,648	273	6.05	0.00%
COMSPSSplines.WarmAvgT	2,687	226	11.89	0.00%
COMSPSSplines.WinterAvgT	-240	45	-5.39	0.00%
COMSPSSplines.ShoulderAvgT	-211	40	-5.29	0.00%
MonthBinary.COVIDSPS	-19,971	1,261	-15.84	0.00%
US_Holidays.ComSPS_HolidayX	-21,247	1,667	-12.75	0.00%

Com SPS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	1096
Deg. of Freedom for Error	1078
R-Squared	0.87
Adjusted R-Squared	0.87
F-Statistic	439.01
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	3.29%
Durbin-Watson Statistic	0.86

Com LPS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	141,365	996	141.98	0.00%
MonthBinary.Feb	14,912	1,499	9.95	0.00%
MonthBinary.Mar	17,528	1,387	12.63	0.00%
MonthBinary.May	16,283	1,535	10.61	0.00%
MonthBinary.Jun	15,705	2,068	7.60	0.00%
MonthBinary.Jul	19,409	2,167	8.96	0.00%
MonthBinary.Aug	19,843	2,090	9.50	0.00%
MonthBinary.Sep	17,636	1,809	9.75	0.00%
MonthBinary.Oct	20,467	1,465	13.97	0.00%
MonthBinary.Dec	19,367	1,692	11.45	0.00%
DOWBinary.WeekEnd	-10,058	637	-15.78	0.00%
COMLPSSplines.WarmAvgT	1,597	65	24.67	0.00%
COMLPSSplines.ShoulderAvgT	289	23	12.73	0.00%
MonthBinary.Dec15_Jan1	-4,066	1,902	-2.14	3.28%
US_Holidays.ComLPS_HolidayX	-3,537	1,479	-2.39	1.71%
MonthBinary.Customer_Com_Outage	-21,387	2,703	-7.91	0.00%

Com LPS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	714
R-Squared	0.88
Adjusted R-Squared	0.88
F-Statistic	346.92
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	3.51%
Durbin-Watson Statistic	0.78

Ind SGS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	19,301	609	31.67	0.00%
DOWBinary.Monday	7,204	321	22.46	0.00%
DOWBinary.Tuesday	7,118	319	22.28	0.00%
DOWBinary.Wednesday	7,003	318	22.01	0.00%
DOWBinary.Thursday	7,039	321	21.90	0.00%
DOWBinary.Friday	6,259	324	19.32	0.00%
DOWBinary.Sunday	-1,522	316	-4.82	0.00%
MonthBinary.Feb	1,196	379	3.16	0.17%
MonthBinary.Mar	2,026	358	5.66	0.00%
MonthBinary.Jun	970	541	1.79	7.32%
MonthBinary.Jul	2,586	569	4.55	0.00%
MonthBinary.Aug	1,629	542	3.01	0.28%
MonthBinary.Sep	806	486	1.66	9.78%
MonthBinary.Oct	3,315	433	7.65	0.00%
MonthBinary.Nov	2,702	380	7.11	0.00%
INDSGSSplines.AvgT	-217	14	-15.81	0.00%
INDSGSSplines.MildAvgT	87	50	1.72	8.54%
INDSGSSplines.WarmAvgT	418	60	6.95	0.00%
INDSGSSplines.SummerAltAvgT	-11	8	-1.48	14.00%
INDSGSSplines.mild_shoulder	174	57	3.06	0.23%
MonthBinary.COVIDpeak_IndSGS	-1,625	376	-4.32	0.00%

Note: Some of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

Ind SGS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	705
Deg. of Freedom for Error	684
R-Squared	0.79
Adjusted R-Squared	0.78
F-Statistic	127.92
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	13.24%
Durbin-Watson Statistic	1.36

Ind LGS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	74,531	1,197	62.25	0.00%
DOWBinary.Monday	36,385	1,380	26.37	0.00%
DOWBinary.TWT	38,233	1,052	36.33	0.00%
DOWBinary.Friday	28,089	1,377	20.40	0.00%
MonthBinary.Jan	5,388	1,642	3.28	0.11%
MonthBinary.Apr	-4,320	1,689	-2.56	1.07%
MonthBinary.May	-4,870	1,959	-2.49	1.31%
MonthBinary.Jun	-4,367	1,630	-2.68	0.76%
MonthBinary.Oct	-4,712	1,797	-2.62	0.89%
US_Holidays.IndLGS_HolidayX	-29,840	1,697	-17.58	0.00%
INDLGSSplines.SummerAvgT	61	30	2.01	4.49%
INDLGSSplines.WkdayWarmAvgT	2,476	642	3.86	0.01%
INDLGSSplines.SummerWkdayWarmAvgT	-2,056	646	-3.18	0.15%
INDLGSSplines.MildAvgT	108	65	1.66	9.66%

Note: One of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

Ind LGS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	716
R-Squared	0.76
Adjusted R-Squared	0.76
F-Statistic	178.77
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	9.57%
Durbin-Watson Statistic	1.22

Ind SPS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	119,591	2,120	56.41	0.00%
DOWBinary.Monday	45,830	1,233	37.16	0.00%
DOWBinary.Tuesday	50,250	1,211	41.48	0.00%
DOWBinary.Wednesday	49,749	1,185	41.98	0.00%
DOWBinary.Thursday	47,035	1,225	38.39	0.00%
DOWBinary.Friday	40,601	1,097	37.02	0.00%
DOWBinary.Saturday	9,151	1,064	8.60	0.00%
MonthBinary.Feb	3,521	1,319	2.67	0.78%
MonthBinary.Mar	-4,119	1,193	-3.45	0.06%
MonthBinary.Apr	-3,010	1,191	-2.53	1.17%
MonthBinary.Aug	10,179	1,117	9.11	0.00%
MonthBinary.Nov	-2,966	1,182	-2.51	1.23%
MonthBinary.Dec	-3,405	1,260	-2.70	0.70%
INDSPSSplines.AvgT	-131	44	-3.01	0.27%
INDSPSSplines.WarmAvgT	519	186	2.79	0.53%
INDSPSSplines.MildAvgT	287	164	1.75	8.09%
US_Holidays.INDSPS_Holidays2	-17,701	1,515	-11.69	0.00%
GMI_Transform.MO_Workspaces	313	36	8.80	0.00%

Note: One of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

Ind SPS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	712
R-Squared	0.87
Adjusted R-Squared	0.87
F-Statistic	287.22
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	4.30%
Durbin-Watson Statistic	0.96

Ind LPS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	262,453	1,611	162.87	0.00%
DOWBinary.Monday	-4,636	964	-4.81	0.00%
DOWBinary.WeekEnd	-17,596	2,340	-7.52	0.00%
MonthBinary.Feb	-10,547	1,416	-7.45	0.00%
MonthBinary.Mar	-5,373	1,368	-3.93	0.01%
MonthBinary.Apr	9,643	1,749	5.51	0.00%
MonthBinary.Jul	13,390	1,474	9.08	0.00%
MonthBinary.Aug	13,093	1,479	8.85	0.00%
MonthBinary.Oct	7,573	1,333	5.68	0.00%
MonthBinary.Nov	7,919	1,359	5.83	0.00%
MonthBinary.Apr2020	-25,465	2,386	-10.68	0.00%
MonthBinary.Sept2020	-4,898	1,785	-2.74	0.62%
INDLPSSplines.ColdAvgT	-171	68	-2.50	1.26%
INDLPSSplines.MildAvgT	1,229	110	11.19	0.00%
INDLPSSplines.WarmAvgT	629	191	3.30	0.10%
INDLPSSplines.WkndAvgT	-221	38	-5.87	0.00%
MonthBinary.Customer_Idle	-6,039	1,222	-4.94	0.00%
US_Holidays.XMASAft	-20,755	2,656	-7.81	0.00%
US_Holidays.XMasHol	-25,661	6,404	-4.01	0.01%
US_Holidays.July4thHol	-20,582	6,339	-3.25	0.12%
US_Holidays.DAJuly4th	-17,666	6,249	-2.83	0.48%
GMI_Transform.MO_Workspaces	491	37	13.31	0.00%

Ind LPS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	730
Deg. of Freedom for Error	708
R-Squared	0.87
Adjusted R-Squared	0.86
F-Statistic	218.66
Prob (F-Statistic)	0
Mean Abs. % Err. (MAPE)	2.71%
Durbin-Watson Statistic	1.07

Energy Sales and Customer Forecast Models[3]

Note: The F-Statistic and associated probability cannot be computed in a regression model, such as the usual SAE specification, that does not include an intercept. Therefore, F-Statistic and associated probability were not reported whenever an SAE model was developed for forecasting purpose or an intercept was not included in the model.

Residential Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
ResidentialVars_Billed.XHeat	1.34	0.03	44.01	0.00%
ResidentialVars_Billed.XCool	2.01	0.04	51.42	0.00%
ResidentialVars_Billed.XOther	0.75	0.02	45.88	0.00%
ResidentialVars_Billed.xCool_shoulder	-0.16	0.08	-2.00	4.98%

[3] 20 CSR 4240-22.030(3)(B)

Residential Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	75
Deg. of Freedom for Error	71
R-Squared	0.98
Adjusted R-Squared	0.98
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	2.29%
Durbin-Watson Statistic	1.67

Residential Customer Count Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
UtilityData.Households	1,108	7	163.75	0.00%
BinaryVars.Apr	-1,191	298	-3.99	0.01%
BinaryVars.May	-1,959	398	-4.92	0.00%
BinaryVars.Jun	-1,976	456	-4.34	0.00%
BinaryVars.Jul	-2,244	487	-4.61	0.00%
BinaryVars.Aug	-2,494	497	-5.02	0.00%
BinaryVars.Sep	-2,833	487	-5.81	0.00%
BinaryVars.Oct	-3,374	456	-7.40	0.00%
BinaryVars.Nov	-3,053	398	-7.67	0.00%
BinaryVars.Dec	-762	298	-2.55	1.22%
AR(1)	0.99	0.02	55.90	0.00%

Residential Customer Count Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	110
Deg. of Freedom for Error	99
R-Squared	1.00
Adjusted R-Squared	1.00
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	0.06%
Durbin-Watson Statistic	1.42

Commercial SGS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CommercialVars_Billing.SGS_XHeat	29,106	1,169	24.90	0.00%
CommercialVars_Billing.SGS_XCool	17,055	638	26.74	0.00%
CommercialVars_Billing.SGS_XOther	879	10.6	82.75	0.00%

Commercial SGS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	75
Deg. of Freedom for Error	72
R-Squared	0.93
Adjusted R-Squared	0.93
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	2.41%
Durbin-Watson Statistic	1.51

Commercial SGS Customer Count Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
BinaryVars.Jan	12,496	1,443	8.66	0.00%
BinaryVars.Feb	12,460	1,444	8.63	0.00%
BinaryVars.Mar	12,439	1,445	8.61	0.00%
BinaryVars.Apr	12,372	1,441	8.59	0.00%
BinaryVars.May	12,399	1,442	8.60	0.00%
BinaryVars.Jun	12,465	1,443	8.64	0.00%
BinaryVars.Jul	12,523	1,444	8.68	0.00%
BinaryVars.Aug	12,465	1,445	8.63	0.00%
BinaryVars.Sep	12,430	1,446	8.60	0.00%
BinaryVars.Oct	12,386	1,447	8.56	0.00%
BinaryVars.Nov	12,374	1,448	8.55	0.00%
BinaryVars.Dec	12,454	1,449	8.60	0.00%
BinaryVars.TimeTrend	3.11	0.03	93.50	0.00%

Commercial SGS Customer Count Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	87
Deg. of Freedom for Error	74
R-Squared	0.99
Adjusted R-Squared	0.99
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	0.12%
Durbin-Watson Statistic	0.12

Commercial LGS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CommercialVars_Billing.LGS_XCool	17,123	374	45.75	0.00%
CommercialVars_Billing.LGS_XHeat	36,520	1,748	20.89	0.00%
CommercialVars_Billing.LGS_XOther	975.15	6.3	155.78	0.00%

Commercial LGS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	60
Deg. of Freedom for Error	57
R-Squared	0.97
Adjusted R-Squared	0.97
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	1.28%
Durbin-Watson Statistic	1.52

Commercial LGS Customer Count Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
BinaryVars.Jan	9,852	128	76.98	0.00%
BinaryVars.Feb	9,851	128	77.06	0.00%
BinaryVars.Mar	9,843	128	77.09	0.00%
BinaryVars.Apr	9,836	128	77.02	0.00%
BinaryVars.May	9,835	128	76.91	0.00%
BinaryVars.Jun	9,854	128	76.98	0.00%
BinaryVars.Jul	9,864	128	76.99	0.00%
BinaryVars.Aug	9,874	128	77.03	0.00%
BinaryVars.Sep	9,882	128	77.08	0.00%
BinaryVars.Oct	9,868	128	76.97	0.00%
BinaryVars.Nov	9,862	128	76.95	0.00%
BinaryVars.Dec	9,855	128	76.94	0.00%
AR(1)	0.98	0.01	138.76	0.00%

Commercial LGS Customer Count Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	107
Deg. of Freedom for Error	94
R-Squared	1.00
Adjusted R-Squared	1.00
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	0.09%
Durbin-Watson Statistic	1.90

Commercial SPS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CommercialVars_Billing.SPS_XHeat	21,478	3,674	5.85	0.00%
CommercialVars_Billing.SPS_XCool	5,433	343.49	15.82	0.00%
CommercialVars_Billing.SPS_XOther	1,142	14.96	76.39	0.00%

Commercial SPS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	51
Deg. of Freedom for Error	48
R-Squared	0.88
Adjusted R-Squared	0.87
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	2.11%
Durbin-Watson Statistic	1.13

Commercial SPS Customer Count Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
BinaryVars.Jan	480	1.69	284.19	0.00%
BinaryVars.Feb	480	1.59	302.47	0.00%
BinaryVars.Mar	480	1.55	310.28	0.00%
BinaryVars.Apr	480	1.64	292.21	0.00%
BinaryVars.May	481	1.68	287.17	0.00%
BinaryVars.Jun	478	1.69	283.82	0.00%
BinaryVars.Jul	479	1.69	283.76	0.00%
BinaryVars.Aug	482	1.69	285.70	0.00%
BinaryVars.Sep	480	1.69	284.48	0.00%
BinaryVars.Oct	479	1.69	283.89	0.00%
BinaryVars.Nov	479	1.69	283.45	0.00%
BinaryVars.Dec	479	1.69	283.74	0.00%
AR(1)	0.61	0.12	5.02	0.00%

Commercial SPS Customer Count Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	50
Deg. of Freedom for Error	37
R-Squared	0.47
Adjusted R-Squared	0.29
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	0.36%
Durbin-Watson Statistic	2.09

Commercial LPS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CommercialVars_Billing.LPS_XCool	14,076	666.71	21.11	0.00%
CommercialVars_Billing.LPS_XOther	877	8.29	105.87	0.00%

Commercial LPS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	75
Deg. of Freedom for Error	73
R-Squared	0.83
Adjusted R-Squared	0.83
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	3.88%
Durbin-Watson Statistic	1.97

Commercial LPS Customer Count Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple Smoothing	0.71	0.13	5.60	0

Commercial LPS Customer Count Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	63
Deg. of Freedom for Error	62
R-Squared	0.45
Adjusted R-Squared	0.45
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	0.65%
Durbin-Watson Statistic	1.87

Industrial SGS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	10,410	2,269	4.59	0.00%
Weather_Trans.Billed_HDD	4	0.23	15.34	0.00%
Weather_Trans.Billed_CDD	6.85	0.43	16.13	0.00%
Binary_Vars.January	1,332	314.42	4.24	0.01%
Binary_Vars.October	1,116	158.74	7.03	0.00%
Binary_Vars.November	1,869	160.26	11.67	0.00%
Binary_Vars.December	2,082	231.41	9.00	0.00%
Econ_Trans.SGS_Index	-176.50	81.63	-2.16	3.63%
Binary_Vars.Pandemic_Shift	-739.97	80.17	-9.23	0.00%

Industrial SGS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	51
Deg. of Freedom for Error	42
R-Squared	0.95
Adjusted R-Squared	0.94
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	2.43%
Durbin-Watson Statistic	1.76

Industrial SGS Customer Count Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Binary_Vars.January	2,311	104.96	22.02	0.00%
Binary_Vars.February	2,312	104.99	22.02	0.00%
Binary_Vars.March	2,313	104.98	22.03	0.00%
Binary_Vars.April	2,304	105.15	21.91	0.00%
Binary_Vars.May	2,303	105.27	21.87	0.00%
Binary_Vars.June	2,303	105.36	21.86	0.00%
Binary_Vars.July	2,301	105.41	21.83	0.00%
Binary_Vars.August	2,298	105.42	21.80	0.00%
Binary_Vars.September	2,296	105.39	21.79	0.00%
Binary_Vars.October	2,300	105.33	21.84	0.00%
Binary_Vars.November	2,302	105.24	21.87	0.00%
Binary_Vars.December	2,305	105.12	21.92	0.00%
AR(1)	0.98	0.01	196.71	0.00%

Industrial SGS Customer Count Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	62
Deg. of Freedom for Error	49
R-Squared	1.00
Adjusted R-Squared	1.00
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	0.13%
Durbin-Watson Statistic	2.02

Industrial LGS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	46,950	6,584	7.13	0.00%
Weather_Trans.Billed_CDD	19	1	14.25	0.00%
Binary_Vars.February	2,336	804	2.91	0.53%
Binary_Vars.April	-2,398	822	-2.92	0.51%
Binary_Vars.May	-2,371	808	-2.94	0.49%
Binary_Vars.June	-2,997	768	-3.90	0.03%
Econ_Trans.LGS_Index	808	223	3.62	0.07%
Binary_Vars.Pandemic_Shift	-3,729	527	-7.08	0.00%
Binary_Vars.End_shift_2018	-4,205	545	-7.71	0.00%

Industrial LGS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	63
Deg. of Freedom for Error	54
R-Squared	0.92
Adjusted R-Squared	0.91
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	1.77%
Durbin-Watson Statistic	1.30

Industrial LGS Customer Count Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Binary_Vars.January	881	89.42	9.85	0.00%
Binary_Vars.February	880	89.42	9.84	0.00%
Binary_Vars.March	880	89.41	9.84	0.00%
Binary_Vars.April	878	89.44	9.82	0.00%
Binary_Vars.May	877	89.46	9.80	0.00%
Binary_Vars.June	879	89.48	9.83	0.00%
Binary_Vars.July	879	89.49	9.82	0.00%
Binary_Vars.August	881	89.49	9.85	0.00%
Binary_Vars.September	883	89.49	9.87	0.00%
Binary_Vars.October	881	89.48	9.85	0.00%
Binary_Vars.November	881	89.46	9.85	0.00%
Binary_Vars.December	880	89.44	9.84	0.00%
AR(1)	0.99	0.01	118.47	0.00%

Industrial LGS Customer Count Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	134
Deg. of Freedom for Error	121
R-Squared	0.99
Adjusted R-Squared	0.99
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	0.21%
Durbin-Watson Statistic	2.60

Industrial SPS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ_Trans.SPS_Index	-4,266	1,525	-2.80	0.84%
Weather_Trans.Billed_CDD	26	13	1.93	6.15%
Binary_Vars.January	240,814	49,775	4.84	0.00%
Binary_Vars.February	222,071	44,472	4.99	0.00%
Binary_Vars.March	223,482	44,481	5.02	0.00%
Binary_Vars.April	223,536	45,163	4.95	0.00%
Binary_Vars.May	220,969	44,731	4.94	0.00%
Binary_Vars.June	226,483	46,979	4.82	0.00%
Binary_Vars.July	226,270	47,428	4.77	0.00%
Binary_Vars.August	223,949	46,006	4.87	0.00%
Binary_Vars.September	224,816	47,016	4.78	0.00%
Binary_Vars.October	222,614	45,375	4.91	0.00%
Binary_Vars.November	223,149	45,476	4.91	0.00%
Binary_Vars.December	233,663	47,955	4.87	0.00%
Binary_Vars.COVID_Lockdowns_SPS	-4,741	1,410	-3.36	0.19%
Binary_Vars.Flooding_SPS	7,895	3,573	2.21	3.40%

Note: One of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

Industrial SPS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	50
Deg. of Freedom for Error	34
R-Squared	0.83
Adjusted R-Squared	0.75
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	1.61%
Durbin-Watson Statistic	0.91

Industrial SPS Customer Count Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Binary_Vars.January	185	0.58	320	0.00%
Binary_Vars.February	185	0.56	329	0.00%
Binary_Vars.March	185	0.56	332	0.00%
Binary_Vars.April	184	0.57	322	0.00%
Binary_Vars.May	185	0.58	320	0.00%
Binary_Vars.June	184	0.58	318	0.00%
Binary_Vars.July	185	0.58	320	0.00%
Binary_Vars.August	185	0.58	320	0.00%
Binary_Vars.September	184	0.58	318	0.00%
Binary_Vars.October	184	0.58	317	0.00%
Binary_Vars.November	184	0.58	318	0.00%
Binary_Vars.December	185	0.58	319	0.00%
AR(1)	0.56	0.08	7.20	0.00%

Industrial SPS Customer Count Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	122
Deg. of Freedom for Error	109
R-Squared	0.36
Adjusted R-Squared	0.29
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	0.59%
Durbin-Watson Statistic	2.19

Industrial LPS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ_Trans.LPS_Index	5,278	29	179.8	0.00%
Binary_Vars.March	11,947	1,777	6.73	0.00%
Binary_Vars.April	19,016	2,009	9.47	0.00%
Binary_Vars.May	33,659	2,399	14.03	0.00%
Binary_Vars.June	27,962	2,019	13.85	0.00%
Binary_Vars.July	41,672	1,921	21.70	0.00%
Binary_Vars.August	44,060	1,909	23.08	0.00%
Binary_Vars.September	24,758	1,920	12.90	0.00%
Binary_Vars.October	27,516	1,910	14.41	0.00%
Binary_Vars.November	16,242	1,916	8.48	0.00%
Binary_Vars.Flooding	-13,658	3,094	-4.41	0.01%
Binary_Vars.COVID_Lockdowns	-21,928	3,094	-7.09	0.00%
Binary_Vars.Customer_Outage_May21	-14,530	4,411	-3.29	0.18%

Industrial LPS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	63
Deg. of Freedom for Error	50
R-Squared	0.94
Adjusted R-Squared	0.93
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	1.58%
Durbin-Watson Statistic	2.13

Industrial LPS Customer Count Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Binary_Vars.January	34	0.32	107	0.00%
Binary_Vars.February	34	0.31	108	0.00%
Binary_Vars.March	34	0.31	108	0.00%
Binary_Vars.April	34	0.32	107	0.00%
Binary_Vars.May	34	0.32	107	0.00%
Binary_Vars.June	34	0.32	106	0.00%
Binary_Vars.July	34	0.32	106	0.00%
Binary_Vars.August	34	0.32	106	0.00%
Binary_Vars.September	34	0.32	105	0.00%
Binary_Vars.October	34	0.32	105	0.00%
Binary_Vars.November	34	0.32	106	0.00%
Binary_Vars.December	34	0.32	106	0.00%
AR(1)	0.85	0.05	19	0.00%

Industrial LPS Customer Count Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	86
Deg. of Freedom for Error	73
R-Squared	0.84
Adjusted R-Squared	0.81
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err (MAPE)	0.65%
Durbin-Watson Statistic	2.29

Non-Coincident System Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Heating Variable	32	3.09	10	0.00%
Cooling Variable	84	9.83	9	0.00%
Base Variable	1	0.04	29	0.00%
January	799	172.70	5	0.00%
February	868	160.54	5	0.00%
March	457	137.58	3	0.15%
May	584	162.27	4	0.06%
June	1026	220.41	5	0.00%
July	1083	230.10	5	0.00%
August	1157	209.10	6	0.00%
September	820	200.20	4	0.01%
October	318	164.54	2	5.81%
November	536	137.51	4	0.02%
December	511.32	157.93	3	0.20%

Note: One of the explanatory variables were retained in the model despite being only marginally statistically significant (p-value>.05). The direction and magnitude of the coefficient are reasonable, the standard error is consistent with other variables, and the interpretation of all of the weather variables is cleaner with the inclusion of this variable.

Non-Coincident System Peak Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	75
Deg. of Freedom for Error	61
R-Squared	0.94
Adjusted R-Squared	0.93
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err (MAPE)	3.06%
Durbin-Watson Statistic	2.04

Time of Use Adjustments

	Hours Reduced	Summer Reduction (Jun - Sept)	Winter Reduction (Oct - May)	Estimated Customer Participation Rate																				
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Evening/Morning Savers	Between 9 am and 9 pm, everyday for all seasons	0.3%	0.3%	40.10%	47.15%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%	54.19%
Overnight Savers	6 am to 10pm everyday for all seasons	6.8%	3.5%	0.06%	0.07%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%
Smart Savers	3 pm to 7 pm on summer (June – September) non-holiday weekdays, and 6 to 8 am and pm (both morning and evening) on non-summer (all other months) non-holiday weekdays	11.8%	9.0%	0.04%	0.05%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
Ultimate Savers	3 pm to 7 pm on summer (June – September) non-holiday weekdays, and 6 to 8 am and pm (both morning and evening) on non-summer (all other months) non-holiday weekdays	12.9%	9.3%	0.03%	0.04%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%

Abbreviations

Res:	Residential
Com :	Commercial
Ind:	Industrial
SGS:	Small General Service
LGS:	Large General Service
SPS:	Small Primary Service
LPS:	Large Primary Service
WN:	Weather Normalized
LTS:	Large Transmission Service

Schedule MM-S15

Compliance References

4. Existing Supply-side Resources

Highlights

- *Ameren Missouri currently owns and operates 10,208 MW of supply-side resources: 4,522MW of coal, 1,194 MW of nuclear, 2,949 MW of natural gas/oil, and 1,543 MW of renewables and storage.*
- *Ameren Missouri retired the Meramec Energy Center at the end of 2022.*
- *Ameren Missouri is scheduled to bring approximately 350 MW of solar capacity online by the end of 2024.*
- *Ameren Missouri has assumed retirement of 217 MW (summer net capacity) of older, less efficient gas and oil-fired combustion turbine generators (CTGs) by the end of 2029, subject to unit-specific evaluations prior to a final decision to retire. Additionally, the Company will be retiring its IL CTGs by the end of 2039 due to legislation passed in Illinois in 2021, including retirement of the Venice Energy Center by the end of 2029.*
- *The baseline retirement dates for Ameren Missouri's coal-fired energy centers, consistent with the Company's 2022 Notice of Change in Preferred Plan, are as follows:*
    - *Rush Island Energy Center retired by the end of 2025.*
    - *Sioux Energy Center retired by the end of 2030.*
    - *Two Labadie Energy Center Units retired by the end of 2036 and the remaining two units retired by the end of 2042.*
    - *Evaluation of alternate retirement dates is discussed in Chapter 9.*

Ameren Missouri owns and operates solar, wind, coal-fired, natural gas-fired, nuclear, hydroelectric and storage energy centers to serve the energy needs of its customers. Ameren Missouri regularly evaluates energy center performance and upgrades that are necessary to operate its plants in an efficient, safe, cost-effective and environmentally friendly manner.

Ameren Missouri has recently completed Keokuk Energy Center upgrades on Units 5 and 15 (the last of 15 main units) in 2021 and 2022 respectively. During the 20-year planning horizon, Ameren Missouri has planned upgrades on Osage Units 2 and 4 which will complete the upgrades for all 27 currently operating hydro units. This IRP's baseline assumptions include the retirement of all of its coal-fired energy centers by the end of 2042, four older and less efficient CTG units by the end of 2029 and all its CTGs in Illinois by the end of 2039.

4.1 Existing Generation Portfolio[1]

Ameren Missouri owns and operates solar, wind, coal-fired, natural gas-fired, nuclear, hydroelectric, and storage energy centers to serve the energy needs of its customers. Table 4.1 reflects the 2023 summer net capability of Ameren Missouri's existing supply-side resources along with accredited capacity for summer and winter. Appendices A and B include a unit rating summary table and existing unit summer and winter accredited capacity for 2023-2043. Note that the seasonal accredited capacity (SAC) values for Callaway reflect its extended outage in 2021. Forward looking SAC values for Callaway reflect normal operation.

Table 4.1 Existing Supply-side Resource Installed Capacity

Existing Resource (MW)	Summer Net Capability*	Summer SAC	Winter SAC
Callaway	1,194	983	1,200
Labadie	2,372	2,378	2,456
Rush Island	1,178	1,204	1,164
Sioux	972	788	749
CTGs	2,949	2,613	1,724
Maryland Heights	6	6	11
Osage	235	234	231
Keokuk	148	139	130
Taum Sauk	440	414	267
High Prairie	400	77	148
Atchison	300	0	0
Solar	14	8	1
Total	10,208	8,843	8,081

4.1.1 Existing Coal Resources

Ameren Missouri has three coal-fired energy centers in its generation fleet. The coal-fired units at our Labadie, Rush Island, and Sioux energy centers have a total summer net generating capability of 4,522 MW.

Numerous projects were completed at the Labadie, Rush Island, and Sioux Energy Centers to comply with the EPA's Effluent Limitation Guidelines (ELG) and Coal Combustion Residual (CCR) rules. A comprehensive discussion of environmental regulations and compliance can be found in Chapter 5 – Environmental Compliance.

[1] 20 CSR 4240-22.040(1); 20 CSR 4240-22.040(2)

Labadie Energy Center

Labadie Energy Center is located outside Labadie, MO, on more than 1,100 acres adjacent to the Missouri River, 35 miles west of downtown St. Louis. The plant consists of four generating units with a combined summer net capability of 2,372 MW. The first unit started operating in 1970, and the plant was fully operational in 1973.

In 2021, the Labadie Unit 4 high pressure (HP) and intermediate pressure (IP) turbines were chemical-foam cleaned, a process that removes deposits without requiring long outages for turbine disassembly, to improve turbine efficiency in a cost-effective manner.

Projects related to environmental compliance continue at Labadie, with ash pond closure projects completed in 2021, and multi-year, Clean Water Act projects starting in 2022.

Rush Island Energy Center

Rush Island Energy Center is located 40 miles south of downtown St. Louis, in Jefferson County, Missouri, on 500 acres on the western bank of the Mississippi River. The plant has two units with a combined net summer capability of 1,178 MW. The first unit started operation in 1976 and the second unit in 1977.

Recent environmental project completion milestones include the Rush Island pond closure project in 2021, and a groundwater improvement project that went into service in 2022.

In December 2021, Ameren Missouri announced it would retire Rush Island Energy Center and filed its change in preferred plan with the Missouri Public Service Commission (MoPSC) in June 2022. MISO subsequently designated the two Rush Island generating units as System Support Resource (SSR) units to maintain grid reliability until transmission and distribution investments can be completed. The Rush Island units are expected to remain in-service as SSR units until certain transmission upgrades are completed by mid-to-late 2025.

Sioux Energy Center

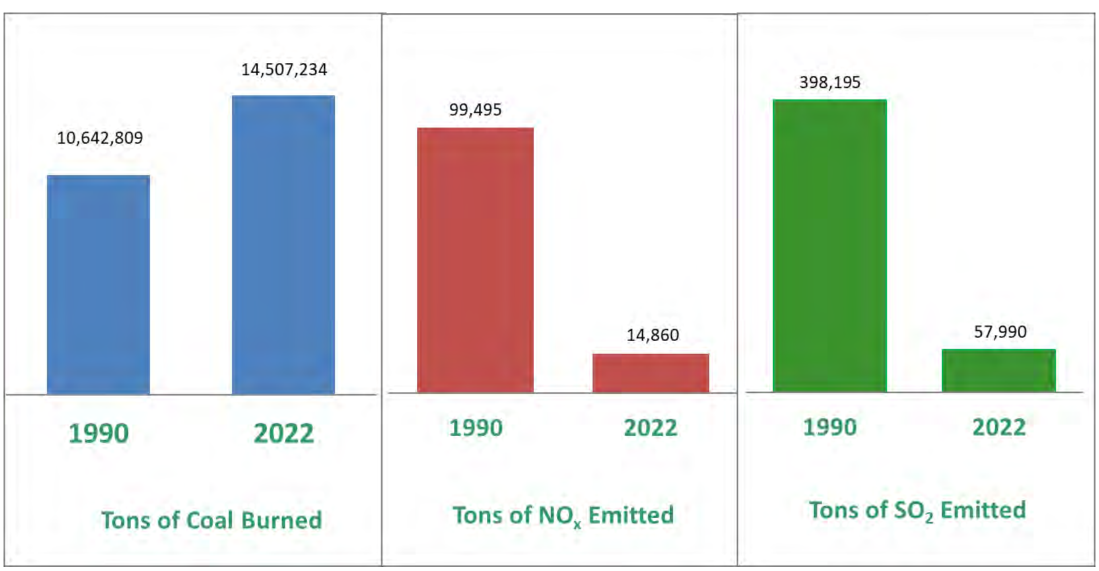
Sioux Energy Center is located in St. Charles County, Mo., 28 miles northwest of downtown St. Louis, on the Mississippi River. It consists of two cyclone boiler units which started operations in 1967 and 1968, respectively, and has a total net summer capability of 972 MW.

Both units at Sioux are equipped with wet flue gas desulfurization (FGD) equipment, commonly referred to as scrubbers, to comply with the Cross State Air Pollution Rule (CSAPR). The FGD systems at Sioux also provide significant co-benefits in complying with EPA's MATS rule for both mercury and particulate emissions. New dry ash handling systems and a new wastewater treatment system went in-service in late 2020. Ash pond closure projects were completed in 2021, and a groundwater improvement project will be completed in 2023.

Historical Emissions from Coal Resources

Ameren Missouri has achieved dramatic reductions in SO_2 and NO_x emissions during the past two decades, despite an increase in the amount of coal consumed to meet our customers' growing energy needs over that period. Over the years, Ameren Missouri has been able to reduce pollutant emissions by using lower-sulfur fuels, by installing cleaner-emitting burners with computer-controlled operation, by improving operation of existing precipitators -- collecting more than 99% of particulates -- and by installing scrubbers at Sioux Energy Center. In addition, Ameren Missouri developed an early, progressive approach to meeting NO_x control regulations. Figure 4.1 shows the decrease in Ameren Missouri's SO_2 and NO_x emissions as coal consumption has increased.

Figure 4.1 NO_x and SO_2 Emissions Reductions



4.1.2 Existing Gas & Oil Resources

Ameren Missouri owns and operates oil- or natural gas-fired combustion turbine generators (CTG) to provide electricity during times of high demand or when its higher utilization plants are not operating due to a forced outage or scheduled maintenance.

Table 4.2 CTG Capability

Plant	Fuel	Net MW
Audrain	Gas	608
Goose Creek	Gas	438
Pinckneyville	Gas	511
Raccoon Creek	Gas	304
Kinmundy	Gas	210
Peno Creek	Gas	172
Venice	Gas	489
Fairgrounds	Oil	55
Mexico	Oil	54
Moberly	Oil	54
Moreau	Oil	54
Total		2,949

Table 4.2 lists the Ameren Missouri combustion turbines and their 2023 summer net generating capabilities. ****A Midcontinent Independent System Operator (MISO) deliverability study determined that the operation of Audrain combustion turbines is subject to a transmission constraint which reduces the plant's available output by approximately 30 MW, which is not reflected in Table 4.1. Based on previous MISO studies, it was assumed that a system upgrade of approximately $5 Million would be required to regain the 30 MW of Audrain capacity.[2] If Ameren Missouri determines that the additional 30 MW capacity from Audrain is needed, a new MISO study would be required to determine the necessary system upgrades and the estimated cost to gain this additional capacity, and a cost-benefit analysis would be performed.****

4.1.3 Existing Nuclear Resource

Callaway Energy Center is located about 100 miles west of St. Louis, Missouri, in Callaway County. The plant started operations in December 1984 and is the only power plant that uses nuclear fuel in Ameren Missouri's generation fleet. Ameren Missouri has continued to make cost-effective investments in Callaway to replace equipment that is at the end of its service life, including components such as turbine rotors, steam generators and main transformers.

Callaway Energy Center is the second largest power generation facility on the Ameren Missouri system with a net summer capability of 1,194 MW.

[2] 20 CSR 4240-22.040(3)(B)

4.1.4 Existing Renewable and Storage Resources

Currently, Ameren Missouri owns 383 MW of hydroelectric resources, 440 MW of pumped storage, 699 MW of wind generation, a purchase power agreement for another 102 MW of wind generation, 15.7 MW (AC) of solar generation, and 8 MW of landfill gas-to-electric generation.

Existing Hydroelectric Resources

Keokuk

Ameren Missouri's Keokuk hydroelectric plant is located on the Mississippi River at Keokuk, Iowa, 180 miles north of St. Louis. The Keokuk Energy Center has a total net summer capability of 148 MW.

More than a million cubic yards of earth and rock were excavated to build the Keokuk dam and plant, which began operation in 1913. An engineering marvel of its time, Keokuk is the largest privately owned and operated dam and hydroelectric generating plant on the Mississippi River. Over the years, Ameren Missouri has continued to invest in the modernization and repair of the plant and dam.

As it passes through the power plant, falling water spins turbines, or water wheels, which drive generators that produce electricity. Keokuk Plant is a "run-of-river plant," meaning that all water flowing downstream passes the plant on a daily basis. An average day of operation at Keokuk Plant saves the equivalent of nearly 1,000 tons of coal. The individual units at the Keokuk Energy Center, each having a nameplate rating of less than 10 MW, were certified as qualified renewable energy resources by the Missouri Department of Natural Resources (MoDNR) in September 2011.

As of 2022, 9 out of 15 unit controllers have been replaced. The remaining 6 will be replaced in 2023 while the balance of plant control system is expected to be complete in 2024.

Osage

Ameren Missouri's Osage hydroelectric plant is located in Lakeside Missouri on the Osage River at the Lake of the Ozarks. The Osage Energy Center has a total net summer capability of 235 MW.

Osage began operation in 1931. For early settlers, the rolling Osage River in the heart of Missouri's Ozark wilderness provided a way of life and a source of livelihood, whether that was fishing, farming, logging or other pursuits. Then in the 1930s, the river was harnessed when Union Electric Company (now known as Ameren Missouri) built Bagnell Dam to provide power for a growing state and a budding economy. The 1930s-era building of Bagnell Dam and Ameren Missouri's Osage hydroelectric plant created a range of recreational opportunities in the now-popular Lake of the Ozarks.

Every hour the Osage Plant operates, other energy resources are preserved. As water passes through the dam, the pressure of the falling water spins water wheels, which drive generators that produce electricity. In a typical year, Osage Plant uses the clean energy of falling water to produce as much power as 225,000 tons of coal or one million barrels of oil. Osage Energy Center produces completely renewable energy, although it does not qualify as a renewable energy resource per Missouri regulations due to the units being greater than 10 MW.

In 2021, Osage completed the last Unit Controller Replacement project, finishing a multi-year effort to update the controls on all eight generating units of the hydroelectric facility. Osage is currently working on the balance of plant control system, pulling all of the unit controllers together, which is expected to be complete in 2023.

Existing Pumped Storage

Taum Sauk

The Taum Sauk pumped storage plant is located approximately 120 miles southwest of St. Louis in the scenic Ozark highlands. The Taum Sauk Energy Center has a total net summer capability of 440 MW.

Taum Sauk Plant began operation in 1963, the turbines were completely rebuilt in 1999, and the upper reservoir rebuild project was completed in 2010. Taum Sauk is used primarily on a peaking basis and is put into operation when the demand for electricity is greatest. The pump storage system works much like a conventional hydroelectric plant, but is usually used only to meet daily peak power demands. Water stored in an upper reservoir is released to flow through turbines and into a lower reservoir during periods of high energy demand. Then, overnight, when the demand for electricity is low, the water is pumped back into the upper reservoir, where it is stored until needed.

Ameren Missouri has initiated projects to replace the Generator Step Up (GSU) Transformers at Taum Sauk. The GSUs link the Taum Sauk generators to the grid, increasing the voltage from the generator to a level suitable for transmission. The new, larger GSUs are sized to handle the full output of the Taum Sauk generators and will reduce environmental risk by replacing the current oil-cooled technology with gas-insulated GSUs. The new GSUs, exciters, and isophase busses will allow each unit to increase its output to 250 MW by the end of 2026.

Existing Renewables

High Prairie Renewable Energy Center

In May 2018, Ameren Missouri entered into an agreement to acquire, after construction, a 400 MW wind farm in Adair and Schuyler counties in northeast Missouri. The wind farm consists of 175 wind turbines that stand nearly 500 feet above the ground. Ameren Missouri began commercially operating the High Prairie Renewable Energy Center in December 2020 and it became certified as a renewable energy resource by the MoDNR in February 2021.

Atchison Renewable Energy Center

In May 2019, Ameren Missouri entered into an agreement to acquire, after construction, a 299 MW wind farm in Atchison County in northwest Missouri. The wind farm consists of 91 wind turbines that range in total height from 442 to 590 feet above ground. In March 2021, Atchison Renewable Energy Center became operational at a reduced capacity of 120 MW; by December 2021, it reached its full operational capacity of 298.6 MW, and received its renewable energy resource certification from the MoDNR in February 2021.

Pioneer Prairie Wind Farm

In June 2009, Ameren Missouri executed an agreement to purchase 102 MW of wind power from Phase II of Horizon Wind Energy's Pioneer Prairie Wind Farm in northeastern Iowa in Mitchell County. This power purchase agreement (PPA) runs from September 2009 through August 2024. The Pioneer Prairie Wind Farm was certified as a qualified renewable energy resource by the MoDNR in September 2011.

O'Fallon Renewable Energy Center

In December 2014 Ameren Missouri began operation of 4.8 MW (AC) of solar generation at the O'Fallon Renewable Energy Center. The O'Fallon facility includes more than 19,000 polysilicon solar panels and is located on 25 acres of land owned by Ameren Missouri.

Ameren Missouri BJC Solar Partnership

In October 2019, the Ameren Missouri BJC Solar Partnership project was completed. This facility generates 1.57 MW (AC) of solar power directly onto the 12.47-kV grid while being hosted by the BJC Parking Garage. This project was completed through the Solar Partnership Pilot Program.

Community Solar Resources

Ameren Missouri owns and operates two solar facilities that exclusively support the company's Community Solar Pilot Program for residential and small business customers. Both facilities are fully subscribed. Due to the success of the pilot program, Ameren Missouri received approval to implement a permanent Community Solar Program within the electric rate review filed in March 2021.

Lambert Community Solar Energy Center

In August 2019, the Ameren Missouri Lambert Community Solar Energy Center began operation of 942 kW (AC) of solar generation. The facility is located on land owned by St. Louis Lambert International Airport just west of the airfield near Lindbergh and Missouri Bottom Road. The facility supports approximately 350 customer enrollments in the Community Solar Pilot Program.

Montgomery Community Solar Center

In March 2022, the Ameren Missouri Montgomery Community Solar Energy Center began operation of 5.74 MW (AC) of solar generation. This facility is currently Ameren Missouri's largest operational solar energy center and supports more than 2,000 customer enrollments in the Community Solar Pilot Program. The tilt-panel design, a first for Ameren Missouri, allows the panels to follow the sun's trajectory through the day, maximizing the amount of energy captured from the sun.

Neighborhood Solar Resources

Ameren Missouri's Neighborhood Solar Program aims to site solar generation at customer partner sites that will inclusively benefit customers through renewables education, visibility, and workforce opportunities. Ameren Missouri will own and operate all Neighborhood Solar systems for the benefit of all customers; host participants provide site access to the partnership. Ameren Missouri is on track to complete six Neighborhood Solar sites prior to the end of 2023 with a combined capacity of 2.54 MW-AC, fully utilizing the $14 million budget allocated through Senate Bill 564. Each site's development incorporated solar education tours and equitable workforce development union pre-apprentice job opportunities for diverse candidates. They are as follows:

South St. Louis Renewable Energy Center

The South St. Louis Renewable Energy Center is a 192 kW-AC parking lot solar canopy in the diverse Dutchtown neighborhood of south St. Louis city. Habitat for Humanity Saint Louis is offering the use of the space so the energy produced there can benefit all Ameren Missouri customers. The site began generating energy in August 2021.

Cape Girardeau Renewable Energy Center

The largest Neighborhood Solar installation at 1.2 MW-AC, the Cape Girardeau Renewable Energy Center went into service in July 2022. This facility is located on the campus of Southeast Missouri State University, providing covered parking for the Show Me Center.

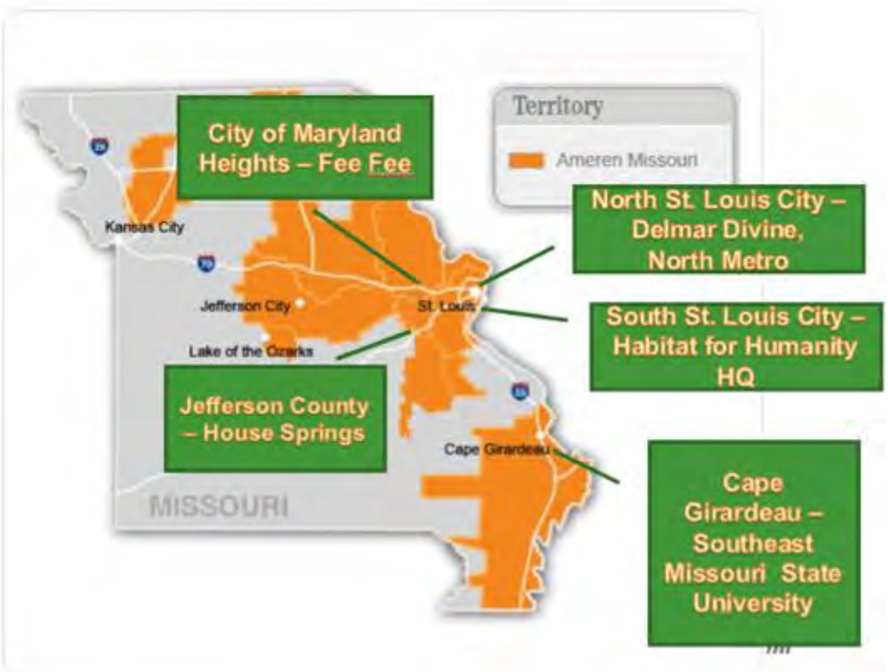
Fee Fee Renewable Energy Center

The Fee Fee Renewable Energy Center is a 504 kW-AC parking lot solar canopy located between Aquaport and Maryland Heights Community Center. The City of Maryland Heights is offering the use of the space so the energy produced there can benefit all Ameren Missouri customers. The site began generating energy in April 2023.

North Metro Renewable Energy Center

The North Metro Renewable Energy Center is a 192 kW-AC parking lot solar canopy located at the Ameren Missouri North Metro Operating Center. The site began generating energy in April 2023.

Figure 4.2 Neighborhood Solar Site Map



Maryland Heights Renewable Energy Center

The Maryland Heights Renewable Energy Center (MHREC) is located in St. Louis County approximately 18 miles northwest of St. Louis. The MHREC is the largest landfill-gas-to-electric facility in Missouri and one of the largest in the country. The facility began operation in June 2012. It has a total net summer capacity of 8 MW. MHREC burns methane gas produced by the IESI Landfill in Maryland Heights, Missouri, in three Solar Mercury 50 gas turbines to produce electricity. The current contract with the landfill guarantees enough gas supply for three generators until 2032. In August 2012, the MHREC was certified as a qualified renewable energy resource by the MoDNR.

4.1.5 Levelized Cost of Energy Evaluation for Existing Resources[3]

The levelized cost of energy (LCOE) was calculated for Ameren Missouri's existing resources. LCOE represents going-forward costs of ownership and operation and provides a basis for comparison to new resource alternatives. It is important to note that the LCOE figures do not fully capture all of the relative strengths of each resource type. Table 4.3 shows the component analysis for the LCOE for each energy center. The average LCOE for Ameren Missouri's entire generating fleet is approximately $43/MWh.

[3] 20 CSR 4240-22.040(2)(A); 20 CSR 4240-22.040(2)(B); 20 CSR 4240-22.040(2)(C)1

Table 4.3 Levelized Cost of Energy Component Analysis for Existing Resources

Existing Resources	Levelized Cost of Energy (¢/kWh)										
	Capital	O&M	Fuel	PTC	Decommission	Pump Cost	Env Capital	CO2	SO2	NOx	Total Cost
Labadie	0.70	0.46	2.20	--	--	--		1.30	0.00	0.19	**4.85**
Rush Island	0.53	2.65	2.64	--	--	--		0.18	0.00	0.40	**6.40**
Sioux	0.19	0.73	2.78	--	--	--		0.52	0.00	0.50	**4.72**
Callaway	1.33	1.41	0.85	--	0.07	--		0.00	0.00	0.00	**3.66**
Audrain CTG	0.19	0.45	5.22	--	--	--		1.24	0.00	0.04	**7.14**
Goose Creek CTG	0.58	0.41	4.76	--	--	--		0.92	0.00	0.04	**6.71**
Pinckneyville CTG	3.29	1.25	3.84	--	--	--		0.74	0.00	0.03	**9.14**
Raccoon Creek CTG	1.01	0.48	4.76	--	--	--		0.92	0.00	0.04	**7.21**
Kinmundy CTG	0.78	0.65	4.41	--	--	--		0.85	0.00	0.03	**6.73**
Peno Creek CTG	12.32	2.08	4.61	--	--	--		1.10	0.00	0.03	**20.14**
Venice CTG	0.34	0.68	4.05	--	--	--		0.26	0.00	0.03	**5.36**
Fairgrounds CTG	0.05	0.09	21.54	--	--	--		0.29	0.00	0.04	**22.00**
Mexico CTG	0.05	0.08	21.75	--	--	--		0.29	0.00	0.04	**22.21**
Moberly CTG	0.05	0.08	21.75	--	--	--		0.29	0.00	0.04	**22.21**
Moreau CTG	0.05	0.08	21.75	--	--	--		0.29	0.00	0.04	**22.21**
Keokuk	1.91	0.56	--	--	--	--		0.00	0.00	0.00	**2.47**
Osage	2.52	1.10	--	--	--	--		0.00	0.00	0.00	**3.62**
Taum Sauk	1.29	1.05	--	--	--	7.42		0.00	0.00	0.00	**9.76**
MHREC CTG	4.53	4.79	3.63	--	--	--		0.00	0.00	0.00	**12.94**
High Prairie	0.24	1.07	--	-1.24	--	--		0.00	0.00	0.00	**0.08**
Atchison	0.00	0.83	--	-1.24	--	--		0.00	0.00	0.00	**-0.41**
Ofallon Solar	0.00	0.29	--	--	--	--		0.00	0.00	0.00	**0.29**
Lambert	0.00	1.70	--	--	--	--		0.00	0.00	0.00	**1.70**
BJC	0.00	2.48	--	--	--	--		0.00	0.00	0.00	**2.48**
Montgomery	0.00	0.25	--	--	--	--		0.00	0.00	0.00	**0.25**
Neighborhood Solar	0.00	1.92	--	--	--	--		0.00	0.00	0.00	**1.92**

4.1.6 Planned Changes to Existing Non-Coal Resources

During the 20-year planning horizon, Ameren Missouri is considering two Osage Energy Center Units for upgrades and the retirement of several CTG units.

The original 89-year-old turbines at Osage units 2 and 4 are scheduled to be replaced by 2024 at a cost of about $35M. These upgrades are expected to result in 2% efficiency improvement; however, Ameren Missouri is currently conducting an ongoing engineering study to better estimate the benefits.

CTG Retirements

Ameren Missouri previously conducted a high-level retirement evaluation of the existing CTG fleet. The potential retirement recommendation is based on operating experience, condition of the assets, and qualitative analysis. The qualitative analysis considered factors such as condition of subsystems, obsolesce of control systems, availability of spare parts, and building condition. Based on the evaluation and in light of current market assumptions, Ameren Missouri plans to retire four of its older gas- and oil-fired CTG units (i.e., Fairgrounds, Mexico, Moberly, and Moreau), with a total net capacity of 217 MW, over the next 20 years. A combination of factors led to the potential CTG retirement recommendations, including the fact that the average age of those units is 43 years; and for some of the units, the long-term availability of spare parts is questionable. The lead time for obtaining spare parts is unknown. Table 4.4 provides a summary of the planned CTG retirements. The planned CTG retirements are included in the base capacity position (see Appendix B).

Table 4.4 Ameren Missouri Potential CTG Retirements during the Planning Period

Unit	Capacity (MW)	Fuel Type	Commerical Operation Date	Age as of 12/31/2023	Retirement Time Frame
Fairgrounds	55	Oil	1974	50	12/31/2029
Mexico	54	Oil	1978	46	12/31/2029
Moberly	54	Oil	1978	46	12/31/2029
Moreau	54	Oil	1978	46	12/31/2029

The results of a detailed condition assessment for each unit will be used as the basis for economic analysis to be considered along with other factors such as overall age, condition, reliability, safety and cost, significant capital needs, near-term capacity value, and availability of spare parts. Such economic analyses are generally initiated when a need for significant capital investment is identified and/or when expected market conditions change substantially.

In September 2021, the Illinois General Assembly passed the Climate and Equitable Jobs Act (CEJA), and Governor Pritzker signed it into law in the same month. Among other things, CEJA provides for the elimination of fossil-fueled generation in Illinois by 2045. The law requires fossil-fueled generators owned by investor-owned utilities to be retired by January 1, 2040; however, the timeline for retirement is accelerated for generators in close proximity to statutorily designated Environmental Justice Communities. Of Ameren Missouri's CTG facilities in Illinois, Venice Energy Center (489 MW) is the only facility that is subject to this requirement. As a result, the Company expects Venice to be retired by January 1, 2030, and the remaining CTGs in Illinois with summer net capability of 1,463 MW to be retired by January 1, 2040.

Oil Back-up Capability

Ameren Missouri is planning to restore the oil backup capability at its Peno Creek and Kinmundy Energy Centers to increase the winter capability by approximately 47 MW and 40 MW, respectively. The Company is also evaluating the addition of oil backup for its Audrain Energy Center. The current estimate for restoration of oil backup at Peno Creek and Kinmundy is less than $10 million. The current estimate for the addition of oil backup at Audrain is approximately $220 million and would add over 300 MW of winter capacity.

4.2 Existing Steam Generation Evaluation

Ameren Missouri has evaluated its coal energy centers in terms of condition, base retirement assumptions, reliability trends, operation and maintenance costs, and capital expenditures. Table 4.5 lists the commercial operation date for each generating unit, the average age at each energy center as of 12/31/2023, and the base retirement assumptions consistent with the Company's 2022 Notice of Change in Preferred Plan filing. Additional retirement dates will be analyzed and reported in Chapter 9.

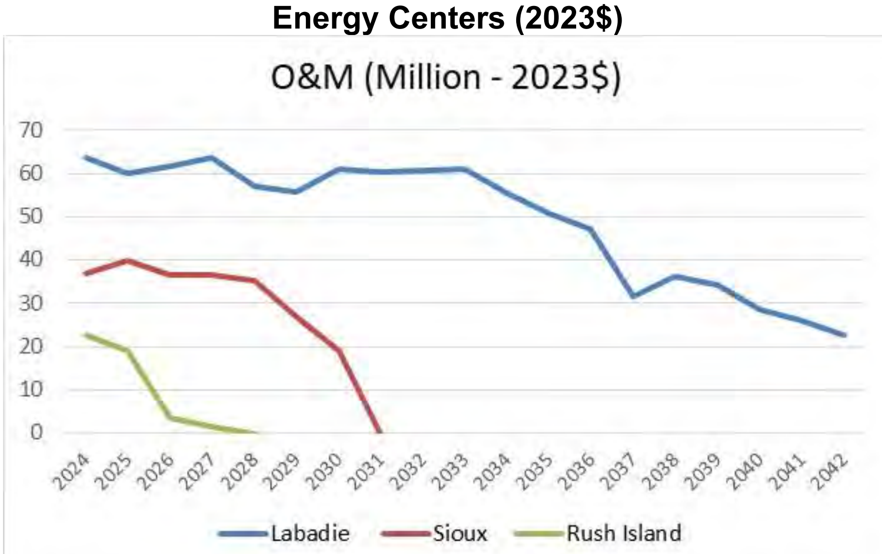
Table 4.5 Ameren Missouri Coal Energy Center Commercial Operation Dates, Average Age, and Base Retirement Assumptions[4]

Energy Center	Commercial Operation Date				Average Age as of 12/31/2023	Base Retirement Assumptions (Retirement Date)
	Unit 1	Unit 2	Unit 3	Unit 4		
Labadie	1970	1971	1972	1973	53	2042
Rush Island	1976	1977			48	2025
Sioux	1967	1968			57	2030

4.2.1 Operations and Maintenance Costs

The plant O&M costs are anticipated to remain flat to declining in real terms in the future. Figure 4.3 shows the future O&M costs from 2024 to 2042 in 2023 dollars using the base retirement date for each energy center. The labor portion of the O&M assumes a 50% pension and benefit loading factor. The O&M forecasts in the figure do not include annual revenues from ash sales. A six-year outage cycle for Labadie and a 3-year outage cycle for Sioux are assumed in the O&M forecast.

Figure 4.3 Future Non-Environmental Annual O&M for Ameren Missouri Coal Energy Centers (2023$)

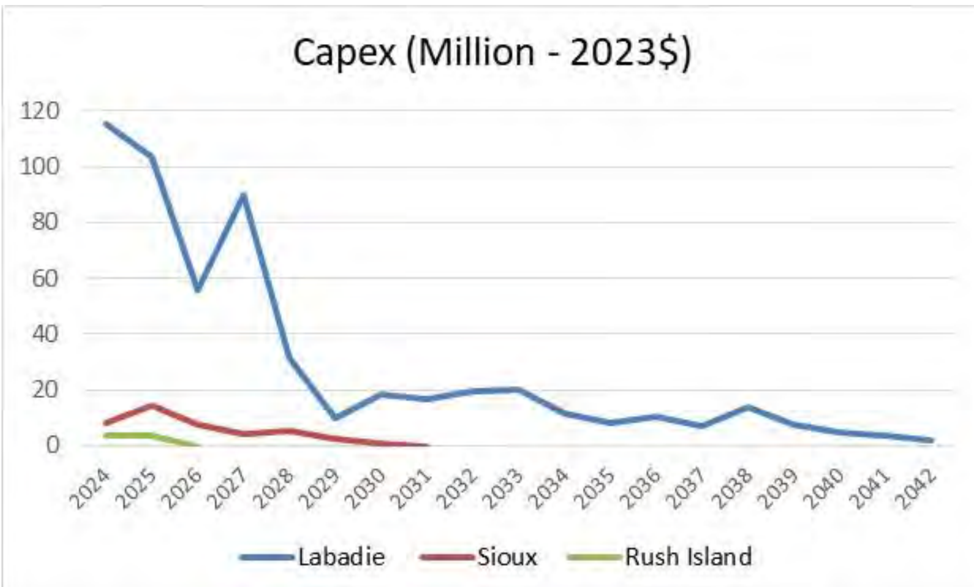


[4] The Labadie generating units are currently assumed to be retired in 2036 (two units) and 2042 (two units).

4.2.2 Capital Expenditures

Figure 4.4 shows the future non-environmental capital expenditures for 2024 to 2042 using the base retirement date for each energy center. Future environmental capital expenditures are discussed in Chapter 5. The future non-environmental plant capital expenditures were provided by Ameren Missouri Power Operations Services and normalized to 2023 dollars using a 2% escalation rate. Note that assumptions for capital expenditures may vary significantly for alternate retirement dates and that such differences are included in the assumptions used for the analysis of alternative resource plans described in Chapter 9.

Figure 4.4 Future Non-Environmental Capital Expenditures Ameren Missouri Coal Energy Centers (2023$)



4.3 Efficiency Improvement[5]

4.3.1 Existing Facility Efficiency Options

Ameren Missouri has implemented various initiatives to improve efficiency and reduce GHG emissions at its existing facilities. These initiatives include replacement of incandescent light bulbs with compact fluorescent light bulbs and LEDs, and standardization of low-energy usage light fixtures during system replacements. Another initiative to improve efficiency and reduce GHG emissions in the operation of heating, ventilation, and air conditioning (HVAC) equipment through the installation of programmable thermostats for control of HVAC systems is expected to reduce energy

[5] 20 CSR 4240-22.040(1)

consumption during off-hours. The projects completed in 2011 through 2021 have reduced energy consumption by more than 3,700 MWh annually and reduced CO_2 emissions by more than 2,600 metric tons annually (assuming 0.7 metric tons of CO_2 per MWh). Ameren Missouri will continue assessing and implementing the projects that prove to be feasible on an ongoing basis.

4.3.2 Existing Energy Center Efficiency Options[6]

Ameren Missouri continues to be focused on maintaining the efficiency of its coal-fired generating units. Projects that improve efficiency that are a benefit to the company and to customers continue to be evaluated and executed when appropriate. Projects and work activities that restore efficiency lost due to equipment degradation or operating issues continue to be evaluated and executed on a regular basis.

Ameren Missouri performs long-term scheduled major maintenance outages. Much of the work performed during these major outages (such as replacement or repair of leaking valves, restoration of duct work, insulation of equipment, and cleaning of equipment) typically results in improved efficiency when the unit returns to service.

Ameren Missouri's generating resources utilize the Plant Reliability Optimization (PRO) process to maintain assets in a cost efficient and effective manner to support conservative operations. The PRO process integrates personnel from all levels of the organization and uses data to assess equipment condition to prioritize and plan resources and work. The process develops, implements, and standardizes best practices system-wide to reduce failure rates on critical equipment, balancing additional maintenance costs against potential production losses to optimize investments, while ensuring equipment performance and condition support of safe and reliable asset operation.

Ameren Missouri continues to utilize performance monitoring on its major Energy Centers and has recently expanded focus to incorporate monitoring of wind and solar assets. Performance monitoring includes analysis of rotating equipment, vibration monitoring, Real Time Alarm Monitoring and expansion of monitoring services to the CTG fleet, along with exploring additional technologies and software to accomplish these goals. The Performance Monitoring function works closely with the Real Time Operations group, and complements Ameren Missouri's existing generation operations and dispatch functions.

Operational monitoring at Ameren Missouri’s coal plants is also an important tool in maintaining the heat rate (efficiency) at the coal plants. EtaPRO is a continuous monitoring software tool used at all the plants to monitor thermal performance of critical

[6] 20 CSR 4240-22.040(1)

equipment. The EtaPRO system is maintained by Performance Engineering and is also used by performance engineers to generate plant heat rate (efficiency) reports. Operations personnel routinely check system components during operation and start-up modes to ensure that valve line-ups are correct and equipment performance is maintained.

4.4 Compliance References

Chapter 4 - Appendix A

Unit Ratings Summary Table[1]

Energy Center	Fuel Type	Summer Net Capability (MW)	2022 Heat Rate (BTU/kWh)	2022 Equivalent Availability (%)	Commercial Operation Date	Installed Environmental Control Technologies
Callaway	Nuclear	1194	9,983	83	1984	NA
Labadie (Units 1-4)	Coal	2,372	10,242	88	Unit 1: 1970 Unit 2: 1971 Unit 3: 1972 Unit 4: 1973	**SO2 Control**: Labadie U1-U4---PRB Fuel **NOx Controls**: Labadie U1-U4---OFA, Low NOx burners, and Combustion Optimizer; Labadie U2&U4---Additional level of SOFA **Particulate Matter**: Labadie U1&U2---Added C&D precipitator, retired A&B; U4-Rebuild of A&B precipitators, Added C precipitator; U3 A&B precipitators, Added C precipitator, SO3 Injection **Hg Controls**: U1-U4---ACI Mercury Controls
Rush Island (Units 1-2)	Coal	1,178	10,510	92	Unit 1: 1976 Unit 2: 1977	**SO2 Control**: Rush Island U1&U2---PRB Fuel **NOx Controls**: Rush Island U1&U2---OFA, Low NOx burners, and Combustion Optimizer **Particulate Matter**: Rush Island U1&U2---ESPs **Hg Controls**: Rush Island U1&U2---ACI Mercury Controls
Sioux (Units 1-2)	Coal	972	10,509	82	Unit 1: 1967 Unit 2: 1968	**SO2 Controls**: Sioux U1&U2---Wet FGD **NOx Controls**: Sioux U1&U2---OFA and SNCR **Particulate Matter**: Sioux U1&U2---ESP followed by WFGD **HG Controls**: Sioux U1&U2---Halogen addition to coal, ACI added to WFGD
Audrain (Units 1-8)	Gas	608	12,304	75	Purchased 2006 Began Operation: 2001	**NOx Controls**: Units 1-8---Dry Low NOx
Goose Creek (Units 1-6)	Gas	438	11,841	89	Purchased 2006 Began Operation: 2003	**NOx Controls**: Units 1-6---Dry Low NOx
Pinckneyville (Units 1-8)	Gas	316	9,540	79	Purchased 2005 Began Operation: 2000-2001	**NOx Controls**: Units 1-4---Water Injection Units 5-8---Dry Low NOx
Raccoon (Units 1-4)	Gas	304	11,839	100	Purchased 2006 Began Operation: 2002	**NOx Controls**: Units 1-4---Dry Low NOx
Kinmundy (Units 1-2)	Gas	210	10,975	68	Purchased 2005 Began Operation: 2001	**NOx Controls**: Units 1-2---Dry Low Nox
Peno Creek (Units 1-4)	Gas	172	10,839	79	2002	**NOx Controls**: Units 1-4---Water Injection
Venice (Units 2-5)	Gas	489	10,989	68	Unit 2: 2002 Units 3-5: 2005	**NOx Controls**: Units 2 and 5---Water Injection Units 3-4---Combustion System Design with Water Injection Unit 5---Dry Low NOx
Fairgrounds	Oil	55	***	63	1974	NA
Mexico	Oil	54	***	95	1978	NA
Moberly	Oil	54	***	83	1978	NA
Moreau	Oil	54	***	84	1978	NA
Osage	Hydro	235	NA	99	1931	**Wildlife:** Fish Net: Turbine design increases dissolved oxygen
Keokuk	Hydro	148	NA	96	1913	NA
Taum Sauk	Pumped Storage	440	NA	98	1963	NA
Maryland Heights	Landfill Gas	9	13,159	68	2012	NA
High Prairie	Wind	381	NA	NA	2014	NA
Atchison	Wind	288	NA	NA	2019	NA
O'Fallon	Solar	4.5	NA	NA	2014	NA
Lambert	Solar	0.9	NA	NA	2019	NA
BJC	Solar	1.6	NA	NA	2019	NA
South St. Louis	Solar	0.2	NA	NA	2021	NA
Montgomery	Solar	5.7	NA	NA	2022	NA
Cape Girardeau	Solar	1.2	NA	NA	2022	NA

NA: Not applicable
***: Not applicable due to low usage

[1] 20 CSR 4240-22.040(1)

Compliance References

Chapter 4 - Appendix B

Baseline Existing Resource Capability Table[1]

A. Generation Summer Accredited Capacity

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Existing Generation Capacity																						
Callaway	Nuclear	983	983	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150
Keokuk	Hydro	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139
Labadie Unit 1	Coal	609	609	609	609	609	609	609	609	609	609	609	609	609	609	609	609	609	609	609	609	-
Labadie Unit 2	Coal	620	620	620	620	620	620	620	620	620	620	620	620	620	620	620	620	620	620	620	620	-
Labadie Unit 3	Coal	560	560	560	560	560	560	560	560	560	560	560	560	560	560	-	-	-	-	-	-	-
Labadie Unit 4	Coal	589	589	589	589	589	589	589	589	589	589	589	589	589	589	-	-	-	-	-	-	-
Rush Island Unit 1	Coal	607	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rush Island Unit 2	Coal	598	598	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sioux Unit 1	Coal	353	353	353	353	353	353	353	353	-	-	-	-	-	-	-	-	-	-	-	-	-
Sioux Unit 2	Coal	435	435	435	435	435	435	435	435	-	-	-	-	-	-	-	-	-	-	-	-	-
Maryland Heights 1	LFG	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Maryland Heights 2	LFG	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Maryland Heights 3	LFG	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total Base Capacity		5497	5497	4460	4460	4460	4460	4460	4460	3672	3672	3672	3672	3672	3672	2523	2523	2523	2523	2523	2523	1295
Osage	Hydro	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234
Taum Sauk Unit 1	Hydro	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223
Taum Sauk Unit 2	Hydro	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191
Audrain 1	Gas	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Audrain 2	Gas	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Audrain 3	Gas	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
Audrain 4	Gas	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64
Audrain 5	Gas	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Audrain 6	Gas	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Audrain 7	Gas	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Audrain 8	Gas	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
Fairgrounds	Oil	27	27	27	27	27	27	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Goose Creek 1	Gas	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	-	-	-	-
Goose Creek 2	Gas	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	-	-	-	-
Goose Creek 3	Gas	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	-	-	-	-
Goose Creek 4	Gas	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	-	-	-	-
Goose Creek 5	Gas	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	-	-	-	-
Goose Creek 6	Gas	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	-	-	-	-
Kinmundy CTG-1	Gas/Oil	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	-	-	-	-
Kinmundy CTG-2	Gas/Oil	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	-	-	-	-

[1] 20 CSR 4240-22.060(4)(B)(9)

Schedule MM-S18

A. Generation Summer Accredited Capacity (continued)

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Existing Generation Capacity																						
Mexico	Oil	52	52	52	52	52	52	52	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Moberly	Oil	47	47	47	47	47	47	47	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Moreau	Oil	51	51	51	51	51	51	51	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peno Creek CTG-1	Gas/Oil	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Peno Creek CTG-2	Gas/Oil	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Peno Creek CTG-3	Gas/Oil	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
Peno Creek CTG-4	Gas/Oil	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
Pinckneyville CTG-1	Gas	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	-	-	-	-
Pinckneyville CTG-2	Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	-	-	-	-
Pinckneyville CTG-3	Gas	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	-	-	-	-
Pinckneyville CTG-4	Gas	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	-	-	-	-
Pinckneyville CTG-5	Gas	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	-	-	-	-
Pinckneyville CTG-6	Gas	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	-	-	-	-
Pinckneyville CTG-7	Gas	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	-	-	-	-
Pinckneyville CTG-8	Gas	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	-	-	-	-
Raccoon Creek 1	Gas	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	-	-	-	-
Raccoon Creek 2	Gas	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	-	-	-	-
Raccoon Creek 3	Gas	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	-	-	-	-
Raccoon Creek 4	Gas	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	-	-	-	-
Venice CTG-2	Gas	35	35	35	35	35	35	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Venice CTG-3	Gas	172	172	172	172	172	172	172	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Venice CTG-4	Gas	161	161	161	161	161	161	161	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Venice CTG-5	Gas	102	102	102	102	102	102	102	-	-	-	-	-	-	-	-	-	-	-	-	-	-
High Prairie	Wind	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
O'Fallon	Solar	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Lambert	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
BJC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
South St. Louis	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Montgomery	Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Cape Girardeau	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Intermediate/Peaking/Intermittent Capacity		3346	3346	3346	3346	3346	3346	3346	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	1474	1474	1474	1474
Total Generation Summer Accredited Capacity		**8843**	**8843**	**7806**	**7806**	**7806**	**7806**	**7806**	**7160**	**6372**	**6372**	**6372**	**6372**	**6372**	**6372**	**5223**	**5223**	**5223**	**3997**	**3997**	**3997**	**2769**

A. Generation Winter Accredited Capacity

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Existing Generation Capacity																						
Callaway	Nuclear	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
Keokuk	Hydro	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Labadie Unit 1	Coal	616	616	616	616	616	616	616	616	616	616	616	616	616	616	616.3	616	616	616	616	616	-
Labadie Unit 2	Coal	586	586	586	586	586	586	586	586	586	586	586	586	586	586	585.5	586	586	586	586	586	-
Labadie Unit 3	Coal	642	642	642	642	642	642	642	642	642	642	642	642	642	642	-	-	-	-	-	-	-
Labadie Unit 4	Coal	612	612	612	612	612	612	612	612	612	612	612	612	612	612	-	-	-	-	-	-	-
Rush Island Unit 1	Coal	602	602	602	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rush Island Unit 2	Coal	562	562	562	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sioux Unit 1	Coal	367	367	367	367	367	367	367	367	-	-	-	-	-	-	-	-	-	-	-	-	-
Sioux Unit 2	Coal	382	382	382	382	382	382	382	382	-	-	-	-	-	-	-	-	-	-	-	-	-
Maryland Heights 1	LFG	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Maryland Heights 2	LFG	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Maryland Heights 3	LFG	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Total Base Capacity		5710	5710	5710	4546	4546	4546	4546	4546	3797	3797	3797	3797	3797	3797	2543	2543	2543	2543	2543	2543	1341
Osage	Hydro	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231
Taum Sauk Unit 1	Hydro	169	169	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207
Taum Sauk Unit 2	Hydro	98	98	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207
Audrain 1	Gas	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Audrain 2	Gas	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Audrain 3	Gas	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Audrain 4	Gas	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Audrain 5	Gas	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Audrain 6	Gas	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Audrain 7	Gas	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
Audrain 8	Gas	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Fairgrounds	Oil	52	52	52	52	52	52	52	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Goose Creek 1	Gas	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	-	-	-	-
Goose Creek 2	Gas	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	-	-	-	-
Goose Creek 3	Gas	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	-	-	-	-
Goose Creek 4	Gas	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	-	-	-	-
Goose Creek 5	Gas	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	-	-	-	-
Goose Creek 6	Gas	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	-	-	-	-
Kinmundy CTG-1	Gas/Oil	55	55	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	-	-	-	-
Kinmundy CTG-2	Gas/Oil	57	57	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	-	-	-	-

A. Generation Winter Accredited Capacity (continued)

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Existing Generation Capacity																						
Mexico	Oil	58	58	58	58	58	58	58	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Moberly	Oil	53	53	53	53	53	53	53	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Moreau	Oil	61	61	61	61	61	61	61	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peno Creek CTG-1	Gas/Oil	31	31	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Peno Creek CTG-2	Gas/Oil	33	33	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Peno Creek CTG-3	Gas/Oil	37	37	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Peno Creek CTG-4	Gas/Oil	30	30	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
Pinckneyville CTG-1	Gas	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	-	-	-	-
Pinckneyville CTG-2	Gas	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	-	-	-	-
Pinckneyville CTG-3	Gas	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	-	-	-	-
Pinckneyville CTG-4	Gas	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	-	-	-	-
Pinckneyville CTG-5	Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Pinckneyville CTG-6	Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Pinckneyville CTG-7	Gas	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	-	-	-	-
Pinckneyville CTG-8	Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Raccoon Creek 1	Gas	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	-	-	-	-
Raccoon Creek 2	Gas	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	-	-	-	-
Raccoon Creek 3	Gas	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	-	-	-	-
Raccoon Creek 4	Gas	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	-	-	-	-
Venice CTG-2	Gas	21	21	21	21	21	21	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Venice CTG-3	Gas	92	92	92	92	92	92	92	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Venice CTG-4	Gas	116	116	116	116	116	116	116	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Venice CTG-5	Gas	61	61	61	61	61	61	61	-	-	-	-	-	-	-	-	-	-	-	-	-	-
High Prairie	Wind	148	146	144	142	139	137	135	133	131	128	126	124	122	119	117	115	113	110	110	110	110
O'Fallon	Solar	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Lambert	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BJC	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South St. Louis	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Montgomery	Solar	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Cape Girardeau	Solar	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Intermediate/Peaking/Intermittent Capacity		2371	2369	2601	2599	2596	2594	2592	2078	2075	2073	2071	2069	2066	2064	2062	2060	2057	1228	1228	1228	1228
Total Generation Winter Accredited Capacity		**8081**	**8079**	**8311**	**7145**	**7142**	**7140**	**7138**	**6624**	**5873**	**5870**	**5868**	**5866**	**5864**	**5862**	**4605**	**4603**	**4600**	**3771**	**3771**	**3771**	**2569**

Schedule MM-S18

Compliance References

5. Environmental Compliance

Highlights

- *Since the 2020 Integrated Resource Plan (IRP) filing, the U.S. Environmental Protection Agency (EPA) has issued a number of new or updated regulations for power plant air, water, and solid waste emissions.*
- *Such environmental regulations affect the operations of Ameren Missouri's Energy Centers; in particular, its coal-fired units.*
- *Ameren Missouri has identified mitigation steps and costs for complying with current and probable future environmental regulations to be used in its evaluation of alternative resource plans.*

Ameren Missouri has made significant investments to comply with existing environmental regulations and maintain a sufficient compliance margin. Rules proposed or promulgated since the IRP filing in September of 2020 include the Illinois Climate and Equitable Jobs Act (CEJA), the Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards (NAAQS), the 2023 update to the Mercury and Air Toxics Standards (MATS), the 2023 Steam Electric Power Generating Effluent Limitations Guidelines (ELG) Proposed Update, and proposed regulations of greenhouse gas emissions under section 111 of the Clean Air Act.

Environmental regulations are an important factor to consider in resource planning. The future regulatory horizon is uncertain with respect to certain regulatory programs such as those addressing greenhouse gas emissions from coal-fired and natural gas-fired generating units. In this IRP, we have not included new coal-fired generation as a candidate resource option, but we will continue monitoring advancements, especially in carbon capture and sequestration (CCS) technology. Ameren Missouri has incorporated assumptions regarding proposed and potential environmental regulations in its "most likely" case, and a corresponding compliance path characterized by environmental retrofits to its existing fleet. The cost and timing of those retrofits are reflected in the risk analysis presented in Chapter 9. Furthermore, the planning scenarios (described in Chapter 2) act as signposts for decision making and therefore are an important aspect of the strategy selection in Chapter 10.

5.1 Overview

Table 5.1 Current & Pending Environmental Regulations

Regulatory Driver	Summary Requirements	Regulation Status	Compliance Timing
Current CSAPR Regulation	Created Group 3 Ozone Season Allowance Program for 12 states including IL reducing NOx ozone season banked allowances and allowance allocations for IL sources	Revised CSAPR Update was published on 4/30/2021 and went into effect on 6/29/2021. The rule reduces seasonal NOx allocations for IL EGUs for the 2021 ozone season and again in 2022 and 2023.	2021 ozone season and beyond
Proposed CSAPR Update	Requires 26 eastern states (including MO) to reduce emissions that contribute to pollution in other states through SIPs or newly promulgated FIP's.	The final pre-publication rule was published in March, 2023. The final rule is expected to be published in the FR during summer, 2023.	2023 ozone season and beyond
Revisions to National Ambient Air Quality Standards (NAAQS)	Lower PM, NOx and SO2 limits; Expansion of non-attainment areas	SO2 final rule June, 2010; EPA proposed redesignation from "unclassifiable" to attainment for area around Labadie based on 2017-2019 data; Redesignation of Jefferson County to attainment pending final action.	SO2: 2017 - 2020
		Fine particulate (PM2.5) lowered 1/15/2013; Attainment designations 03/2015; Missouri in attainment. EPA retained the current 12 mg/M3 standard in 2020. EPA announced new standards in January, 2023, proposing to lower the standard to a level between 9 and 10 micrograms per cubic meter.	PM2.5: 2025 - 2028
		Ozone standard lowered, final rule 12/2015; Attainment designations complete April 2018; St. Louis/Metro East area marginal nonattainment and size of area reduced.	EPA proposed to retain standard in 2020
Mercury and Air Toxics Standards (MATS)	Reduction in emissions of Mercury, HCl (proxy for acid gases) and particulate emissions (proxy for non-mercury metals)	New Rule Update proposed in April, 2023.	Estimated to be 2025.

Regulatory Driver	Summary Requirements	Regulation Status	Compliance Timing
Clean Air Visibility Rule (CAVR)/Regional Haze Rule	Application of Best Available Retrofit Technology (BART); Targets reduction in transported SO2 and NOx; status of CSAPR may require state to change approach.	EPA issued revisions in Jan 2017 and guidance in 2018; MO working with affected sources and federal land managers to develop an approvable state plan in early 2021. States submit plans for second compliance period in 2021.	MDNR consulted with Federal Land Managers on a draft state plan. Missouri state plan submitted in 2022.
Clean Water Act Section 316(a) Thermal Standards	Implementation through NPDES permit conditions	Evaluation covered by NPDES permits	New thermal requirements implemented at Labadie; other plants contain similar requirements in existing NPDES permits.
Clean Water Act Section 316(b) Protection of Aquatic Life	Case-by-case determination of controls required to meet entrainment standards; national standard for impingement	Studies 2015 - 2017; Compliance 2022 - 2024	Labadie NPDES Permit required intake modifications are in-progress. Other Plants NPDES permit requirements to be determined.
Waters of The United States (WOTUS)[1]	Protection of additional streams and tributaries	The EPA and Corps of Engineers finalized revisions and issued the Navigable Waters Protection Rule: Definition of "Waters of the United States" in December, 2022.	Final rule effective March 20, 2023.
Revisions to Steam Electric Effluent Limitations Guidelines (ELG)	Dry ash handling and Installation of wastewater treatment facilities; Implemented through NPDES permit conditions	EPA linked ELG rule to CCR rule; EPA has stayed certain compliance deadlines during rulemaking to revise the final rule.	All ELG required modifications now complete.
Coal Combustion Residuals (CCR)	Conversion to dry bottom ash and fly ash; Closure of existing ash basins; Dry disposal in landfill	Final determination that CCRs are nonhazardous by EPA in December 2014; final rule April 2015, effective October 19, 2015. Federal legislation (WINN Act) to revise rule signed December 16, 2016. Additional USEPA rulemakings in progress.	Basin closures and corrective measures in process. Completion in advance of regulatory deadline.
Clean Air Act Regulation of Greenhouse Gases (GHG)/Affordable Clean Energy Rule (ACE)	New Source Performance Standard (NSPS) for new, modified, reconstructed units; state emission limits (CO2) for existing sources	Clean Power Plan final rule was stayed by Supreme Court 2/9/2016;	CPP was stayed; on 6/30/22, the SCOTUS issued a ruling in West Virginia v. EPA that noted the CPP is unlawful. EPA recently proposed a new rule regulating GHGs.

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

Ameren Missouri is subject to various environmental laws and regulations enforced by federal, state (Missouri and Illinois) and local authorities. Table 5.1 summarizes the current environmental regulations for which Ameren Missouri must implement mitigation measures, along with expectations for compliance requirements for certain potential regulations. The following sections describe the status of the major current and future regulations that may govern the operations of Ameren Missouri facilities. Given the lack of certainty regarding future regulatory programs, Ameren Missouri has necessarily made good faith assumptions based upon available information regarding potential future compliance measures. Such assumptions are subject to revision.

5.2 Air Regulation and Compliance Assumptions

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

In 2015, the EPA issued the Clean Power Plan (CPP), which would have established CO_2 emissions standards applicable to existing power plants. The CPP was challenged in the DC Circuit Court of Appeals, however, the United States Supreme Court stayed the rule in February 2016, before the case was heard. As a result, the CPP was never implemented. The EPA promulgated the Affordable Clean Energy (ACE) rule as a replacement for the CPP in September 2019, repealing the CPP in the process. The ACE rule established emission guidelines for states to follow in developing plans to limit CO_2 emissions from coal-fired electric generating units. The ACE rule defined certain efficiency measures that could be applied directly to coal fired boilers as the Best System of Emission Reduction (BSER). The DC Circuit Court vacated the ACE rule on January 19, 2021. On June 30, 2022, the US Supreme Court reversed and remanded the DC Circuit Court decision deciding that EPA did not have the authority to "devise emissions caps based on the generation shifting approach the Agency took in the Clean Power Plan." The US EPA announced that it was developing a replacement to the ACE Rule and further challenges to the ACE rule have been held in abeyance pending issuance of the new rule. [To be updated to include proposed regulation of greenhouse gas emissions under section 111 of the Clean Air Act.]

Attainment Designations for the National Ambient Air Quality Standard for Ozone

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

The St. Louis area was designated as marginal with a marginal area attainment date of August 2021. Based on the 2018-2020 design value the St. Louis area failed to attain the 2015 standard and a bump up to moderate non-attainment was expected. However, because the St. Louis area 2019-2021 design value met the 2015 standard, Missouri DNR submitted a redesignation request in January 2022. Illinois EPA was working on a similar request for the IL portion of the St Louis non-attainment area. Unfortunately, prior to Illinois EPA's submission, 2022 ozone data indicated that the St. Louis Area ozone design value for 2020-2022 would show non-attainment. As a result, EPA bumped up the St. Louis Ozone non-attainment area to moderate nonattainment in 2022.

National Ambient Air Quality Standard for SO_2

The EPA lowered the SO_2 ambient standard to 75 ppb on June 2, 2010. Initial attainment designations were finalized on August 5, 2013 and included the designation of two areas in Missouri as nonattainment. The two nonattainment areas included an area in the vicinity of Kansas City (portions of Jackson County) and an area around Herculaneum (portions of Jefferson County). In 2015, the Missouri Department of Natural Resources (MDNR) finalized attainment plans for both areas. The areas are required to demonstrate compliance with the new SO_2 standard no later than October 4, 2018. For the Herculaneum area, the MDNR has over three years of air quality monitoring data that indicates the area is in attainment with the standard. At MDNR’s request, on June 23, 2017, the EPA proposed a determination that the area has attained the SO_2 ambient standard. On September 13, 2017, the EPA published a final determination that the Jefferson County area is in attainment with the SO_2 ambient standard. In December 2017, the MDNR submitted a formal request to the EPA to re-designate the Jefferson County SO2 nonattainment area to attainment.

As a part of MDNR’s state implementation plan for the Herculaneum area, Ameren Missouri entered into an agreement in 2015 to install an ambient SO_2 monitoring network in the vicinity of the Rush Island Energy Center. The agreement also includes lower SO_2 emissions limits for the Rush Island, Labadie and Meramec Energy Centers that took effect on January 1, 2017. The ambient SO_2 monitors near the Rush Island Energy Center began gathering data in December 2015 and, to date, measured values are significantly below the ambient air quality standard for SO_2. In each calendar year since

Schedule MM-S19

commencement of the monitoring network through December 31, 2019, quality-assured data has recorded fourth-highest hourly ambient SO_2 levels between 14 ppb and 30 ppb; 60 to 80 percent below the air quality level allowed (75 ppb) under the SO_2 NAAQS.

In addition to the initial attainment designations, the EPA is taking steps to complete the designation process for the SO_2 ambient standard. The EPA entered into a consent order with the Sierra Club and the Natural Resources Defense Council on March 2, 2015, and also finalized the “Data Requirements Rule” on August 21, 2015. The Data Requirements Rule requires states to evaluate emissions from “large sources” of SO_2 (generally greater than 2000 tons SO_2/year) by either the use of air dispersion modeling or ambient air quality monitoring. For areas where states choose to use modeling to determine attainment status states including Missouri, submitted their designations (and supporting information) to the EPA by January 13, 2017. Subsequently, the EPA designated those areas by December 31, 2017. For sources in Missouri for which the modeling option of the Data Requirements Rule was utilized, the MDNR completed the modeling analysis in the fall of 2016. In December 2016, the Missouri Air Conservation Commission approved the MDNR recommendation of attainment for eight sources in Missouri that included the Meramec Energy Center. The attainment recommendations were submitted to the EPA. On September 5, 2017, the EPA issued the preliminary designations for the modeling option, and the final designations were made on December 21, 2017.

For areas where states choose monitoring, states had to submit monitoring plans to the EPA by July 2016, and sources are required to have monitors installed by January 1, 2017. After 3 years of monitoring data is collected (2017-19), the states must certify the data collected by May 2020. The EPA will designate these areas either attainment or nonattainment by December 2020. Non-attaining areas must be in compliance by December 2025.

The Consent Order addresses areas that contain any stationary source not announced for retirement that according to the EPA’s Air Markets Database emitted in 2012 either (a) more than 16,000 tons of SO_2, or (b) more than 2,600 tons of SO_2 and had an average emission rate of at least 0.45 lbs. SO_2/MMBtu. The EPA finalized designations for these areas in July 2016. These areas have up to 5 years to achieve attainment. In September 2015, the MDNR recommended that the area around the Labadie Energy Center be designated as unclassifiable. In April 2015, Ameren Missouri began operating SO_2 ambient monitors to determine whether the area is in compliance with the SO_2 air quality standard. On June 30, 2016, the EPA issued a final determination of “unclassifiable” for the area around the Labadie Energy Center. Data collected from the ambient SO_2 monitors indicates that air quality in the vicinity of the Labadie Energy Center complies with the EPA standards. In accordance with the EPA’s Data Requirement Rule, the ambient SO_2 monitoring network for the Labadie Energy Center has been enhanced and two additional monitors are in service as of January 2017. In each calendar year since commencement of the monitoring network in 2015, air quality data has recorded ambient SO_2 design concentration between 18 ppb and 38 ppb; approximately 50 to 76 percent below the SO_2 NAAQS. No exceedances of the SO_2 NAAQS have occurred between 2015 and present. There is now three full years of data from the expanded monitoring system available to EPA that demonstrates ambient conditions that are well-below the SO_2 NAAQS. Under the DRR, the EPA and the MDNR are reassessing the attainment classification using certified monitoring data from the 2017 through 2019 time period. In August, both the MDNR and the EPA proposed to re-designate the area around Labadie from unclassifiable to attainment. The EPA is expected to finalize the re-designation by the end of the year. Ameren Missouri continues to operate the monitoring systems and submit the data to both the MDNR and the EPA. Based on monitoring data gathered to date and the EPA proposal to designate the area as attainment, we have assumed the area around Labadie will ultimately be designated as "attainment." Ameren Missouri's assumptions for compliance regarding SO_2 emissions reflect this expectation as well as expected steps necessary to comply with The Cross State Air Pollution Rule (CSAPR).

Revisions to the National Ambient Air Quality Standard for Fine Particulate Matter

On December 14, 2012, the EPA revised the National Ambient Air Quality Standard for fine particulate matter (PM2.5). The previous standards for PM2.5 were promulgated in 1997 and 2006 and included an annual standard and a 24-hour standard. The annual standard, which was set in 1997, was 15 micrograms per cubic meter (µg/m3), and the 24-hour standard, which was set in 2006, is 35 µg/m3. The revised NAAQS finalized in December 2012 retained the 24-hour standard but lowered the annual standard from 15 µg/m3 to 12 µg/m3. In December 2013, the MDNR recommended that the entire state of Missouri, including the St. Louis area that includes Franklin, Jefferson, St. Charles, and St. Louis Counties and St. Louis City, be designated as “attainment/unclassifiable.” Based on 2010 through 2012 ambient air monitoring data, all monitors in Missouri were in compliance with the standard. In January 2015, the EPA designated the St. Louis area and the metro-East area in Illinois as unclassifiable due to insufficient quality assured monitoring data for the state of Illinois to assess compliance with the 2012 annual fine particle standard. In December 2018, the MDNR submitted a request to the EPA to re-designate the Missouri portion of the unclassifiable area to attainment. Illinois has corrected the problems the EPA identified with their air quality monitoring data, and both Missouri and Illinois now have complete, quality assured, and certified ambient PM2.5 monitoring data for three years (2015-2017) demonstrating that the area is in attainment with the PM2.5 standard. Based on the current data, the area is in attainment. Ameren Missouri expects the area to remain in attainment and thus no further mitigation would be required at Ameren Missouri’s facilities.

The Clean Air Act requires the EPA to review all of the ambient standards on a periodic basis. In December 2020, the EPA finalized a rule to retain the current standard for fine particulate matter. On January 6, 2023, US EPA proposed to lower the standard for fine particulate matter to a range or 9-10 $\mu g/m^3$.

CSAPR and the CSAPR Update Rule

CSAPR was finalized on July 6, 2011 replacing the Clean Air Interstate Rule (CAIR). CSAPR established new allowances for the annual nitrogen oxides (NO_x) and sulfur dioxide (SO_2) trading programs and the seasonal NO_x trading program. CSAPR uses newly created allowances and thus there is no initial bank to rely on from the Acid Rain or CAIR programs to use for any potential shortfall. CSAPR was slated to become effective January 1, 2012, but the rule was stayed by a federal court decision on December 30, 2011 in response to several legal challenges. On June 26, 2014, the EPA filed a motion with the United States (U.S.) Court of Appeals for the District of Columbia (D.C.) Circuit to: (1) remove the stay of CSAPR and, (2) delay for three years all of the compliance deadlines that had not already passed when the stay was enacted. On October 23, 2014, the D.C. Circuit court lifted the stay. On December 3, 2014, the EPA implemented a three-year toll that moved the starting date for Phase 1 of CSAPR to January 1, 2015, and January 1, 2017 for Phase 2. Ameren Missouri units are currently in-compliance with the CSAPR limits for both SO_2 and NO_x.

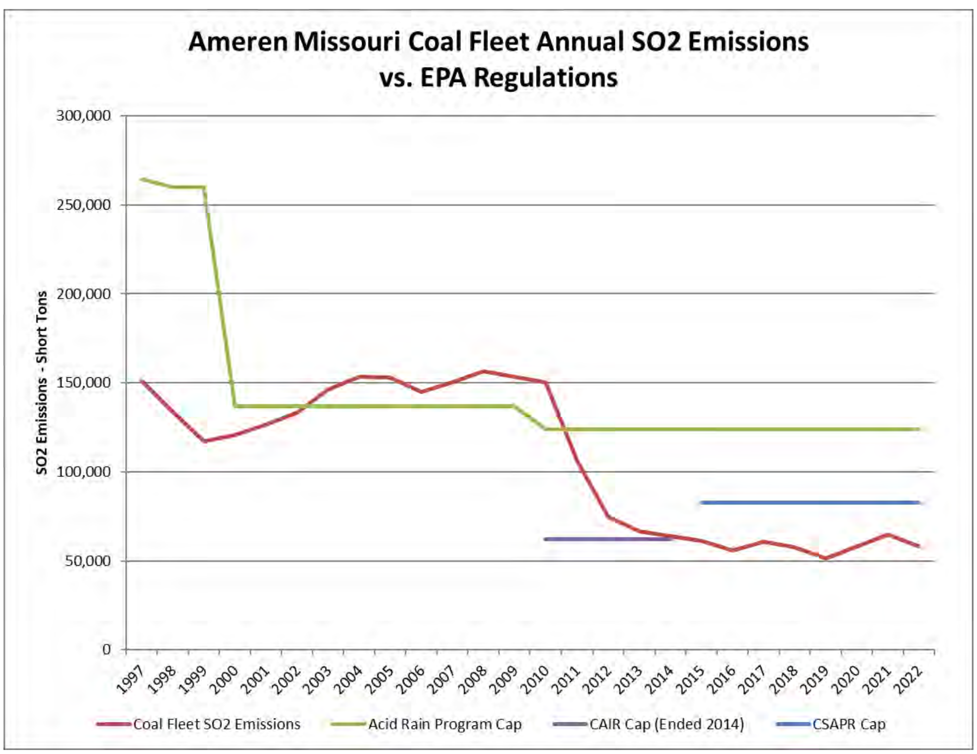
USEPA has recently made changes to the Cross State Air Pollution Rule (CSAPR) to meet the Good Neighbor requirements of the Clean Air Act for the 2015 Ozone Standard. The rule will apply to 23 states. A prepublication version of the rule is available but the date of publication in the Federal Register has not yet been determined. The rule will take effect 60 days after publication in the Federal Register. The changes to the rule will apply to Ameren Missouri EGUs in both Illinois and Missouri and impact Ameren Missouri's CSAPR allowances and compliance strategy going forward. If the rule is published on or after April 1, 2023, the changes will go into effect after the start of the 2023 ozone season and will change allowance allocations for the 2023 ozone season.

CSAPR changes will reduce NOx Ozone Season allowance allocations to Ameren EGUs beginning in the 2023 ozone season. The new rule includes "dynamic budgeting", wherein EPA will recalculate allowance allocation budgets every year. Through this process, EPA will remove banked allowances every year to a percentage of the total Group 3 budget. These provisions will require significant efforts regarding long term compliance planning. The rule is still being evaluated with respect to compliance options for Ameren Missouri.

In September 2021, the Illinois General Assembly passed the Climate and Equitable Jobs Act (CEJA), which affects gas-fired peaking generation units owned by Ameren Missouri and located within Illinois. The law includes requirements for emissions reductions from fossil-fueled generators, among other provisions. CEJA includes emission limits on fossil-fueled units based on actual emissions for the period 2018-2020 and enforced on a rolling 12-month basis, with exceptions for emergency operation to support grid reliability. It also includes requirements for eliminating CO_2 emissions from fossil-fueled units. Based on the Company's review of the statutory requirements, this effectively requires the retirement of simple cycle gas-fired combustion turbine generators (CTGs) by January 1, 2040. Accelerated emission reduction requirements are imposed on units near statutorily defined Environmental Justice Communities. This provision affects Ameren Missouri's Venice Energy Center, which effectively requires retirement of its units by January 1, 2030. The Company's recently filed Notice of Change in Preferred Resource Plan reflects retirement of Venice by the end of 2029 and all other Ameren Missouri CTGs in Illinois by the end of 2039.

Ameren Missouri established a plan to comply with the revised Cross States Air Pollution Rule ozone season allowance allocation that was finalized by the EPA in May 2017 for the 2018 ozone season. Ameren Missouri's strategy for NOx compliance was to continue operation of low NOx burner (LNB) and over-fire air (OFA) systems at the coal-fired energy centers as well as neural net optimization systems to enhance NOx emission reduction. In addition, the installed selective non-catalytic reduction (SNCR) systems at the Sioux Energy Center were tuned and available for use if needed for additional NOx reduction. The cost of operation of the SNCR systems was compared to the cost of purchasing additional NOx allowances to determine the most cost effective compliance approach.

Figure 5.1 Ameren Missouri Coal Fleet SO_2 Emissions vs EPA Regulations



Schedule MM-S19

Figure 5.2 Ameren Missouri Coal Fleet Annual NO_x Emissions vs EPA Regulations

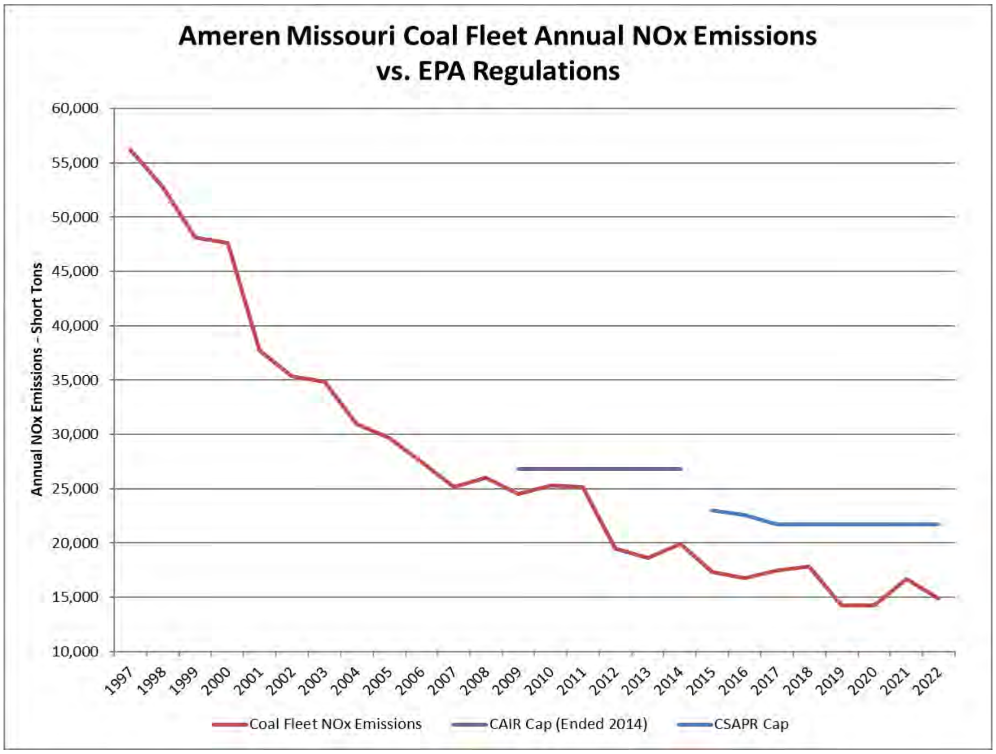
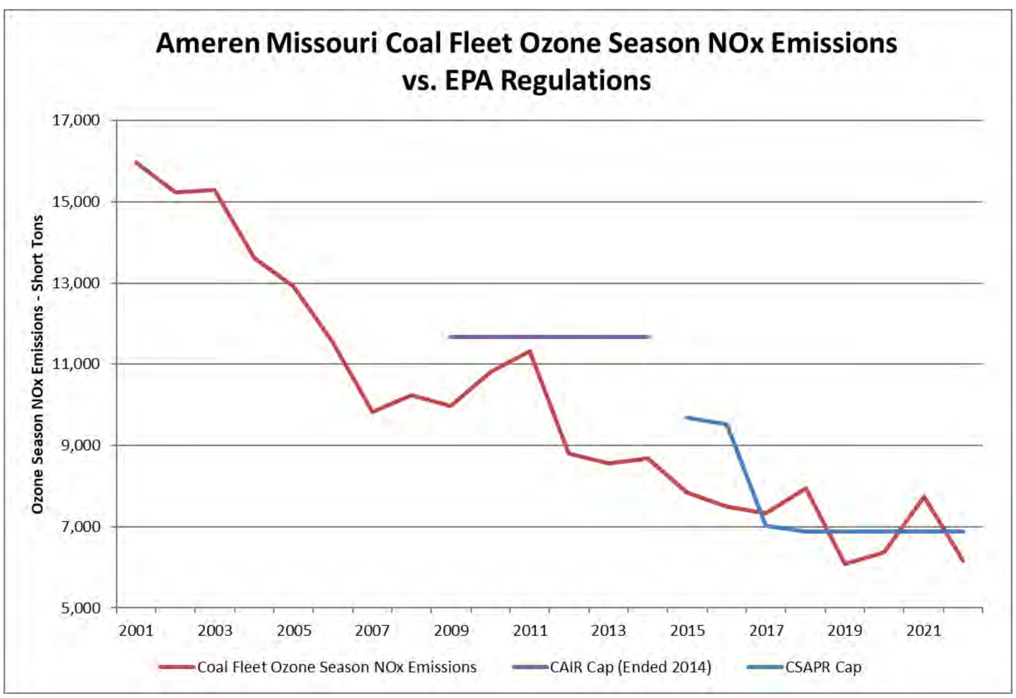


Figure 5.3 Ameren Missouri Coal Fleet Ozone Season NO_x Emissions vs EPA Regulations



Maximum Achievable Control Technology (MACT) Standards to Control Mercury and Other Hazardous Air Pollutants for Electric Generating Units (EGU)

The MACT rule for EGU's was effective on April 16, 2012. This final rule is known as the Mercury and Air Toxics Standards (MATS). The MATS includes standards for mercury, particulate matter as a surrogate for non-mercury metals hydrogen chloride (HCl) as a surrogate for acid gases, work practices for organic emissions and monitoring requirements. The MATS standard also includes more stringent emission limits for new sources.

Ameren Missouri’s Rush Island and Sioux Energy Centers were compliant with the MATS on April 16, 2015. The Labadie and Meramec (units 3 & 4) Energy Centers received a one-year extension and achieved compliance with the MATS on April 16, 2016. Units 1 & 2 at the Meramec Energy Center began burning natural gas only on April 16, 2016, and thus were not subject to MATS. Ameren Missouri installed Activated Carbon Injection technologies at all four of its coal-fueled energy centers and made modifications to the existing PM controls at its Labadie Energy Center. In addition, Ameren Missouri will utilize work practices and fuel choices to meet the other MATS regulated hazardous air pollutants. The figures below show Ameren Missouri’s coal fleet compliance with the MATS requirements. Ameren Missouri is currently achieving compliance with some margin. On April 5, 2023, EPA released a proposal to tighten certain aspects of the Mercury and Air Toxics Standards (MATS) (Proposed Rule). Specifically, EPA is generally proposing to lower the emission limit for filterable particulate matter (fPM), remove the emission limits for total and individual non-mercury (Hg) hazardous air pollutant (HAP) metals, require the use of continuous emissions monitoring systems (CEMS) to demonstrate compliance with the PM standard, lower the Hg emission limit for lignite coal fired electric generating units (EGUs), and eliminate one of the two definitions of “startup” in MATS. Ameren Missouri is currently reviewing the details of this proposed update to the MATS rule and will be determining if additional compliance measures will be necessary. Ameren Missouri will also work with industry work groups to determine if specific comments to EPA should be submitted during the comment period.

The following data is based on a 30-day rolling average comprised of hourly data when the emission unit is operating. If the unit is not operating there will be gaps in the 30-day rolling average.

Figure 5.4 Labadie MATS Compliance – Mercury

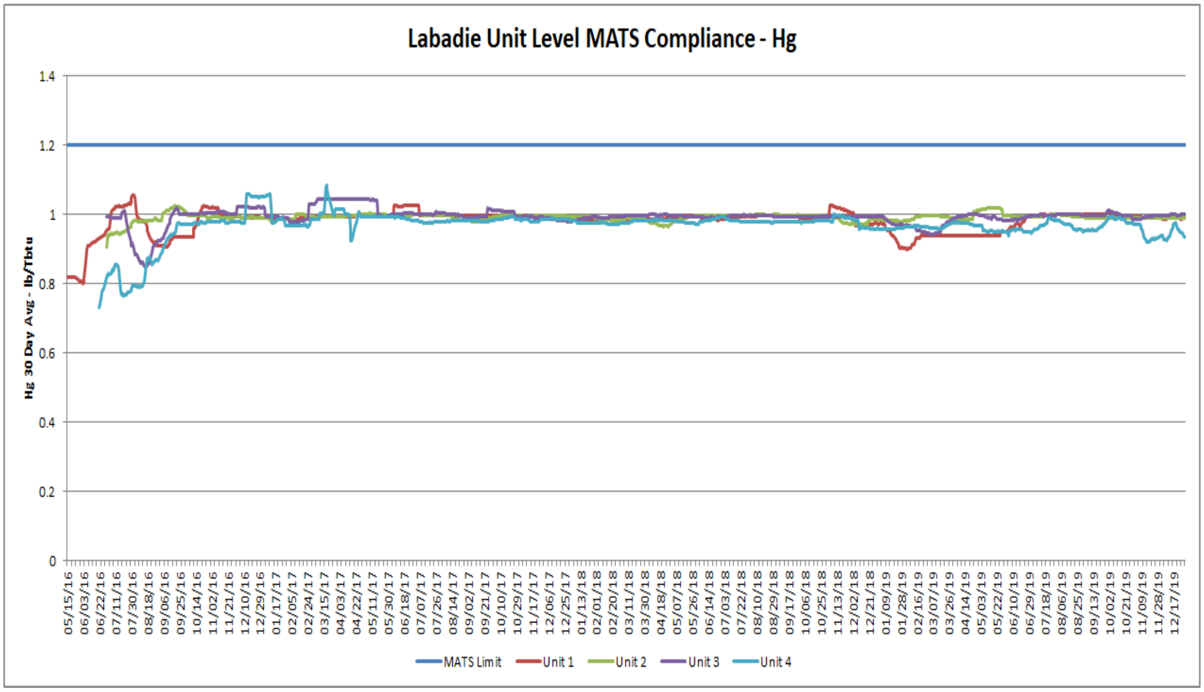
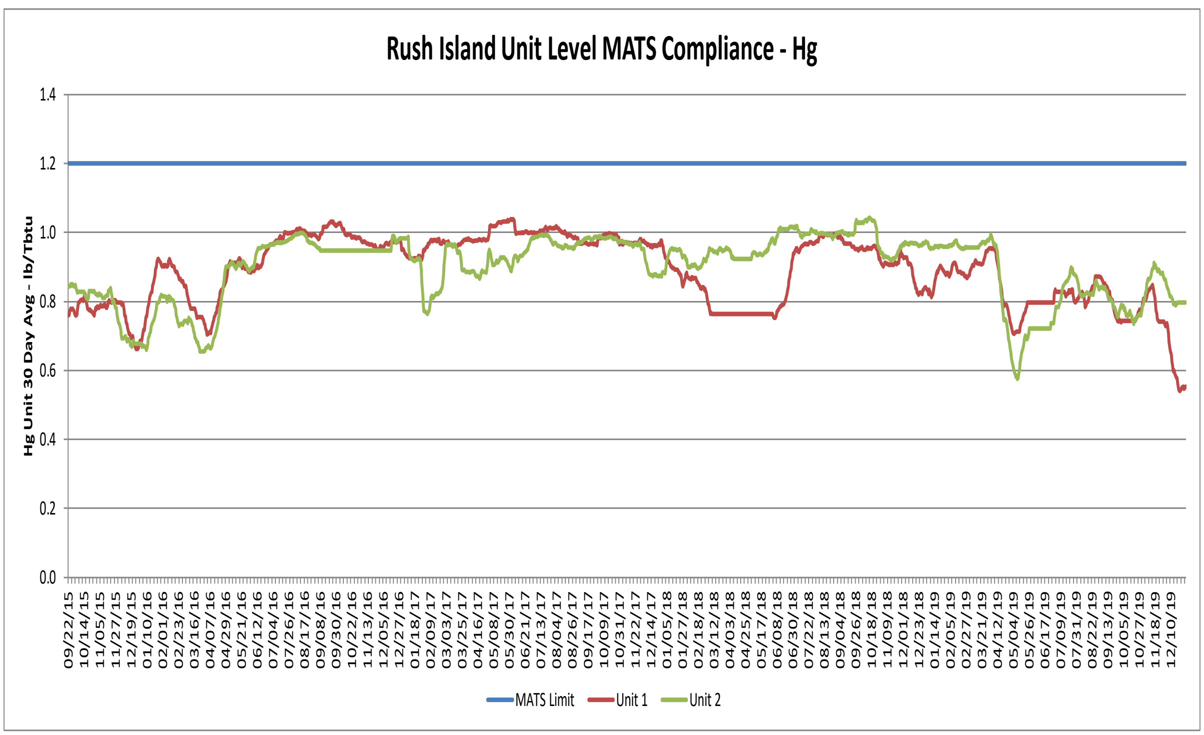


Figure 5.6 Rush Island MATS Compliance – Mercury



Schedule MM-S19

Figure 5.7 Sioux MATS Compliance – Mercury

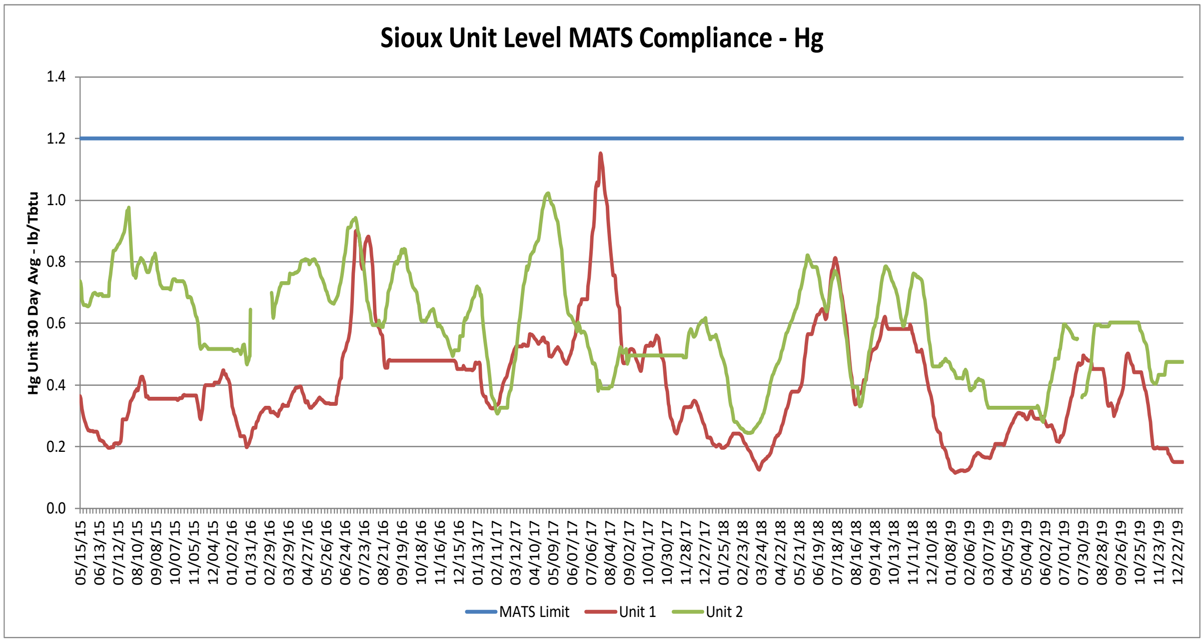
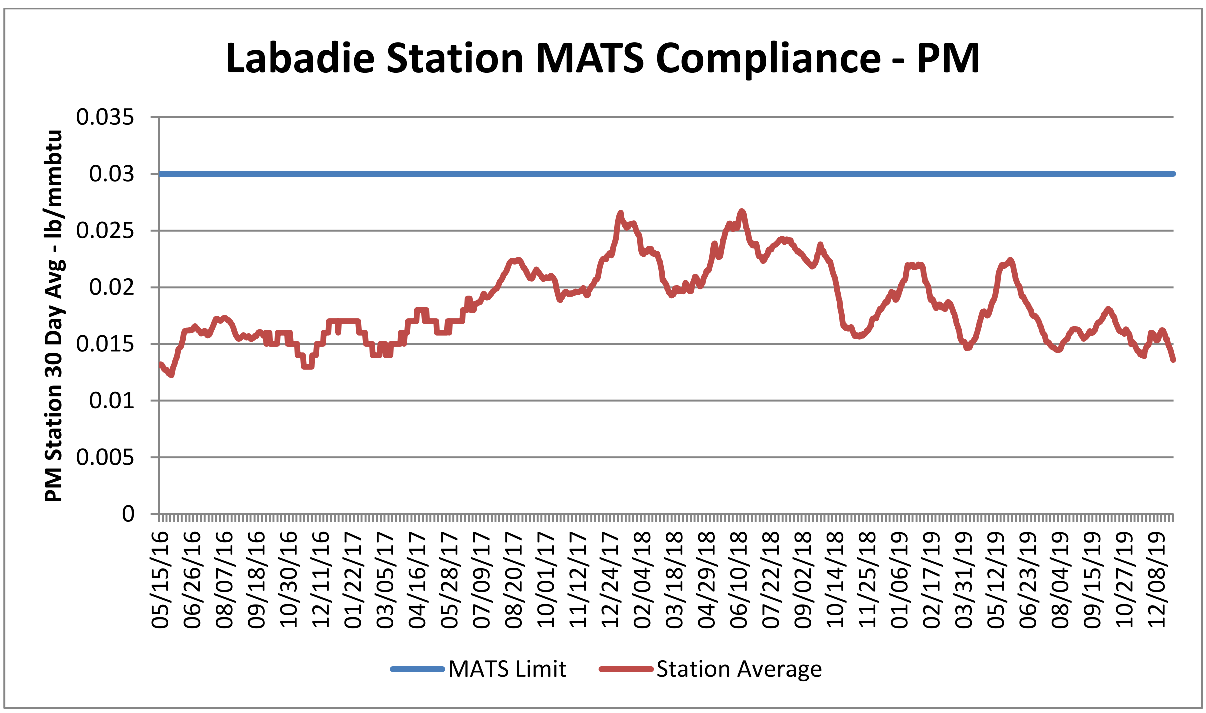


Figure 5.8 Labadie MATS Compliance – PM



Schedule MM-S19

Figure 5.10 Rush Island MATS Compliance – PM

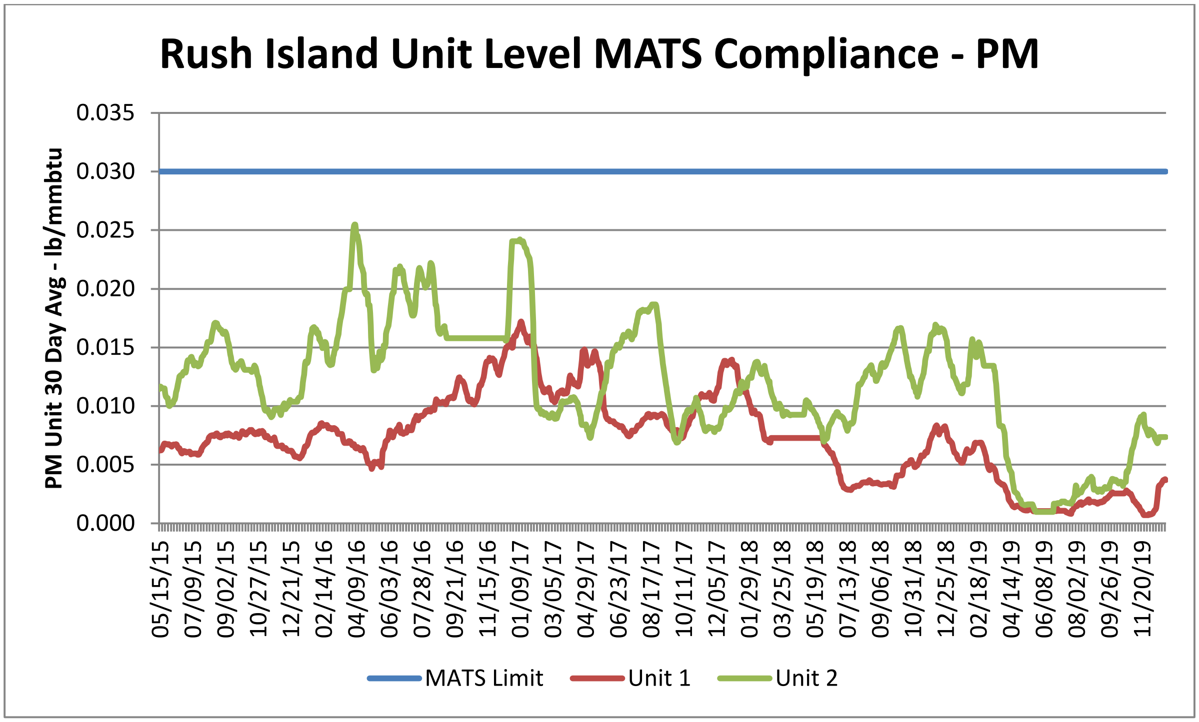
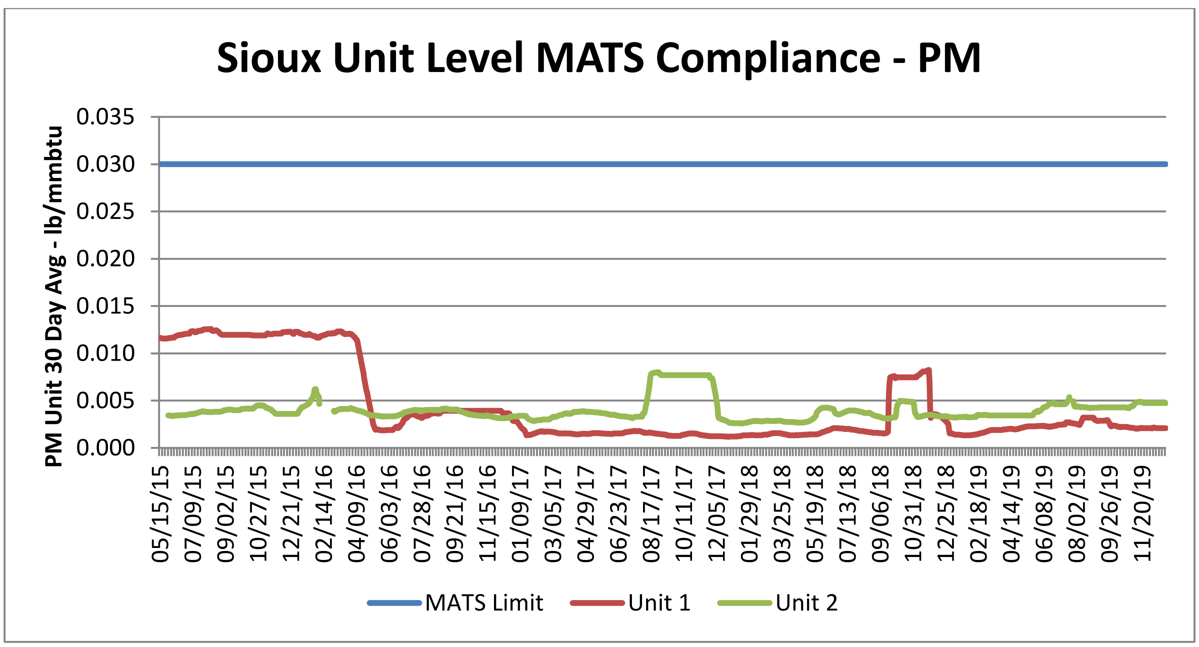
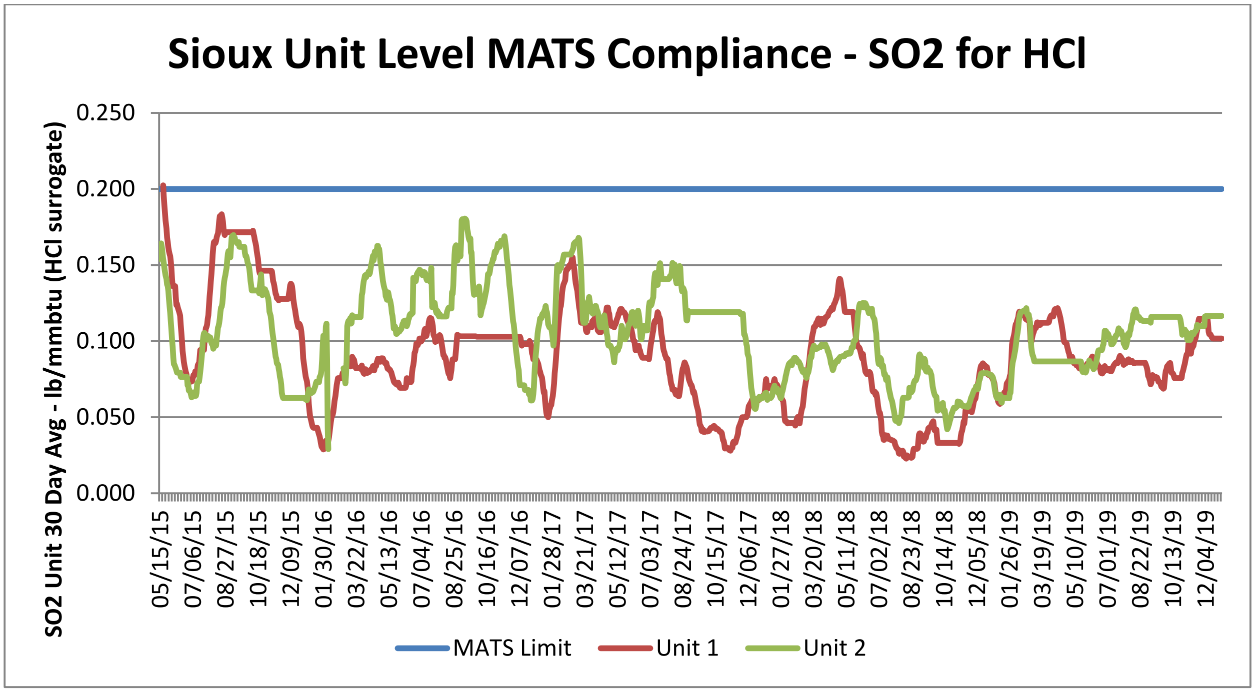


Figure 5.11 Sioux MATS Compliance – PM



Schedule MM-S19

Figure 5.12 Sioux MATS Compliance – HCl (Sioux uses SO_2 as a surrogate)



Clean Air Act Regional Haze Requirements

The goal of the Regional Haze Rule is to set visibility equivalent to natural background levels by 2064 in Class I areas. Class I areas are defined as national parks exceeding 6,000 acres, wilderness and national memorial parks exceeding 5,000 acres and all international parks in existence on August 7, 1977. There are currently 156 Class I areas, two of which are in the State of Missouri (Hercules Glade and Mingo). As part of the first planning period (2008-2018), states have developed implementation plans necessary to meet the glide path for the first 10-year planning period. In addition, the Regional Haze Rule requires compliance with Best Available Retrofit Technology (BART) for SO_2 & NO_x for the first planning period. The EPA has determined that compliance with CSAPR meets the BART requirements. Ameren Missouri is fully compliant with CSAPR, and thus, is compliant with the BART requirements. On August 26, 2022, the Missouri Department of Natural Resources (MDNR) submitted its State Implementation Plan (SIP) to EPA for approval. The SIP was approved by the Missouri Air Conservation Commission as the Missouri Regional Haze Plan for the Second Planning Period. As part of this SIP, Ameren Missouri entered into agreements with MDNR to assure continued use of existing control technology.

Clean Air Act – New Source Review (NSR)

Ameren Missouri is required to review projects that it intends to perform under 40 CFR 52.21(r)(6) to determine if NSR permitting is applicable for existing major sources. For new facilities not located at Ameren Missouri's existing facilities, evaluations are performed based on the level of expected emissions and whether these projects fall under regulations defined under the New Source Performance Standards (NSPS) (Clean Air Act Section 111), National Emission Standards for Hazardous Air Pollutants (NESHAP) (Clean Air Act Section 112) or other state construction permitting requirements.

- Ameren Missouri continues to review major projects at its existing facilities related to maintenance activities and compliance initiatives (e.g., electrostatic precipitator (ESP) upgrades, ACI systems for MATS compliance…) for the EPA's and the state's regulations.
- Ameren Missouri currently is not involved in construction of new major air pollutant emitting facilities requiring compliance with NSPS, NESHAP or other state air regulations.

5.3 Water Regulation and Compliance Assumptions

Clean Water Act (Amended 1972)

The Clean Water Act (CWA), in conjunction with State regulations, establishes pollutant-specific water quality standards for discharges to surface waterbodies. The National Pollutant Discharge Elimination System (NPDES) permit process provides for protection of water resources for industrial facilities. Technology and water quality based effluent limitations are in place to ensure water quality meets the applicable standards. In order to comply with effluent standards, it may be necessary to modify operations and/or install additional water pollution control equipment to meet a water quality standard.

CWA, Section 316(a) Thermal Discharges.

Section 316(a) of the CWA requires limitations on thermal discharges from industrial sources, including power plants.

The EPA and MDNR regulate cooling water systems at the Ameren Missouri energy centers through the NPDES permit program. The Missouri Department of Natural Resources administers the NPDES permit program for sources in Missouri including the Ameren Missouri energy centers.

The Labadie Energy Center cooling water discharge and the associated thermal plume have been studied extensively since the facility's initial NPDES permit application. Energy center operations have not changed significantly since the original studies were performed. Further biological studies were voluntarily and periodically performed over the years. In 2017, the MDNR approved a biological study plan in accordance with the current NPDES permit for the Labadie energy center. In 2016, Ameren Missouri requested a modification to the Labadie Energy Center NPDES permit to allow use of a site-specific model to determine compliance with Missouri Water Quality Standards (MWQS). The model established that an effluent limitation expressed as a Thermal Discharge Parameter (TDP) would ensure compliance with the water quality standard. In May 2017, the MDNR issued a revised NPDES permit establishing a thermal effluent limitation of 0.95 TDP for both the interim and final thermal effluent limitations.

The TDP limit incorporates a 5 percent margin of safety to ensure compliance with the MWQS. Nevertheless, there is the potential for occasional, infrequent exceedances (less than one percent of the time on average based on existing data) of the MWQS. This could occur during conditions of extraordinarily high ambient river temperature and/or extraordinarily low river flow leading Ameren Missouri to seek alternative thermal effluent limitations. In April 2020, Ameren Missouri submitted CWA 316(a) Final Demonstration proposing an alternative temperature effluent limit to ensure continued operation of the Labadie Energy Center, at the same time, assuring the protection and propagation of a balanced indigenous aquatic community in the lower Missouri River. In December 2021, MDNR issued a final NPDES permit for the Labadie Energy Center.

Ameren Missouri has identified operating procedures it would implement to address any thermal issues. This will allow it to avoid requirements to install cooling towers at the Labadie Energy Center. In addition, Ameren Missouri does not believe there are any thermal issues at its other fossil energy centers that would require cooling towers.

CWA, Section 316(b) Entrainment and Impingement of Aquatic Organisms

Section 316(b) of the CWA was established to protect fish and aquatic habitat from detrimental impacts associated with water intake structures. At energy centers, aquatic organisms can be impinged (e.g., trapped or pinned against the intake screens) and entrained (e.g., pass through the screens, enter the heat exchanger and then be discharged) within cooling water intake structures/piping and condenser systems. The EPA and MDNR establish regulations to limit adverse impacts associated with cooling water intake structure operation through the NPDES permit process. Compliance with CWA §316(b) standards may incorporate performance and/or design criteria, or the utilization of specific control technologies. The presence of threatened or endangered species at a cooling water intake structure could potentially result in the need for additional operational and physical changes.

The EPA issued revised CWA §316(b) regulations on August 15, 2014. While the rules do not expressly require the installation of cooling towers at all facilities, they are expected to result in capital expenditures for modifications to existing cooling water intake structures to achieve compliance. All facilities with a cooling water intake structure are required to perform studies for review by the MDNR and other agencies. Facilities withdrawing in excess of 125 million gallons of water per day are required to perform additional studies to determine what control technologies are required. Intake structure owners are provided the option of selecting one of seven different impingement

Schedule MM-S19

compliance options. These options include: (1) closed cycle cooling; (2) 0.5 foot per second (ft./sec) through-screen velocity (by design); (3) 0.5 ft./sec through-screen velocity (as measured); (4) existing off-shore velocity cap; (5) modified traveling water screens; (6) a “suite of technologies” determined by the permit writer to represent the best available technology; or (7) any technology that results in an annual impingement mortality rate of less than 24%. For those facilities that withdraw over 125 million gallons of water per day, or at the discretion of the permitting authority, the regulation also requires the reduction of entrainment similar to closed cycle cooling or a site-specific standard. New generating units are required to install closed cycle cooling.

The compliance options that have been considered to meet the CWA §316(b) include the following.

To meet the impingement and entrainment standards:

- Modified traveling water screens
- Installation of Fine Mesh Screens
- Installation of closed cycle cooling using Cooling Towers

In 2015, Ameren Missouri began two-year entrainment characterization studies as the next step in complying with Section 316(b). Due to the retirement of the Meramec Energy Center at the end of 2022, no additional mitigation is necessary. Fish studies performed at the Callaway Energy Center have resulted in the determination that no additional modifications of its intake structure are required to achieve compliance with CWA §316(b) requirements.

In January 2020, Ameren Missouri submitted the NPDES permit renewal application for the Labadie Energy Center. The application included the Section 316(b) report. This report details the results of the biomonitoring studies and the selected path forward for implementing impingement and entrainment modifications at the intake structure

Coarse-mesh modified traveling water screens have been found to be the more appropriate impingement mortality reduction technology at the Labadie Energy Center. In the 2021 final NPDES permit for Labadie Energy Center, the MDNR agreed with the studies and required new traveling water screens to be installed; that work is now on-going with completion expected before the 5-year permit renewal.

Since the Rush Island Energy Center is expected to be retired within the next several years, no additional modifications are expected. The Sioux Energy Center permit renewal application is currently being reviewed by MDNR. 316(b) study reports were submitted with the permit application and recommended modifications to the existing traveling water screens and fish pump system.

CWA, Steam Electric Effluent Limitation Guidelines Revisions

Sector specific effluent limitation guidelines are periodically updated by the EPA to ensure best available technology is utilized in the treatment of wastewater discharges, including those from steam electric power plants. On November 3, 2015, the EPA issued a revised rulemaking for steam electric power plant discharges. Although most of the impact of this rule is associated with discharges from flue gas desulfurization (FGD) wastewater, the rule prohibits discharges of ash transport water. As a consequence, Ameren Missouri completed projects at the Labadie, Rush Island and Sioux energy centers to construct new or augmented fly ash handling systems and new bottom ash handling systems. Ameren Missouri has also completed projects to construct and operate new wastewater treatment systems to manage discharges from various power plant systems such as demineralizer regenerations, storm water, and other process wastewater.

In 2020, the EPA finalized a rule revising the regulations for the Steam Electric Power Generating category. That rule revised requirements for two specific waste streams produced by steam electric power plants: flue gas desulfurization (FGD) and bottom ash transport water. This new rule did not affect Ameren's generating fleet.

5.4 Solid Waste Regulation and Compliance Assumptions

Coal Combustion Residuals

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

Ameren Missouri is executing its compliance strategy in advance of the regulatory deadlines. The Company continues to monitor the potential for further changes in regulations that may impact resource planning decisions. Table 5.3 below shows the capex and O&M assumptions for environmental mitigation.

Groundwater Remediation

In late 2020 Ameren Missouri paired with an outside consulting firm on a groundwater remediation project at the Rush Island Energy Center. This pilot project was set up to ultimately improve groundwater quality around the site by using a pump and treat method. Groundwater removed through extraction wells is treated in an above ground structure, then discharged through injection wells back into the ground. Removing groundwater impurities mechanically in conjunction with natural attenuation will speed up reductions of groundwater constituents. Building upon the success of that pilot project, Ameren Missouri completed the full-scale implementation at Rush Island. A similar full-scale project was substantially complete at Sioux in 2022 as well. Design of a similar system at the Labadie Energy center is on-going.

Ash Pond Closure Initiatives

Ash basin impoundments at the Rush Island, Labadie, and Sioux Energy Centers are now complete. Remaining Meramec Energy Center ash basins will be closed in 2023 and 2024. The closure of these ash ponds will reduce our consumption of approximately 11 billion gallon of water per year. With regard to groundwater and drinking water concerns, extensive analyses and tests have been undertaken by an independent third-party expert (many of which are beyond regulatory requirements).

Those tests have concluded:

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

Additionally, the Sioux Energy Center completed a new Interim gypsum basin in 2022 with the full gypsum cell planned for completion in 2023. Design and closure of the previous gypsum basin is planned to begin in 2023.While mitigation has been included in our analysis for current and certain potential future regulations, further changes in regulations are possible. The Company continues to monitor the potential for further changes in regulation that may impact resource planning decisions. Table 3.2 below shows the capex and O&M assumptions for environmental mitigation. [2]

[2] 20 CSR 4240-22.040(1)

Schedule MM-S19

Table 5.3 Environmental Mitigation Costs

Facility	Environmental Mitigation	Regulation	In-Service Year	Cost (incl. AFUDC) $ Million	O&M $ Million
Labadie	Landfill Cell	CCR	2033	11	-
	Traveling Screens	CWA 316	2025	24	0.5 *
	Groundwater Improvement	CWA	2025	26	1.4 $^{\alpha}$
	NOx Control	CSAPR	2025	0.3	
	SCR	CSAPR	2027	400	5.0
Labadie	Total Environmental			461	7
Rush Island	NPDES Permitting	CWA 316 (b)	2023	0.4	-
	Groundwater Improvement	CWA	2023	0.4	1.0
Rush Island	Total Environmental			0.4	1
Sioux	Landfill Cell Closure	CCR	2022	9	-
	Landfill Cell	CCR	2022	8	-
	Aquatic Life	CWA 316 (b)	2026	8	-
	Groundwater Improvement	CWA	2024	3	0.7 $^{\alpha}$
	NOx Control	CSAPR	2024	1	
Sioux	Total Environmental			18	0.7
TOTAL	Total Environmental			**479**	**8.6**

* One time expense in 2024

$^{\alpha}$ Average annual over lifetime

Note: SCR costs are preliminary.

5.5 Compliance References

6. New Supply Side Resources

Highlights

- *Large scale wind resources exhibit the lowest cost on a levelized cost of energy (LCOE) basis among all candidate resource options without tax incentives.*
- *With federal investment tax credits (ITC) or production tax credits (PTC), large scale solar resources closely follow wind resources as low-cost energy resources in addition to providing significant summer peak capacity benefits.*
- *Battery storage has been identified as a candidate resource option in addition to pumped storage.*
- *Ameren Missouri selected three natural gas technologies as final candidate resource options – Gas Combined Cycle with and without carbon capture and sequestration (CCS), and Gas Simple Cycle Combustion Turbine. Gas Combined Cycle exhibits the lowest LCOE among non-renewable generation resources.*

The supply-side screening analysis of various coal, gas, and renewable power generation technologies used in the 2020 IRP was reviewed by Ameren Missouri subject matter experts and updated for use in the 2023 IRP. Supply chain constraints and challenges have created upward pressure on wind and solar technology unit-costs, but to a large extent these challenges have been offset by extended and expanded tax credits included in the 2022 Inflation Reduction Act (IRA). Other incentives in the IRA also make the use of hydrogen and carbon capture and sequestration projects more attractive than they have been in the past. This IRP focuses on solar, wind, storage, and natural gas (both simple cycle and combined cycle) as potential new supply-side resources. Nuclear generation is also included due to its ability to provide around-the-clock carbon-free energy.

Ameren Missouri continues to monitor the universe of storage resource options, including pumped hydro storage, compressed air energy storage (CAES), stacked blocks (gravity storage), liquid air, and several battery energy storage system (BESS) technologies. Pumped hydroelectric storage is still an energy storage resource included in our evaluation of alternative resource plans as a major supply-side resource. However, with the advancements in BESS, including various lithium-ion and flow battery technologies, and the challenges associated with permitting new pumped hydroelectric storage facilities, BESS is the primary energy storage resource included as a major supply-side resource in the near to medium term.

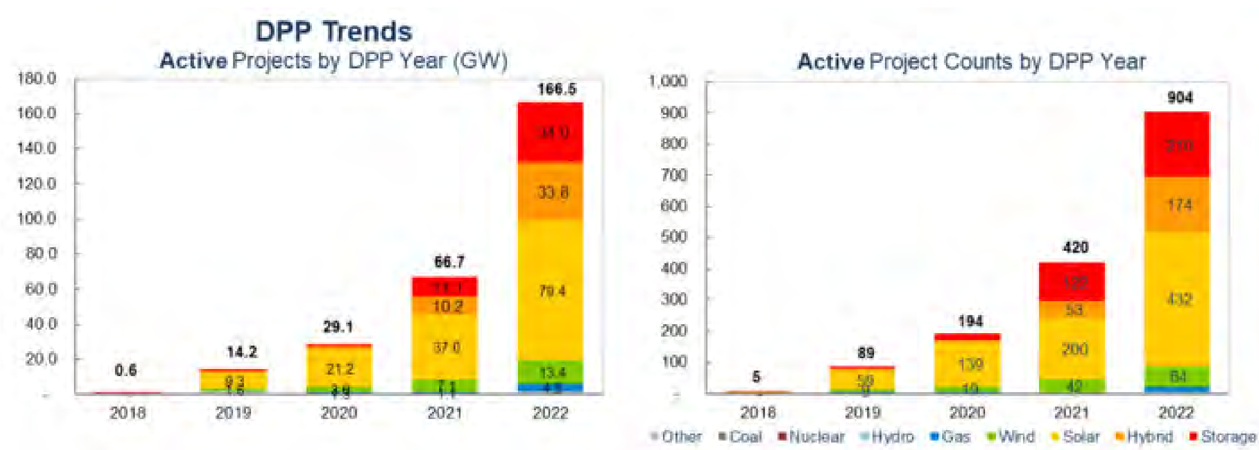
While some energy storage technologies have not been selected for integration analysis, it is important to note that the use cases for such technologies continue to develop, as does the consideration of appropriate market treatment for the services that these technologies can provide. Such ongoing developments will continue to be considered as part of our ongoing resource planning, including consideration of technologies and services provided by and to the transmission and distribution systems.

Capital costs for all preliminary candidate supply-side options include any necessary transmission interconnection costs. No preliminary candidate supply-side resource option was eliminated from further consideration due to interconnection or other transmission analysis.[1]

6.1 Potential Renewable Resources[2]

As of March 2023, the Midcontinent Independent System Operator (MISO) shows a year-over-year increase across all renewable technology generation interconnection (GI) requests. Although wind project GI requests ticked meaningfully upwards in 2022, they are still far outnumbered by solar projects by both project count and total capacity. 2022 also saw an increase in the number of storage project GI requests, from 122 projects in 2021 up to 210 in 2022. All GI requests proceed through the Definitive Planning Phase (DPP) process as MISO and the appropriate transmission owners evaluate how the generation projects will affect the bulk electric system. Figure 6.1 shows DPP trends by year, in terms of both capacity (left) and project count (right).

Figure 6.1 MISO Generator Interconnection: Overview[3]



There are a total of three DPP iterations, and GI requests may proceed to the next phase or be withdrawn depending on business case decisions for each project. The recent extension of federal tax credits for wind, solar, and storage through the IRA is expected to further accelerate the development of these resources across MISO, as seen already in the large increase in projects in the queue in 2022. A detailed characterization of the

[1] 20 CSR 4240-22.040(4)(B); 20 CSR 4240-22.040(4)(C)
[2] 20 CSR 4240-22.040(1); 20 CSR 4240-22.040(2); 20 CSR 4240-22.040(4)(A)
[3] https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf

information gathered through Ameren Missouri's subject matter experts for use in the 2023 IRP can be found in Chapter 6 – Appendix A.

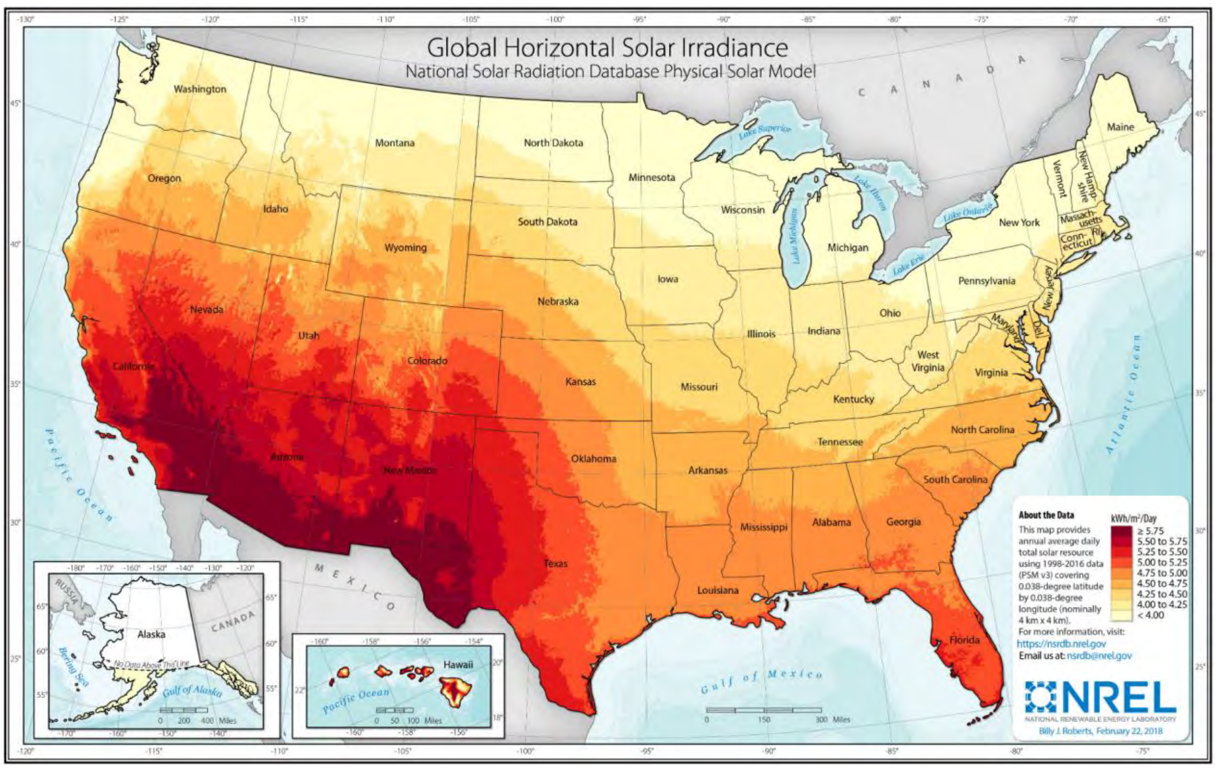
6.1.1 Potential Solar Resources

Based on a review of available solar technologies and Ameren Missouri's service territory, flat-plate solar photovoltaic (PV) is among the most practical, common, and cost-effective technologies for implementation.

Solar Resource & Technologies

The solar resource has three primary components: direct, diffuse, and ground reflected solar irradiances. Global Horizontal Irradiance (GHI) is the sum of all irradiances observed by a flat-plate over time. A map of the GHI for the U.S. is shown in **Error! Reference source not found.**.

Figure 6.2 U.S. Global Horizontal Irradiance Map



As illustrated in the figure above, Missouri has a reasonably strong solar resource. St. Louis specifically averages an annual GHI value of 4.36 kWh/m^2-day.[4]

Concentrating solar power (CSP) technologies convert direct normal irradiance (DNI) into thermal energy to generate electricity via steam-turbine or engine. While the desert southwest has the highest DNI, there is ample GHI across much of the U.S. Solar PV technologies convert GHI into electricity via the photovoltaic effect. Both flat-plate PV and

[4] NSRDB Physical Solar Model (PSM); St. Louis; TMY hourly data; GHI

concentrating photovoltaic (CPV) collectors can be used to generate solar energy. Flat-plate collectors may be monofacial or bifacial, meaning light is collected on the top and bottom of the module. Due to the low cost of silicon-based materials and ample GHI resource across the U.S, bifacial flat-plate PV is the most practical and cost-effective solar technology.

Flat Plate Photovoltaics

PV capacity has grown to be the most common form of solar technology in the U.S., and Ameren Missouri expects it will remain the dominant solar technology option for deployment for the foreseeable future. As of March 2023, Wood Mackenzie reported there were nearly 90 GW of PV operating in the U.S. and 125 GW in the contracted pipeline. Of the utility-scale solar contracts signed in 2020, only 4% were under a mandated renewable portfolio standard, while more than 80% of projects were signed under voluntary procurement by a utility or corporate off-taker.[5] This is evidence of the continued improvement in technology and implementation techniques including:

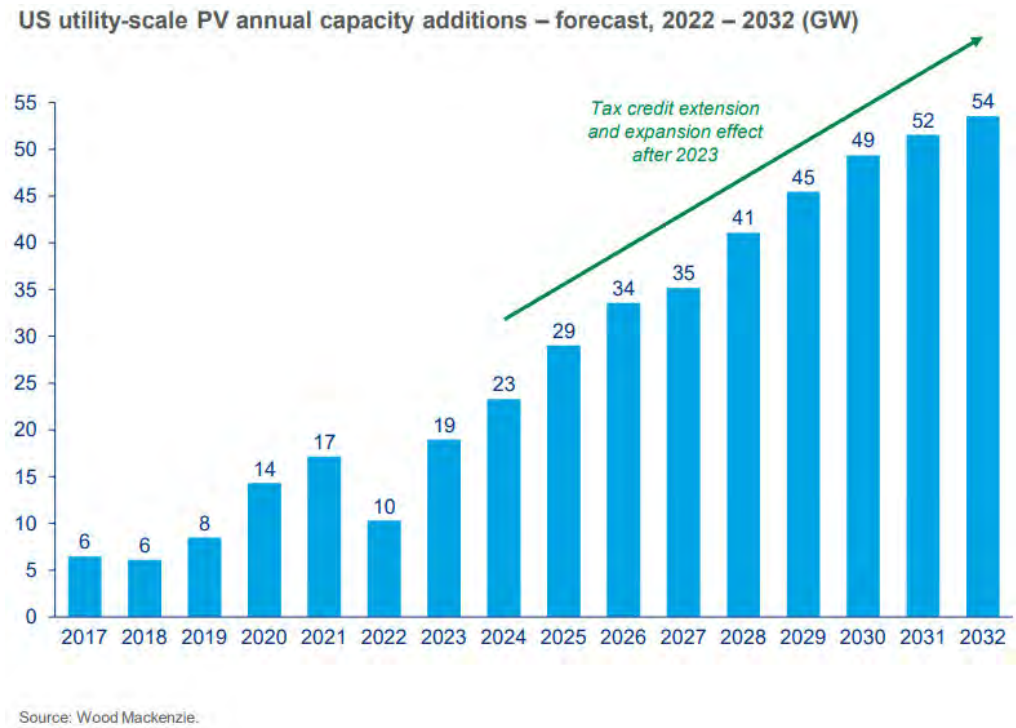
- Adoption of glass-on-glass bifacial modules that decreases degradation and extends its useful life
- Widespread use of single-axis trackers that yields higher capacity factors along with extended energy production windows
- Increase of solar module to inverter (DC:AC) ratios to further increase capacity factor

In the coming years, PV will continue to realize tax credit benefits thanks to the IRA. The IRA returned the Investment Tax Credit (ITC) to 30% of qualified costs and enabled PV to take advantage of the Production Tax Credit (PTC), which has historically been limited to wind projects. These full credits are contingent upon the project meeting prevailing wage and apprenticeship requirements. The law also enables projects to qualify for bonus tax credit adders including a domestic content adder (10% bonus) that applies to projects utilizing a defined amount of US manufactured materials, and an energy community adder (10% bonus) that applies to projects located in qualified areas such as brownfield, former fossil fuel sites, and those with lower employment rates.

As discussed above, the IRA is expected to lead to increased PV capacity additions as depicted in Figure 6.3.

[5] Wood Mackenzie US Utility Scale Solar Market Update: Q4 2022, Page 14

Figure 6.3 U.S. Utility-Scale PV Annual Capacity Additions – Forecast 2022-2032[6]



These capacity additions may further exacerbate supply chain challenges that have arisen due to the following:

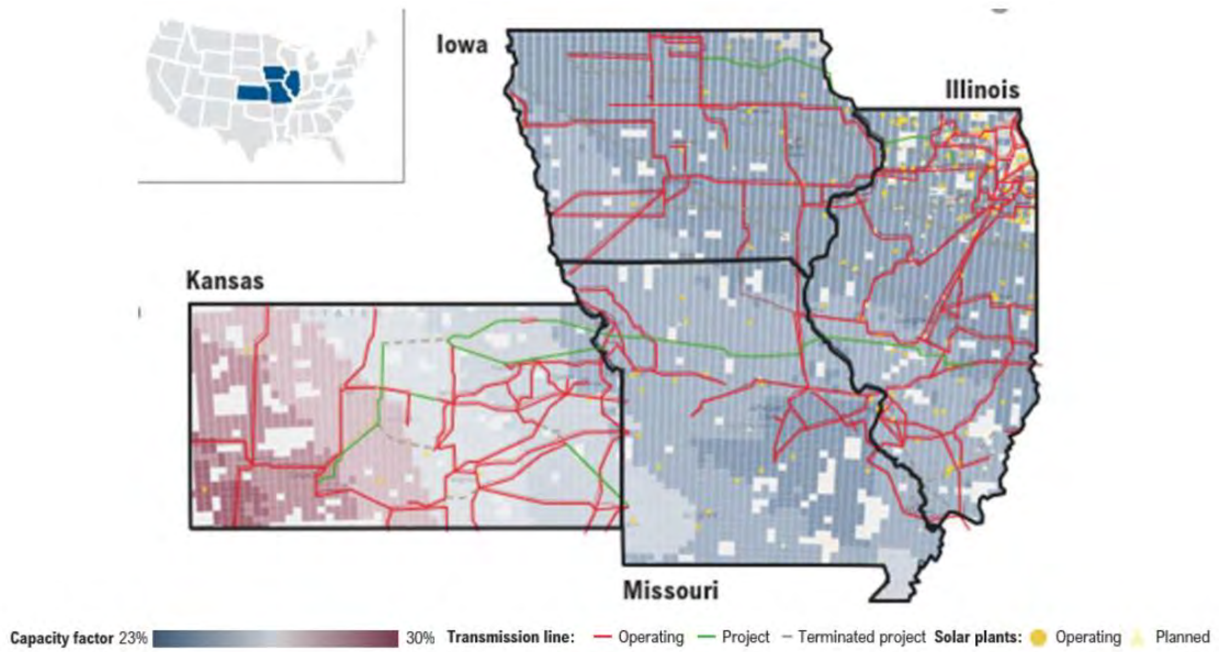
- Pandemic induced bottlenecks for key solar equipment in addition to increased containerized freight prices,
- U.S. Department of Commerce (DOC) anti-dumping and countervailing duties investigation in 2022, leading to potential significant punitive and retroactive tariffs on solar panels procured from Southeast Asia. An executive order signed by President Biden imposing a two-year moratorium on solar panel tariffs for solar projects completed by December 2024 has exponentially increased near term demand for solar panels,
- Passage of the Uyghur Forced Labor Prevention Act (UFLPA) banning imports of solar panels from China's Xinjiang region, leading to significant importation delays at U.S. customs,
- High U.S. inflation and a constrained construction labor market and increasing labor costs economy-wide.

Continued deployment of both PV and wind, discussed below, may be further constrained by the transmission system. More specifically, the high volume of MISO interconnection applications is leading to the need for additional transmission upgrades and to delays in receiving Generator Interconnection Agreements (GIAs). Interconnection queue reform remains critical for MISO as utilities across the ISO work to bring new resources online.

[6] Wood Mackenzie US Utility Scale Solar Market Update: Q4 2022, Page 6

Figure 6.4 overlays solar resource capacity factors, existing and planned projects, and existing and planned transmission lines in Ameren Missouri's region.

Figure 6.4 Map of Solar Capacity Factors, Development, and Transmission Lines[7]



Source: Roland Berger; NREL; S&P Global. Note: AC capacity factor.

The transmission system constraints coupled with balance of system savings may lead to repowering or extending the life of PV facilities. When repowering, the solar PV modules and inverters are replaced at or near end-of-life to maintain the power output of the facility. While the expected economic life of a utility-scale PV facility is 30 years in Missouri, developer land leases often extend out 35 years and beyond – an indication that the market is considering these strategies for the future. Ameren Missouri continues to evaluate how repowering strategies may provide value for customers.

Ameren Missouri Photovoltaics

In addition to the solar assets currently in operation in Ameren Missouri's generation fleet, the Company plans to build additional solar resources in the coming years. Two of those solar resources have received regulatory approval and are moving forward with construction: Huck Finn and Boomtown Renewable Energy Centers. Each planned solar resource addition is detailed below:

Huck Finn Renewable Energy Center

Huck Finn Renewable Energy Center is a 200 MW-AC solar energy center located in Audrain and Ralls County, Missouri. The resource received regulatory approval on

[7] Roland Berger Market Study: The Risk of Ameren Missouri Delaying Renewable Development; May 2022, pg. 24

February 8, 2023 and is currently under construction. It is expected to be commercially operational in late 2024 and will be utilized to support Ameren Missouri's compliance with the Missouri Renewable Energy Standard.

Boomtown Renewable Energy Center

Boomtown Renewable Energy Center is a 150 MW-AC solar energy center located in White County, IL. The resource received regulatory approval on April 12, 2023 and is currently under construction. It is expected to be commercially operational in late 2024 and will be utilized to support the Renewable Solutions Program.

Table 6.1 lists the primary characteristics of solar resources. Chapter 6 – Appendix A contains more detailed information.

Table 6.1 Forecasted Potential Solar Resources (2023$) **

**

Despite supply chain challenges, Ameren Missouri expects that on average the installed cost of solar will continue to decline in real terms, and therefore is using a declining curve informed by market data and the NREL 2022 Annual Technology Baseline (ATB) data, which is shown in Figure 6.5 below.

Figure 6.5 Base Solar Overnight Capital Cost Assumption (2023$) **

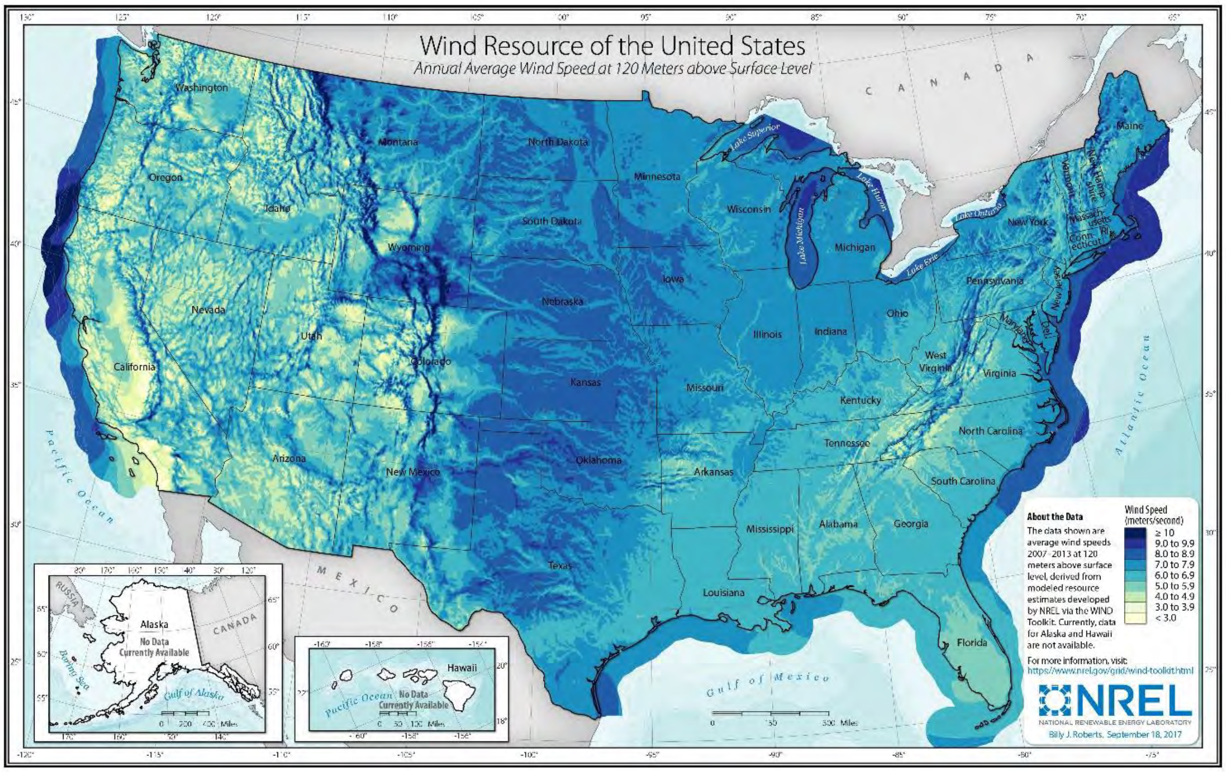
**

6.1.2 Potential Wind Resources

Wind Resource & Technologies

Missouri, historically, has seen limited deployment of wind generation in comparison to its western neighbor states. This is because the wind speed drops moving from west to east as one crosses the Kansas-Missouri border. Figure 6.6 below, which maps the average wind speed at 120 meters above surface level illustrates this fact.

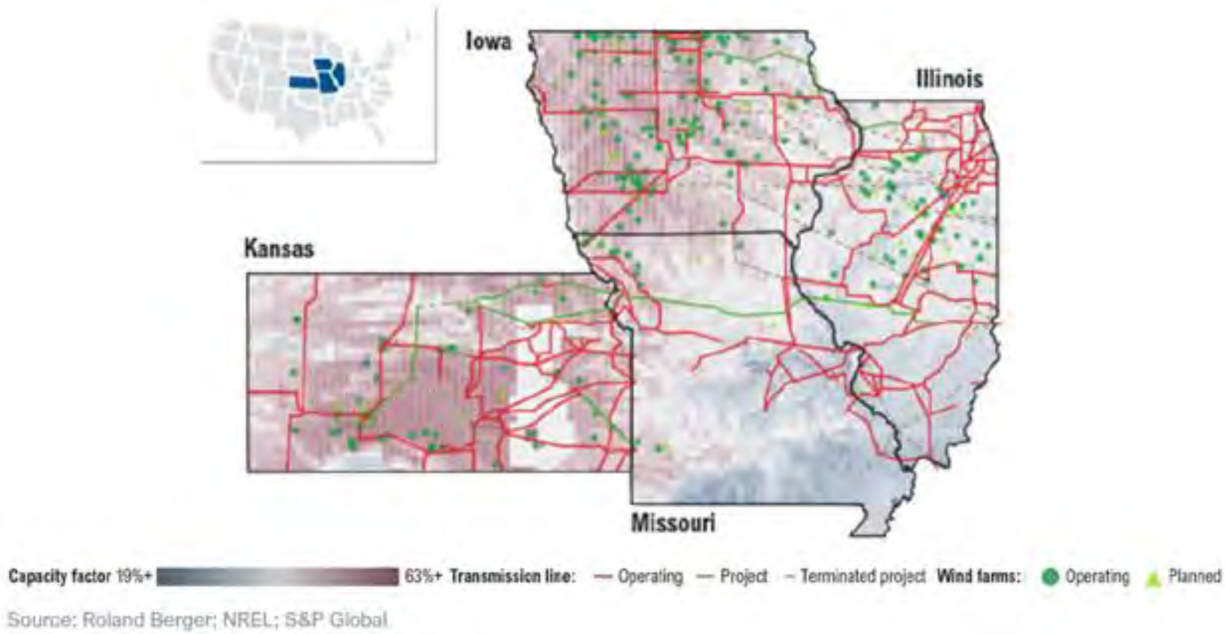
Figure 6.6 U.S. Wind Resource Map – 120 m above surface level[8]



The lower wind resource has translated into fewer wind projects as illustrated in Figure 6.7 below.

[8] https://www.nrel.gov/gis/assets/images/wtk-120m-2017-01.jpg

Figure 6.7 Map of Wind Capacity Factors, Development, and Transmission lines[9]

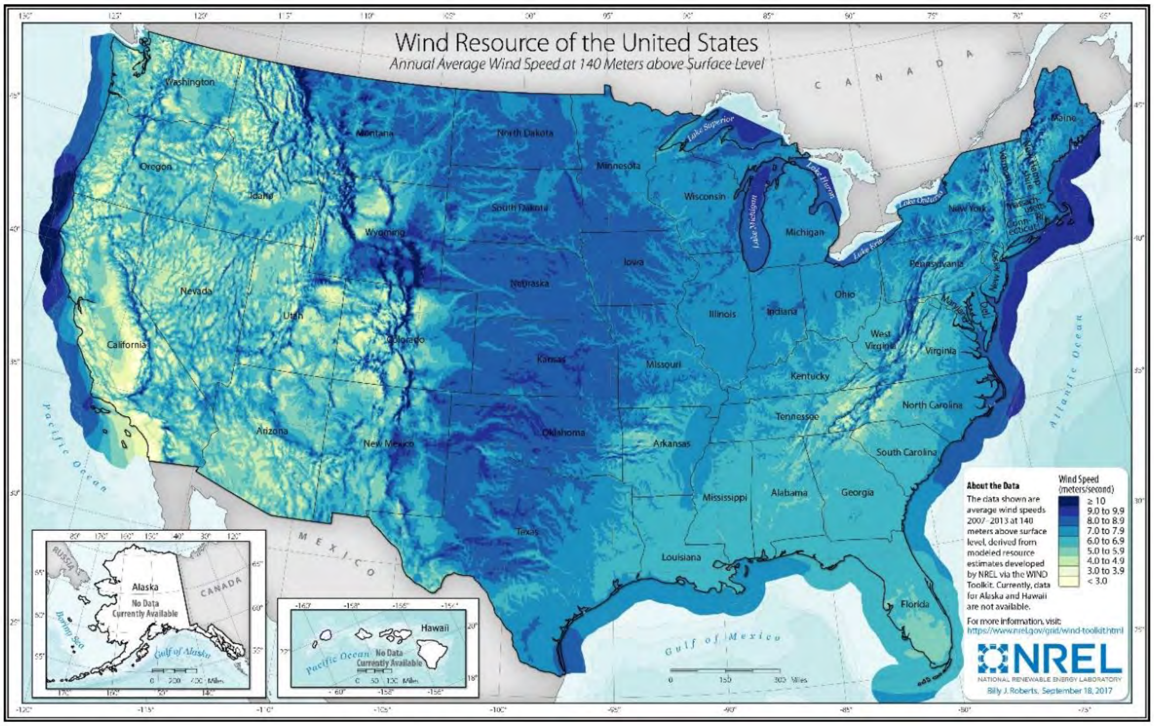


However, with the advent of new technologies, modern turbines are getting bigger and can be mounted on higher masts. The height for turbine "hub," the part of the turbine that houses the nacelle, generator, and other ancillary systems has been increasing, with the most recent turbine models at hub heights of 140 meters or more.[10]

The NREL map below, Figure 6.8 shows the wind speed at 140 meter above the surface level.

[9] Roland Berger Market Study: The Risk of Ameren Missouri Delaying Renewable Development; May 2022, pg. 12
[10] https://www.vestas.com/en/products/enventus-platform/v150-6-0

Figure 6.8 U.S. Wind Resource Map – 140 m above surface level[11]



As the map shows, Missouri has considerably more regions of good wind resource (shown in dark blue colors) at the 140-meter height, which may benefit Ameren Missouri's future pursuit of wind generation opportunities in the state.

Ameren Missouri Wind

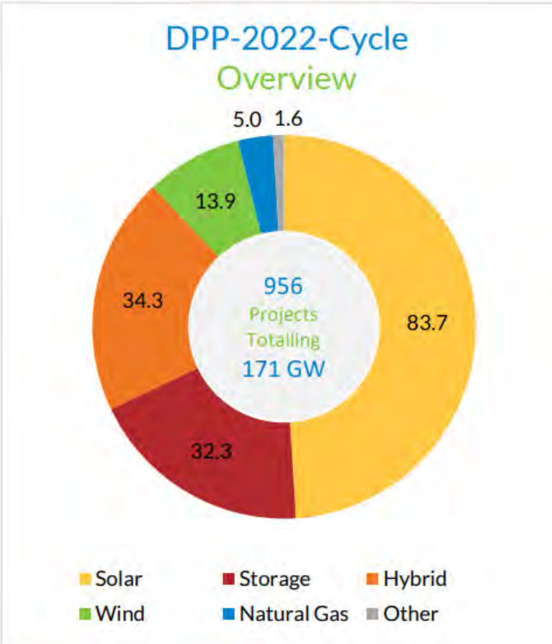
Ameren Missouri currently has two wind facilities in its generation fleet as discussed in Chapter 4: the Atchison Renewable Energy Center, and the High Prairie Renewable Energy Center.

Ameren is evaluating the wind (and solar) projects submitted in response to its request for proposals (RFP) in 2022 and may bring a wind project forward after completing the project preliminary diligence. In the near-term, wind project opportunities in Ameren Missouri's region appear more limited than solar project opportunities. Lower wind resource, longer wind development timelines, and (until the recent passage of the IRA) declining PTC values combined have likely been driving the relatively slow wind deployment in the region.

[11] https://www.nrel.gov/gis/assets/images/wtk-140m-2017-01.jpg

However, the continued technology evolution for wind together with the recently extended tax credits in the IRA has helped increase interest in wind development in the region, as demonstrated in the MISO GIA queue statistics shown in Figure 6.9.

Figure 6.9 MISO 2022 Generator Interconnection Queue Submissions[12]



Fuel	# of Requests	GW
Solar	469	83.7
Storage	231	32.3
Hybrid	163	34.3
Wind	66	13.9
Natural Gas	21	5.0
Other	6	1.6
Grand Total	**956**	**170.8**

FUEL	# OF REQUESTS	GW
Central	**301**	**54.5**
Solar	137	22.1
Storage	78	13.1
Hybrid	66	14.6
Wind	16	2.9
Natural Gas	4	1.8
East (ATC)	**30**	**4.0**
Solar	10	1.2
Storage	11	1.7
Hybrid	2	0.1
Wind	1	0.2
Natural Gas	6	1.0
East (ITC)	**89**	**14.9**
Solar	57	9.2
Storage	22	3.8
Hybrid	8	1.5
Natural Gas	2	0.3
South	**400**	**71.9**
Solar	222	44.5
Storage	83	7.2
Hybrid	79	15.8
Wind	10	2.6
Natural Gas	1	0.2
Other	5	1.6
West	**136**	**25.4**
Solar	43	6.8
Storage	37	6.5
Hybrid	8	2.2
Wind	39	8.2
Natural Gas	8	1.7
Other	1	0.0
Grand Total	**956**	**170.8**

As Figure 6.9 shows, there are around 5,500 MW of new wind project applications in the 2022 MISO queue for the MISO Central and the MISO South regions providing a reasonably robust medium-term pipeline of wind projects for Ameren Missouri.

12 https://cdn.misoenergy.org/2022%20GIQ%20Submission%20Statistics626443.pdf

Accordingly, Ameren Missouri will continue to look for opportunities to evaluate and advance wind projects from this medium-term pipeline.

Lastly, Ameren will also be evaluating the potential for new wind (and other technologies) around its retiring generation station using the MISO generator replacement process or combining wind (or solar) with its existing combustion turbine generation facilities to leverage the transmission capacity.

Using market data for available regional wind projects as a reference point, Ameren Missouri subject matter experts revised the cost and operational characteristics of wind resources to be used in the 2023 IRP as can be seen in Table 6.3. Chapter 6 – Appendix A contains more detailed information.

Table 6.3 Forecasted Potential Wind Resources (2023$)**

**

Ameren Missouri expects that on average the installed cost of wind will continue to decline in real terms, and therefore, is using a declining curve informed by market data and the NREL 2022 Annual Technology Baseline (ATB) data as shown in Figure 6.10.

Figure 6.10 Base Wind Overnight Capital Cost Assumption (2023$)**

**

6.1.3 Potential Storage Resources[13]

Ameren Missouri has considered a range of storage resource options, including pumped hydro storage, CAES, stacked blocks (gravity storage), liquid air, and a number of BESS technologies. A high-level fatal flaw analysis was conducted as part of the first stage of the supply-side selection analysis for storage resources. Options that did not pass the high-level fatal flaw analysis consist of those that could not be reasonably developed or implemented by Ameren Missouri. Two options passed the initial screen: pumped hydroelectric energy storage, and lithium-ion battery energy storage. Table 6.3**Error! Reference source not found.** lists primary characteristics of storage resources. Chapter 6 – Appendix A contains detailed resource characteristics.

Pumped Hydroelectric Energy Storage

Pumped hydroelectric energy storage is a large-scale, mature, commercial utility-scale technology used at many locations in the United States and worldwide. Conventional pumped hydroelectric energy storage uses two water reservoirs, separated vertically. During lower priced hours (historically off-peak periods), water is pumped from the lower reservoir to the upper reservoir. During high priced periods, (typically on-peak hours), the water is released from the upper reservoir to generate electricity. Church Mountain, located about midway between Taum Sauk State Park and Johnson Shut-ins State Park, was identified as the potential site for a new 600 MW pumped hydro plant. Multiple design factors can materially impact the costs of a pumped storage facility, including geography, installed capacity, and storage time. Costs used in the 2020 IRP were escalated for inflation, adjusted for the transmission interconnection cost, and were used for the LCOE calculation in Table 6.3 Potential Energy Storage Resources.

Battery Energy Storage Systems

Battery Energy Storage Systems have been identified and deployed throughout the United States as a supply-side and a demand-side resource. BESS are capable of providing services such as frequency regulation, frequency response, load shifting, and renewable energy smoothing, to name a few. As more intermittent renewable generation is deployed within Ameren Missouri's service territory and surrounding regions, BESS will become more valuable as a controllable grid resource.

Ameren Missouri continues to analyze different BESS chemistries.[14] Technologies such as sodium-sulfur, while mature, have limited capabilities when compared to emerging technologies, such as lithium-ion and redox flow batteries. Advanced lead-acid batteries also continue to improve and face a challenging market with the continued pressure from lithium-ion battery products.

[13] 20 CSR 4240-22.040(1); 20 CSR 4240-22.040(2); 20 CSR 4240-22.040(4)(A); EO-2023-0099 1.G
[14] 20 CSR 4240-22.040(2)(C)2

Lead Acid Batteries

Since 2015, Ameren Missouri has been supporting applied research and the actual piloting of this technology at the Missouri University of Science and Technology in Rolla, MO. Today, we are designing, procuring, and deploying this technology at a Managed Charging for Fleet EVs site for Ameren vehicles.

Ameren Missouri is committed to supporting our region's economic development by helping bring to market lead-acid battery products that are mined, processed, manufactured, marketed, and recycled in our state. Through the above-described demonstration project, we will evaluate the safety and techno-economic performance of lead-acid battery technology around the following use cases: Resiliency, demand charge management, demand response, optimum charger dispatch

Some of the challenges Ameren Missouri has observed for advanced lead-acid batteries include lower energy density as compared to lithium-ion chemistries, larger footprint requirements for similar performance to lithium-ion applications, and performance and cyclic-life limitations. Lead-acid battery technology is very mature and has mature recycling opportunities to address overall performance, however, this application of energy storage has not demonstrated that it is a commercially viable and widely deployed technology for the reasons mentioned above.

Gravitational Energy Storage (GES)

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

Figure 6.11 Concrete Block Storage System – Fully Charged to Fully Discharged[15]

The leading company commercializing this technology is Energy Vault. They offer storage of energy for several hours using low-cost materials that can be locally sourced almost anywhere. Designed to be deployed in 10MWh blocks, the system can be configured to either 2-6 hours duration or 6-12 hours. A demonstration project rated at a nominal 5MW of power and 35MWh of energy has already been built in July 2020 and connected to the grid in Switzerland.

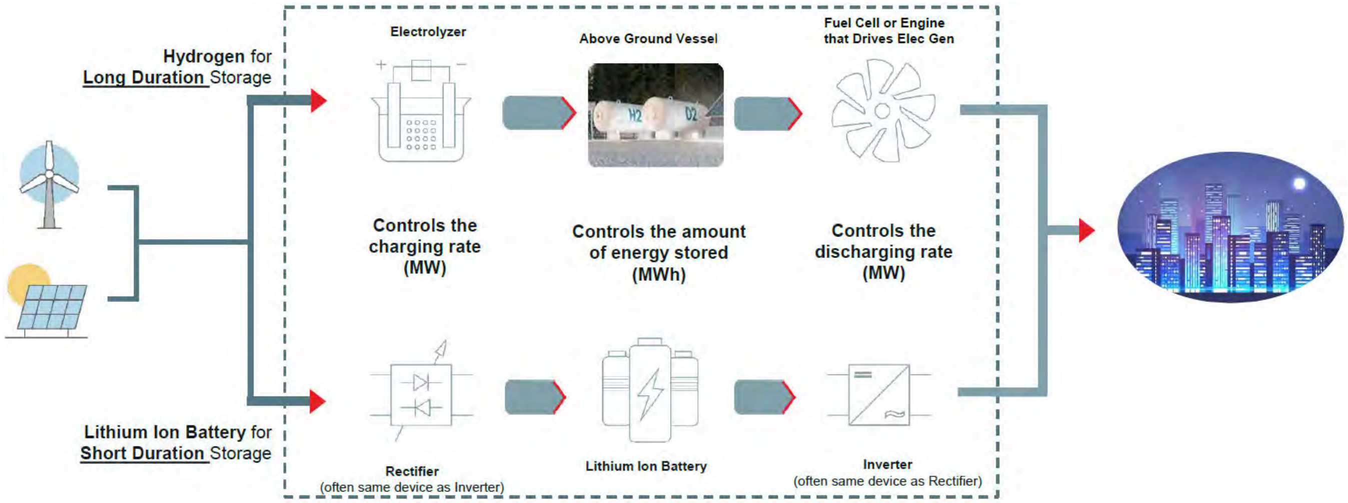
Another GES technology is Advanced Rail Energy Storage (ARES). ARES uses rail technology to harness the power of gravity. ARES' highly efficient electric motors drive mass cars uphill, converting electric power to mechanical potential energy. When needed, mass cars are deployed downhill delivering electric power to the grid quickly and efficiently. Currently, there is only one project under development in Pahrump, Nevada.[16]

Hydrogen Production & Storage

Hydrogen provides long-duration energy storage. Hydrogen can be stored and then consumed when needed by combustion in a combustion turbine, fuel cell, or industrial process. The amount of stored energy will depend on the size of tanks and other equipment. Ameren is investigating the potential application of hydrogen energy storage and planning demonstration projects.

[15] https://www.businesswire.com/news/home/20181106006096/en/Energy-Vault-Announces-Commercial-Availability-of-Transformative-Utility-Scale-Energy-Storage-Technology-Yielding-Unprecedented-Economic-Benefits-to-Global-Energy-Providers
[16] https://aresnorthamerica.com/

Figure 6.12 Equivalency Between Lithium Ion and Hydrogen Storage Systems[17]



Ameren has completed a feasibility study that considered a variety of loads: (1) transportation (hydrogen buses and tractor trailers); (2) blending (to feed into a load that can take natural gas and hydrogen); and (3) hydrogen fuel cell (for electrical loads as shown in the above illustration). The study concluded that it is technically feasible for hydrogen to address all of the above loads. However, commercially available system components have not yet been optimized for wide adoption.

Above Ground/Underground Compressed Air Energy Storage (CAES)

Deployed facilities are comparable to pumped-hydro power plants. In a CAES plant, rather than pumping water from a lower to a higher pond, ambient air is compressed and stored under pressure in an above-ground vessel or underground cavern. When electrical energy is needed, heated and expanded pressurized air is used to power a generator by an expansion turbine.

- Air heats up when compressed from atmospheric pressure to a storage pressure of approximately 1,015 psia (70 bar).
- Standard multistage air compressors use inter- and after-coolers to reduce discharge temperatures to 300/350°F and cavern injection air temperature to 110/120°F.
- The heat of compression therefore is extracted during the compression process or removed by an intermediate cooler.
- In the diabatic storage method, the loss of this heat energy must be compensated for during the expansion turbine power generation phase by heating the high-pressure air in combustors using natural gas fuel, or alternatively, using the heat of a combustion gas turbine exhaust in a recuperator to heat the incoming air before the expansion cycle.

[17] Mitsubishi Power Technical Sales Material

- In the adiabatic storage method, the heat of compression is thermally stored before entering the cavern and used for adiabatic expansion while extracting heat from the thermal storage system.

Large volume storage sites are required because of the low storage density. Underground and above-ground storage are viable options. For larger energy storage requirements, preferred locations include artificially constructed salt caverns in deep salt formations. Salt caverns are characterized by high flexibility, no pressure losses within the storage repository, and no reaction with the oxygen in the air and the salt host rock. If no suitable salt formations are present, it is also possible to use natural aquifers. However, tests must be carried out first to determine whether the oxygen reacts with the rock and with any microorganisms in the aquifer rock formation, which could lead to oxygen depletion or the blockage of the pore spaces in the reservoir. Depleted natural gas fields are also being investigated for compressed air storage; in addition to the depletion and blockage issues mentioned above, the mixing of residual hydrocarbons with compressed air will have to be considered.

Currently, there are only two CAES projects in operation – one in Alabama and the other in Germany.

Liquid Air Energy Storage (LAES)

A large-scale, long-duration energy storage technology that can be installed at the site of demand. Liquid nitrogen or liquefied air (~78% air) is the operating fluid. LAES systems can capture industrial low-grade waste heat/waste cold from co-located operations and exhibit performance traits similar to pumped hydro storage. The systems' size ranges from about 5MW to 100+ MWs, and since capacity and energy are uncoupled, they are ideal for long-term uses.

The LAES process utilizes parts and subsystems that are mature technologies that are readily accessible from significant OEMs, despite being novel at the system level. The technology extensively utilizes established power generation and industrial gas sector processes.

Three fundamental mechanisms comprise LAES:

> Stage 1 - Getting the device charged: The charging device is an air liquefier, which draws air from the environment, cleans it, and then chills it to below-freezing temperatures until the air liquefies. One liter of liquid air is created from 700 liters of atmospheric air.
>
> Stage 2 - Energy store: An insulated tank with low pressure is used as the energy storage, and liquid air is kept there. The use of this apparatus for the bulk storage of LNG, liquid nitrogen, and oxygen is already widespread. The industrial tanks that are used have the capacity to keep GWh of energy.

Stage 3 - Power Restoration: Liquid air is drawn from the tank(s) and pumped to high pressure when electricity is needed. The air is evaporated and superheated to ambient temperature. This produces a high-pressure gas, which is then used to drive a turbine.

In conclusion, LAES offers an output of hundreds of MWs, can be deployed at large-scale, and has an intrinsic capability for long-duration energy storage. To increase system efficiency, LAES systems can use industrial waste heat/cold from thermal generation facilities, steel mills, and LNG terminals. LAES makes use of proven components with established long lifespans (30 years or more), and performance.

Redox Flow Batteries (RFB)

They represent one class of electrochemical energy storage devices. The name “redox” refers to the chemical reduction and oxidation reactions employed in the RFB to store energy in liquid electrolyte solutions which flow through a battery of electrochemical cells during charge and discharge. The energy is stored in the volume of electrolyte, which can be in the range of kilowatt-hours to tens of megawatt-hours, depending on the size of the storage tanks. The power capability of the system is determined by the size of the stack of electrochemical cells. The amount of electrolyte flowing in the electrochemical stack at any moment is rarely more than a few percent of the total amount of electrolyte present (for energy ratings corresponding to discharge at rated power for two to eight hours). Flow can easily be stopped during a fault condition. As a result, system vulnerability to uncontrolled energy release in the case of RFBs is limited by system architecture to a few percent of the total energy stored. This feature is in contrast with packaged, integrated cell storage architectures (lead-acid, Li-Ion, etc.), where the full energy of the system is always connected and available for discharge.

RFBs are suited for applications with power requirements in the range of tens of kilowatts to tens of megawatts, and energy storage requirements in the range of 500 kilowatt-hours to hundreds of megawatt-hours.

Redox flow batteries have one main architectural disadvantage compared with integrated cell architectures of electrochemical storage. RFBs tend to have lower volumetric energy densities than integrated cell architectures, especially in the high power, short duration applications. This is due to the volume of electrolyte flow delivery and control components of the system, which is not used to store energy, so a system is not as compact as other technologies might be for a similar output.

Redox flow batteries show great promise with regard to cyclic life and performance but have not demonstrated commercial viability at the time of this IRP filing. Ameren Missouri continues to monitor and network with other utilities, such as San Diego Gas & Electric (SDG&E), as they operate their vanadium-redox flow battery at their Miguel

Substation. The SDG&E redox flow battery currently tests voltage, frequency and power outage support as well as shifting energy demand.

Lithium-ion Batteries

In addition to electric vehicle and backup systems for residential and commercial applications, lithium-ion (Li-ion) systems have emerged as the preferred choice for new grid-scale storage systems in the United States. Li-ion battery prices have fallen an average of more than 22% year-over-year since 2013.[18] Furthermore, just within MISO, the capacity of energy storage interconnection requests has increased dramatically from 140 MW in 2017 to 32 GW in 2022. Many of the MISO interconnection requests for energy storage are also paired with an intermittent renewable resource, such as solar.

Li-ion batteries have also been deployed in the PJM regional transmission organization and the New York Independent System Operator to provide frequency regulation. The California Independent System Operator (CA-ISO) demonstrates the need for energy storage to provide capacity and demand management. For background, California public utilities expect a capacity shortfall in Southern California and have responded to an order from the California Public Utilities Commission to meet this need. Furthermore, Tesla has received much notice for installing a 100-MW battery in Australia that provides grid stabilizing services.

Table 6.2 shows the energy storage technologies that were evaluated as candidate resource options. Lithium-ion battery energy storage was selected as an energy storage resource to be evaluated in the remaining resource planning process as a major supply-side resource in addition to pumped hydro storage. Ameren Missouri expects that on average the cost of batteries will continue to decline, and therefore has assumed a declining cost curve using Roland Berger and NREL data.

Table 6.4 Potential Energy Storage Resources (2023$)**

**

[18] *SEPA 2019 Utility Energy Storage Market Snapshot*

Figure 6.13 Base Solar Overnight Capital Cost Assumption (2023$) **

**

6.1.4 Potential Hydroelectric Projects

Ameren Missouri previously performed studies to identify potential hydroelectric supply-side resources and projects; however, in this IRP, is using generic project characteristics from EIA and NREL. In addition to cost, several factors contribute to the feasibility of these projects, including accessibility of a water resource, environmental constraints, and regulatory definitions that define what types and sizes of hydropower are considered “renewable." For instance, the state of Missouri defines “renewable” hydropower in the Renewable Energy Standard (RES), which states hydropower generators can only be considered renewable energy sources if they meet the criteria, “hydropower (not including pumped storage) that does not require a new diversion or impoundment of water and that has a nameplate rating of 10 megawatts or less.”

Table 6.5 contains details of a generic hydroelectric project. Hydro resource was evaluated assuming a 60-year economic life. Because the cost estimates are screening level estimates and because obtaining necessary licenses from the FERC can be complex, a more detailed evaluation of specific projects would be necessary before moving forward with a decision to construct.

Table 6.5 Potential Hydroelectric Resource

Resource Option	Plant Output (MW)	Project Cost with Owner's Cost, Excluding AFUDC ($/kW)	First Year Fixed O&M Cost ($/kW)	First Year Variable O&M Cost ($/MWh)	Assumed Annual Capacity Factor (%)	LCOE without Incentives (¢/kWh)
Hydro	50	$5,704	$99.0	$0.0	60%	19.61

6.1.5 Potential Landfill Gas Projects

Landfill gas (LFG) is produced by the decomposition of the organic portion of waste stored in landfills. LFG typically has methane content in the range of 45 to 55% and is considered an environmental issue. Methane is a potent greenhouse gas, 25 times more harmful than CO_2 by some estimates. In many landfills, a collection system has been installed, and the LFG is being flared rather than being released into the atmosphere. By adding power generation equipment to the collection system (reciprocating engines, small gas turbines, or other devices), LFG can be used to generate electricity. LFG energy recovery is currently regarded as one of the more mature and successful waste-to-energy technologies. There are currently nearly 532 operational LFG energy systems in the United States.[19]

Ameren Missouri continues to operate the Maryland Height Renewable Energy Center (MHREC) at the IESI Landfill in Maryland Heights, Missouri. Previous studies have identified other landfills within the Ameren Missouri service territory that could support another LFG facility. At this time, however, other renewable resources are more abundant and more cost effective. Ameren Missouri will continue to monitor this technology for opportunities for future deployment.

6.1.6 Potential Biomass Projects

A study on potential biomass project feasibility had previously been conducted for Ameren Missouri. The study included identification of potential sites, technologies, resource locations, characteristics and availability, and costs. Several factors, including resource location and geographical constraints related to potential biomass projects, coupled with the cost structure and technology stagnation, especially in comparison to significant improvements in other renewable technologies, have reduced the focus on biomass as a new supply-side resource in this IRP.[20] Ameren Missouri will continue to monitor this

[19] https://www.epa.gov/lmop/landfill-gas-energy-project-data-and-landfill-technical-data

[20] 20 CSR 4240-22.040(2)(C)2

resource potential for technological advancements and cost structure improvements. Any potential future project proposals will be evaluated as they materialize.

6.1.7 Innovative Renewables Deployment[21]

Ameren Missouri is exploring various methods to incorporate and deploy more renewable generation throughout its service territory. Among those methods are:

Community Solar: Ameren Missouri included an application for approval of a permanent Community Solar Program within the electric rate review filed in March 2021. The program features a variety of improvements to enhance the participation experience for customers. This proposal was approved as part of the electric rate review settlement agreement, and, as a result, the permanent Community Solar Program was rolled out to residential and small commercial customers in the latter half of 2022. The program redesign expands access and affordability by (1) lowering the program enrollment fee, (2) enabling customers to match up to 100% of their usage with solar energy, and (3) accelerating new facilities construction timelines.

Renewable Solutions: In 2022, Ameren Missouri filed for approval of a new subscription renewable energy program, the Renewable Solutions Program. Renewable Solutions is a voluntary renewable energy subscription program designed for larger commercial, industrial, and governmental customers. Many of Ameren Missouri's larger customers have publicly expressed their desire for near-term access to renewable energy in the form of sustainability goals for both carbon dioxide emission reduction and renewable energy supply. The program is designed to offer those customers a pathway to meet their sustainability goals with local renewable energy while reducing cost and risk for all Ameren Missouri customers. The Renewable Solutions Program was approved on April 12, 2023 and the first phase of the program, which will be supported by the Boomtown Renewable Energy Center, is fully subscribed.

6.2 New Thermal Resources

6.2.1 Potential Natural Gas Options

The 2020 IRP included discussion of multiple natural gas supply-side resource options, addressing base, intermediate, and peaking load requirements.

Ameren Missouri previously studied combined cycle technology, including the evaluation of potential combined cycle generating configurations, and potential facility locations. Any future investment will require an updated evaluation to consider the latest technologies,

[21] EO-2023-0099 1.E

costs, and developments that may impact a new energy center location. For example, since our last IRP, a new 24-inch natural gas pipeline has been constructed, bringing gas from the Rockies Express Pipeline in Illinois into Missouri, through St. Charles and north St. Louis counties. Multiple combined cycle configurations are possible, providing the opportunity and flexibility to tailor a supply-side resource solution to future requirements and constraints in a cost-effective manner. In this IRP, Ameren Missouri also included combined cycle with 98.5% carbon capture as a potential resource.

Table 6.6 contains details of potential natural gas projects. These projects were evaluated assuming a 30-year economic life. Because the cost estimates for these resources are screening level estimates developed from EIA, NREL, EPRI and Roland Berger data, a more detailed scope and evaluation of specific projects would be necessary before moving forward with a decision to construct.

Table 6.6 Potential Natural Gas Resources (2023$)

Resource Option	Plant Output (MW)	Project Cost with Owners Cost, Excluding AFUDC ($/kW-AC)	First Year Fixed O&M Cost ($/kW-year)	First Year Variable O&M Cost ($/MWh)	Assumed Annual Capacity Factor (%)	LCOE without Incentives (¢/kWh)
Greenfield Combined Cycle	1,200	$1,220	$62.0	$2.7	40%-80%	9.8 - 6.77
Greenfield Combined Cycle with CCS	1,135	$2,207	$106.5	$8.4	40%-80%	15.01 - 9.63
Simple Cycle	1,150	$994	$8.1	$5.2	5%	33.02

Project costs in the table include transmission interconnection costs as discussed in Chapter 7, and these costs may be avoided if they are constructed at retired coal energy center sites. It should also be noted that fixed O&M costs for both CC options include firm gas costs. The CC with CCS option also include additional capex and O&M for transportation and storage of captured CO_2 assuming a 100-mile pipeline is needed for transportation. Details can be seen in Table 6.7.

Table 6.7 Carbon Transportation and Storage Cost Assumptions (2023$)

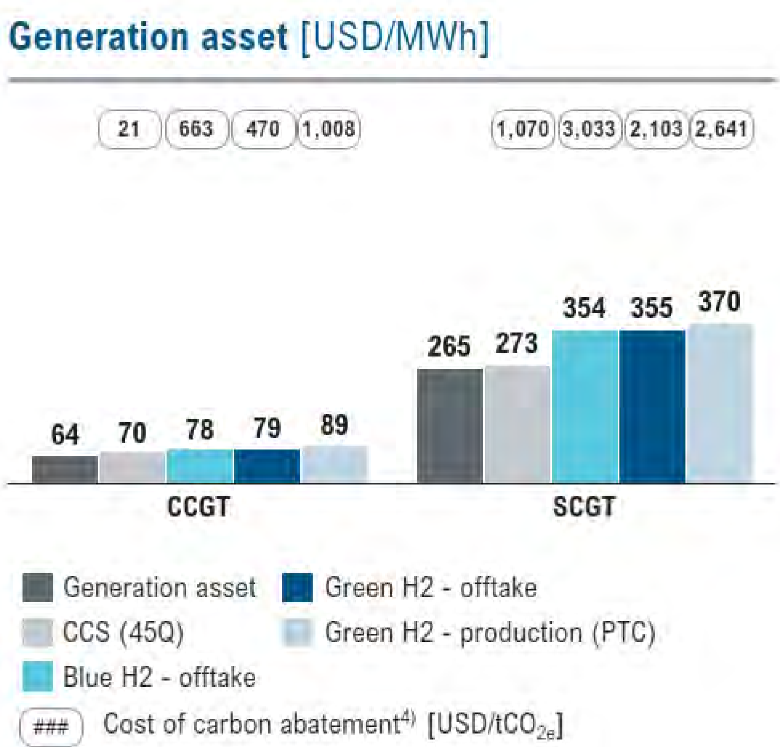
Sequestration Costs	Transportation			Storage	
	Capex ($/mile)	Pipe O&M (% of Capex)	Pump and Other O&M (% of Capex)	Storage Capex ($/ton)	Storage O&M ($/ton)
Transport and Store	750,994	2.3%	4.5%	$5.39	$4.84

Other thermal technologies remain as potential candidates for new supply-side resources, including reciprocating engines. Ameren Missouri will continue to monitor these arenas for technological advancement and cost structure improvements.

Hydrogen

The IRA includes incentives for the production of green hydrogen in the form of production tax credits. Ameren Missouri has evaluated the economics of carbon emission abatement with the help of Roland Berger. The analysis reflects blending hydrogen with natural gas at a rate of 20 percent hydrogen (by volume). This analysis was performed under both an offtake agreement structure and ownership and operation of electrolyzers by Ameren Missouri. The analysis was performed for both CC and SC gas units and compared to the cost of abatement for CCS. The results of the analysis are shown in Figure 6.11 below. Based on these results, Ameren Missouri expects that hydrogen could play a limited role in abatement of carbon emissions from gas generation if hydrogen production for industrial uses can also produce economic green hydrogen for electric generation as an ancillary benefit. It should be noted that hydrogen production in the region is still expected to provide economic benefits by supporting industrial decarbonization for applications that are more difficult to electrify even if hydrogen is not used as a fuel for electric generation.

Figure 6.14 Comparative Economics of Hydrogen Fuel



6.2.2 Potential Nuclear Resources

Consistent with Ameren Missouri's previous IRP filings, new nuclear was considered in this IRP for carbon-neutral around-the-clock generating capabilities. Ameren Missouri evaluated a conventional nuclear resource and a small modular reactor (SMR). Details are shown in Table 6.8.

Table 6.8 Potential Nuclear Resources

Resource Option	Plant Output (MW)	Total Project Cost Including Owners Cost, Excluding AFUDC ($/kW)	Annual Decommissioning Costs ($1,000)	First Year Fixed O&M Cost ($/kW-year)	First Year Variable O&M Cost ($/MWh)	Assumed Annual Capacity Factor (%)	LCOE (¢/kWh)
SMR	864	$8,492	$13,448	$122.1	$3.86	95%	15.81
AP1000	1,100	$10,109	$17,931	$151	$3.64	94%	19.60

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

NuScale Power's SMR received the U.S. Nuclear Regulatory Commission's design certification in January 2023.[22] The NuScale Power Module is a 77 MWe advanced light-water SMR. Each power plant can house up to 12 modules, which will be factory-built and about a third of the size of a large-scale reactor. Its unique design allows the reactor to passively cool itself without any need for additional water, power or even operator action.[23]

DOE is supporting the siting of the nation’s first SMR plant at Idaho National Laboratory. First module is expected to begin operating in 2029, with the remaining modules expected to come online by 2030.

6.3 Power Purchase Agreements

After discussions with Ameren Missouri’s Asset Management and Trading organization it was determined that there were no pending potential long-term power purchases for consideration at the time of the analysis. Furthermore, Ameren Missouri learned from its experience in developing the 2008 and 2011 IRPs that soliciting the market for long-term power purchases or sales is not productive for bidders given the data at this stage of the analysis is generic, and potential respondents are reluctant to share information on

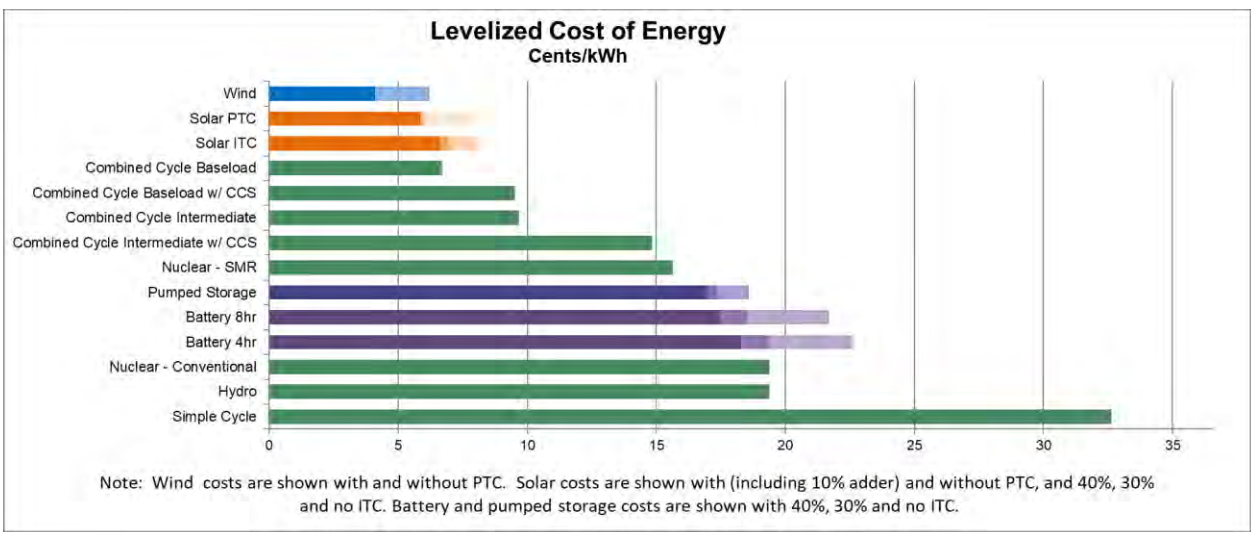
[22] https://www.federalregister.gov/documents/2023/01/19/2023-00729/nuscale-small-modular-reactor-design-certification
[23] https://www.energy.gov/ne/articles/nrc-approves-first-us-small-modular-reactor-design

potential agreements without a reasonable expectation for an executed contract. Evaluation of generic power purchase agreements would not be expected to yield different results in terms of relative performance of resource types, as the only reasonable assumption that could be made absent specific information would be that such an agreement would be effectively cost-based.

6.4 Final Candidate Resource Options[24]

Error! Reference source not found. 6.15 demonstrates the LCOE with incentives (e.g., investment tax credits or production tax credits, if applicable) for a range of potential supply side resources. It is important to note that levelized cost of energy figures, while useful for convenient comparisons of resource alternatives, do not fully capture all of the relative strengths of each resource type. For example, wind resources are intermittent resources and therefore cannot be counted on for meeting peak demand requirements in the same way a nuclear or gas-fired resource can. Similarly, using an energy cost measure to evaluate peaking resources such as simple cycle combustion turbine generators (CTGs) does not fully reflect their value as a capacity resource or their quick-start capability. Table 6.9 shows the component analysis for the levelized cost of energy figures.

Figure 6.15 Levelized Cost of Energy



[24] 20 CSR 4240-22.040(4); 20 CSR 4240-22.040(4)(C)

Table 6.9 Levelized Cost of Energy Component Analysis[25]

Potential Resource	Levelized Cost of Energy (¢/kWh)								
	Capital	Fixed O&M	Variable O&M	Fuel	Resource Specific Cost	CO_2	SO_2	NO_X	Total Cost
Wind[1]	5.03	1.26	0.00	--	-2.13	--	--	--	**4.16**
Solar[1]	7.42	0.80	--	--	-2.09	--	--	--	**6.14**
Solar[2]	6.27	0.80	--	--	--	--	--	--	**7.07**
Combined Cycle: Greenfield	1.90	1.13	0.34	2.73	--	0.65	0.00	0.02	**6.77**
Combined Cycle w/ CCS: Greenfield[3]	3.44	1.85	0.51	3.17	0.62	0.01	0.00	0.02	**9.63**
Nuclear: SMR[4]	11.17	1.95	0.51	1.99	0.19	--	--	--	**15.81**
Nuclear: AP1000[4]	15.07	2.44	0.48	1.42	0.20	--	--	--	**19.60**
Hydro	15.64	3.97	0.00	--	--	--	--	--	**19.61**
Storage: Pumped Hydro[2,5]	10.75	0.27	0.48	--	6.05	--	--	--	**17.56**
Storage: Li-Ion Battery (8h)[2,5]	11.99	1.98	0.00	--	4.76	--	--	--	**18.73**
Storage: Li-Ion Battery (4h)[2,5]	12.21	2.64	0.00	--	4.76	--	--	--	**19.61**
Simple Cycle: Greenfield	24.44	2.37	0.66	4.40	--	1.05	0.00	0.10	**33.02**

1. Resource Specific Cost: Full PTC
2. 30% ITC
3. Resource Specific Cost : Carbon dioxide transportation and storage cost
4. Resource Specific Cost: Decommissioning fund
5. Resource Specific Cost : Battery charging/pump cost

The LCOE for future resource options is an important measure for assessing these options. However, it is not the only factor that must be considered in making resource decisions. Facts and conditions surrounding future environmental regulations, commodity market prices, economic conditions, economic development opportunities, and other factors must be considered as well. A robust range of uncertainty exists for many of these factors, all of which leads to one overriding conclusion – maintaining effective options to pursue alternative resources in a timely fashion is a prudent course of action.

[25] 20 CSR 4240-22.040(2)(B); 20 CSR 4240-22.040(2)(C)1

6.5 Compliance References

Chapter 6 - Appendix A

Characterization Data – New Resources[1]

6.1 Technology Characterization

Cost, performance, and operating characteristics were developed for renewable resources, energy storage, and thermal resources with input from Ameren Missouri's internal resources. Detailed characteristics data is presented in the Tables at the end of this appendix.

6.2 Capacity, Capacity Factor, and Operations Mode

The selection of practical size ranges for each of the technologies is based on Ameren Missouri's ability to plan for and reasonably implement the technology. New resources cover a broad range of operations modes: baseload, intermediate, peaking, and intermittent (e.g., wind, solar). Table 6A.2 lists capacity and operations mode for new resources.

6.3 Commercial Availability

The commercial status of each of the evaluated technologies was qualitatively assessed. Developing technologies consist of all other technologies that may have limited experience, have been utilized in demonstration projects, or consist of laboratory-tested conceptual designs; e.g., SMR.

6.4 Capital Cost Estimates

Screening level, overnight EPC capital cost estimates were developed for all evaluated options and expressed in 2023 dollars. The values presented are reasonable for today's market conditions, but, as demonstrated in recent years, the market is dynamic and unpredictable. Power plant costs are subject to continued volatility and the estimates in this report should be considered primarily for comparative purposes. The costs presented in this report were developed in a consistent manner and are reasonable relative to one another.

The EPC estimates include costs for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs on an overnight basis and are representative of "inside the fence" project scope. The overall

[1] 20 CSR 4240-22.040(1)

Schedule MM-S21

capital cost estimates consist of three main components: EPC Capital Cost, Owner’s Cost (excluding Allowance for Funds Used During Construction [AFUDC]), and Owner’s AFUDC Cost. EPC estimates for all evaluated options are presented in Table 6A.3.

An allowance has been made for Owner’s costs (excluding AFUDC). Items included in the Owner’s costs include “outside the fence” physical assets, project development, and project financing costs. These costs can vary significantly, depending upon technology and unique project requirements. Owner’s costs were developed as a percentage of the EPC capital cost as shown in the tables referenced above. Owner’s costs are assumed to include project development costs, interconnection costs, spare parts and plant equipment, project management costs, plant startup/construction support costs, taxes/advisory fees/legal costs, contingency, financing and miscellaneous costs. Table 6A.1 shows a more detailed explanation of potential owner’s costs. Project cost including owner's costs (excluding AFUDC) is presented in Table 6A.3.

For the purposes of characterizing all of the evaluated options, the AFUDC was calculated by applying the Company's current allowed ROE and long-term interest rate to the cash flows during permitting and construction period, with the construction duration being defined as the time period from Notice to Proceed (NTP) to Commercial Operation Date (COD). Project timeline is presented in Table 6A.2and AFUDC percentage is presented in Table 6A.5.

Table 6A.1 Potential Items Included in Owner's Costs

Project Development: Site selection study Land purchase/options/rezoning Transmission/gas pipeline rights of way Road modifications/upgrades Demolition (if applicable) Environmental permitting/offsets Public relations/community development Legal assistance **Utility Interconnections:** Natural gas service (if applicable) Gas system upgrades (if applicable) Electrical transmission Supply water Wastewater/sewer (if applicable) **Spare Parts and Plant Equipment:** Air quality control systems materials, supplies, and parts Acid gas treating materials, supplies and parts Combustion turbine and steam turbine materials, supplies, and parts HRSG materials, supplies, and parts Gasifier materials, supplies, and parts Balance-of-plant equipment materials, supplies and parts Rolling stock Plant furnishings and supplies Operating spares **Owner's Project Management:** Preparation of bid documents and selection of contractor(s) and suppliers Provision of project management Performance of engineering due diligence Provision of personnel for site construction management	**Plant Startup/Construction Support:** Owner's site mobilization O&M staff training Supply of trained operators to support equipment testing and commissioning Initial test fluids and lubricants Initial inventory of chemicals/reagents Consumables Cost of fuel not recovered in power sales Auxiliary power purchase Construction all-risk insurance Acceptance testing **Taxes/Advisory Fees/Legal:** Taxes Market and environmental consultants Owner's legal expenses: • Power Purchase Agreement (PPA) • Interconnect agreements • Contracts--procurement & construction • Property transfer **Owner's Contingency:** Owner's uncertainty and costs pending final negotiation: • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreement (e.g., interconnection contract costs) **Financing:** Development of financing sufficient to meet project obligations or obtaining alternate sources of funding Financial advisor, lender's legal, market analyst, and engineer Interest during construction Loan administration and commitment fees Debt service reserve fund **Miscellaneous:** All costs for above-mentioned Contractor-excluded items, if applicable

6.5 Non-Fuel Fixed O&M Costs

First year fixed O&M costs (in 2023$s) were developed for each of the evaluated options, and for future years a 2% escalation rate was used after escalating the first year at 3.1%. Fixed O&M costs include labor, materials, contracted services, and G&A costs. Natural gas combined cycle resource fixed O&M costs include firm gas transportation cost. For hydro, wind, solar, and battery energy storage systems all O&M costs are considered to be fixed O&M.

All O&M cost estimates are presented in Table 6A.3. Non-Fuel variable O&M for thermal resources is discussed in Section 6.7.2.

6.6 Scheduled and Forced Outages

Scheduled maintenance intervals were obtained from original equipment manufacturers (OEMs) or estimated on the basis of Black & Veatch or Ameren Missouri subject matter expert experience for each of the technologies. Where information was not available, maintenance intervals were estimated using data gathered from comparable technologies.

Where available, generic equivalent forced outage rate were gathered for each of the technologies and are presented in Table 6A.2. The information was taken from the NERC GADS database and published literature to the extent that data were available. When information was not available, values were estimated using data gathered from comparable technologies.

6.7 Thermal Resource Characteristics

6.7.1 Thermal Performance

Natural gas and nuclear performance are based on EIA, NREL and EPRI data. Natural gas emission rates (SO_2, NO_x and CO_2, and PM10) are based on EIA data.

Table 6A.2 lists heat rate data for thermal resources.

6.7.2 Non-Fuel Variable O&M

Variable O&M costs include water consumption, waste and water discharge treatment cost and consumables such as water treatment chemicals and lubricants. Combined cycle variable O&M includes catalyst replacement, ammonia, water, and water discharge treatment cost for emissions reduction equipment. Simple Cycle variable O&M incudes starts based CT Major Maintenance VOM costs.

6.7.3 Natural Gas Technology Options[2]

Combined Cycle

The following assumptions have been made for this resource option:

1. AQCS:
   - Dry low NO_x burners and SCR for NO_x control.
   - CO oxidation catalyst for CO and VOC controls.
2. Inlet air evaporative cooling above 59° F.
3. Triple-pressure heat recovery steam generation (HRSG).
4. A mechanical-draft, counterflow, cooling tower assumed for heat rejection.
5. No HRSG bypass dampers and stacks.
6. No supplemental HRSG firing
7. Operation on Natural Gas (Dual Fuel Capable)

Combined Cycle with CCS

The following assumptions have been made for this resource option:

1. 98.5% carbon capture
2. CO_2 Compressor, CO_2, pump, CO_2 drying package.
3. SCR for NO_x control
4. Triple-pressure HRSGs
5. Natural draft cooling tower

Simple Cycle

Performance, emissions, and cost estimates were prepared for the following simple cycle technologies:

- One generic industrial frame Model F CT.

The following assumptions have been made for simple cycle option:

1. Dry low NO_x (DLN) burners would be included for NO_x control.
2. Operation on Natural Gas (Dual Fuel Capable)

[2] 20 CSR 4240-22.040(1)

6.7.4 Nuclear Technology Option[3]

AP1000

Following assumptions have been made for this resource:

1. Design life - 40 years
2. Thermal Output - 3,451 MWt, Electrical Output - 1,100 MWe
3. Uranium Dioxide Fuel Rods (157 fuel assemblies, 17ft x 17ft fuel lattice, 12ft fuel length)
4. 18 month refueling interval, 24 day refueling duration
5. Two natural draft cooling towers
6. Annual decommissioning fund contribution based on Ameren Missouri's 2020 triennial funding update filing for Callaway Energy Center.

SMR

Following assumptions have been made for this resource:

1. Design life - 40 years
2. Thermal Output - 3000 MWt, Electrical Output - 864 MWe
3. Uranium Dioxide Fuel Rods, (156 assemblies, 1 foot square by 6 feet long)
4. 10 day refueling every 2 years, 6-week turbine outage every 6 years5. A number of natural draft cooling towers appropriate to final design
6. Annual decommissioning fund contribution based on Ameren Missouri's 2020 triennial funding update filing for Callaway Energy Center.

[3] 20 CSR 4240-22.040(1)

6.8 Supporting Tables

Table 6A.2 – Resources, Capacity and Performance[4]

Resource Option	Resource	Operations Mode	Renewable Resource	Technology Description	Plant Output, MW	Heat Rate HHV, Btu/kWh	Assumed Fuel Type/ Source	Fuel Flexibility	Technology Maturity	Permitting, months	NTP to COD, months	Assumed Annual Capacity Factor, %	Forced Outage Rate, %
Wind	Wind	Intermittent	Yes	Wind	100	n/a	n/a	n/a	Mature	36 to 60	12	42%	n/a
Solar	Solar	Intermittent	Yes	PV	100	n/a	n/a	n/a	Mature	12 to 18	6	26%	1%
Pumped Storage	Storage	Peaking	No	Hydro	600	n/a	n/a	n/a	Mature	21 to 27	48	25%	
Li-Ion Battery (4h)	Storage	Peaking	No	Li-Ion	4	n/a	n/a	n/a	Mature	6 to 12	6	17%	1%
Li-Ion Battery (8h)	Storage	Peaking	No	Li-Ion	4	n/a	n/a	n/a	Mature	6 to 12	6	33%	1%
Hydro	Hydro	Baseload	Yes	Hydro	6	n/a	n/a	n/a	Mature	21 to 27	24	40%	3%
Combined Cycle	Natural Gas	Intermediate	No	H Class CCCT	1,200	6,148	Natural Gas	No	Mature	18	24	40%	5%
Combined Cycle with CCS	Natural Gas	Intermediate	No	H Class CCCT	1,135	7,138	Natural Gas	No	Developing	18	24	40%	5%
Simple Cycle	Natural Gas	Peaking	No	F Class SCCT	230	9,895	Natural Gas	Yes	Mature	18	22	5%	5%
Nuclear - SMR	Nuclear	Baseload	No	Nuclear	864	11,991	Nuclear	No	Developing	24	42	95%	5%
Nuclear - Conventional	Nuclear	Baseload	No	AP1000	1100	10,440	Nuclear	No	Mature	24	72	94%	2%

4 20 CSR 4240-22.040(1), 20 CSR 4240-22.040(2)(C)(1)

Table 6A.3 – Cost Estimates[5]

Resource Option	Resource	Tax Life, years	Economic Life, years	Owner's Cost, %	EPC Capital Cost, $1,000	EPC Capital, Cost $/kW	Project Cost - Includes Owners Cost, Excluding AFUDC $1,000	Total Project Cost- Includes Owners Cost, Excluding AFUDC, $/kW
Wind	Wind	5	30	3%	192,192	1,922	197,900	1,979
Solar	Solar	5	30	8%	178,241	1,782	192,500	1,925
Pumped Storage	Storage	20	40	14%	1,205,629	2,009	1,374,600	2,291
Li-Ion Battery (4h)	Storage	5	15	4%	5,869	1,467	6,104	1,526
Li-Ion Battery (8h)	Storage	5	15	4%	11,496	2,874	11,956	2,989
Hydro	Hydro	20	60	22%	28,052	4,675	34,224	5,704
Combined Cycle	Natural Gas	20	30	12%	1,307,143	1,089	1,464,000	1,220
Combined Cycle with CCS	Natural Gas	20	30	12%	2,236,558	1,971	2,504,945	2,207
Simple Cycle	Natural Gas	15	30	13%	202,319	880	228,620	994
Nuclear - SMR	Nuclear	15	40	20%	6,114,240	7,077	7,337,088	8,492
Nuclear - Conventional	Nuclear	15	40	20%	9,266,583	8,424	9,789,244	10,109

[5] 20 CSR 4240-22.040(5)(B); 20 CSR 4240-22.040(5)(C)

Table 6A.4– Non-Fuel O&M, Fuel, and Environmental Characteristics[6]

Resource Option	Resource	First Year Fixed O&M Cost, $1,000/yr	First Year Fixed O&M Cost, $/kW-yr	First Year Variable O&M Cost, $1,000/yr	First Year Variable O&M Cost, $/MWh	NOx, lbm/MMBtu	SO2, lbm/MMBtu	CO2, lbm/MMBtu	CO, lbm/MMBtu	PM10, lb/MMBtu
Wind	Wind	3,640	36	0	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar	1,440	14	0	0.0	n/a	n/a	n/a	n/a	n/a
Pumped Storage[1]	Storage	2,700	5	4,730	3.6	n/a	n/a	n/a	n/a	n/a
Li-Ion Battery (4h)	Storage	133	33	0	0.0	n/a	n/a	n/a	n/a	n/a
Li-Ion Battery (8h)	Storage	199	50	0	0.0	n/a	n/a	n/a	n/a	n/a
Hydro	Hydro	594	99	0	0.0	n/a	n/a	n/a	n/a	n/a
Combined Cycle	Natural Gas	74,400	62	11,353	2.70	0.008	0.000	117	0.014	0.003
Combined Cycle with CCS	Natural Gas	120,878	107	33,407	8.40	0.008	0.000	1.76	0.014	0.003
Simple Cycle	Natural Gas	1,863	8	524	5.20	0.090	0.000	119	0.015	0.005
Nuclear - SMR	Nuclear	105,494	122	27,754	3.86	n/a	n/a	n/a	n/a	n/a
Nuclear - Conventional	Nuclear	166,100	151	32,971	3.64	n/a	n/a	n/a	n/a	n/a

1- Excludes Charging/Pump Costs for Storage, Round-Trip-Efficiency and Market Price dependent

6 20 CSR 4240-22.040(1), 20 CSR 4240-22.040(2)(A)

Table 6A.5– Economic Parameters and LCOE[7]

Resource Option	Resource	Plant Maintenance Pattern, week/year	Water Consumption, gal/min	VOM Escalation Rate, %	Present Worth Discount Rate, %	Fixed Charge Rate, %*	AFUDC Rate, %	Candidate Option	Cost Rank	LCOE, ¢/kWh*
Wind	Wind	N/A	0	2.0%	6.59%	8.60%	5.40%	Yes	1	4.16
Solar	Solar	N/A	0	2.0%	6.59%	8.45%	3.70%	Yes	2	6.14
Pumped Storage	Storage	N/A		2.0%	6.59%	8.41%	18.50%	Yes	6	17.56
Li-Ion Battery (4h)	Storage	N/A	0	2.0%	6.59%	8.83%	3.70%	Yes	10	20.47
Li-Ion Battery (8h)	Storage	N/A	0	2.0%	6.59%	8.83%	3.70%	Yes	7	19.58
Hydro	Hydro	1	0	2.0%	6.59%	9.99%	11.10%	No	9	19.61
Combined Cycle	Natural Gas	Note 1	4,200 - 5,900	2.0%	6.59%	9.99%	6.10%	Yes	3	6.77
Combined Cycle with CCS	Natural Gas	Note 1	3,200 - 4,600	2.0%	6.59%	9.99%	6.10%	Yes	4	9.63
Simple Cycle	Natural Gas	Note 2	0 - 100	2.0%	6.59%	9.82%	6.30%	Yes	11	33.02
Nuclear - SMR	Nuclear				6.59%	9.24%	14.90%	Yes	5	15.81
Nuclear - Conventional	Nuclear		19,413	2.0%	6.59%	9.24%	28.80%	Yes	8	19.60

Note 1-Equivalent Operating Hours (EOH) based maintenance. Significant overhaul for CT every 25,000 EOH and major overhaul every 50,000 EOH.
Note 2- Equivalent starts based maintenance. Significant overhaul every 900 equivalent starts, major overhaul every 2400 equivalent starts. 56 starts/year assumed.

* Wind and solar shown with full PTC, batteries and pumped storage with 30% ITC.

[7] 20 CSR 4240-22.040(2)(C)1, 20 CSR 4240-22.040(2)(C)2

Schedule MM-S21

6.9 Compliance References

7. Transmission and Distribution

Highlights

- *Ameren Missouri will construct nineteen of twenty-six transmission projects that have been approved by the Midcontinent Independent System Operator (MISO) Board of Directors in Missouri for completion before 2026.*
- *Ameren Missouri has developed the Smart Energy Plan (SEP), a comprehensive, forward-looking plan designed to upgrade the electric grid and bring significant benefits to customers.*
- *The plan includes $9.9 billion of electric investments from 2023 through 2027 that will, among other things, accelerate our investment in smart grid technologies, system hardening efforts, and upgrading infrastructure.*

Ameren Missouri is continuously maintaining or replacing aging infrastructure in order to meet its obligation to provide safe and adequate service and to endeavor to meet its customers' reliability expectations. Rapid growth during the 1960s and 1970s, spurred by a housing boom and the advent of air conditioning, resulted in a replacement of the previous vintage infrastructure and an even larger, new system. As growth has slowed over time, the infrastructure has not experienced optimal turnover. This lack of asset turnover means our existing grid is heavily populated with 40 to 60-year-old equipment that is at risk of failure, obsolescence, and inefficiencies as compared to modern equipment. While the company has always worked to improve its electric grid, SEP has allowed Ameren Missouri to markedly increase its efforts in this area with its plans to make investments to replace its aging grid infrastructure so that it can continue to provide customers safe and adequate service. On the transmission side, a total of 26 transmission projects have been approved by the MISO Board of Directors for construction in Missouri for completion before 2026. Ameren Missouri will construct 19 of these projects. The projects will mitigate future reliability issues and provide for continued safe and reliable service to customers.

7.1 Transmission

7.1.1 Existing System[1]

Ameren Missouri owns and operates a 2,970 mile transmission system that operates at voltages from 345 kV to 138 kV. The system is composed of the following equipment:

- 1,313 miles of 138 kV transmission circuits.
- 835 miles of 161 kV transmission circuits.
- 978 miles of 345 kV transmission circuits.
- Substations that make up the Bulk Electric System:
    - 23 extra high voltage substations with a maximum voltage of 345 kV.
    - 39 substations with a maximum voltage of 161 kV.
    - 34 substations with a maximum voltage of 138 kV.

7.1.2 Regional Transmission Organization Planning[2]

Since 2004, Ameren Missouri has been a member of MISO, a Regional Transmission Organization (RTO). MISO was approved as the nation's first RTO in 2001 and is an independent nonprofit organization that supports the delivery of wholesale electricity and operates energy and capacity markets in 15 U.S. states and the Canadian province of Manitoba.

A key responsibility of the MISO is the development of the annual MISO Transmission Expansion Plan (MTEP). Ameren Missouri is an active participant in the MISO MTEP development process. Participation in the MISO MTEP process is the method by which Ameren Missouri's transmission plan is incorporated into the annual MTEP document. The overall planning process can be described as a combination of "Bottom–Up" projects identified in the individual MISO Transmission Owners' transmission plans which address issues more local in nature and are driven by the need to safely and reliably provide service to customers, and projects identified during MISO's "Top-Down" studies, which address issues more regional in nature that provide economic benefits or address public policy mandates or goals.[3] MISO's Long Range Transmission Plan (LRTP), which resulted in approval of approximately $10 billion of new transmission projects[2], including approximately $1billion of investments in Missouri is an example of the top-down approach. These projects were approved as a part of the MTEP21 process.

Through these MTEP related activities, Ameren Missouri works with MISO, adjacent RTOs and Transmission Planning Regions, adjacent MISO Transmission Owners and stakeholders to promote a robust and beneficial transmission system throughout the

[1] 20 CSR 4240-22.045(1)
[2] 20 CSR 4240-22.045(3)
[3] 20 CSR 4240-22.045(3)(B)1

Midwest region. Ameren Missouri's participation helps ensure that opportunities for system expansion that would provide benefits to Ameren Missouri customers are thoroughly examined. This combination of Bottom-Up and Top-Down planning helps ensure all issues are addressed in an effective and efficient manner.[4]

Guidance is provided to MISO on the assumptions, inputs, and system models that are used to perform the various analyses of the overall MISO transmission system. Ameren Missouri's participation in the MTEP development process includes: review of MISO and stakeholder developed material, comments and feedback, and working to assure the projects approved in the MTEP are in the interests of the Ameren Missouri customers. Ameren Missouri is regularly represented by attendance and participation in the MISO stakeholder organizations which are key components of the MTEP development process including the:

- Planning Advisory Committee (PAC) – The PAC provides input to the MISO planning staff related to the process, adequacy, integrity and fairness of the MISO wide transmission expansion plan.
- Planning Subcommittee (PSC) – The PSC provides advice, guidance, and recommendations to MISO staff with the goal of enabling MISO to efficiently and timely execute its planning responsibilities, as set forth in the MISO Tariff, MISO/Transmission Owner Agreement, Federal Energy Regulatory Commission (FERC) Orders applicable to planning and other applicable documents.
- Interconnection Process Working Group (IPWG) – The IPWG has the goal of reducing study time and increasing certainty associated with new requests to connect generation to the transmission grid within MISO.
- Sub-regional Planning Meetings (SPM) – The SPMs are hosted by MISO in accordance with FERC Order 890, to encourage an open and transparent planning process. Stakeholders are encouraged to participate in discussions of planning issues and proposals on a more local basis and discuss projects, issues and concepts that are potentially driving the need for new transmission expansions.
- Loss Of Load Expectation Working Group (LOLEWG) – The LOLEWG works with MISO staff to perform Loss of Load Expectation analysis that calculates the congestion free Planning Reserve Margin requirements as defined in the Module E of the MISO Tariff.
- Regional Expansion Criteria and Benefits Working Group (RECBWG) – The RECBWG is a forum for stakeholders to provide input in the various processes used in the MISO tariff to allocate the cost of transmission system upgrades and improvements to the appropriate beneficiaries.

[4] 20 CSR 4240-22.045(3)(B)1; 20 CSR 4240-22.045(3)(B)2; 20 CSR 4240-22.045(3)(B)3

- Interregional Meetings – Numerous meetings are held each year with PJM RTO, SPP RTO, and the Southeastern Regional Transmission Planning Region to discuss, evaluate and consider interregional transmission issues and identify opportunities for transmission expansion, consistent with the respective RTO's regional planning processes.
- Other Committees, Task Forces and Working Groups as appropriate.

The result of the MTEP process is a compilation of transmission projects that are needed to address system reliability requirements, improve market efficiency, and/or provide specific system benefits as delineated in the MISO Tariff. The MTEP identifies solutions to meet regional transmission needs and to create value opportunities through the implementation of a comprehensive planning approach.

Each MTEP document is identified by the year in which it was completed. Appendix A of each MTEP lists and briefly describes the transmission projects that have been evaluated, determined to be needed and subsequently approved by the MISO Board of Directors. The MTEP21 document is the culmination of more than 18 months of collaboration between MISO planning staff, MISO Transmission Owners, and stakeholders. Each MTEP cycle focuses upon identifying system issues and improvement opportunities, developing alternatives for consideration, evaluating those options to determine the most effective solutions and finally identifying the preferred solution. As described in more detail in the MISO Tariff, the primary purposes of the MTEP process are to identify transmission projects that:

- Ensure the transmission system supports the customer's needs in a continued safe and reliable manner.
- Provide economic benefits such as increased market efficiency and resultant overall lower energy cost.
- Facilitate public policy objectives such as integrating renewable energy resources.
- Address other issues or goals identified through the stakeholder process.

The interconnection of new generation resources to the transmission system under MISO's control is also an important part of the overall transmission planning effort. Ameren Missouri actively participates in regional generation interconnection studies for proposed generation interconnections inside and outside of the Ameren Missouri area. Participation in these transmission studies ensures that they are performed on a consistent basis and that the proposed connections and any system upgrades needed on the Ameren Missouri transmission system are properly integrated and scheduled to maintain system reliability.

With the approval of MTEP21, a total of 26 transmission projects have been approved by the MISO Board of Directors for construction in Missouri before 2026. A summary of the projects is shown in the table below. Table 7.1 also includes the proportion of transmission service charges arising from the projects that will be assigned to the Ameren MO load zone.[5] The costs of these projects are not impacted by whether the project is constructed by Ameren Missouri or an affiliate.

Table 7.1 MTEP Transmission Projects in Missouri in MTEP21 or Prior – Summary

Project Type	Number of Projects	Estimated Total Project Cost ($Million)	Estimated Percentage of Transmission Service Charges Arising from the Projects to be assigned to the Ameren Missouri Load Zone
Baseline Reliability or Reliability/Other Projects Not Cost Shared	24	$501	100%
GIP projects	2	$17	8%

A brief description of the 26 transmission projects can be found in Appendix A.[6]

A key component of fulfilling Ameren Missouri's obligation of continuing to provide safe and adequate service is the identification of potential future needed transmission upgrades. A list of projects that are under consideration by Ameren Missouri and MISO and that are located totally or partially in Missouri is provided in Appendix A in Table 7A.2.

Current and previous transmission system expansion plans can be found on MISO's website: https://www.misoenergy.org/planning/planning/[7]

Revenue Credits from Previously Constructed Regional Transmission Upgrades[8]

Regional transmission upgrades, such as Multi-Value Projects (MVP) and Market Efficiency Projects, are eligible for cost sharing under Attachment GG or MM of the MISO Tariff. Ameren Missouri does not have any Multi-Value or Market Efficiency projects which result in revenue credits. However, Ameren Missouri does have four Baseline Reliability Projects that were approved for regional cost sharing under a prior version of Attachment GG. Ameren Missouri expects approximately $10.6 million of Schedule 26 revenue in planning year 2023-24. It should be noted that over 90% of Ameren Missouri's Attachment GG revenue requirement will be allocated to the AMMO pricing zone and reflected in the rates paid by Ameren Missouri retail and wholesale customers.

[5] 20 CSR 4240-22.045(3)(A)4
[6] 20 CSR 4240-22.045(6)
[7] 20 CSR 4240-22.045(3)(C)
[8] 20 CSR 4240-22.045(3)(A)5

7.1.3 Ameren Missouri Transmission Planning[9]

Ameren Missouri's transmission strategy is centered upon meeting the evolving needs of its customers and Ameren Missouri's commitment to provide them safe and adequate service, and to endeavor to meet their increasing reliability expectations. Each year the Ameren Missouri transmission system is thoroughly examined and studied to verify it will continue to provide Missouri customers with reliable and adequate service through compliance with all applicable North American Electric Reliability Corporation (NERC) standards as well as Ameren's Transmission Planning Criteria and Guidelines.

The studies identify potential system conditions where reduced reliability may occur in the future. Additional studies are then performed to evaluate all practical alternatives to determine what, where, and when system upgrades are required to address the future reliability concern. This annual review identifies any transmission system reinforcements necessary to provide reliable and safe service in response to changing system conditions. These studies consider the effects of overall system load growth, the adequacy of the supply to new and existing substations to meet local load, the expected power flows on the bulk electric system and the resulting impacts on the reliability of the Ameren Missouri transmission system.

In order to successfully achieve the goal of a safe and reliable transmission system, Ameren Missouri participates in a multitude of transmission planning activities including:

- MISO Transmission Expansion Plan development
- MISO regional generation interconnection studies
- NERC reliability standards development,
- Participation in SERC regional planning and assessment activities,

This high level of involvement affords the opportunity to supply comments and provide input to these many transmission planning processes which supports the goal of maintaining a reliable and safe transmission system which will meet the current and future needs of our Missouri customers.

As part of the Ameren Missouri Transmission Planning Process, the ability of transmission system improvements to reduce transmission system losses is considered. A major aspect of Ameren Missouri's focus of providing continued safe and adequate service to our customers and to meet their reliability expectations is maintaining transmission equipment and replacing aging infrastructure when it approaches the end of its operational life. The Ameren Missouri area experienced rapid economic growth and substantial investment in transmission infrastructure during the 1960s and 70s. Considerable portions of the transmission system are now over forty years old and are

[9] 20 CSR 4240-22.045(3)(B)1; 20 CSR 4240-22.045(3)(B)2; 20 CSR 4240-22.045(3)(B)3; 20 CSR 4240-22.045(3)(B)4

reaching the end of their operational life with a commensurate increased risk of failure and higher maintenance expense. The existing equipment is also less efficient than comparable modern equipment. Ameren Missouri is working to address the most critical issues by making targeted investments to replace its aging grid infrastructure to maintain system reliability, consistent with available capital.

7.1.4 Transmission Impacts of Potential Ameren Missouri Generation Resource Additions/Retirements & Power Purchases/Sales[10]

As part of the determination of the proper combination of resources needed to serve the Ameren Missouri load, the size and location of potential future generation resources are estimated. This requires an assessment of the transmission system enhancements necessary to safely and reliably deliver energy from these potential future resources.

Table 7.2 provides a high-level assessment of interconnection costs for the listed potential future generation resources. These estimates do not include costs for non-MISO affected systems but do include estimated cost of network upgrades in MISO footprint, which may be impacted by other new resources connecting to the grid, revisions to resource timing, new transmission projects and other factors. Actual projects and costs would be determined via the MISO generation interconnection process at the time these projects are developed.

Table 7.2 Transmission Project Costs for New Generation **

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As part of the determination of the proper combination of resources needed to serve the Ameren Missouri load, the need for continued operation of existing resources is examined. This requires determining the overall impact of retiring existing generation resources on the transmission system and identifying any system upgrades necessary to maintain safe and adequate service after the resource is no longer available.

[10] 20 CSR 4240-22.040(3); 20 CSR 4240-22.040(3)(A); 20 CSR 4240-22.045(1)(B); 20 CSR 4240-22.045(1)(C); 20 CSR 4240-22.045(3)(D);

Table 7.3 and Table 7.4 contain the results of a high-level assessment of the cost to Ameren Missouri customers of transmission system upgrades needed to provide continued safe and adequate service when the indicated Ameren Missouri generators retire within the planning period. These estimates may be impacted by new resources connecting to the grid, revision of the shutdown timeframe, new transmission projects and other factors.

Table 7.3 Estimated Transmission Project Costs for Reactive Support **

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Table 7.4 Estimated Transmission Project Costs for Thermal Upgrades **

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Transmission Impacts due to New Generation Resource Connections within the MISO Footprint or Point-to-Point Transfers of Energy within the MISO Footprint to Ameren Missouri

Ameren Missouri participates in regional generation interconnection studies for proposed generation interconnections inside the MISO footprint. Participation in these activities ensures that the studies are performed on a consistent basis and that the proposed connections are integrated into the Ameren Missouri system to maintain system reliability. Power flow, short-circuit, and stability analyses are performed to evaluate the system impacts of the requested interconnections. If system deficiencies are identified in the connection and system impact studies, additional studies are performed to refine the limitations and develop alternative solutions.

New Generation Resources - Future generation resources within the MISO footprint seeking to connect to the transmission system will be subject to the interconnection requirements described in the MISO Tariff and applicable MISO Business Practice Manuals. In order to interconnect to the transmission system, the resource owner must provide project details including location, resource size, type of service requested, when it wants to connect, etc. After this information has been received, the impacted Transmission Owner and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably interconnect the generation resource to the transmission system.

Point to Point Transactions - The MISO Tariff and applicable MISO Business Practice Manuals describe the process by which transmission service requests can be made to have firm point-to-point transmission service within the MISO footprint. The entity requesting service would provide details including: source and delivery locations, quantity of energy to be transmitted, timing and duration of delivery, etc. After this information has been received, the impacted Transmission Owner(s) and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably support the requested transmission service. The transmission upgrades needed to support a transmission service request will not be determined until the completion of the system study and analysis. The MISO Tariff and MISO Business Practice Manuals that are in effect at the time when the point-to-point transmission service request is submitted will describe the process by which Financial Transmission Rights (FTRs) are allocated and can be obtained by entities.

The total cost of any necessary transmission upgrades cannot be determined until a resource interconnection request and/or a transmission service request has been submitted to MISO via the process described in the MISO Tariff and applicable Business Practice Manuals and the necessary transmission system studies have been performed. The result of the studies will identify the transmission system upgrades necessary to safely and reliably fulfill the transmission service request or generation interconnection request. The studies will include a description of the needed transmission system reinforcements, their location, in service date and estimated total cost. Therefore, the cost of any needed system upgrades will not be known until the system study and analysis is complete.

Transmission Impacts due to New Generation Resources outside the MISO Footprint affecting the MISO Transmission System or Point-to-Point Transfers of Energy from Outside the MISO Footprint to Ameren Missouri

Ameren Missouri participates in generation interconnection studies for proposed generation interconnections for generators located outside of the MISO footprint. Participation in these activities ensures that the studies are performed on a consistent basis and that the impact of the proposed connections do not adversely affect the Ameren Missouri system reliability. Power flow, short-circuit, and stability analyses are performed to evaluate the system impacts of the requested interconnections. If system deficiencies are identified in the connection and system impact studies, additional studies are performed to refine the limitations and develop alternative solutions.

Point to Point Transactions - The MISO Tariff and applicable MISO Business Practice Manuals describe the process by which transmission service requests can be made to have firm point-to-point transmission service into the MISO footprint from a generation resource located outside the MISO footprint. The entity requesting service would provide details including: source and delivery locations, quantity of energy to be transmitted, timing and duration of delivery, etc. After this information has been received, the impacted TO(s) and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably support the requested transmission service. The transmission upgrades needed to support a transmission service request will not be determined until the completion of the system study and analysis. The MISO Tariff and MISO Business Practice Manuals that are in effect at the time when the point-to-point transmission service request is submitted will describe the process by which FTRs are allocated and can be obtained by entities.

The total cost of any necessary transmission upgrades cannot be determined until a transmission service request has been submitted to MISO via the process described in the MISO Tariff and applicable Business Practice Manuals and the necessary transmission system studies have been performed. The results of the studies will identify the transmission system upgrades necessary to safely and reliably fulfill the transmission service request. The studies will include a description of the needed transmission system reinforcements, their location, in service date and estimated total cost. Therefore, the cost of any needed system upgrades will not be known until the system study and analysis is complete.

7.1.5 Cost Allocation Assumptions for Modeling[11]

The MISO Tariff allocates 100% of the Baseline Reliability Projects revenue requirements to the local zone where the project is located. The MVP revenue requirements are

[11] 20 CSR 4240-22.045(3)(A)4

collected under MISO Tariff Schedule 26-A, which is charged to Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules. MISO estimated charges include the MVPs approved in December 2011and the LRTP projects approved in 2022 as part of MTEP21 by the MISO Board of Directors. Overall, Ameren Missouri expects approximately 7.3% of the MVP costs to be assigned to its load zone.

7.1.6 Advanced Transmission System Technologies[12]

The Company will continue to evaluate the latest technologies when developing long-range plans to maintain and strengthen the reliability, resiliency, and flexibility of the transmission system. With customer focus in mind, we will position ourselves to act if innovative technologies present opportunities to solve anticipated grid deficiencies at a higher value than traditional methods. Federal, state and RTO policies continue to develop to address operational and market issues related to emerging technologies. Ameren Missouri will monitor and work to shape these policies when applicable to result in the most favorable outcomes for our stakeholders. Increasing customer adoption of advanced technology, including distributed energy resources (DERs), will impact energy demand and usage of the transmission system as the load becomes more dynamic. In line with Ameren's 2030 Vision, the transmission system of the future will be a vital component of a more integrated, bi-directional, and smarter electrical grid. Ameren Missouri will need to plan the system to transform from one designed to deliver central station generation to customer load into a modern system that will accommodate more variable and geographically dispersed generating facilities connected at both transmission and distribution voltage levels. Flexibility will be key to maintaining reliable service in the face of various uncertain future scenarios. Emerging technologies and their declining costs are also likely to introduce new areas in which Ameren Missouri will need to compete to retain and win customers by ensuring our service is reliable and affordable. To ensure customer value in the future, the entire electrical grid will be better utilized as a vehicle to offer individualized service to customers and market participants including the ability to buy and sell energy with the energy company and others.

Innovation and modern technology are the catalyst for creating customer value and enhancing efficiency that will keep our product affordable in the future. Just as the transition to renewables will influence expansion of the transmission grid, so too will new technologies and the need to integrate grid connected devices to the energy networks.

Invert based resources (IBR) are starting to connect to the Ameren Missouri transmission system in larger numbers to replace the power lost by retiring synchronous generation. IBRs consist of anything that converts direct current to alternating current, including

[12] 20 CSR 4240-22.045(3)(A)2; 20 CSR 4240-22.045(3)(A)4; 20 CSR 4240-22.045(3)(B); 20 CSR 4240-22.045(1)(D); 20 CSR 4240-22.045(4)(A); 20 CSR 4240-22.045(4)(C); 20 CSR 4240-22.045(4)(D); 20 CSR 4240-22.045(4)(E)1; 20 CSR 4240-22.070(1)(B)

photovoltaic, new wind turbines, and battery energy storage systems. The location of the IBRs results in the loss of the load voltage regulation that used to be performed by the retiring local synchronous generation. Along with the softer voltages, the system as a whole will be weaker, which results in falling fault current, which leads to a larger voltage bump when closing static reactive devices onto the system and difficulty for transmission-based distance relays to determine direction.

If needed, the required voltage regulation can be replaced by adding reactive resources close to where the generation was retired. Ameren Missouri put its first STATCOM into service at Meramec substation in 2022 for that reason. The Meramec STATCOM not only provides voltage regulation and dynamic fault recovery voltage boosting, but also provides two new technologies for improved system performance. The STATCOM was also specified with independent phase control, which was adapted on Ameren's request to produce negative phase sequence current during a fault to polarize transmission relays so they can correctly determine the direction of a fault. In early 2024, Ameren Missouri will be installing its first variable reactor, which allows for larger overall sized reactors, which help control the system voltage in light load conditions. These reactors can move with the system, giving dynamic voltage control, but do not significantly bump the system on closure.

Recently, Ameren Missouri has updated its transmission-level substation design to continually monitor all elements of the substation to remove single points of failure, including new items such as battery monitors. By using fiber and IEC61850, which is ethernet technology, to connect relays and the remote terminal units, control switches and lockouts have been eliminated, wiring and the number of panels has been reduced, along with reducing the size of the control building.

Ameren has started scanning its transmission-level substations, which allows for virtual field visits and increased accuracy in scoping. The scanning allows for viewing nameplates and taking measurements while increasing safety, by reducing the need to visit the substation. The use of both 3D technology and smart wiring has made designs more accurate and the has increased the efficiency and accuracy of field prints.

Building on the advancement in unmanned aerial vehicles, or drones, artificial intelligence (AI) is now being used to analyze the three hundred thousand photographs taken each year, at a rate of 1500 photos an hour. Presently the AI has been taught to detect woodpecker damage, and is currently learning to detect broken crossarms, insulator damage, birds' nests and objects that have been built within the right of way of the transmission line.

The work on the network model manager continues to synergize all the engineering planning modeling process, to avoid manual activity and to eliminate modeling errors. As the load becomes more dynamic, and the generation more intermittent, the requirement of accurate input data and the need to run a multitude of scenarios to cover possible future scenarios demands an adaptive integrated planning model that optimizes solutions that are reliable, affordable and resilient.

Technological advances and declining costs on the customer side are expected to continue. This will introduce the possibility of the need to compete for customers that may have cost competitive alternatives to grid-connected energy. Grid connected customer adoption of DERs and energy efficiency driven by product technology will affect the usage of the transmission system. Planning will continue to be needed for a variety of uncertain future scenarios to ensure a reliable transmission system.

7.1.7 Ameren Missouri Affiliates Relationship[13]

Ameren Missouri's focus is upon continuing to provide safe and adequate service to its customers. Ameren Missouri has prioritized its capital investments to address local issues including: improving its aging distribution and transmission infrastructure and energy centers, accomplishing mandated environmental investments, implementing mandated transmission upgrades (e.g., for NERC compliance), and complying with other state and federal mandates (such as the Missouri Renewable Energy Standard (RES)). These kinds of investments must be made to deliver safe and adequate service to Ameren Missouri’s customers.

An Ameren Missouri affiliate, Ameren Transmission Company of Illinois (ATXI), invests capital in transmission infrastructure that provides a variety of benefits to transmission customers both inside and outside of the MISO Ameren Missouri pricing zone. For example, the recently constructed MISO MVPs consisted of a portfolio of large transmission projects providing reliability, economic, and public policy benefits to customers throughout the Midwest. Alternatively, ATXI also invests in smaller, more localized projects that benefit multiple parties within the MISO Ameren Missouri pricing zone. ATXI is currently constructing a new substation near Rolla, Missouri, that will more efficiently utilize existing high voltage lines, which will provide reliability enhancements to Ameren Missouri retail customers as well as Rolla Municipal Utilities. Ameren Missouri does not plan to construct these kinds of projects because it is in the best interests of its Missouri customers that it invests its limited capital only in generation, distribution and transmission investments needed to provide safe and adequate service to its load, including the transmission improvements needed to connect an Ameren Missouri generating unit to the grid. Because of its limited capital, Ameren Missouri has concluded that it should not invest in other transmission projects, such as MVPs, because investing in regional transmission would undermine Ameren Missouri’s ability to deliver safe and

[13] 20 CSR 4240-22.045(3)(B)5; 20 CSR 4240-22.045(5)

adequate service. The building of these projects by ATXI will not impact the cost of the project relative to construction by Ameren Missouri.

7.1.8 Avoided Transmission and Distribution Cost[14]

Avoided transmission and distribution costs are based upon integrated system effects and are difficult to quantify, as opposed to energy and capacity costs where there are markets that provide specific prices. As part of integration modeling, Ameren Missouri estimated the MW impacts of demand side management (DSM) programs and a corresponding reduction in transmission and distribution capital expenditures.

Ameren Missouri has previously calculated the marginal cost of system capacity in lieu of avoided transmission/distribution costs; however, this approach presents complications due to the fact that projects serve a variety of purposes - capacity upgrades to serve incremental system load, capacity upgrades to serve relocated system load, and refurbishment or replacement of equipment to avoid imminent failure. Therefore, Ameren Missouri decided to follow the 'Current Values Approach,' which is a more straightforward approach and is used by other utilities.[15] The Current Values Approach estimates an average cost of serving the load by taking the net transmission/distribution plant in service and dividing it by the weather-normalized peak load. Ameren Missouri further applied the condition/reliability factor as it has done in its previous IRPs to the average cost of serving the load estimated using the Current Values approach, as not all expenditures can be deferred by the DSM programs. The resulting avoided transmission and distribution costs can be found in Appendix A, Table 7A.3.

7.2 Distribution

7.2.1 Existing System[16]

Ameren Missouri delivers electricity to approximately 1.2 million customers across its service territory in Missouri, including the greater St. Louis area, through the primary distribution system power lines that operate at voltage levels ranging from 2,400 volts (V) through 69,000 V. Ameren Missouri has over 33,000 circuit miles of electric distribution lines, which supply electricity to 63 counties and more than 500 communities where businesses operate and people live.

Approximately 70% of Ameren Missouri's distribution system operates at 12,470 V, 12% operates at 4,160 V, and 11% operates at 34,500 V. The remaining 7% operates at other nominal voltage levels. (See Figure 7.1 for further information.)

[14] 20 CSR 4240-22.045(2); 20 CSR 4240-22.045(3)(A)3
[15] https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf
[16] 20 CSR 4240-22.045(1)

Figure 7.1 Power Flow

Here is how electricity flows from a power plant to an electric customer:

1. Electricity travels from the power plant over high-voltage transmission lines.
2. At a substation, the electricity's voltage is lowered so that it can travel over the distribution system.
3. Main distribution power lines bring electricity into communities.
4. Local distribution power lines serve neighborhoods and individual customers.
5. Service drops carry electricity from pole-mounted or pad-mounted transformers, which lower the voltage again, to customer premises.

Much of the distribution system in rural areas is supplied via single substations operating in radial configurations. Long distribution feeders are usually required to serve multiple isolated rural communities. Long feeders are usually equipped with automatic reclosers to interrupt fault currents and isolate damaged sections, thereby restoring service to upstream portions of the feeder and its respective customers. Where possible, normally open tie switches are installed in downstream sections of feeders to provide emergency service from another source during upstream planned or unplanned outages. The company installs capacitors and/or voltage regulators, as necessary, to counteract voltage drops and maintain proper voltage levels along lengthy circuits.

A more interconnected distribution system is justified to serve densely populated urban areas. Although substations operate in radial configurations, two or more supply circuits are normally available on the primary side of substation transformers. Each customer is served by a single power source at any given time, but the company can re-configure the interconnected system to maintain service to customers via alternate sources when portions of the system must be de-energized to perform maintenance or complete repairs. Although voltage levels tend to be less of an issue in closely coupled, interconnected systems, the company does employ capacitors to maintain power factor[17] within prescribed limits.

Finally, a portion of the distribution system is networked, meaning customers are continuously connected to more than one power source. Examples include the 208Y/120 V underground distribution network in downtown St. Louis and the 69 kV network that supplies communities throughout central Missouri, including Jefferson City, Kirksville, Moberly, and Montgomery City. Networked systems offer the advantage of supplying customers from more than one power source so that they are less susceptible to a sustained total loss of power. However, since the system is networked, disturbances in the distribution system tend to affect a larger number of customers. Automatic isolation of faulted equipment and control of power flow in networked systems are more difficult than in radial systems. For these and other reasons, the Company employs networked systems on a limited basis in Missouri.

Ameren Missouri's distribution system includes both overhead and underground power lines. Underground lines (24% of the total distribution line miles) are more aesthetically pleasing and are significantly less vulnerable to weather-caused damage but can take longer to repair upon failure.

7.2.2 The Aging Grid

As previously stated, much of Ameren Missouri's existing electrical grid was expanded during the 1960s and 1970s. This was a period of increased electricity use driven by significant suburbanization, increased use of air conditioners, and industrial growth. Today, decades later, much of this infrastructure is rapidly approaching obsolescence, with the associated increased risk of failure and inefficiencies as compared to modern equipment.

One area where we can especially see the impact of an aging system is in the challenges we face in operating effectively in the face of extreme weather while under peak demand conditions. As recent winter storms have shown us, there are areas of the grid where a lack of capacity to meet growing peak loads, combined with little operating flexibility, could leave limited ability to switch and restore customers in the event of downed power lines, much less during extreme weather. This has resulted in what we consider excessive customer outages, for prolonged periods.

Another example is distribution substations. When SEP investments began in 2019, over 250 of our distribution substations contained either a transformer or circuit breaker that was installed more than 50 years ago. These substations with critical components beyond their expected lives serve over 500,000 of our 1.2 million customers. If we had not begun upgrading our substation fleet in 2019, over 50 additional distribution substations serving an additional 200,000 customers would have a critical component reach 50 years of age by 2023.

An example of the distribution grid approaching obsolescence is our underground system, which continues to increase in age as over 2,900 miles -over 30% of our underground system- has already exceeded its expected life, presenting an increasing risk to customer reliability and safety. Over 800 miles of the system is categorized as First Generation and Older, meaning it has already exceeded its expected 40-year life. First Generation and Older lines have more than twice the number of failures compared to a Fourth Generation, which includes cable that has not yet reached its expected life.

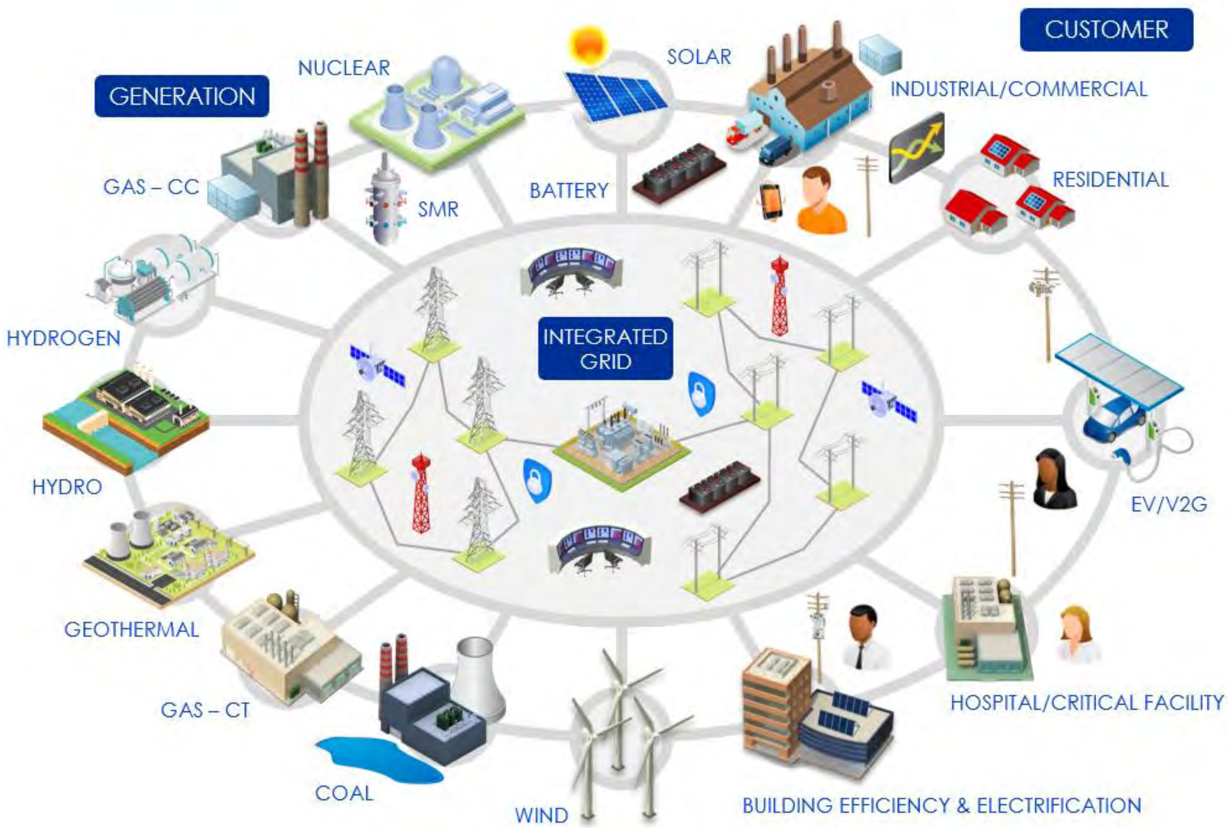
In addition, a large portion of our overhead system is over its expected life. One marker we have for the age of the overhead system is pole age. The expected life of Ameren's poles is 45 years, and our data shows that any pole over the age of 45 years old is eight times more likely to fail inspections than those that are under 30 years old. Over a third of Ameren Missouri's poles are well over the age of 45 years, meaning that approximately 1,600 miles of Ameren Missouri's distribution grid is at increased risk of failing inspections.

While the correlation of age and reliability across an asset, or set of assets, lifecycle is a simplistic representation of a much more complex interplay of factors such as loading, maintenance cycles, exposure to weather, among many other elements, the fact that there is a significant correlation shows how important it is that we properly invest in our system.

7.2.3 The Integrated Grid of the Future

Beyond the need to replace or upgrade aging and end-of-life components, and an increased prevalence of automation and "smart" devices, today's energy grid inherently operates much the same as it has for the past 100 years. Yet, the electric grid of tomorrow will need to be more complex. We expect that the traditional central station generation, transmission, and distribution system will evolve into the Integrated Grid, which will incorporate increasing levels of distributed energy resources and customer interfaces (e.g., connected devices and homes, electric vehicles). Such changes will work together in a coordinated, bi-directional fashion to continuously and reliably maintain the balance between resources and demand, as seen in Figure 7.2. This grid will help support customers' growing expectations, provide them greater insight into their energy usage, and better inform choices over how they use energy.

Figure 7.2 Power Flow – Future State



7.2.3 Smart Energy Plan

7.2.3.1 Introduction

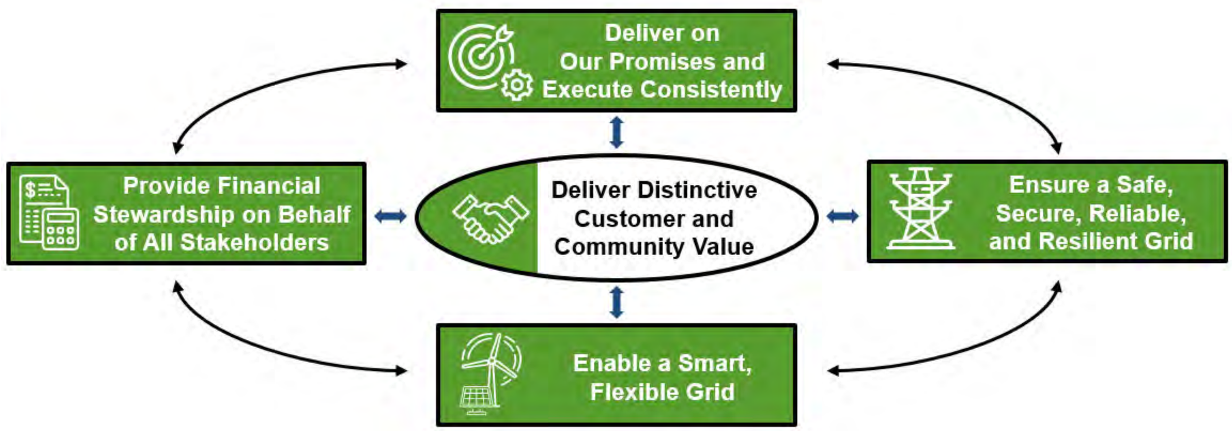
At Ameren Missouri, we are working diligently for our customers, the communities we serve, and our co-workers through Ameren Missouri's Smart Energy Plan. In 2018, the Missouri legislature, energy companies, customers, business organizations, and Missouri leaders collaborated on passing a landmark energy legislation (Missouri Senate Bill 564) that modernized Missouri's energy policies, enabling the SEP. In 2022, the Missouri legislature reiterated their support of SEP through the passage of SB 745. This bill ensured the continuance of these critical grid modernization efforts, which are vital to our customers and the communities we serve.

This forward-looking plan includes $9.9 billion of electric investments from 2023 through 2027 that will, among other things, support our investments in replacing and upgrading aged infrastructure, system hardening and resiliency efforts, and adding smart grid technologies. These investments are supporting customer reliability – they have already prevented over 6.5 million minutes of customer outages in 2022. As we build this grid of the future, Ameren Missouri continues working to keep rates as low as possible while making the necessary investments to build a stronger, smarter and cleaner energy system for our customers. That's why our residential rates remain 18% below the Midwest average compared to other electric utilities. The plan also accelerates the construction of smart energy infrastructure that will drive job creation and economic development across Missouri.

7.2.3.2 SEP Strategic Goals

Based upon our vision of the Integrated Grid, Ameren Missouri has developed guiding principles that put customer value front and center to drive implementation of the Smart Energy Plan, as shown in Figure 7.3.

Figure 7.3 Smart Energy Plan Guiding Principles



These guiding principles are underpinned by a number of outcome-driven strategic goals:

- Upgrade aging and under-performing assets (e.g., substations, overhead and underground assets). As part of our plan, we are addressing the lowest performing circuits across our service territory to improve reliability for our customers.
- Automate portions of the electric distribution system by deploying smart switching devices with associated circuit upgrades and accompanying communications technologies to help significantly reduce the length of outages.
- Harden the 34 kV and 69 kV electric distribution system with a stronger, more secure energy delivery backbone, strategically using stronger poles, standoff insulators, shield wire, and wind tolerant conductors that will better withstand severe weather. Hardened circuits are designed to avoid momentary outages due to lightning strikes, as well as the possibility of extended outages from high winds and other severe weather.
- Employ smart grid technologies (e.g., relaying, monitoring, fault information, communications) as we upgrade aging and end-of-life infrastructure and install new substations to improve reliability for customers and mitigate risk.

- Improve operating flexibility, increase capacity, and enable a bi-directional flow of power from future DERs by upgrading substations and lines and adding smart switches. When severe weather or other events occur, customers can have power restored through switching to prevent or reduce extended outages, but only if lines and substations have the capacity to serve additional load. Part of this work includes the strategic conversion of some areas served by 4 kV power lines to a system standard of 12 kV. This allows for the use of standardized equipment and increased operational flexibility through the ability to add ties between circuits to allow switching to occur. Additionally, this will allow us to serve customers' future needs that continue to change with the transition to electrification.
- Continue to execute the underground revitalization program in the City of St. Louis and surrounding communities. The program significantly reduces aging and end-of-engineered-life infrastructure, some of which is over 100 years old, while increasing route diversity, thus reducing the risk of very long and widespread outages due to a single incident.
- Develop a communications network to monitor and unlock the full benefits from smart automated devices and enable analytics from connected grid devices.
- Provide Smart Meter time-of-use rates, improving customer options for managing their bills and shifting load from peak to off-peak times to benefit the grid.

7.2.3.3 Smart Energy Plan Highlights

Smart Meter Program

The Ameren Missouri Smart Meter Program continues to upgrade all electric meters, gas modules, and the associated communication network in the Missouri service territory over approximately six years, from 2019 through 2024. This work includes:

- Installing 1.2 million Electric Advance Metering Infrastructure (AMI) meters (residential and commercial/industrial), which provide greater usage insights and capabilities for customers.
- Installing 132,000 Gas AMI modules (residential and commercial/industrial).[18] This does not include new gas meters, only the communication module of the meters.
- Deploying a modern RF mesh network, enabling two-way communication.
- Installing an Advanced Meter Data Management System.
- Modernizing the Ameren Missouri Meter Shop to facilitate the receipt and quality testing of purchased meters.
- Creating an Ameren Missouri Network Lab.

These upgraded electric meters and gas modules will replace all of the antiquated Automated Meter Reading (AMR) meters/modules. The existing AMR meters/modules use meter reading technology that is more than 20 years old and were installed between 1995 and 2000, thus exceeding their expected life (projected to have a 15 to 20-year life). These upgrades are expected to have a number of associated benefits:

- Smart sensors, switches, self-healing equipment, work together to rapidly detect and isolate outages and more quickly restore power in the event of a service disruption.
- Smart meters enable Ameren Missouri to pinpoint outages in order to more quickly restore customers' service. Smart meter rate options (e.g., time-of-use rates) help customers manage their bills and shift load from peak to off-peak times to benefit the system.
- Improved mobile and web-based tools provide customers with greater visibility into their energy usage and greater control to manage their energy costs. Customer rates are kept affordable through a reduction in meter infrastructure operating costs by, for example, reduction in meter reading costs and enabling remote disconnect/reconnect capabilities.

From 2019 through 2022, Ameren Missouri installed 772,600 electric AMI meters, along with 54% of the RF mesh network, the meter shop, and network lab. In 2023, we plan to install another 294,000 electric AMI meters.

Substations

Ameren Missouri has approximately 530 distribution substations and more than 100 bulk-supply substations on its system. As was previously discussed in Section 7.2.2 – The Aging Grid, there is a significant population of substations, which serve more than 40% of our customers, that are approaching end-of-life and contribute significantly to reliability issues and increasing maintenance costs.

To combat this trend, Ameren Missouri's SEP called for at least 70 new or upgraded substations in the first five years (2019 through 2023)[19] of the program. These new and upgraded substations will improve energy service reliability through a network that is more efficient. From 2019 through 2022, we have upgraded 75 substations and are forecasted to upgrade another 36 substations in 2023, meeting our original SEP goal. Our long-term goal is to upgrade another 100 substations.

Modernized substations feature automated sensors and smart technology equipment to create a self-healing system that more rapidly detects and informs us of outages and reroutes power to restore service. They also include other "smart" technology equipment (see Section 7.2.7.3 Smart Substation Technologies).

Distribution Automation

More than ten years ago, Ameren Missouri started to deploy distribution automation (DA) devices across the grid. This program was developed due to the significant improvement in reliability, up to 40%, when these devices were added to circuits. Ameren Missouri was able to greatly accelerate this process through the SEP and facilitate having greater portions of the system equipped with smart, automated equipment that improves remote visibility and control. Because of this, the system is able to rapidly detect outages, reroute power, and restore service. From 2019 through 2022, we have installed 1,178 DA devices and are forecasted to install 290 DA devices in 2023 out of a total of approximately 2,350 DA devices, which is considered full distribution deployment. The result of full DA deployment will be self-healing capabilities across much of the distribution system.

Grid Resiliency

The Grid Resiliency category supports reliability by adding capacity to serve localized growing loads and to improve the flexibility and switching ability of Ameren Missouri's substations and lines. Switching power flow around an outage through an alternate pathway is the fastest way to restore customers who are impacted by a grid outage. However, the ability to switch is often impaired by infrastructure that is already at or near capacity due to load growth or design constraints. One impact of these constraints is the requirement to disable substation automatic transfer schemes during periods when loads are higher (e.g., during summer or winter peaks). There are currently 24 substations operated in this manner during the summer season. These substations are a focus of the category, prioritized by their load and number of customers served. Improvements in this category will also serve growing areas with commercial and industrial customers and areas with expanding subdivisions.

Underground Revitalization

Our plan for Underground Revitalization is to increase reliability by upgrading aging and end-of-life infrastructure in downtown and surrounding metro St. Louis. From 2019 through 2022, we upgraded 64 miles of our underground network infrastructure and are forecasted to upgrade another 17 miles in 2023. After such investments in 2023, 76 of the total 116 miles in downtown St. Louis will be underground. Historically, our underground network has exhibited a very high level of reliability. However, as the underground infrastructure ages beyond its useful life, complications and delays can arise when performing unplanned outage repair work. New underground pathways are being built to upgrade aged, paper insulated, lead covered cable with more environmentally friendly Ethylene Propylene Rubber cable. These new pathways and cables are being installed in a route-diverse configuration to eliminate the possibility of multiple underground cable failures from a single event.

Additionally, the Underground Revitalization strategy is contributing to grid modernization by incorporating the installation of modern switching equipment to remotely manage the grid. Automated switching can reduce outages experienced by customers from hours to seconds and minimize the time required to locate and make repairs to underground assets.

Underground Cable

In Ameren Missouri's service territory, almost 8,000 miles of underground cable exist, with more than 30% having reached its expected life of 40 years. Our plan targets this end-of-life underground cable infrastructure. From 2019 through 2022, we upgraded 320 miles of underground cable and are forecasted to upgrade another 81 miles of underground cable in 2023. Our long-term goal is to upgrade 800 miles of underground cable.

The two major types of upgrades are direct buried primary laterals that supply subdivisions and lead feeder exit cables coming from substations. In the direct bury upgrade program, Ameren' Missouri's historic strategy has been to reactively replace sections of cables upon failure. Our current strategy is to utilize a proactive, planned approach and identify problematic primary laterals and/or entire subdivisions that require full replacement. This approach will improve efficiencies, help balance resources, and improve reliability for customers. Since primary cables are the mainstay of the subdivisions, they will become the focus versus the ties to individual houses.

Private LTE

Initially, our plan is to deploy private Long Term Evolution (PLTE) transmitters to approximately 50 sites in the greater St. Louis metropolitan area to provide uniform PLTE coverage. This expansion will provide a consistent, private cellular network to operate additional smart devices and will provide better real-time system operational information. This is part of a larger effort further described in Section 7.2.7.4, Multi-Layered Network Architecture. As a part of Ameren Missouri's SEP, we aim to complete the installation 15 PLTE towers through 2023.

7.2.4 Initiatives

7.2.4.1 System Inspection[17]

Ameren Missouri assesses the age and condition of distribution system equipment with regular inspection, testing and equipment replacement programs as described below.

[17] 20 CSR 4240-22.045(1)(A)

Circuit and Device Inspections

Ameren Missouri inspects distribution circuits (2,400 V to 69,000 V) at least every four years in urban areas and every six years in rural areas, in compliance with Missouri PSC Rule 20 CSR 4240-23.020, to protect public and worker safety and to proactively address problems that could diminish system reliability. The program includes follow-up actions required to address noted deficiencies. Inspections include all overhead and underground hardware, equipment, and attachments, including poles. Infrared inspections are performed on overhead facilities, underground-fed transformers, and switchgear to detect any abnormalities in equipment. Wooden poles are treated every 12 years as appropriate for purposes of life extension. Inspectors may also measure impedance of the static-protected grounding system. Radio-controlled capacitors, reclosers, and sectionalizers are inspected on a four- or six-year cycle in conjunction with circuit inspections. Ameren Missouri also replaces a number of transformers each year with higher efficiency units when corrosion, oil leaks, or other visually detectable issues occur.

Substation Asset Management

Ameren Missouri schedules substation maintenance to maximize reliability of equipment and selectively performs various diagnostic tests to obtain meaningful data to predict and prevent failures. Many tests, such as infrared scanning to detect abnormal equipment heating, can be performed with the equipment in-service. Corrective maintenance is scheduled largely on the basis of diagnostic data, with the intent of restoring equipment to full functionality. As discussed in Section 7.2.7, Advanced Distribution System Technologies, when it is no longer practical to make repairs, old equipment is replaced or upgraded with new equipment, and where practical, advanced technology that places an emphasis on system automation is installed, resulting in improved efficiency and reduction of losses.

7.2.4.2 System Planning[18]

Ameren Missouri expects and plans for today's electric grid to evolve into a more integrated and complex system, one more capable of operating in the face of extreme weather and has developed a broad modernization strategy to that end. A key aspect of our SEP vision and this strategy is to increase operating efficiency and flexibility which allow for increasing levels of distributed energy resources and customer interfaces, all working together in a coordinated, bi-directional fashion. While our approach is in its early stages, we are taking steps to build the necessary tools, capabilities, competencies, and organizational structures to proactively deliver this energy future.

A significant step in this process is the coordination and centralization of key planning functions to better enable a true integrated distribution planning approach. Although Ameren Missouri has had a consolidated System Planning function for the sub-

[18] 20 CSR 4240-22.045(1)(A)

transmission system for many years, it wasn't until 2019 that the company began consolidating key elements of distribution planning and created a Low Voltage Planning Group. Additionally, a position for DER planning was added in 2022. These centralized groups are providing subject matter expertise and streamlining efforts including load analysis, engineering methods/best practices, and worst performing circuits. We also include the analysis of the impact of larger solar installations on the distribution system, hosting capacity for DER and EV, electrification, and further innovation in the distribution system.

Annual Load Analysis and System Planning Process

Ameren Missouri records historical summer and winter peak load conditions (power, power factor, phase balance and voltage levels) at bulk and distribution substations. Distribution loads are temperature-corrected to represent 1-in-10-year maximum values using multipliers derived from statistical analyses of historic load data for several types of area load characteristics. Temperature adjustments for bulk substations are derived from historical temperature vs. loading profile curves from the distribution substations fed by the bulk substation. Engineers also enter adjustments for known or expected specific local load growth from factors including but not limited to planned residential subdivisions, apartments or condominium complexes, and commercial and industrial developments.

Engineers also calculate bulk-supply substation loads using a power flow computer model that simulates the electric power delivery system. Using temperature-corrected distribution substation loads and current equipment ratings as inputs, the software calculates bulk-supply substation loads. The substation loads are then compared to temperature-corrected values and used to evaluate what, if any, diversity factors apply at each bulk-supply substation.

After verifying the validity of the system model, engineers conduct seasonal planning studies of winter and summer peak conditions, evaluating worst case single-contingency failure scenarios for all bulk-supply substations, 34,500 V and 69,000 V circuits, distribution substations, and distribution circuits. These studies pinpoint system limitations and enable engineers to identify upgrades required to maintain adequate system capacity. The maintenance of adequate system voltage levels is included in the analyses.

Planning system upgrades to withstand single-contingency outage conditions ensures that load levels will remain within circuit capabilities for such events. Under normal conditions (the majority of the time), individual circuit elements operate at lower load levels with correspondingly lower losses.

In all the load analysis and system planning described above, the impacts of energy efficiency are included as a consideration based on the historical summer and winter peak load baselines. Historical realized energy efficiency benefits are a reliable indicator, from a system planning perspective, of what system impacts and conditions we can expect to exist from energy efficiency in the future.

Distribution System Engineering Analyses

The Transformer Load Management (TLM) system relates customers to the distribution transformers serving them, allowing Ameren Missouri to predict transformer peak demand and apparent power from the customers' total monthly energy usages. Ameren Missouri uses this information to analyze distribution circuits and to reduce distribution losses through the more efficient loading of transformers. Additionally, customer meters are automatically read during peak load periods to confirm the transformer peak demands calculated with the TLM system.

Synergi Electric software by Det Norske Veritas – Germanischer Lloyd and PSS/E software by Siemens PTI are used to analyze distribution circuits, ensuring reliable, safe, and efficient operation of the distribution system. Synergi or PSS/E is used for: load estimation, power flow analysis, voltage flicker, phase balancing, and capacitor placement. Both software systems allow engineers to analyze existing, alternate, or proposed configurations for over/under voltages/currents, line losses, appropriate conductor sizing, and optimal capacitor placement.

Supervisory Control and Data Acquisition (SCADA) is used to remotely monitor and control the electric distribution system. Engineers use SCADA data to ensure that system models properly reflect real distribution system conditions, thereby enabling better planning of future system development.

Capital Project Evaluation[19]

As part of SEP, Ameren Missouri routinely assesses the feasibility and cost effectiveness of potential system expansion and modernization projects. Both conventional and advanced technologies are regularly considered. Due to the age of our grid and recent trends in load growth, the majority of approved projects focus on system reliability improvement and modernization.

In 2022, Ameren Missouri developed project evaluation methodologies and frameworks to justify the six SEP categories of investments. Below is the breakdown of Ameren Missouri's frameworks and applicable evaluation criteria used in these justification methodologies:

[19] 20 CSR 4240-22.045(4)(C); 20 CSR 4240-22.045(4)(D); 20 CSR 4240-22.045(4)(D)1; 20 CSR 4240-22.045(4)(D)2; 20 CSR 4240-22.045(4)(E); 20 CSR 4240-22.045(4)(E)1

Figure 7.4 Project Evaluation Framework

Criteria	Grid Resiliency	Downtown Underground	Smart Grid	System Hardening	Underground Cable	Substation Condition Based
Age/Asset Vintage	✓	✓	✓	✓	✓	✓
Asset Condition	✓	✓		✓	✓	✓
Asset performance		✓		✓	✓	✓
Potential for Community Impact	✓	✓	✓	✓	✓	✓
Safety		✓			✓	✓
Capacity	✓					
Operating Flexibility	✓					
Circuit Topology/Grid Visibility			✓			
Final Evaluation	Two check marks results in eligibility for a Substation CBM capital project					

Electric Vehicles and Industry Trends

Our innovation is guided by the Ameren vision – leading the way to a sustainable energy future – which rests on four pillars: environmental stewardship, social impact, governance, and sustainable growth. We are driving environmental stewardship forward with efforts like the DC fast charging projects, coupled with research into large stationary batteries. This allows us to reduce the impact of DC fast chargers on our distribution circuits. We are also making a social impact through our St. Louis Vehicle Electrification Rides for Seniors (SiLVERS) program and Diversity, Equity and Inclusion Accelerator, which provides direct support to disadvantaged communities in our service territory.

Ameren Missouri is also monitoring electric vehicle growth as new loads join the system. We are currently engaging EPRI to investigate the impacts on our system for expected EV growth. The study also intends to examine and propose updated service transformer planning standards for new homes in the service territory.

7.2.5 System Efficiency[20]

7.2.5.1 Periodic System Loss Study

Ameren Missouri evaluates the efficiency of its overall electric delivery system on a periodic basis by performing a comprehensive loss study. Losses in each portion of the system are calculated under peak load conditions using the computer software noted previously. Loss data from these evaluations are used in ongoing system planning activities, load research activities, and as supporting information for rate reviews.

7.2.5.2 System Upgrade and Expansion Projects

By their nature, many types of energy delivery upgrade and expansion projects improve system efficiency by reducing load current, I^2R losses, or both. Examples of such projects include:

- Constructing new circuits or rebuilding existing circuits that make use of higher operating voltages, as in the conversion of power lines from 4 kV to 12 kV or the migration toward 138 kV-fed distribution substations in specific and limited circumstances
- Constructing new circuits or rebuilding existing circuits with larger conductors
- Reconnecting single phase loads on three phase circuits to achieve balanced system phase currents
- Constructing new pad-mounted transformers with distribution automation devices to eliminate aged, rural (less than 2.5 MVA) substations
- Upgrading existing substations or strategically placing new substations to serve areas with increasing load density, using 38 kV switchgear
- Reconfiguring distribution feeders as appropriate when connecting new customers

7.2.6 Distributed Generation

Ameren Missouri evaluates distributed generation (DG) and their impact on the distribution system. One example is the Ameren Missouri owned and operated South St. Louis Renewable Energy Center, a Neighborhood Solar project in St. Louis. This project includes the connection of 200 kW AC solar photovoltaic generation (also referred to as Habitat for Humanity) to the local 4 kV distribution system.

Potential projects are analyzed on a case-by-case basis. At this time, Ameren Missouri is evaluating the potential installation of additional photovoltaic generating capacity at a number of locations. There are a multitude of factors that influence the evaluation of potential DG installations such as noise and/or emissions ordinances, operational complexities associated with fuel availability, equipment maintenance, and the fact that

[20] 20 CSR 4240-22.045(1)(A)

traditional system expansion projects usually provide secondary benefits like improving reliability which can offset the costs of installing DG.

Ameren Missouri generally cannot dispatch customer-owned DG at this time, so this type of resource is not included when performing load analysis and system improvement evaluations. Chapter 8 explores distributed generation as a demand-side resource.

7.2.7 Advanced Distribution System Technologies[21]

Ameren Missouri has developed the SEP to transform our electric grid and create a distribution infrastructure that is more secure, modern, resilient, reliable, and efficient. As part of this plan, the company has a number of previously discussed strategies to foster and disseminate proven advanced distribution system technologies broadly across our system.

7.2.7.1 Conventional vs. Advanced Technology Equipment

While the basic function of power delivery systems is not changing (we still need generators, transformers, overhead and underground circuits, switches, circuit breakers, fuses, etc.), what is new is the ability to better sense system conditions, evaluate the health of system equipment, and employ either local or remote control schemes through advanced equipment via high-speed two-way digital communications technology. Some replacements are programmatic (on a set schedule), while others are implemented as equipment is replaced due to age or failure. Several types of conventional equipment and their advanced technology replacements are outlined below. This list is representative of present options, but certainly does not include every advanced technology item available today or in the future.

[21] 20 CSR 4240-22.045(1)(A); 20 CSR 4240-22.045(1)(D); 20 CSR 4240-22.070(1)(B); 20 CSR 4240-22.045(4)(B); 20 CSR 4240-22.045(4)(E)1

Conventional Equipment	Advanced Technology Equipment
Solid Blade Manual Switch	Remote Control Switch with SCADA communication and current/voltage monitors or Electronic Recloser
Oil Type Recloser	Electronic Recloser with SCADA communication and current/voltage monitors and fault location capability
Faulted Circuit Indicator	Faulted Circuit Indicator with SCADA communication
Capacitor Control (Time / Temp / 1-way comm.)	Local/Remote Capacitor Control with 2-way comm. and current, voltage, kVA and status monitors
Underground Manual Switch	Pad-mounted Switch with SCADA communication and current/voltage monitors and fault location capability
Network Protector	Advanced Network Protectors with SCADA communication and current/voltage/load and equipment condition monitoring capability
Electromechanical Relays	Microprocessor Based Relays with SCADA communication and current/voltage/load/fault impedance/equipment condition monitoring/etc. capability
Transformer Bushing Tests	Online Bushing Power Factor Monitoring
Transformer Oil Tests	Online Transformer Oil Monitoring
Fuse	Trip Saver Fuse – acts as a recloser after initial fault; if fault does not clear it then operates as a fuse and isolate the fault
Circuit Breaker Timing Tests	Online Breaker Timing and Contact Wear Monitoring

7.2.7.2 Automated Switching Applications

Ameren Missouri's design strategy for the sub-transmission (34.5 & 69 kV portion of our distribution system) system includes providing redundant service in a preferred-reserve fashion to distribution substations with load in excess of 10 MVA. Substations with loads below 10 MVA typically employ radial configurations with single supplies. In densely populated areas, redundant sub-transmission circuits are typically available at each substation, but redundant circuits are not always available at all substations in less populated areas. In such locations, redundant sub-transmission supplies are typically provided via automated switching devices in nearby circuits and a radial supply circuit is extended to the substation in question. Ameren Missouri focuses on minimizing the length and exposure associated with such radial supply circuits until further development achieves full redundancy at the substation.

Whether a line switch or part of a substation, Ameren Missouri employs modern, SCADA-controlled, automatic smart switching devices in order to limit the time and effort required to execute switching actions. Substation transfer schemes are designed for automatic operation, while line switches may be designed for automatic or remote-control operation, depending upon the circumstances involved. Conventional manual switches are only employed in less critical locations, where the device does not allow for automatic or remote operation. In recent years, several existing manual switches have been upgraded to remote control capability or replaced by new SCADA-controlled equipment.

As previously discussed in section 7.2.3.3 Smart Energy Plan Highlights, Ameren Missouri's strategy for automating 12 kV distribution circuits is to install SCADA-equipped smart switching devices (at least one bisecting the feeder backbone and at least one tying the downstream section to a different feeder) to limit the load dropped due to a single line contingency to roughly half the feeder's peak load. Although this is a general design objective, it can only be implemented in those cases where the existing circuit topology supports the restoration of unfaulted line sections to a different feeder. Where appropriate, Ameren Missouri is prioritizing projects based on the Worst Performing Circuit (WPC) list and Customers Experiencing Reliability above Targets (CERT) list. The first priority is the WPCs, with the second priority to add DA on CERT feeders. Within these groups, Ameren Missouri uses reliability history, number of total customers impacted, truck rolls, patrol times, and effect to existing high-impact locations to prioritize upgrades. Our long-term goal is to have one smart switch (DA device) per approximately 400 customers to provide more reliable service throughout our territory.

7.2.7.3 Smart Substation Technologies

For many years Ameren Missouri has been building substations that are considered "smart" by today's standards. As a means of ushering in the next generation of substation intelligence in the industry, Ameren Missouri has adopted Smart Substation Design Guidelines to incorporate combinations of the following features into the standard design of capital projects:

- Fault detection and location monitoring
- Switchgear circuit breaker timing and contact wear monitoring
- Circuit breaker trip coil failure monitoring
- Multi-function temperature sensing

These projects include the construction or re-build of entire substations as well as the installation or replacement of substation transformers. Additionally, going forward, mobile substation transformer and switchgear purchases will feature a combination of these types of sensors.

Industry data indicates that over the long term, the capture and trending of substation transformer diagnostic sensor data can reduce substation outage events due to unforeseen transformer failures and extend the average operating lives of these large assets. Ameren Missouri plans to continue installing sensor technology on substation transformers over time as an integral part of its capital substation projects, including those undertaken for reasons of load growth, reliability upgrade, or condition-based maintenance.

7.2.7.4 Multi-Layered Network Architecture

Currently, several isolated and overlapping networks are operating in support of AMR meters, radio-controlled line capacitors, substation SCADA and automated switching, none of which is sufficient for the long-term expansion and widespread use of intelligent end devices. We anticipate that more capacity will be required for ultimate end device populations in the tens of thousands. We also expect more speed could be required to support large file transfers from remote diagnostic sensors in substations.

In response, Ameren Missouri has developed and is deploying a multi-layered network architecture intended to support existing smart applications and enable future applications – a Wide Area Network (WAN) backbone for backhauling large amounts of field application data, Local Area Networks (LANs) for aggregating intelligent end device data (typically at substation locations), and Field Area Networks (FANs) for supporting communication with field end devices beyond and downstream from the substation.

Ameren Missouri is developing a WAN that leverages various industry-proven transport systems such as fiber, digital microwave, and common carrier leased services, and likely features a mix of private and non-shared public infrastructure of either a wired or wireless nature. Over time, WAN infrastructure additions will focus on the connection of substations and other key network entry points, the delivery of information to the control center(s), and the application of necessary security layers throughout the network architecture.

Ameren Missouri is deploying LAN technology over time at substations as their specific locations are identified as effective aggregation points for planned feeder deployments of intelligent end devices like automated line switches, capacitors, and regulators. Since these devices are being deployed on the distribution system by circuit or substation, the already owned or leased substation site becomes the preferred choice for this aggregation. Targeting these deployments at "smart" substation sites also allows for communications consolidation and maximizing the impact of LAN infrastructure investment.

In some areas of the Ameren Missouri service territory, the FAN will feature a radio frequency (RF) mesh network that is both self-organizing and self-optimizing, dynamically routing data communications amongst a diverse set of paths that wirelessly interconnect multiple end devices. In other areas, the FAN will feature a more traditional point-to-multipoint RF network or a cellular-based alternative, depending on the application and its inherent reliability and latency requirements. Ameren Missouri plans to adopt the use of intelligent end devices with open architectures as endorsed by National Institute of

Science and Technology standards, regardless of the smart applications involved and the other technology choices made.

7.2.7.5 Advanced Distribution Management System (ADMS)

In 2014, Ameren Missouri implemented an Advanced Distribution Management System as a means of providing an integrated suite of software applications with which to manage the electric distribution system. ADMS is a highly integrated system of applications that provides distribution system operators a common user interface with which to monitor and control the distribution system on a daily basis. It not only replaced existing applications like outage management and switching orders, and enhanced features of Supervisory Control and Data Acquisition, but it also incorporates advanced applications such as dynamic circuit modeling, switching and restoration simulations, and a distribution system dashboard.

ADMS is foundational to future Ameren Missouri Smart Grid planning since it enables advanced applications that rely on the integration of functions formerly separate and distinct. In addition, ADMS allows for growth and scalability that is not feasible on legacy platforms and provides the flexibility to add and integrate future applications.

7.2.7.6 Supervisory Control and Data Acquisition

Ameren Missouri’s strategy for substation supervisory control and data acquisition is to programmatically introduce remote load monitoring at existing substations lacking such capability for purposes of improving daily operations and facilitating the long-term planning of substation assets. Remote outage detection and supervisory control features will be introduced at existing substations lacking such capability on a strategic basis in association with other capital projects.

Ameren Missouri’s 30+ years of experience in this area has shown that continuously updated load information on substation components can quickly identify unforeseen overloads, release capacity by allowing for daily operation closer to margin, and greatly enhance outage restoration activities. Remote metering also enables automatic transfer capability in smart switching applications and enables feeder level optimization via phase balancing and the operation of line capacitors. Supervisory control of switching devices further enhances operations by allowing for real-time outage notification and immediate intervention by dispatchers in restoration scenarios.

There are approximately 160 Ameren Missouri distribution substations without outage detection and supervisory control capability. Ameren Missouri’s plan is to convert these substations opportunistically over time as other capital projects are undertaken to replace their switching devices. Ameren Missouri is also funding the programmatic addition of metering and SCADA capabilities at some of these substations, which are not scheduled for other upgrade projects in the foreseeable future.

7.2.7.7 Capacitor Control

Smart line capacitor operation has helped Ameren Missouri maintain a consistent 98% distribution system power factor over the last twenty years. However, the capacitor control technology available today allows for feeder level efficiencies and degrees of optimization that were never before possible. The use of "smart" capacitor controls not only helps achieve these levels of efficiency and optimization, but also effectively controls customer end use voltages, and reliably supports the reactive requirements of the transmission system. Ameren Missouri leverages the ADMS system capabilities to integrate substation load monitoring with "smart" line capacitor operation in order to achieve these goals.

Ameren Missouri's first step as part of this automation strategy is the deployment of the next generation of "smart capacitor" technology on the distribution and sub-transmission systems. Ameren Missouri will leverage the need to replace the existing 25-year old line capacitor control system in operation today in the St. Louis metro area for this deployment. To this end, 2,300 capacitor controls will be upgraded over the next 5-10 years.

Additionally, Ameren Missouri will be installing "smart" capacitors in place of the remaining 425 non-fixed units in the service territory. This deployment will take place over time by circuit, substation, or group of adjacent substations, coincident with the deployment of automated switches in order to maximize the benefits associated with the communications investment.

7.2.7.8 Voltage Optimization

Ameren Missouri has engaged a third party, EPRI (Electric Power Research Institute), to evaluate the possible costs and benefits for Ameren Missouri to employ Voltage Optimization through Conservation Voltage Reduction (CVR). CVR is the process of operating near the lower voltage threshold at the customer delivery point and has previously been utilized by utilities as a means to achieve energy savings if their system attributes are favorable. To estimate the possible cost and savings potential of CVR for Ameren Missouri, this project seeks to evaluate the load make up of AMO customers, possible voltage control equipment, and voltage control methods that could be utilized. We anticipate this study to be completed in the late Summer of 2023.

7.3 Compliance References

Chapter 7 - Appendix A

Transmission and Distribution Supplemental Information

Table 7A.1 MTEP Transmission Projects in Missouri[1]

Project Approved	Project Title	Project Description	Allocation Type per FF	Estimated Cost	Expected ISD (Max)
A in MTEP21	New Belleau 138 kV Capacitor Bank	Install 120 Mvar capacitor bank at Belleau 138 kV	BRP	$3,500,000.00	06/02/2025
A in MTEP20	Reconductor Bland-Tegeler 138 kV line	Reconductor line to 1200 A summer emergency capability	BRP	$30,800,000.00	06/01/2023
A in MTEP20	Replace Mason 345/138 kV Transformer	Replace 345/138 kV, 560 MVA Transformer #2 with a 700 MVA unit	BRP	$10,800,000.00	01/01/2026
A in MTEP20	Upgrade Labadie 345 kV substation	Upgrade switches and CTs to 3000A. Labadie 345 kV bus-tie 2-3 Upgrade	BRP	$1,600,000.00	12/01/2024
A in MTEP20	New Wright City 345 kV substation	Joint project between Ameren Missouri and AECI. Tap the Ameren Missouri Labadie-Montgomery 345kV line via a new 3-breaker, 345kV ring bus near the intersection of the line and the AECI (Central Electric Power Coop) 161kV line west of Charrette. Rebuild the existing 161kV line between the tap point and the AECI Wright City Substation as double-circuit 345/161kV. Install new 345/161kV step down transformer at Wright City.	BRP	$52,700,000.00	06/01/2026
A in MTEP21	New Burns 345 kV Substation (J1145 Solar)	Construct 3 position ring bus on Montgomery-McCredie 345 kV line for 250 MW Show Me State Solar project J1145	GIP	$12,800,000.00	06/01/2024
A in MTEP20	New Blue Bird Solar (J817) interconnection	Add terminal facilities at Warrenton 161 kV substation to interconnect J817,	GIP	$3,700,000.00	06/01/2024

[1] 20 CSR 4240-22.045(3)(A)1; 20 CSR 4240-22.045(3)(A)6

A in MTEP21	New Sikeston 161 kV Substation	Construct new Comstock (Sikeston) 161kV breaker-and-a-half substation to interconnect Ameren's Miner-Sikeston line and Sikeston Board of Municipal Utilities' New-Madrid-Sikeston 161kV line. The City of New Madrid will install a 161/69kV xfmr to serve new industrial customer.	Other	$8,500,000.00	06/01/2024
A in MTEP20	Upgrade Tyson 138 kV substation	Replace overstressed 138 kV breakers	Other	$9,900,000.00	12/01/2023
A in MTEP20	Reconfigure Viburnum 161/34 kV Substation	Install 2 161 kV line breakers and 1 161 kV circuit switcher on the transformer to split the CLK-CMCO-2 line and create 2 circuits into Viburnum Substation.	Other	$4,800,000.00	12/01/2024
A in MTEP20	Replace Tyson 345/138 kV Transformer	Replace XFMR 1 with a hardened unit and replace the 138kV XFMR 1 breaker and Replace XFMR 3 breaker.	Other	$11,700,000.00	12/01/2023
A in MTEP20	Relocate Page 138 kV substation to new Bugle 138 kV Substation	Relocate the existing 138 kV Page substation to the new Bugle site. 138 kV to be built as breaker and a half arrangement.	Other	$51,500,000.00	06/01/2024
A in MTEP20	Rebuild Page-Sioux 138 kV line (4)	Rebuild existing Missouri River crossing (Str. 112-117)	Other	$24,800,000.00	12/02/2024
A in MTEP20	Upgrade Kelso 345/161 kV substations	Install new 3000 A circuit breaker and motor-operated disconnect switch on 345 kV position V3. Replace the existing Kelso substation 336 MVA auto transformer #1 with a 560 MVA transformer. Replace the existing Kelso substation 161 kV bus tie 1-2 position H7 circuit breaker and bus disconnect switches. Replace the existing Kelso substation 161 kV position H6 circuit breaker and disconnect switch, upgrade the bus conductor of position H6 to achieve a minimum current carrying capability of 3000 A. Replace the existing Kelso substation H3 and H4 161 kV circuit breakers and	Other	$18,100,000.00	12/01/2024

Schedule MM-S23

		disconnect switches in the CAPE-KEL-2 and KEL-MINR-2 terminals. Upgrade Kelso substation positions H3 and H4 bus conductors to achieve a minimum current carry capability of 2000 A. Replace the existing Kelso substation 161 kV disconnect switch on position H10. Replace the existing Kelso substation H11 and H12 161 kV disconnect switches (line and bus) in the CAPE-KEL-3) and KEL-MORLEY-3 terminals.			
A in MTEP20	Rebuild Pike 161 kV Substation	Rebuild the Pike 161 kV substation to a Ring bus configuration.	Other	$18,000,000.00	12/01/2023
A in MTEP20	Upgrade McClay 138 kV Substation	Add breakers to each of the 138 kV lines and upgrade relays.	Other	$3,000,000.00	06/01/2023
A in MTEP20	New Barrett Station 138/12 kV Transformer No. 2	Install 3 breakers in a main-tie-main configuration with an open bus tie to facilitate the installation of a 2nd transformer. Install circuit switchers on the existing and new transformers.	Other	$20,500,000.00	12/31/2022
A in MTEP20	New Dougherty Ferry 138/12 kV substation	Tap the Mason-Meramec-1 & 2 lines to provided a main-tie-main configuration for the installation of a new 138-12 kV substation.	Other	$19,400,000.00	12/01/2025
A in MTEP20	Rebuild Lutesville-St. Francois 345 kV line	Rebuild 63 miles of 345kV wood H-frame circuit.	Other	$62,800,000.00	12/01/2024
A in MTEP20	Upgrade Spencer Creek 345 kV substation	Replace switches on 345kv pos V3, V5, V6, V7 and reactor position.	Other	$600,000.00	06/01/2022
A in MTEP20	Replace Structures Bland-Franks 345 kV line	Replace structures and shield wire on approximately 44 miles 345kV line.	Other	$52,000,000.00	06/01/2026
A in MTEP20	New Highway M 138/12 kV substation	Install 2 unit 138-12.47 kV substation on a site adjacent to the Dardenne Substation.	Other	$20,000,000.00	12/01/2024
A in MTEP20	New Fountain Lakes 138/12 kV transformer No. 2	Add 2nd 138-12 kV unit at Fountain Lakes Substation.	Other	$9,300,000.00	12/01/2024
A in MTEP20	New Montgomery 345 kV shunt reactor	Install 50 Mvar shunt reactor at Montgomery 345 kV substation.	Other	$3,800,000.00	12/01/2024
A in MTEP20	New Fredericktown 138 kV substation	Install 138 kV ring bus at Fredericktown Substation	Other	$11,100,000.00	12/01/2023

A in MTEP20	New Wittenberg-Trail of Tears 138 kV line	Wabash Valley- Install new Wittenberg ring bus switching station on the Grand Tower-Perryville line. Reconfigure Trail of Tears substation to BAAH. Install new 161 kV line from Trail of Tears to Charmin Bulk Substation. Install 2 breakers at Charmin Bulk Substation. Ameren - Install 12 miles of new 138 kV line from Wittenberg Substation to Trail of Tears Substation. Install new 161-138 kV transformer at Trail of Tears Substation.	Other	$52,200,000.00	06/01/2024

Table 7A.2 Transmission Projects under Consideration[2]

Project Name	Project Description	Expected ISD (Max)
New Vanhorn 345 kV Substation for Wolf Creek Solar (J1352)	Construct the Interconnection Facilities at the J1352 Interconnection Switching Station, line cut-in and relay upgrades. Vanhorn sub on Montgomery-Spencer Creek 345 kV line.	06/01/2025
New Tunnel (Freeburg, MO) 138/25kV Substation	Build a new 138-25 kV substation near the town of Freeburg, MO	06/01/2028
Replace Pole and Insulator Program - MTEP23	Pole and Insulator Replacements requested by Maintenance.	12/01/2025
Replace Breakers and Relays Program - MTEP23	Breaker and Relay Upgrades Requested by Maintenance (Missouri and Illinois)	12/01/2025
Upgrade Effingham NW-Neoga 138 kV line	Upgrade terminal equipment at Hannibal West, replace two structures and shunts in Neoga – Effingham NW 138 kV line. These are Non-SSR related needs.	12/01/2024
Replace Mason 345/138 kV Transformer No. 1	Replace Mason 345/138 kV Transformer #1 with a 700 MVA Unit	12/01/2025
New Huck Finn Solar 345 kV interconnection (J956)	Connect a 200MW solar farm via 345 kV leadline from Interconnection Customer collector substation to existing Spencer Creek switching station.	06/01/2024
Upgrade Warson 161 kV substation	Line BKRs on 4 line terminals, High Side interrupting devices on XFMRs 1,2,3,4, Add bus tie 2-3 BKR	06/02/2025
Reconfigure Moreau 161 kV substation	Construct a four position (six ultimate) 161 kV ring bus at Moreau	06/01/2025
New McBaine 161 kV substation	New switching station at McBaine tap off LYMT-OVRT-3	06/01/2025
Rebuild Sioux-Meppen North-Hull 138 kV line	Rebuild the Sioux-Meppen North-4 from Str. 180-Meppen North and the entire Meppen North-Hull-1494 138 kV line to upgrade aging infrastructure and improve system reliability.	12/15/2024
Upgrade Rush Island 345 kV Substation	Upgrade the Rush Island 345 kV bus to 3000A capability	04/01/2024
Upgrade Guthrie 161 kV substation	Add a 161 kV line breaker to the 161 kV GUTH-LYMT-3 line at Guthrie.	12/01/2024

[2] 20 CSR 4240-22.045(6)

Upgrade Hunter 161 kV substation	Add Line breakers on H2 and H10; High Side Interrupting Devices on XFMR 1, 2, 3	12/01/2025
Upgrade Sioux 138 kV Substation	Upgrade 15H posn to higher ampacity to increase available capacity of the 700MVA Auto XFMR	12/01/2026
Upgrade St Francois 345 kV substation	Install a new circuit breaker at St. Francois Sub position V43 to complete the ring bus.	12/01/2024
Rebuild Clark 138/161 kV Substation to 138 kV BAAH	Rebuild Clark 138/161 kV Substation to have a 138 kV BAAH bus with 8 positions (4 existing lines, 2 XFMRs, bring in RIV-ALFM-6636) and a 161 kV ring bus with 6 positions (2 existing lines, 2 XFMRs, and new line position to Viburnum). Rebuild the existing Clark-Viburnum 161 kV line to be double circuit 161 kV lines. Add a 161 kV terminal at Viburnum Substation. Route the RIV-ALFM-6636 138 kV line into the new Clark 138 kV BAAH bus. Install 161kV PCB (or CS) on XFMR 3. Install 138kV PCB on XFMR 3. Replace existing differential relaying with new 161kV bus diff, XFMR diff, and 138kV bus diff.	12/01/2027
Reconfigure Mason-Carrollton-Sioux 138 kV lines	Split the ~2 mile Mason-Carrollton-8/Carrollton-Sioux-8 138 kV lines into two separate circuits to avoid the loss of a single structure causing a long-term outage on both Carrollton supplies.	06/01/2025
Upgrade Oran 161 kV substation	Add 161 kV ring bus to split the Kelso- Morley-3 line into two lines	06/01/2026
Upgrade Selma 161 kV substation	Add line breakers to Selma-Rivermines-2 & DPFE-Selma-1 Add High Side Interrupting devices to XFMR 1 & 2	12/01/2024
Upgrade Dardenne 161 kV substation	Add line breakers to Dardenne	12/01/2024
Convert Viaduct 115 kV facilities to 161 kV	Convert 115 kV facilities at Viaduct to 161 kV. Eliminate Viaduct 161 to 115kV transformer T1 by bypassing it, and by changing the taps on Viaduct XFMR 1 from 115 to 161kV. Replace 115kV OCB #5210 with a 161kV puffer breaker.	12/01/2024
Upgrade Pilot Knob 161 kV substation	Add circuit switcher for XFMR 1 and line breaker for 161 kV FLET –PKNB -2	12/01/2025
Rebuild Troy-Pike 161 kV line	Add Dual OPGW to the TROY-PIKE-1 Line from Pike to the Auburn tap (Structure 309 or so). Adding OPGW to the TROY-PIKE-1 line will require the line to be rebuilt. Since the line is being rebuilt, dual OPGW is to be added. At the Auburn tap the OPGW will be terminated to allow a connection to the AECI Fiber on their portion of the TROY-PIKE-1 line and brought the rest of the way to the new Harley Substation.	06/01/2024

New Copley 138-12 kV Substation	Build a new four position 138 kV Ring bus needed to connect two 13/12 kV transformers	12/01/2024
Rebuild Stoddard-Essex 161 kV line	Rebuild the 5.4 mile Stoddard-Essex-3 161 kV Transmission Line with T2 conductor rated at 2,000 amps Summer Emergency Conditions and 2 EA 72-Fiber OPGW shield wires.	06/01/2025
New Bugle 138 kV Capacitor (120 Mvar)	120 Mvar Capacitor at Bugle	12/01/2024
New Firebrick Wind Farm (J1026)	J1026 is seeking interconnection service for 380 MW for Wind facility. The Connection will be made at the 345 kV Spencer Creek Substation	06/01/2024
New Zachary generation interconnection FCAs (J1025-J1182)	Install a 2nd Zachary 345/161 kV transformer, construct a 2nd Zachary - Adair 161 kV transmission line, and re-route existing Appanoose-Adair 161 kV Transmission line.	12/01/2025
New Northeast Missouri Wind interconnection (J1025)	Construct the new 345 kV Fabius substation in Knox County, Missouri to provide a Point of Interconnection for the Generating Facility with a terminal that will consist of all necessary terminal equipment to connect the J1025 leadline to 345kV Fabius substation bus. J1025 is a 300 MW Wind project interconnecting to the Zachary-Maywood 345 kV line	06/01/2024
New Morris Solar interconnection (J1182)	One 345 kV terminal in the Zachary substation. The terminal will consist of all necessary terminal equipment to connect the J1182 leadline to the Zachary substation bus. J1182 is a 250 MW Solar project interconnecting to the Zachary substation 345 kV bus	11/01/2024
Reconfigure Warrenton 161 kV substation	Install a 161 kV Ring bus at Warrenton Substation	06/01/2024
New Overton 345/161 kV transformer No. 2	Add a second 345/161 kV Transformer at Overton.	12/30/2024
New Dillon 138 kV Capacitor Bank (14 Mvar)	Add a 14 Mvar capacitor bank at Dillon with a separate breaker. The existing 28 Mvar bank will be reduced to 14 Mvar.	06/01/2023
Upgrade Callaway 345 kV Substation	Add breakers on the high side of safeguard transformer A and B at Callaway 345 kV substation	12/01/2026
New Adna 345 kV Ring Bus for J1107 Lutesville Solar	The Adna switching station will be a ring bus arrangement with three-line terminal positions and provisions for one additional future terminal position. The existing Kelso-Lutesville 345 kV transmission line will be cut.	11/01/2024

Add J994 Guthrie Solar at Guthrie 161 kV	Add 161 kV terminal in the Guthrie substation for J994 project.	06/01/2025
Add J987 Warren Solar at Montgomery 161 kV	Add 161 kV terminal in the Montgomery substation for the J987	06/01/2025
New Bullion 161 kV Ring Bus for J1087 Kelso Solar	Construct a new 161 kV switching station in Scott County, Missouri to provide a Point of Interconnection for the Generating Facility. The new 161 kV Bullion switching station will have a four-terminal ring-bus design with three terminal positions installed. Split the existing Kelso – Miner 161 kV transmission line.	12/01/2024
New Harley 161 kV Ring Bus for J1268 Winfield Solar	Build a 161 kV three position ring bus along the Troy-Pike 161 kV transmission line in Lincoln County, Missouri. This is for Winfield Solar J1268.	12/01/2023
New Vanduser 161 kV Ring Bus for J1034 Ringer Solar	Construct a new 161 kV switching station in Stoddard County, Missouri to provide a Point of Interconnection for the Generating Facility. The new Vanduser 161 kV J1034 Interconnection Switching Station will have a four-terminal ring-bus design with three terminal positions installed. Split the existing Morley – Stoddard 161 kV transmission line	06/01/2025
New Rootbeer 345 kV Ring Bus for J976 Split Rail Solar	Construct a new 345 kV switching station in Warren County, Missouri to provide a Point of Interconnection for the Generating Facility. The new Rootbeer 345 kV J976 Interconnection Switching Station will have a four-terminal ring-bus design with three terminal positions installed. Split the existing Belleau – Montgomery 345 kV transmission line.	12/01/2025
New Wildwood 345/138 kV Transformer No 2	Upgrade 560 MVA TX to a 700 MVA 345/138 kV Transformer	06/01/2024
New Overton 161 kV Capacitor Bank	New 67 MVAR Capacitor at Overton 161 kV	04/01/2024
New Rush Island Area Statcoms	Add 250 MVAR Statcom at Bugle, Arnold, Mason and Highway N substations.	06/01/2025

Table 7A.3 Transmission and Distribution Avoided Costs[3]

Avoided Cost	Transmission $/kW-yr	Distribution $/kW-yr
2024	$1.5	$21
2025	$1.5	$22
2026	$1.6	$23
2027	$1.6	$23
2028	$1.6	$23
2029	$1.7	$24
2030	$1.7	$24
2031	$1.7	$25
2032	$1.8	$25
2033	$1.8	$26
2034	$1.8	$26
2035	$1.9	$27
2036	$1.9	$28
2037	$1.9	$28
2038	$2.0	$29
2039	$2.0	$29
2040	$2.1	$30
2041	$2.1	$30
2042	$2.1	$31
2043	$2.2	$32

[3] 20 CSR 4240-22.045(2); 20 CSR 4240-22.045(3)(A)3; 20 CSR 4240-22.050(5)(A)1

Compliance References

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prepared for

AMEREN MISSOURI

Ameren MISSOURI

2023 DSM MARKET POTENTIAL STUDY

FINAL REPORT

April
2023

prepared by
GDS ASSOCIATES INC
BRIGHTLINE GROUP

Schedule MM-24

Schedule MM-24

Schedule MM-24

1 EXECUTIVE SUMMARY

1.1 BACKGROUND & STUDY SCOPE

As part of their larger 2023 Integrated Resource Plan (IRP), Ameren Missouri commissioned GDS Associates ("GDS") and Brightline Group, collectively "the GDS Team", to assess energy savings potential to help inform future planning efforts. This project included several areas of analysis, which are collectively referred to as the 2023 DSM Market Potential Study, or 2023 study.

The GDS Team developed four distinct areas of analysis:

- Residential and business sector energy efficiency potential;
- Demand response peak load reduction potential;
- Distributed Energy Resource (DER) potential.
- Sensitivity and Scenario analyses

This report describes the methodology and results of these four areas of analysis. The 2023 study also included additional tasks including historical performance variance analysis, and potential benchmarking. The former aided with the development of the various potential estimates, and the latter helps frame the results of this 2023 study with studies recently completed in other electric utility service territories.

Each area of analysis sought to identify and assess a wide-range of demand-side resources across all major customer classes, market segments, and end-uses.[1] Although each of area of analysis is largely autonomous, for ease of reporting the four areas of analyses, as well as a review of the primary market research, these studies were ultimately combined into the single report presented here.

1.2 TYPES OF POTENTIAL ANALYZED

This potential study provides a roadmap for both policy makers and Ameren Missouri as they develop strategies and programs for energy efficiency (EE), demand response (DR), and distributed energy resources (DERs) in the Ameren Missouri service area. In addition to technical and economic potential estimates, the development of achievable and program potential estimates for a range of feasible measures is useful for program planning and modification purposes. Unlike achievable and program potential estimates, technical and economic potential estimates do not include customer acceptance considerations for measures, which are often among the most important factors when estimating the likely customer response to new programs. For this study, the GDS Team produced the following estimates of demand side management potential:

- Technical potential
- Economic potential
- Achievable potential
    - Maximum achievable potential
    - Realistically achievable potential
- Program potential
    - Maximum achievable potential
    - Realistically achievable potential

For each level of potential, this detailed report presents the energy savings, peak demand savings, benefits, and costs for the Ameren Missouri service area for the period of 2024-2043, a 20-year time frame.[2]

[1] 20 CSR 4240-20.050 (1)(A)1 through 3; 20 CSR 4240-20.050 (3)(B)

[2] 20 CSR 4240-20.050 (3)(G)

Schedule MM-24

1.3 APPROACH SUMMARY

The purpose of this market potential study is to provide a foundation for the continuation of utility-administered energy efficiency and demand response programs in the Ameren Missouri service area, to determine the remaining opportunities for cost-effective energy savings, demand savings, and distributed energy resources for the Ameren Missouri service area. This study has examined a full array of technologies, programs, and energy efficient building practices that are technically achievable.

The GDS Team used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the business sector (commercial and industrial), the GDS team utilized a bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of electric energy load. Bottom-up approaches were also used in the demand response and DER analyses for all sectors. Chapters 3 through 5 include a wide-ranging discussion of numerous methodological considerations utilized in the respective energy efficiency, demand response, and distributed energy resource analyses.

1.4 STUDY LIMITATIONS AND CAVEATS

As with any assessment of potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency measure lives, savings, and costs (total measure costs, incremental costs, and incentive costs)
- Projected penetration rates for energy efficiency measures
- Projections of energy avoided costs
- Future known changes to codes and standards
- End-use saturations and fuel shares

While the GDS Team has sought to use the best and most current available data (including the use of new primary market research in key market subsegments of interest based on stakeholder feedback) there are often reasonable alternative assumptions which would yield slightly different results. For instance, the analysis assumes that many existing measures, regardless of their current efficiency levels, can be eligible for future installation and savings opportunities. Other studies may select a narrower viewpoint, limiting the amount of potential from equipment that is already considered to be energy efficient. Additionally, the models used in this analysis must make several assumptions regarding program delivery and the timing of equipment replacement that may ultimately occur more rapidly (or more slowly) than currently forecasted.

Furthermore, while the lists of energy efficiency measures examined in this study analysis represent technologies available on the market today and characterized in the Ameren Missouri submittal tool[3], as well as a limited amount of emerging technologies not characterized or currently offered by Ameren, these measure lists may not be exhaustive. The GDS Team acknowledges that new efficient technologies may become available over the course of the 20-year study timeframe that could produce efficiency gains and costs at different levels than those currently assumed.

To address some of these limitations, sensitivities to address uncertainties surrounding customer participation and cost-effectiveness are also included in the energy efficiency, demand response, and DER analyses. The study also attempts to benchmark the potential results against other studies, both regionally and nationally. This holistic approach creates a robust data set from which to draw meaningful conclusions.

[3] MEEIA 4 2024-2030 Ameren Missouri Submittal Tool Measures Index 3.2

The 2023 study focuses on energy efficiency measures where electric savings are the primary benefit. However, select measures may provide additional secondary benefits (i.e. opportunities to improve the building shell in homes/businesses with fossil fuel heating and electric cooling, or low-flow water devices) that could be quantified by other utilities.[4] Where applicable, this combination of primary and secondary benefits may afford Ameren Missouri opportunities for joint utility coordination. Although notable challenges to joint delivery exist, including concerns over cross-fuel competition, added complexity to the regulatory process, and program imbalances, co-delivery of efficiency programs may be able to provide additional savings opportunities and/or reduced costs for specific measures and/or programs.[5]

Last, where possible, the GDS Team and Ameren Missouri collaborated to ensure consistency with assumptions and methodological considerations that are expected to be employed during the program planning process. However, final program designs and implementation strategies may need additional flexibility to target specific or underserved markets, address equity concerns, or react to changing customer preferences.

1.5 POTENTIAL SAVINGS OVERVIEW

The following several sub-sections provide an overview of the energy efficiency potential for residential and business customers, peak demand reduction potential from demand response programs, and distributed energy resource potential. Chapters 3 through 5 of this report provide additional summary data and methodological considerations and descriptions.

1.5.1 Energy Efficiency Potential for Residential Market Rate Customers

Figure 1-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 20-year timeframes. The respective 20-yr technical and economic potential is 37% and 33% of residential sector sales. The MAP reaches 3.1% in three years and grows to 10.1% over ten years, while the RAP reaches 2.4% in three years and grows to 8.2% over ten years. The MAP and RAP reach 17% and 14% of residential sector sales, respectively, over the 20-yr timeframe of the study. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

[4] 20 CSR 4240-20.050 (2)(F)

[5] Successful Practices in Combined Gas and Electric Utility Energy Efficiency Programs. ACEEE. Report U1406. August 2014.

Schedule MM-24

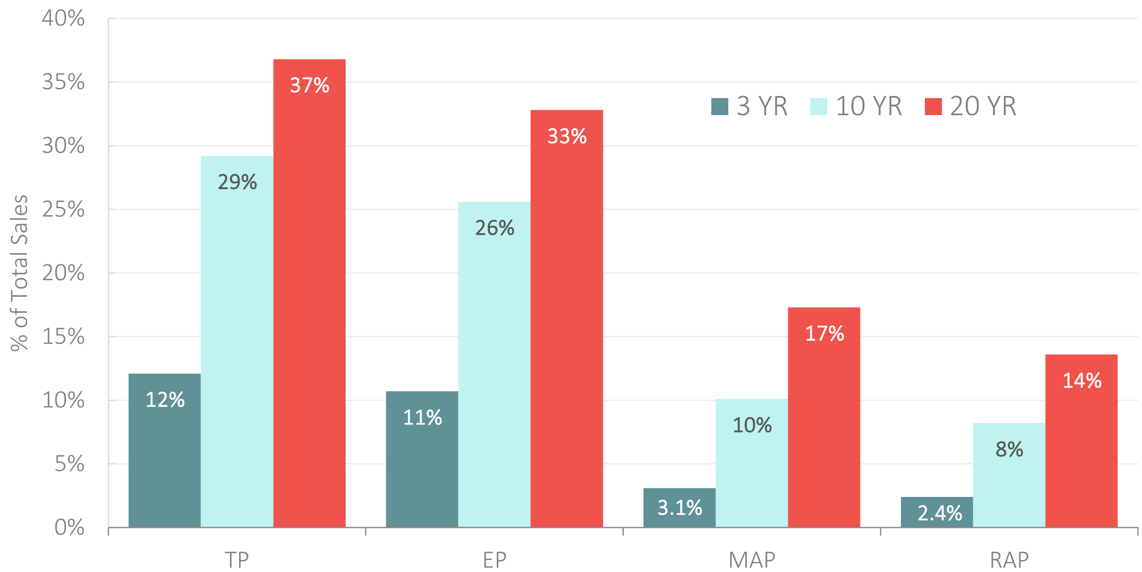


FIGURE 1-1: OVERVIEW OF RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

Table 1-1 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The MW demand savings for each level of potential are also provided. In 2024, the RAP is 0.8% of sector sales with more than 105,000 MWh in estimated energy savings and 47 MW in demand savings. By 2033, the estimated cumulative annual savings in the RAP scenario reaches 8.2% of sector sales at 1.2 million MWh and 418 MW in demand savings.

TABLE 1-1: RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2024	2025	2026	2033	2043
MWh					
Technical	621,001	1,178,484	1,680,446	4,363,340	6,134,445
Economic	552,293	1,048,092	1,491,718	3,835,712	5,474,181
MAP	135,879	277,386	425,110	1,508,303	2,878,344
RAP	105,159	216,057	333,390	1,223,770	2,262,238
Forecasted Sales	13,508,700	13,523,783	13,910,491	14,966,747	16,671,167
Technical	4.6%	8.7%	12.1%	29.2%	36.8%
Economic	4.1%	7.8%	10.7%	25.6%	32.8%
MAP	1.0%	2.1%	3.1%	10.1%	17.3%
RAP	0.8%	1.6%	2.4%	8.2%	13.6%
MW					
Technical	216	415	580	1,398	1,863
Economic	192	369	516	1,186	1,536
MAP	59	119	181	524	799
RAP	47	95	144	418	601

1.5.2 Energy Efficiency Potential for Business Customers

Figure 1-2 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 20-year timeframes. The respective 20-yr technical and economic potential is 35% and 32% of residential sector sales. The MAP reaches 6.4% in three years and grows to 17.1% over ten years, while the RAP reaches 4.7% in three years and grows to 12.6% over ten years. The MAP and RAP reach 22% and 16% of residential sector sales, respectively, over the 20-yr timeframe of the study. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

Schedule MM-24

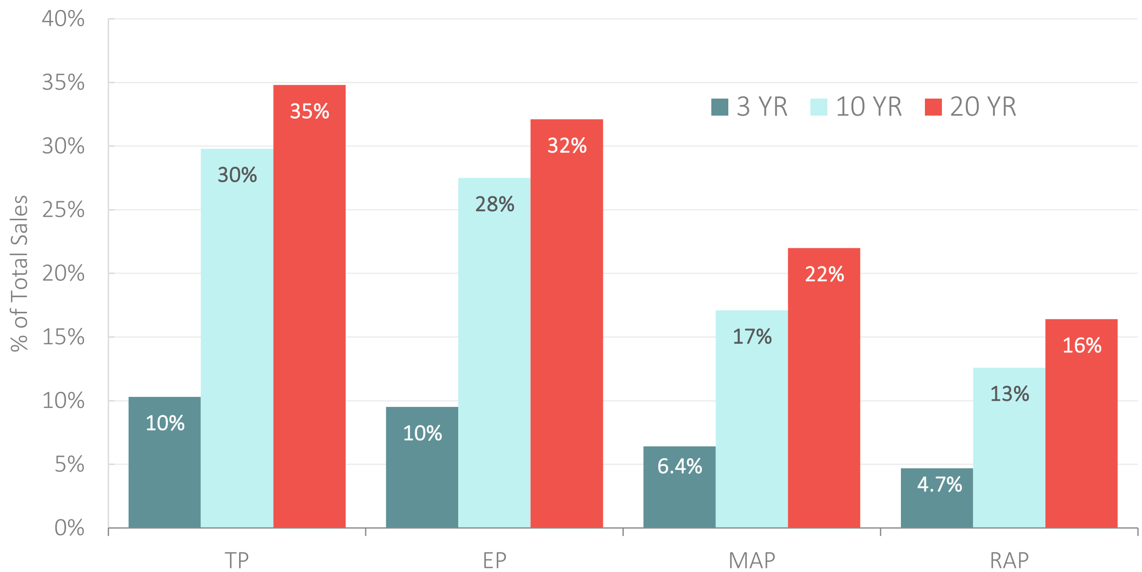


FIGURE 1-2: OVERVIEW OF BUSINESS ENERGY EFFICIENCY POTENTIAL

Table 1-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The MW demand savings for each level of potential are also provided. In 2024, the RAP is 1.6% of sector sales with more than 233,000 MWh in estimated energy savings and 63 MW in demand savings. By 2033, the estimated cumulative annual savings in the RAP scenario reaches 12.6% of sector sales at 1.9 million MWh and 557 MW in demand savings.

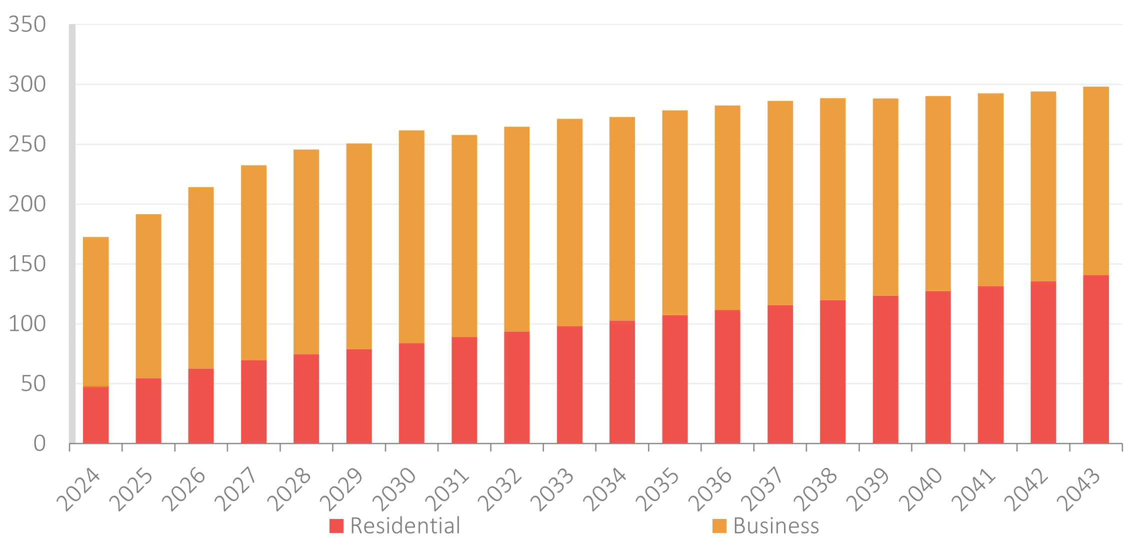
TABLE 1-2: BUSINESS CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2024	2025	2026	2033	2043
MWh					
Technical	468,422	963,866	1,483,470	4,458,691	5,462,287
Economic	436,911	897,084	1,380,145	4,116,578	5,036,977
MAP	316,388	623,887	921,943	2,554,287	3,452,685
RAP	233,465	458,816	678,451	1,885,518	2,573,513
Forecasted Sales	14,451,697	14,465,588	14,529,355	15,026,417	15,778,731
Technical	3.3%	6.7%	10.3%	29.8%	34.8%
Economic	3.0%	6.2%	9.5%	27.5%	32.1%
MAP	2.2%	4.3%	6.4%	17.1%	22.0%
RAP	1.6%	3.2%	4.7%	12.6%	16.4%
MW					
Technical	135	281	436	1,375	1,716
Economic	127	265	410	1,292	1,618
MAP	96	191	285	849	1,155
RAP	63	126	188	557	766

1.5.3 Demand Response Potential for All Customers

Figure 1-3 shows the annual demand response RAP potential by sector. These demand reduction values are present at the customer meter level of the Ameren Missouri grid. The total RAP rises to nearly 300 MW by 2043.

FIGURE 1-3. CUMULATIVE ANNUAL BASE CASE SUMMER PEAK MW RAP POTENTIAL BY SECTOR



1.5.4 Distributed Energy Resource Potential for All Customers

Table 1-3Table 1-3: summarizes the combined heat and power (CHP) cumulative annual potential estimates for electric demand and Table 1-4 for electric energy. 2043 technical market potential for CHP represents 22.0% of the 2043 business sector sales forecast and economic potential represents 6.4% of the 2040 business sector sales forecast.

TABLE 1-3: SUMMARY OF CHP ELECTRIC DEMAND MARKET POTENTIAL

Year	Technical (MW)	Economic (MW)	MAP (MW)	RAP (MW)
2026	6.4	1.5	0.7	0.6
2033	22.5	5.3	2.5	1.8
2043	120.0	28.5	8.8	4.0

TABLE 1-4: SUMMARY OF CHP ELECTRIC ENERGY MARKET POTENTIAL

Year	Technical (MWh)	Economic (MWh)	MAP (MWh)	RAP (MWh)
2026	90.465	26,187	14,203	12,583
2033	639,313	185,060	91,052	73,339
2043	4,251,069	1,230,559	469,316	284,237

Table 1-5 and Table 1-6 summarize the Solar PV cumulative energy potential estimates for electric generation for the residential and non-residential sectors respectively. Table 1-7 and Table 1-8 summarize the Solar PV cumulative demand potential estimates for the residential and non-residential sectors. 2043 technical market potential for Solar PV represents 36.8% of the 2043 residential and business sector sales forecast combined.

TABLE 1-5: SUMMARY OF RESIDENTIAL SOLAR PV ELECTRIC DEMAND MARKET POTENTIAL

Year	Technical DC Capacity (MW)	Technical Peak Capacity (MW)[6]	Economic (MW)	MAP (MW)	RAP (MW)

[6] This peak capacity represents the alternating current (AC) production between the hours of 16 and 18 and may not align with MISO Resource Adequacy models.

Schedule MM-24

2026	14.6	62	0	0	0
2033	2,155	914	0	0	0
2043	6,015	2,551	0	0	0

TABLE 1-6: SUMMARY OF NON-RESIDENTIAL SOLAR PV ELECTRIC DEMAND MARKET POTENTIAL

Year	Technical DC Capacity (MW)	Technical Peak Capacity (MW)[7]	Economic (MW)	MAP (MW)	RAP (MW)
2026	30.6	13.4	4.24	2.30	2.04
2033	216	94.4	30	14.8	11.9
2043	1,441	629	200	76.2	46.1

TABLE 1-7: SUMMARY OF RESIDENTIAL SOLAR ELECTRIC ENERGY MARKET POTENTIAL

Year	Technical (MWh)	Economic (MWh)	MAP (MWh)	RAP (MWh)
2033	3,072,067	0	0	0
2043	8,571,985	0	0	0

TABLE 1-8: SUMMARY OF COMMERCIAL SOLAR ELECTRIC ENERGY MARKET POTENTIAL

Year	Technical (MWh)	Economic (MWh)	MAP (MWh)	RAP (MWh)
2033	309,125	97,290	47,867	38,554
2043	2,058,371	647,830	247,044	149,596

[7] This peak capacity represents the alternating current (AC) production between the hours of 16 and 18 and may not align with MISO Resource Adequacy models.

2 BASELINE FORECAST

The load forecast is a critical input into Ameren Missouri's 2023 DSM Market Potential Study, having various uses in estimation of residential and business sector potential. Therefore, our Team took considerable time and effort to review Ameren's most recently completed load forecast models and documentation to produce the various forecast components necessary as inputs into this analysis. The chapter describes the various ways in which the forecast is used for this study, presents the baseline and disaggregated forecasts, and describes the methodology and data sources used by GDS for the purposes of generating the load forecasts that were used in the potential analysis.

2.1 AMEREN MISSOURI'S LOAD FORECASTING SYSTEM

Ameren employs a sophisticated load forecasting system that uses econometric and Statistically Adjusted End-Use ("SAE") models to project number of consumers, average consumption per consumer, and total energy sales by class. Residential, Commercial, and Industrial consumers are projected using traditional econometric techniques. Residential average usage and commercial energy sales are projected using SAE model specifications. Industrial energy sales are projected using econometric techniques.

A residential SAE model specification takes end-use data drawn from utility, regional, and even national sources and develops monthly end-use indices designed to predict average household consumption. The end-use data includes market share of key electric consuming appliances, average device efficiency trends, average building shell efficiency trends, price elasticity of demand, income elasticity of demand, and elasticity associated with the average number of people per household. A cooling index is developed to represent space cooling load and is further modified by Cooling Degree Days to incorporate summer weather into the model. Likewise, a heating index representing space heating is modified by Heating Degree Days. Finally, a base index is developed to represent consumption of all other end-uses in the home.

A commercial SAE model specification is very similar to a residential specification, with end-use energy intensity indices developed based on area employment in various industry codes. National and regional commercial data is used to estimate end-use consumption for various industries (for example, restaurants will have higher cooking usage shares than offices). Ameren also projects impacts of DSM programs it has run in the past. This includes MEEIA Cycle I through Cycle III programs, plus various pre-MEEIA programs.

2.2 ADJUSTMENTS TO THE AMEREN MISSOURI LOAD FORECAST

Before assessing the future potential for energy efficiency, demand response, or distributed energy resources in the Ameren Missouri service area, a few modifications to the 2021-vintage Ameren forecast were necessary to create an adjusted baseline forecast. These modifications are addressed in more detail below.

2.2.1 Current DSM Impacts

Although the load forecast provided by Ameren Missouri already excluded the impacts of future DSM impacts, historical DSM impacts were included in the load forecast projections. While each Missouri Energy Efficiency Investment Act (MEEIA) cycle only lasts three years, the effects of those measures installed last beyond that three-year period. An important question is how to handle the savings of those programs at the expiration of the current measure. GDS evaluated three possible options:

1) Assume the full savings potential is repeated. This implicitly assumes all participants in the program would participate again at the same level, even without the program in place. This indicates full transformation of the entire DSM market from Cycles 1 through 3.

Schedule MM-24

2) In the second approach, it is assumed that free riders only would continue to install efficient equipment or behave efficiently even without the DSM program in place, but all others would revert to the minimum standard of efficiency. This represents an approach in which none of the participants that were not already actively engaged in efficiency and conservation would have been transformed by participation in the program.

3) The last approach is one in which free riders remain engaged in efficient behaviors plus some portion of the remaining participant population is transformed. Consistent with the approach in the 2019 MPS for Ameren Missouri, customers were segmented according to their perceptions of energy efficiency and conservation. GDS has assumed that "Active Conservers" and "Cost-Focused Conservers" would represent the proportion of the population transformed. In the residential sector, this is equivalent to a 22% assumed transformation rate in excess of free ridership. In the C&I sector, 25% of the market is assumed transformed.

The GDS and Ameren team selected the third option for this study. This approach recognizes the likelihood that some portion of program participants that were not originally free riders would likely continue to exhibit efficient behaviors but that not all such consumers would do so.

2.2.2 Naturally Occurring Efficiency Savings

The end-use appliance efficiency trends in the SAE model framework show appliance efficiency changing over time, often showing average equipment efficiency above current equipment standards. These trends are a byproduct of assumptions regarding natural occurring efficiency. In order to estimate the amount of energy associated with naturally occurring efficiency, GDS used appliance stock accounting information developed as part of the SAE modeling framework. The average device efficiency curve was recomputed by only allowing appliance replacements and new appliances in a given year to be purchased at the minimum standard level. The result is a new trend in efficiency that approaches the minimum standard without exceeding it. The new efficiency estimate was then run through the SAE regression modeling to produce the estimated change in end-use energy sales because of the new estimated efficiency without naturally occurring effects.

2.2.3 Adjustment for Large C&I Opt-Out Customers

20 CSR 4240-20.094(7)(A) states that, any customer meeting one or more of the following criteria shall be eligible to opt-out of participation in utility-offered demand-side programs: (1) The customer has one or more accounts within the service territory of the electric utility that has a demand of 5,000 kW or more; (2) The customer operates an interstate pipeline pumping station; or (3) The customer has accounts within the service territory of the electric utility that have, in aggregate across its accounts, a coincident demand of 2,500 kW or more in the previous 12 months, and the customer has a comprehensive demand-side or energy efficiency program and can demonstrate savings at least equal to those expected from utility-provided demand-side programs.

Ameren provided a list of all business customers that have opted out of participating in Ameren Missouri's MEEIA programs, and the associated sales from these customers was removed from the business sector sales forecast and thus, from the base estimates of future efficiency potential.[8]

[8] A sensitivity on savings was performed that included current opt-out customers.

2.2.4 Reclassification of Load

Last, the 2021 Ameren Missouri business sector customer database designated commercial and industrial rate code based on current tariff definition. When only using the account type/tariff definition to classify customers as either commercial or industrial, there were several manufacturing type premises classified as commercial, as well as several typically commercial customers classified as industrial, (i.e. a retail service building coded as an industrial account).

Conversely, the dataset also identified each business by Standard Industry Code (SIC). We then mapped these industry codes to a specified building type, and lastly classified the building type as either commercial or industrial. Customers with a building type classified as "Industrial Manufacturing" were coded as Industrial customers, while all other building types were coded as Commercial. This reclassification shifted approximately 4.3% of commercial sales (net of opt-outs), or 529,000 MWh, to the industrial sector.

2.3 LOAD FORECAST COMPARISON

Figure 2-1 demonstrates the impacts of the adjustments noted above to the overall Ameren forecast for 2024. The bar on the left is the original Ameren forecast for 2024, including the impacts of Ameren Missouri's MEEIA DSM activities, but excluding future DSM. The Business as Usual "BAU" forecast includes the adjustments to DSM impacts to account for decay in DSM savings as well as to net out the impacts of naturally occurring savings already embedded in the forecast. Both adjustments result in a relatively small increase to the Ameren forecast. The last two bars provide the adjustments from excluding active opt-out customers, as well the reclassification of C&I load noted above.

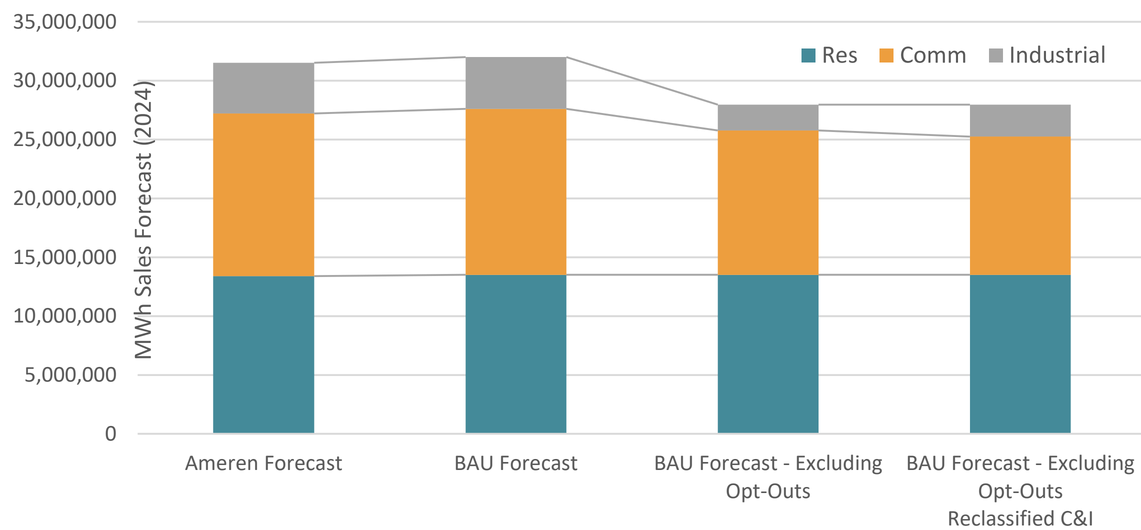


FIGURE 2-1: STEP-BY-STEP COMPARISON OF ADJUSTMENTS TO 2021 AMEREN LOAD FORECAST

Figure 2-2 depicts the total system load forecast for the MPS study timeframe of 2024-2043, following the adjustment noted in Section **Error! Reference source not found.**.

Schedule MM-24

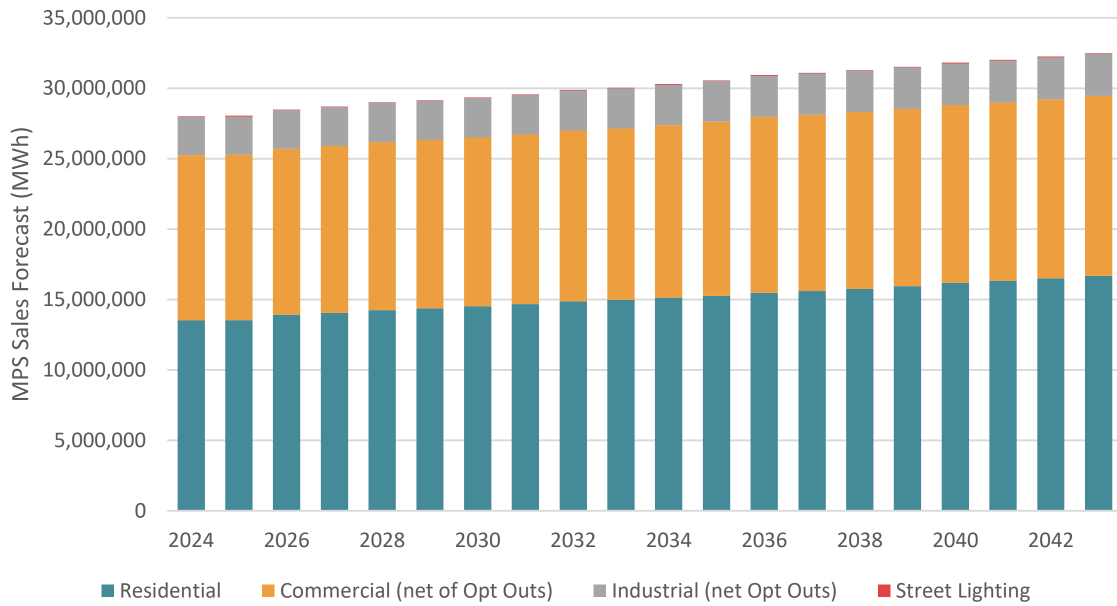


FIGURE 2-2: TOTAL SYSTEM LOAD FORECAST (NET OF OPT-OUTS) USED IN MPS

2.4 LOAD FORECAST DISAGGREGATION

The baseline forecasts represent projected total energy sales by class. For the potential studies, it is useful to have the class forecasts disaggregated in several different ways. This section presents the forecast disaggregation scenarios that will be used by GDS in developing the market potential study.

2.4.1 Residential Sector

The baseline residential forecast for the study is disaggregated across 12 different end-uses. These end-use level forecasts are important in helping to calibrate measure-level savings estimates as well as for making interactive effects adjustments in the potential model to avoid over-estimating (double-counting) savings. Table 2-1 provides a breakdown by end-use (consolidated to 12 end-uses).

TABLE 2-1: END-USE BREAKDOWN OF SALES FORECAST (2024)

End Use	Sales	% of Total
Heating	3,154,377	23.4%
Cooling	2,878,571	21.3%
Water Heating	681,379	5.0%
Cooking	337,032	2.5%
Refrigerator	807,659	6.0%
Freezer	167,857	1.2%
Dishwasher	85,109	0.6%
Clothes Washer	31,795	0.2%
Dryer	697,350	5.2%
TV	557,157	4.1%
Lighting	1,425,917	10.6%
Miscellaneous	2,684,495	19.9%
Total	13,508,700	100%

Schedule MM-24

2.4.2 Business Sector

In the business sector, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. GDS received a BAU sales forecast from Ameren for the residential, commercial and industrial sectors. As noted above, the C&I forecast was adjusted from the BAU Baseline by using SIC information from Ameren to reclassify usage as commercial or industrial. SIC information from Ameren, along with CBECS building type consumption tables, was then used to segment the forecast into building types. The forecast was further segmented into end-uses by building type using CBECS 2012 end-use survey data. Figure 2-3 provides a breakdown of commercial electric sales by building type for the commercial segment of the business sector. Retail (16%), Office (23%), and Other (21%) are the leading contributors of stand-alone building types to the total commercial electric sales.[9]

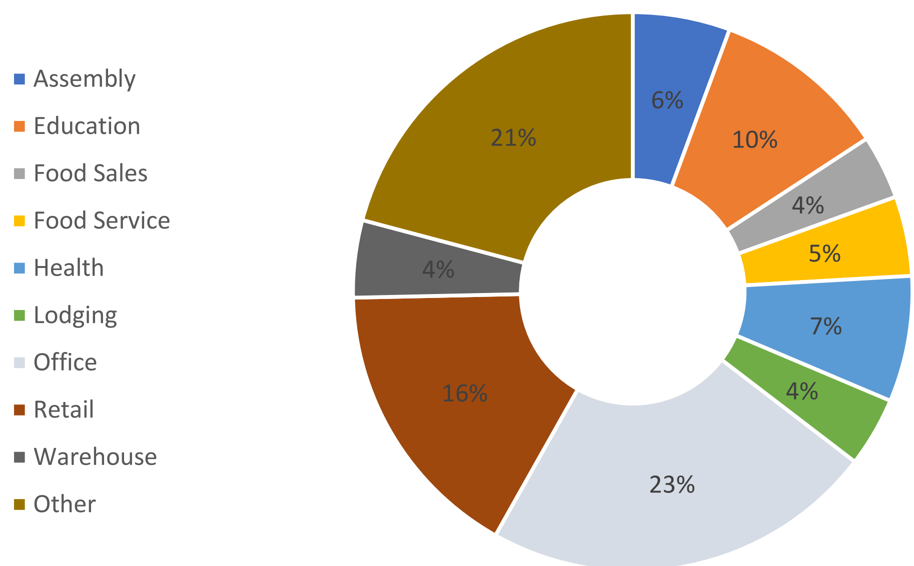


FIGURE 2-3: COMMERCIAL ELECTRIC SALES BREAKDOWN BY BUILDING TYPE

Figure 2-4 provides an illustration of the leading end-uses across all building types in the commercial sector. Lighting typically represents 20% of the commercial business sector load across buildings, with space cooling and ventilation each typically representing 10% or more across building types. Shares of refrigeration and office/computing are often dependent on the type of building, with refrigeration loads greatest in food sales and food service while office/computing loads are greatest in offices and education.

[9] "Other" building types include buildings that engage in several different activities, a majority of which are commercial (e.g. retail space), though the single largest activity may be industrial or agricultural; "other" also includes miscellaneous buildings that do not fit into any other category.

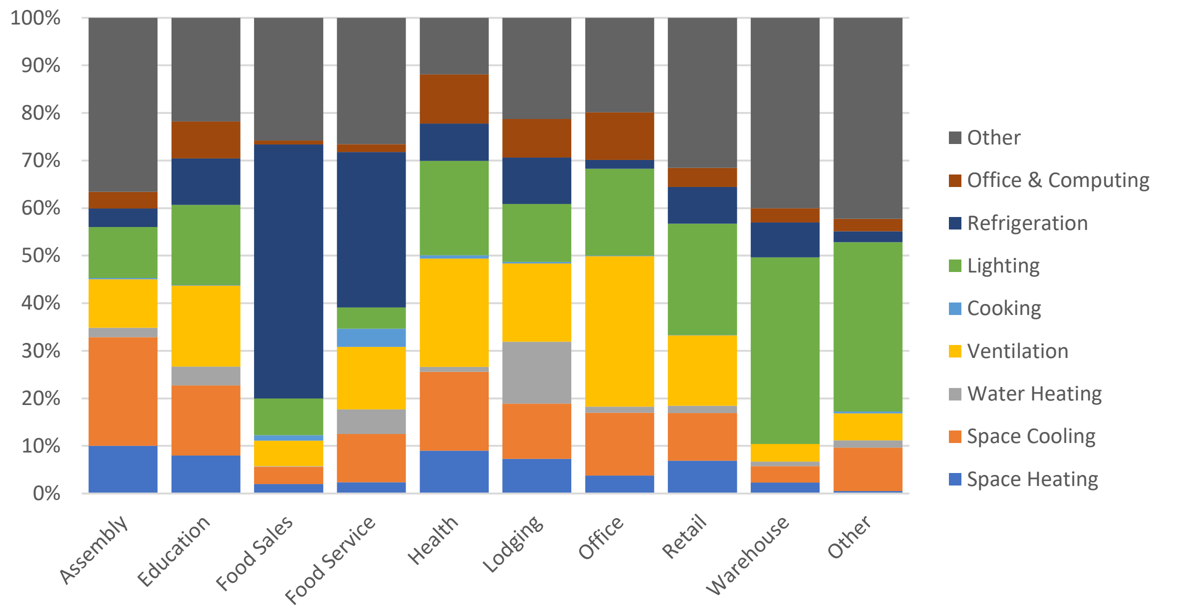


FIGURE 2-4: COMMERCIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE

Figure 2-5 depicts in the industrial segment of the business class, broken down by both industry type (left pie chart) and end-use (right pie chart). Food, plastics and rubber, chemical, and miscellaneous manufacturing were the leading industry types according to SIC code. The industrial machine drive end-use is the dominant share of industrial electric sales, followed by process heating, lighting, and HVAC. The industry type and end-use breakdowns are based on the redistributed industrial sales that are net of opt-out customers in the Ameren Missouri service area.

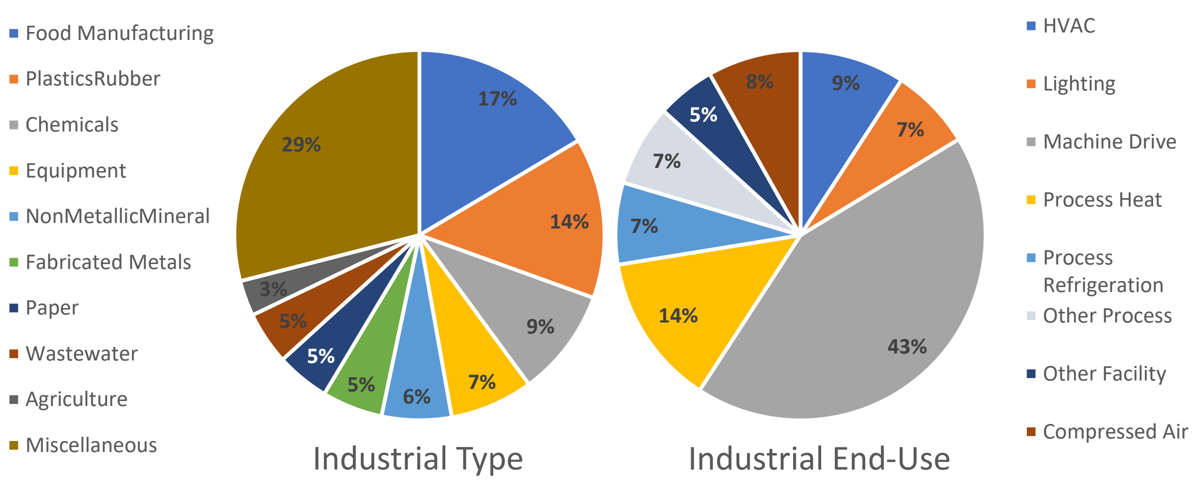


FIGURE 2-5: INDUSTRIAL SECTOR BREAKDOWN BY INDUSTRY TYPE AND END-USE (EXCLUDE OPT-OUT CUSTOMERS)

Schedule MM-24

3 ENERGY EFFICIENCY POTENTIAL ANALYSIS

3.1 ANALYSIS APPROACH[10]

This section describes the overall methodology proposed to assess the electric energy efficiency potential for market-rate residential and business customers in the Ameren Missouri service area. Many of the methodological considerations discussed within this section are generally applicable to the demand response and DER analyses found in subsequent chapters of this report, with important distinctions in methodological approach noted in their respective chapters.

The main objectives of this Market Potential Study were to estimate the technical, economic, maximum achievable potential ("MAP") and realistic achievable potential ("RAP") of energy efficiency in the Ameren Missouri service territory; and to quantify these estimates of potential in terms of MWh and MW savings, expected incremental and cumulative program participants, and associated costs, for each level of energy efficiency potential.[11] An overview of these results is found in subsequent sections and chapters of this report. Detailed appendices also provide a catalog of assumptions and annual outputs associated with this analysis.[12]

3.1.1 Overview of Approach

For the residential sector, GDS utilized a bottom-up approach to the modeling of energy efficiency potential, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build-up the technical potential, by applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential, taking into consideration incentives and estimates of annual adoption rates.

For the business sector, GDS employed a bottom-up modeling approach to first estimate measure-level savings, costs, and cost-effectiveness, and then applied measure savings to all applicable shares of energy load.

3.1.2 Market Characterization

The initial step in the analysis was to gather a clear understanding of the current market segments in the Ameren Missouri service area. The GDS team coordinated with Ameren Missouri to gather electric utility sales and customer data to define appropriate market sectors, market segments, vintages, saturation data and end uses.

The GDS team relied on market research conducted as part of the 2020 study to inform critical elements of the market potential study.[13] The research objectives of this effort were based on a gap analysis, conducted by the GDS Team, and subsequent prioritization of data needs.

3.1.2.1 Forecast Disaggregation

As noted in Chapter 2, through the development of the baseline forecasts, the GDS Team produced disaggregated forecasts by sector and end-use. The produced baseline forecasts were disaggregated by sector and then further segmented as follows[14]:

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[10] 20 CSR 4240-20.050 (3)(I)
[11] 20 CSR 4240-20.050 (3)(G)3 through 5
[12] 20 CSR 4240-20.050 (3)(H); complete models will be provided to Ameren Missouri as a deliverable for this study.
[13] 20 CSR 4240-20.050 (2)
[14] 20 CSR 4240-20.050 (1)(A)1 and 20 CSR 4240-20.050 (3)(B)

- ***Residential.*** The residential forecast was broken out by housing type between existing and new construction. Segmentation at the end-use level was done using building energy simulation modeling.
- ***Commercial.*** Typically based on major Energy Information Administration (EIA) Commercial Buildings Energy Consumption Survey (CBECS) business types: retail, warehouse, food sales, office, lodging, health, food service, assembly, and education. Businesses that were identified as non-profit were also segmented separately and the eligible portions were included in the assessment of income-eligible potential under the business social services program.
- ***Industrial.*** As determined by actual load consumption shares and major industry types as defined by EIA's Manufacturing Energy Consumption Survey (MECS) data.[15]

The segmentation analysis was performed by applying Ameren Missouri-specific segment and end-use consumption shares, derived from Ameren Missouri's customer database and SIC code analysis (building segmentation), and by EIA CBECS and MECS data (end-use segmentation) to forecast year sales. Within the residential, commercial and industrial market segments, the produced forecasts were segmented by the major end uses shown in Table 3-1.

TABLE 3-1: ELECTRIC END-USE LOADS[16]

Residential	C&I	
	Commercial	Industrial
Heating	Interior Lighting	Lighting
Cooling	Exterior Lighting	HVAC
Water Heating	Refrigeration	Machine Drive
Cooking	Space Cooling	Process Heat
Refrigerator	Space Heating	Process Cool / Refrigeration
Freezer	Ventilation	Other Process
Dishwasher	Water Heating	Process – Machine Drive
Clothes Washer	Plug Loads / Office Equipment	Other Facility
Dryer	Cooking	Compressed Air
TV	Other	Water / Wastewater
Light	Whole Building / Behavioral	Process – Agriculture
Miscellaneous		Whole Building / Behavior

3.1.2.2 Eligible Opt-Out Customers

In Missouri, commercial or industrial customers with significant peak demand requirements and/or meet specific criteria (see Section 2.2.3) are eligible to opt out of utility-funded electric energy efficiency and demand response programs. In the Ameren Missouri service area, approximately 14% of commercial sales have opted out of utility-funded electric energy efficiency programs, while nearly 44% of industrial sales have opted out.[17]

[15] Industrial sector potential was ultimately aggregated into an additional building type in the business sector analysis.
[16] 20 CSR 4240-20.050 (1)(A)3
[17] These percentages were calculated based on the 2021 Ameren Missouri business customer data and 2021 billing history. Note, the percentages are based on the redistributed C&I sales, as discussed in Section 2.2.4 of the report.

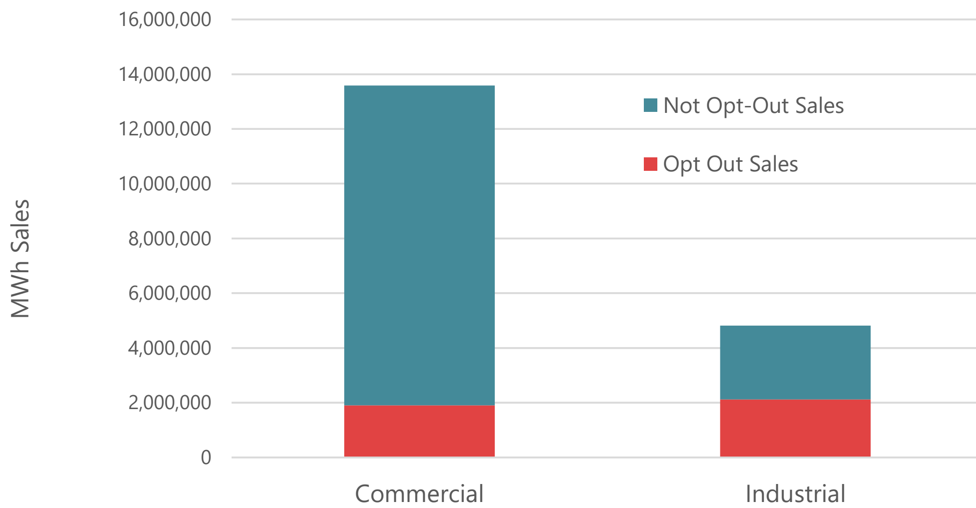

FIGURE 3-1: 2024 BUSINESS SECTOR OPT-OUT SALES

Figure 3-1 shows the total sales for the business sector, as well as the sales, by sector that have currently opted out of paying the charge levied to support utility-administered energy efficiency programs. The portion of sales that have not opted out include both ineligible load (i.e. does not meet the eligibility requirement) as well as eligible load that has not opted out.

The MPS focuses most report elements on the electric energy efficiency potential savings in the business sector excluding sales from opt-out customers. Results of business sector potential that includes savings from Ameren Missouri's opt-out customers are provided as a sensitivity later in this report.

3.1.2.3 Building Stock/Equipment Saturation

To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary.

3.1.2.3.1 Residential Sector

For the residential sector, GDS relied on the primary research from the 2020 study. This research allowed for the GDS Team to characterize the baseline and efficiency saturations of the residential sector using housing-type and income-type specific data in most cases. In some cases, the sample sizes were too small to provide estimates at this level of granularity, and in these cases either housing-type or income-type specific estimates are used.

Other data sources included ENERGY STAR unit shipment data, Ameren Missouri evaluation reports, and the EIA Residential Energy Consumption Survey data from 2020. The ENERGY STAR unit shipment data filled data gaps related to the increased saturation of energy efficient equipment across the U.S. in the last decade.

3.1.2.3.2 Business Sector

GDS primarily used the latest market research collected from the 2020 study as well as data from the EIA Annual Energy Outlook (AEO) to inform two main assumptions for the potential study, the Base Case factor and saturation of efficient equipment.

The Base Case Factor is the fraction of the end use energy that is applicable for the efficient technology in given market segment. The EIA AEO data provides a regional forecast of energy consumption by end-use and equipment type (e.g. lighting type, major HVAC equipment, refrigeration equipment) that can be used to further disaggregate end-use sales to major equipment type. This data was supplemented with data collected as part of Ameren Missouri's prior market research efforts. Prior Ameren Missouri baseline studies collected counts for equipment and energy usage levels for the lighting, heating, cooling, water heating, motors and refrigeration end-uses.

GDS reviewed and developed additional base case factors for other end-uses through review of the Energy Savings Potential and R&D Opportunities for Commercial Building Appliances (2015 Update) report developed by the U.S. Department of Energy (DOE). This report also provided end-use consumption estimates by equipment type for commercial cooking equipment, dishwashers, IT and office equipment, water heaters and commercial laundry equipment. Refrigeration base case factors were supplemented with data from DOE Refrigeration Study - Energy Savings Potential and Research & Development Opportunities for Commercial Refrigeration.

Data collected for the 2019 Ameren Missouri Baseline Study was leveraged to develop remaining factors for many of the measures. Saturation data from this study was updated to reflect interim energy efficient achievements from Ameren Missouri's 2019-2021 DSM savings to estimate the current remaining factors for measures within the lighting, ventilation and office & computing end-use categories. The ENERGY STAR® Unit Shipment and Market Penetration Report for Calendar Year 2021 was used to determine remaining factors for commercial cooking equipment, refrigerators and freezers, computer and data center equipment and commercial dishwashers.

3.1.2.4 Remaining Factor

The remaining factor is the proportion of a given market segment that is not yet efficient and can still be converted to an efficient alternative. It is, by definition, the inverse of the saturation of an energy efficient measure. This study makes several assumptions regarding the future potential of equipment that is already efficient, or will become efficient, over the analysis timeframe.

For measures that are not yet efficient, estimated savings reflect the initial measure assumptions developed as part of the MPS and are typically consistent with the Ameren Missouri submittal tool, and discussed in Section 3.1.3.3, below. The question, then, is whether there is any additional future potential to be quantified from homes/businesses that already possess an efficient measure. Consistent with the 2020 study and assumptions used to develop the load forecast used in this study (see Section 2.2.1), the team developed our models to allow a portion of these existing measures to be refilled, during their natural replacement cycle, by assuming that consumers will either backslide back to baseline technologies or that advances in the efficiency of equipment will enable new technologies, tiers, or improved standards to replace the current measure and allow for continued savings opportunities. Since the precise level of savings and measure characterizations for these future measures is not presently known, the methodology adopted assumes that subsequent equipment replacement that occurs over the course of the 20-year study timeframe, and at the end of the initial equipment's useful life, will continue to achieve similar levels of energy savings, relative to improved baselines, at similar incremental costs.

There are, of course, exceptions to this logic. Select measures were considered one-time efficiency opportunities and are not eligible to be replaced/refilled in the analysis once it has been initially converted to efficient status. Examples of these measures include variable frequency drives, motor controls, comprehensive residential retrofits, and most shell measures (insulation, air sealing, door improvements). Other exceptions in this study include measures that are known to be impacted by codes or standards or are considered to have reached the limit of technological advancements in efficiency (ex. Screw-based LED Lighting, where future efficiency improvements are expected to be minimal compared to historic baselines) and miscellaneous residential electronics with high market penetration.

An additional adjustment was made to business sector lighting to reflect the rapid replacement of inefficient lighting with LED technologies by Ameren Missouri in recent years. The business sector lighting potential was modeled as a market opportunity with baseline lighting technologies replaced with LEDs at the rate of 1 divided by the baseline technology's measure life. During the initial year calibration process to ensure 2024 savings were benchmarked against historical and/or planned savings, the GDS team front-loaded the replacement opportunities years for these inefficient technologies so that LED replacements would be introduced into the technical potential earlier than would have otherwise happened.

Last, we have also assumed that measures that are converted during early years of the analysis but reach the end of their useful life over the 20-year analysis timeframe, are also eligible for future installations assuming the same adjustment for future efficiency and/or costs and the same stated exceptions.

3.1.3 Measure Characterization

3.1.3.1 Measure Lists

The study's sector-level energy efficiency measure lists were informed by a range of sources. The primary resource for developing the measure included Ameren Missouri's most recent Submittal Tool/TRM. In addition to this resource, additional measures were considered for inclusion by referencing current Ameren Missouri program offerings, prior Ameren Missouri and other regional potential assessments and program offerings, other regional technical reference manuals, and commercially viable emerging technologies, among others.[18] Measure list development was a collaborative effort in which GDS developed a draft measure lists that was shared with Ameren Missouri and stakeholders for qualitative review. The final measure lists ultimately included in the study reflects the informed comments and considerations from the parties that participated in the measure list review process.[19] The measure list for the residential income-eligible customers closely mirrored the measures included in the market-rate analysis. This ensures that a thorough review of remaining potential not limited only to existing offerings to income-eligible customers and current program designs.[20]

In total, GDS analyzed 185 residential and 195 business measure types for Ameren Missouri. To help inform future program planning and to align with existing offerings, many measures were included in the study as multiple permutations to account for different specific market segments, such as different building types, efficiency levels, and replacement/delivery options.[21] GDS developed a total of 3,135 measure permutations for this study. Each permutation was screened for cost-effectiveness according to the Total Resource Cost (TRC) Test. The parameters for cost-effectiveness under the TRC are discussed in detail later in Section 3.1.6. [22]

In select cases, certain measures initially considered for inclusion in the 2023 Ameren Missouri MPS were ultimately screened out of the quantitative analysis. Measures were qualitatively screened out for several possible reasons, including recently changed baselines, limited applicability, assumed current market baseline, and historically poor customer acceptance.

3.1.3.2 Emerging Technologies

GDS considered several specific emerging technologies as part of analyzing future potential.[23] In the residential sector, these technologies include several smart technologies, including connected lighting, smart window coverings, heat pump dryers, cool roofs[24] and smart vents/sensors. In the business sector, specific emerging technologies considered

[18] 20 CSR 4240-20.050 (3)(A); In addition, Ameren Missouri performed a broad review of programs available around the country through the Energy Star website as part of the measure list review.

[19] 20 CSR 4240-20.050 (3)(C)

[20] 20 CSR 4240-20.050 (3)(A)

[21] 20 CSR 4240-20.050 (1)(A)2; 20 CSR 4240-20.050 (3)(E)

[22] 20 CSR 4240-20.050 (5)(B)

[23] 20 CSR 4240-20.050 (1)(E)1

[24] EO-2023-0099 1A (Special Contemporary Issues)

Schedule MM-24

as part of the analysis include strategic energy management, advanced lighting controls, advanced rooftop controls, cool roofs and cloud-based energy information systems ("EIS"). While this is likely not an exhaustive list of possible emerging technologies over the next 20 years it does consider many of the known technologies that are available today but may not yet have widespread market acceptance and/or product availability.

In addition to these specific technologies, GDS acknowledges that there could be future opportunities for new technologies as equipment standards improve and market trends occur. While this analysis does not make any explicit assumption about unknown future technologies, the methodology assumes that subsequent equipment replacement that occurs over the course of the 20-year study timeframe, and at the end of the initial equipment's useful life, will continue to achieve similar levels of energy savings, relative to improved baselines, at similar incremental costs.

3.1.3.3 Assumptions & Sources

A significant amount of data is needed to estimate the electric savings potential for individual energy efficiency measures or programs across the residential market-rate and business sectors. GDS utilized data specific to Ameren Missouri when possible. Evaluation report findings and the Ameren Missouri Submittal Tool/TRM were leveraged to the extent feasible – additional data sources were only used if these first two sources either did not address a certain measure or contained outdated information. Following the collection of primary market research, select fields in the Ameren Missouri Submittal Tool were updated to incorporate the latest findings.

Additional sources for measure data included the Illinois TRM and the Michigan Energy Measures Database (MEMD). Additional source documents also included American Council for an Energy-Efficient Economy (ACEEE) research reports covering topics like emerging technologies.[25]

Considerable effort was expended to identify, review, and document all available data sources in the development of reasonable and supportable assumptions regarding measure lives; measure costs (incremental or full costs as appropriate); measure electric savings; and saturations for each energy efficiency measure included in the final list of measures examined in this study.[26]

Measure Savings[27]: GDS relied primarily on the Ameren Missouri Submittal Tool as well as the latest Ameren Missouri evaluation report findings and collected primary research to inform calculations supporting estimates of annual measure demand and energy reduction impacts as a percentage of base equipment usage. For measures not included in the Ameren Missouri Submittal Tool, GDS estimated savings from a variety of sources, including:

- Illinois TRM, MEMD
- Engineering analyses
- Secondary sources such as the ACEEE, DOE, EIA, ENERGY STAR©, and other technical potential studies

For each measure, estimates of annual energy and demand reductions are also characterized to provide seasonal on- and -off peak impacts.[28]

[25] For example: Energy Impacts of Smart Home Technologies. Report A1801. ACEEE. 2018; Smart Buildings: A Deeper Dive into Market Segments. Report A1703. 2017; Rate Design Matters: The intersection of Residential Rate Design and Energy Efficiency. Report U1703. 2017.

[26] The appendices and supporting databases to this report provide the data sources used by GDS to obtain up-to-date data on energy efficiency measure costs, savings, useful lives and saturations.

[27] 20 CSR 4240-20.050 (3)(G)1

[28] 20 CSR 4240-20.050 (6)(B); The energy efficiency potential study utilizes seasonal load shapes to assess the cost-effectiveness of measures. More granular hourly load shapes of energy impacts will be developed for inputs into the IRP as needed.

Measure Costs*[29]*: Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.

GDS obtained measure cost estimates primarily from Ameren Missouri program planning databases and evaluation reports. GDS also used the following data sources to supplement measure cost data:

- Illinois TRM, MEMD
- Secondary sources such as the ACEEE, ENERGY STAR, and National Renewable Energy Lab (NREL)
- Program evaluation and market assessment reports completed for utilities in the Pacific Northwest (Bonneville Power Administration) and California

Costs and savings for new construction and replace on burnout measures were calculated as the incremental difference between the federal minimum efficiency standard (where applicable) and the energy efficiency measure. This approach was utilized because the consumer must select an efficiency level that is at least equal to the federal minimum efficiency standard when purchasing new equipment. The incremental cost is calculated as the difference between the cost of high efficiency and standard efficiency (code compliant) equipment. However, for retrofit or direct install measures, the measure cost was the "full" cost of the measure, as the baseline scenario assumes the consumer would not make energy efficiency improvements in the absence of a program. In general, the savings for retrofit measures are calculated as the difference between the energy use of the removed equipment and the energy use of the new high efficiency equipment (until the removed equipment would have reached the end of its useful life).[30]

Measure Life: Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the Ameren Missouri Submittal Tool and used the following data sources for any additional measures:

- Illinois TRM, MEMD, and other regional/state TRMs
- Manufacturer data
- Savings calculators and life-cycle cost analyses

All measure savings, costs, and useful life assumption sources for residential market-rate and business sectors are documented in Appendix B and Appendix C.

3.1.3.4 Treatment of Codes & Standards

By law, the DOE is expected to review each national appliance standard every six years and publish either a proposed rule to update the standard or determine that no change to the existing standard is needed. The analysis is not intended to predict how or when energy codes and standards will change over time. Therefore, there are only limited known improvements to federal codes and standards to reasonably account for in this analysis.[31]

The primary adjustment in this analysis impacts residential screw-based lighting. Although DOE did issue a final rule stating the Energy Independence and Security Act of 2007 (EISA) backstop has not been triggered and adopted a narrow definition of general service lighting, based on discussion with Ameren Missouri program administrators and a review of the implied efficacy of residential lighting in Ameren's residential load forecast[32], the base case analysis for the 2023 MPS severely limited the future potential for residential lighting.

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[29] 20 CSR 4240-20.050 (3)(G)5A

[30] EO-2023-0099 1A (Special Contemporary Issues) Tax credits as part of the Inflation Reduction Act were considered in the energy efficiency measure characterization.

[31] 20 CSR 4240-20.050 (3)(C)

[32] Implied assumptions embedded in the Ameren load forecast for residential lighting indicate a wattage somewhere between an LED and CFL.

The base case assumes only a limited number of direct-install screw-based lighting opportunities for standard, specialty, and reflector bulbs over the analysis period.

3.1.4 Types of Potential

Potential studies often distinguish between several types of energy efficiency potential: technical, economic, achievable, and program. However, because there are often important definitional issues between studies, it is important to understand the definition and scope of each potential estimate as it applies to this analysis.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable and program potential attempts to estimate what savings may realistically be achieved through market interventions, when it can be captured, and how much it would cost to do so. In this analysis, achievable and program potential were included an assessment of maximum and achievable potential, with maximum achievable assuming aggressive incentive levels and optimistic delivery conditions and realistic achievable potential closely calibrated to historical incentive levels and current program awareness.

Figure 3-2 illustrates the types of energy efficiency potential considered in this analysis.

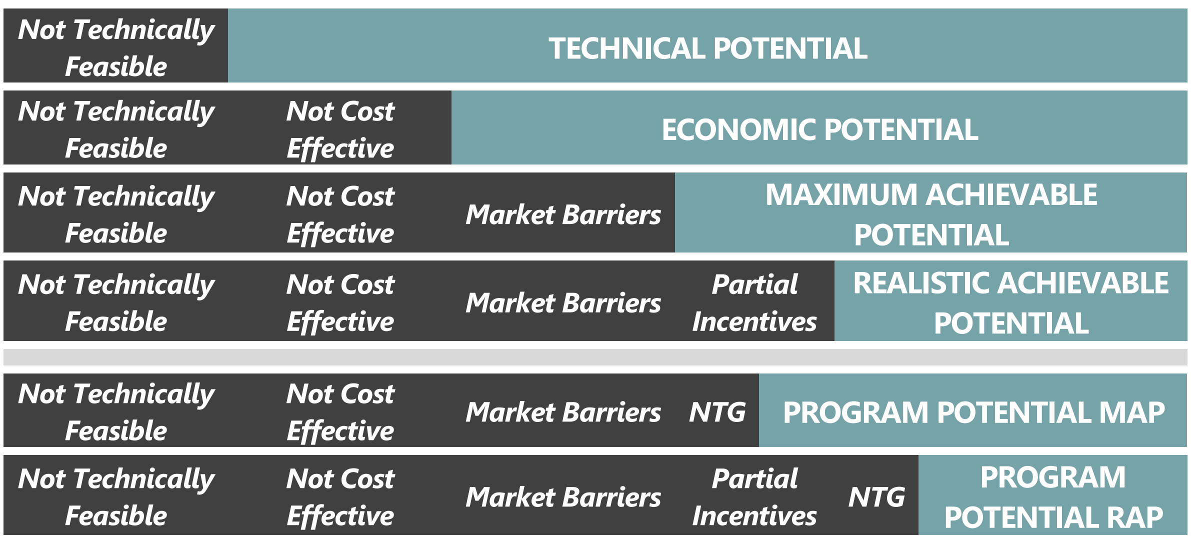


FIGURE 3-2 TYPE OF ENERGY EFFICIENCY POTENTIAL[33]

3.1.5 Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential only constrained by factors such as technical feasibility of measures. Under technical potential, GDS will assume that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation will be assumed to be resource constrained and that it is not possible to install all retrofit measures all at once. Rather, retrofit opportunities will be assumed to be replaced incrementally until 100% of stock will be converted to the efficient measure over a period of no more than 20 years.

[33] Reproduced from "Guide to Resource Planning with Energy Efficiency." November 2007. US Environmental Protection Agency (EPA). Figure 2-1. Modified to depict the additional levels of achievable and program potential included in this study.

Schedule MM-24

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 3-1 below. The business (C&I) sector employs a similar analytical approach.

EQUATION 3-1 CORE EQUATION FOR RESIDENTIAL SECTOR TECHNICAL POTENTIAL

TECHNICAL POTENTIAL OF EFFICIENT MEASURES = *Total Number of Households* X *Base Case End Use Intensity (kWh/unit)* X *Saturation Share* X *Remaining Factor* X *Feasibility Factor* X *Savings Factor*

Where…

Base Case Equipment End-Use Intensity = the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case equipment end-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Saturation Share = the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential central air conditioner cooling, the saturation share would be the fraction of all residential electric customers that have electric central air conditioner cooling in their household.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of central air conditioners that is not already energy efficient.

Feasibility Factor = (also functions as the applicability factor) the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (e.g., it may not be possible to install central air conditioners in all homes because of space limitations).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

3.1.5.1 Competing Measures & Interactive Effects Adjustments[34]

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

Baseline Saturation Adjustment. Competing measure shares may be factored into the baseline saturation estimates. For example, nearly all homes can receive insulation, but the analysis will create multiple measure permutations to account for varying impacts of different heating/cooling combinations and will apply baseline saturations to reflect proportions of households with each heating/cooling combination.

Applicability/Feasibility Factor Adjustment. GDS will combine measures into measure groups, where total applicability factor across measures is set to 100%. In instances where there are two (or more) competing technologies for the same electrical end use, such as central air conditioners with different tiers of efficiency, an applicability factor aids in determining the proportion of the available population assigned to each measure. In estimating the technical potential, measures with the most savings are given priority for installation. The applicability factors for Economic Potential, MAP and RAP are adjusted to account for cost-effectiveness screening results.[35]

Interactive Savings Adjustment. As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity equipment measures (versus retrofit measures that can be installed at any time). For example, the savings from a building shell measures are adjusted down to reflect the efficiency gains of installing efficient HVAC equipment. The

[34] 20 CSR 4240-20.050 (3)(G)2

[35] HVAC measure applicability with respect to early replacement and market opportunity measures are allocated in approximation with MEEIA Cycle 4 planning estimates.

analysis also prioritizes efficiency measures relative to conservation (behavioral) measures. These impacts are accounted for in all phases of estimated potential savings.

3.1.6 Economic Potential[36]

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the TRC Test) as compared to conventional supply-side energy resources. Both technical and economic potential ignore market barriers to ensuring actual implementation of energy efficiency. Finally, they typically only consider the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration, program evaluation, etc.) that would be necessary to capture them.

The State of Missouri Revised Statutes, Chapter 393, Section 393.1075.1, states that "The commission shall consider the total resource cost test a preferred cost-effectiveness test." The TRC test calculations in this study follow the prescribed methodology detailed in the latest version of the California Standard Practice Manual (CA SPM). The California Standard Practice Manual establishes standard procedures for cost-effectiveness evaluations for utility-sponsored or public benefits programs and is generally considered to be an authoritative source for defining cost-effectiveness criteria and methodology. This manual is often referenced by many other states and utilities.

Although the TRC Test was used as the primary screening test for measure, program, and portfolio cost-effectiveness for inclusion in economic, achievable, and program potential, measure level screening results for the Utility Cost Test (UCT) and Participant Cost Test (PCT) are also provided in the appendices of this report.[37] In each year of the analysis, the benefits of each measure are calculated as the cumulative energy and demand impact multiplied by all applicable avoided costs; the net present value of annual lifetime benefits are then compared against the cost of each measure.[38] Further definitions of the tests are outlined below:

The TRC test measures benefits and costs from the perspective of the utility and society as a whole. The benefits include the net present value of the energy and capacity saved by the measures but exclude any natural gas or other fossil fuel benefits. The forecast of electric avoided costs of energy and capacity were obtained from Ameren Missouri and represent their most recent forecast of avoided electric benefits.[39] The costs are the net present value of all costs to implement those measures. These costs include full incremental costs (both utility and participant contributions), but no incentive payments that offset incremental costs to customers and no lost revenues.[40] The full incremental costs include single upfront costs and operational & maintenance costs where applicable. While non-incentive costs were not included in the measure-level screening of electric energy efficiency potential, they were included in further assessments of potential at the achievable and/or program potential level. Programs passing the TRC test (that is, having a B/C ratio greater than 1.0) result in a decrease in the total cost of energy services to electric ratepayers.[41]

The UCT, also referred to as the Program Administrator Cost Test (PACT) measures the costs and benefits from the perspective of the utility administering the program. As such, this test is characterized as the revenue requirement test. Benefits are the net present value of the avoided energy and capacity costs resulting from the implementation of the measures. Costs are the administrative, marketing and evaluation costs resulting from program implementation along

[36] 20 CSR 4240-20.050 (5)

[37] 20 CSR 4240-20.050 (5)(B); 20 CSR 4240-20.050 (5)(C); 20 CSR 4240-20.050 (5)(E); 20 CSR 4240-20.050 (5)(F); 20 CSR 4240-20.050 (5)(G)

[38] 20 CSR 4240-20.050 (5)(A)

[39] 20 CSR 4240-20.050 (5)(A)1 through 3; the MPS makes use of the avoided cost forecast provided by Ameren Missouri, and includes avoided capacity, transmission and distribution, and avoided energy. Ameren separately documents the methods and assumptions supporting the development of their avoided cost forecast in their IRP. The base avoided costs do not explicitly include any value for reduced carbon emissions. The MPS includes a sensitivity on avoided costs that could be considered as an examination of the potential impacts of additional environmental costs and the IRP, itself, is also expected to assess these impacts.

[40] 20 CSR 4240-20.050 (5)(B)(1); 20 CSR 4240-20.050 (5)(B)(3)

[41] 20 CSR 4240-20.050 (5)(D)

with the costs of incentives but do not include lost revenues.[42] Programs passing the UCT result in overall net benefits to the utility, thus making the program worthwhile from a utility cost accounting perspective.

The PCT measures the benefits and costs from the perspective of program participants, or customers. Benefits are the net present value savings that participating customers receive on their electric bills as a result of the implementation of the energy efficiency and demand response measures plus incentives received by the customer. Costs are the customer's up-front net capital costs to install the measures. If the customer receives some form of a rebate incentive, then those costs are considered as a credit to the customer and are added to the customer's total benefits.

All measures that are not found to be cost-effective based on the results of the measure-level cost effectiveness screening were excluded from the economic and achievable potential. Feasibility factors were then re-adjusted and applied to the remaining measures that are cost effective, where appropriate.

For measures applicable to the income-qualified segment of the residential sector, any measure that was offered via Ameren Missouri's income-eligible program was not required to have a TRC benefit-cost ratio greater than 1.0 (i.e. net benefits are greater than costs).[43]

3.1.7 Achievable Potential[44]

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study will evaluate two achievable potential scenarios:

- ***Maximum Achievable Potential*** estimates achievable potential from aggressive adoption rates based on paying incentives equal to 100% of measure incremental costs and increased program awareness.
- ***Realistic Achievable Potential*** estimates achievable potential with Ameren Missouri paying incentive levels (as a percent of incremental measure costs) and program awareness closely calibrated to historical levels but is not constrained by any previously determined spending levels.

3.1.7.1 Market Adoption Rates

The assumed level of customer participation (take rate) for each energy efficiency measure is a key driver of achievable potential estimates. To inform estimates of future market adoption, the GDS Team relied on both the historical achievements of Ameren Missouri in prior years, as well as measure specific final adoption rates that were developed primary market research activities conducted for the 2020 study.[45] The historical benchmarking provides a point-estimate to serve as an initial "ground floor" market adoption rate while the final adoption rates from the market research reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios. Addition detail, including an example demonstrating how the final market adoption curve was developed is provided below. A complete list of annual market adoption rates by measures are included in appendices to this report.

[42] 20 CSR 4240-20.050 (5)(C)1; 20 CSR 4240-20.050 (5)(C)2

[43] 20 CSR 4240-20.050 (5)(D)

[44] 20 CSR 4240-20.050 (2)(G)5B

[45] 20 CSR 4240-20.050 (2)

Initial Year Measure Adoption. First year adoption levels were informed either by recent historical[46] or planned performance (where possible) or by the primary market research indicating the current saturation of energy efficient equipment.

Long-Term Market Adoption Rates. The final adoption scores that resulted from the willingness-to-participate (WTP) surveys serve as the point-estimate for the long-term market adoption potential for the realistic achievable scenario. Final adoption score calculations were based on a battery of questions which assessed (1) the respondent's willingness to adopt energy efficiency technologies or participate in demand response programs in scenarios with varying levels of program support, (2) the magnitude of the respondent's financial and non-financial barriers to adoption/participation, and (3) their awareness of Ameren Missouri energy efficiency programs and/or high efficiency technologies. Measure specific final adoption scores in the RAP scenario were based on the assumed current incentive level.

For the maximum achievable scenario, the final adoption score was adjusted upward, assuming an increase in customer awareness of Ameren Missouri programs and/or technologies. Specifically, the MAP scenario assumed an awareness factor adjustment of 73% or maintained the original awareness factor score if already 73% or higher.

Adoption Curve. Once the initial year adoption rate (Point A) and long-term adoption rates (Point B) are determined, the remaining step was to determine the rate and duration to get from Point A to Point B. The 2023 study employed a standard s-curve that was set to either 15 years (in MAP scenario) or 20 years (in RAP scenario) with the end-point estimate from the market research conducted for the 2020 study. The 1st year point estimate is then used to establish the number of years remaining to reach the long-term adoption rate and the slop of adoption. An example of this process is provided below.

[46] GDS performed a historical benchmarking and variance analysis between Ameren Missouri's evaluated performance relative to estimates of potential included in the 2020 study. This variance analysis helped to identify measures with significant variation between prior potential models and actual results.

Using a residential refrigerator as an example, the maximum adoption rate for the market-rate single family appliance end-use is 66%, assuming 100% incentive. The realistic adoption rate, also for the market-rate single family appliance end-use, is 45% (based on an assumed incentive that covers 50% of the incremental cost of an energy efficient refrigerator). In addition, according to the primary market research, approximately 25% of refrigerators in the Ameren Missouri service area are already energy efficient, serving as the point-estimate for the initial year adoption rate. The assumed 15-year MAP and 20-year RAP adoption curves, as well as the initial year adoption rate are all shown in the left line chart.

For the final adjusted adoption curve, the intersection of the initial year adoption rate and the unadjusted MAP and RAP adoption curve identifies the new shape of the curve. Using the initial year adoption rate of approximately 25% for energy-efficient refrigerators the MAP starting point shifts along the initial MAP curve to Year 6 (with 9 years remaining to reach the long-term MAP adoption rate of 66%), and to Year 11 (also with 9 years remaining to reach the long-term RAP adoption rate of 45%). The final adjusted MAP and RAP adoption curves are shown in the right line chart.

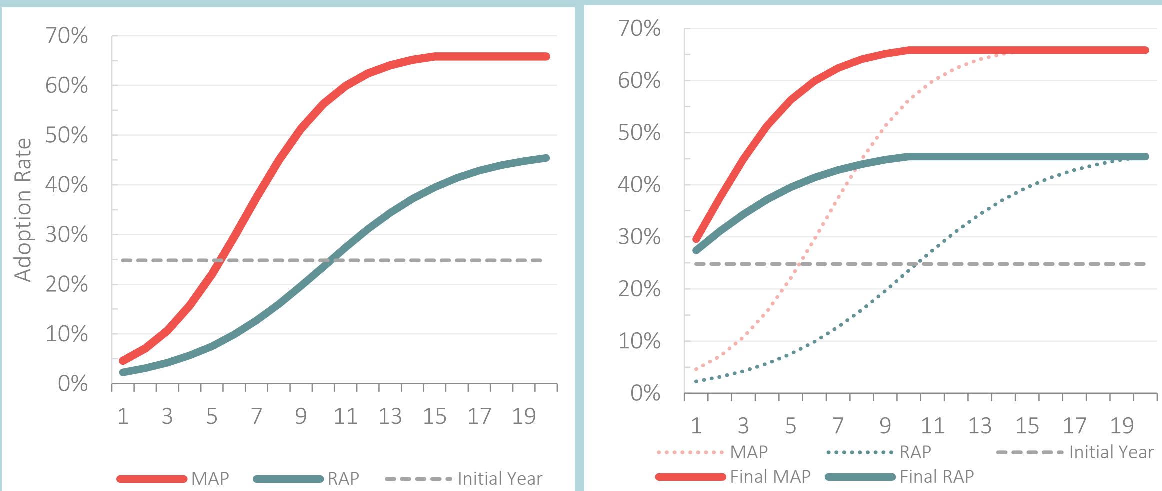


FIGURE 3-3: EXAMPLE INITIAL ADOPTION CURVES *(left)* **AND FINAL ADJUSTED ADOPTION CURVES FOR MAP AND RAP** *(right)*

3.1.7.2 Program Costs

GDS conducted a summary review of available information pertaining to Ameren Missouri's evaluated energy efficiency program performance. GDS reviewed each of Ameren's filed annual evaluation reports for 2021-2023 and collected various data points including Ameren direct and indirect expenditures to establish benchmarking data on Ameren's performance of their DSM programs under MEEIA. Metrics tracked included:

- Gross and Net Energy Savings
- Incentive expenditures as a percentage of incremental measure costs
- Administrative cost ($ per 1st-year kWh saved)

The purpose of this step was to understand historical program delivery performance, and to help inform estimates of maximum and realistic achievable potential. Table 3-2 summarizes the observed incentive cost trends observed for the Ameren Missouri territory and applied to the analysis.[47] Incentives were derived primary from the Ameren Missouri submittal tool. For study measures that do not map directly to a current offering or were not in the submittal tool, GDS calculated the average incentive level by sector and/or program and applied these "typical" incentive levels to the new measures. The incentive cost assumptions below were applied in the RAP and program RAP scenarios. The remaining

[47] 20 CSR 4240-20.050 (3)(G)5B

portion of the incremental measure cost is assumed to be borne by the consumer.[48] MAP and program MAP assume that incentives are equal to 100% of incremental measure cost.

TABLE 3-2: AVERAGE AMEREN MISSOURI INCENTIVE LEVELS BY END-USE

Residential	Incentive as a % of Incremental Measure Cost	Business	Incentive as a % of Incremental Measure Cost
Appliances	86%	Compressed Air	48%
Behavior	84%	Cooking	31%
Building Shell	55%	Hot Water	38%
Custom	100%	HVAC	24%
Electronics	92%	Lighting	43%
HVAC	67%	Miscellaneous	33%
Lighting	72%	Motors	53%
Pool	53%	Plug Loads	38%
Water Heating	92%	Refrigeration	38%
New Construction	92%	Whole Building	34%

Consistent with National Action Plan for Energy Efficiency (NAPEE) guidelines[49], utility non-incentive costs were also included in the overall assessment of cost-effectiveness in the achievable and program potential MAP and RAP scenarios. Initial Year (2024) non-incentive costs were developed using recent PY21-PY23 actual program cost data. Program non-incentive costs were calculated on a gross $ per first-year kWh saved. Where a three-year trend was present, GDS applied the latest year $/kWh to forecasted potential incremental annual savings to develop an estimate of future year non-incentive budgets. If a consistent trend was not present, the average $/kWh over the last three program years was used. Future year non-incentive costs were then escalated annually at half the rate of inflation%. [50]

Non-incentive costs were developed for each program by sector.[51] Figure 3-4 shows the historical non-incentive costs and by sector used to develop the assumptions for the 2023 study.

[48] 20 CSR 4240-20.050 (3)(G)5D

[49] National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Efficiency Potential Studies. Prepared by Optimal Energy. This study notes that economic potential only considers the cost of efficiency measures themselves, ignoring programmatic costs. Conversely, achievable potential should consider the non-measures costs of delivering programs. Pg. 2-4.

[50] As noted earlier in the report, measure costs and utility incentives were not escalated over the 20-year analysis timeframe to keep those costs constant in nominal dollars. Non-incentive costs were escalated at only ½ the rate of inflation to acknowledge the possibility of select operational efficiency gains off-setting administrative increases from salary raises, cost-of-living and other factors.

[51] 20 CSR 4240-20.050 (3)(G)5E; 20 CSR 4240-20.050 (3)(G)5F

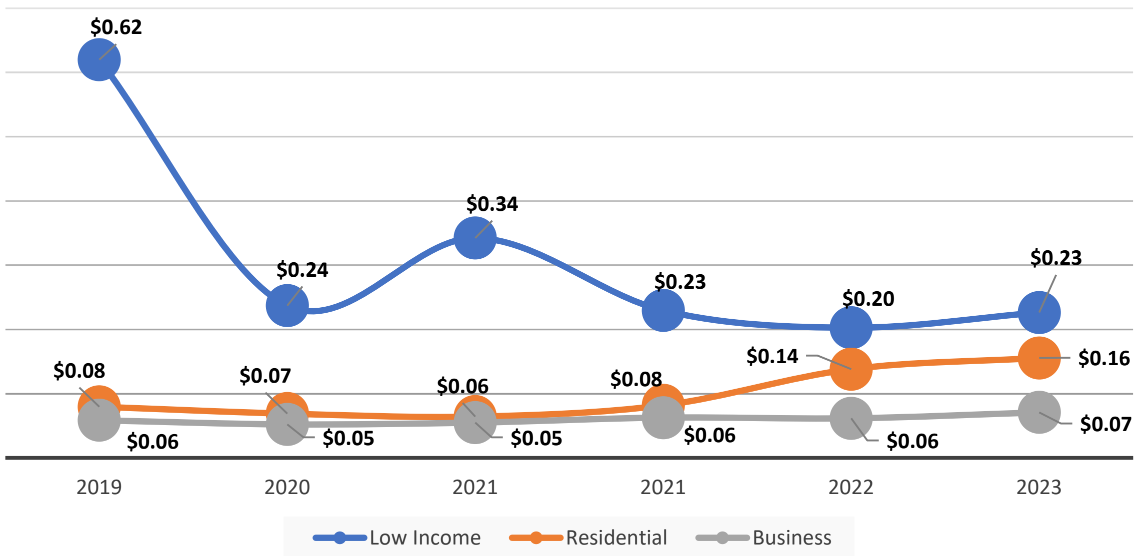


FIGURE 3-4 HISTORICAL NON-INCENTIVE COSTS BY SECTOR

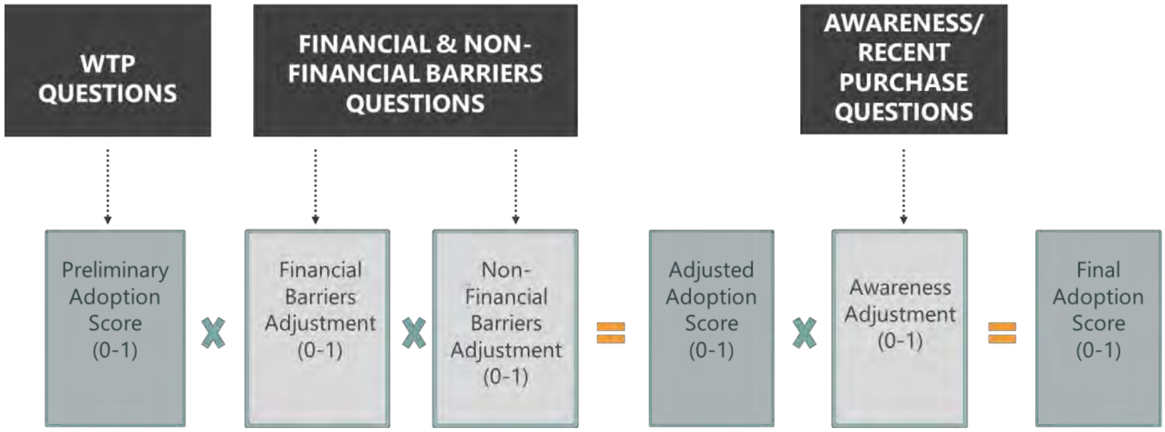
3.1.7.3 Adoption Curve Market Data

One of the major objectives of the primary research conducted for the 2020 study was to develop survey research that could be utilized to develop measure/program adoption curves to develop estimates of achievable potential. Table 3-3 describes the end-uses or categories in which adoption rate estimates were developed for energy efficiency, demand response programs, or distributed energy resources.

TABLE 3-3: ADOPTION RATE CATEGORIES ANALYZED

Willingness to Participate	EE End Uses	DR Programs	DER
Residential Customers	Heating/CAC Heat Pump Water Heater Major Appliances Insulation/Air Sealing	Central AC Control	Solar PV (Purchase) Solar PV (Lease) Electric Vehicles (EVs)
MF Building Owners	Heating/CAC Heat Pump Water Heater Insulation/Air Sealing	n/a	Solar PV (Purchase) Solar PV (Lease)
Business Customers	HVAC Equipment Water Heating Equip. Refrigeration Lighting Equipment	Central AC Control Water Heater Control Customized DR	Solar PV (Purchase) Solar PV (Lease)

Adoption rate calculations were based on a battery of questions which assessed (1) the respondent's willingness to adopt energy efficiency technologies or participate in demand response programs in scenarios with varying levels of program support, (2) the magnitude of the respondent's financial and non-financial barriers to adoption/participation, and (3) their awareness of Ameren Missouri energy efficiency programs and/or high efficiency technologies. Adoption rates were calculated based on the equation shown below.



EQUATION 3-2: ADOPTION RATE FORMULA FOR FINAL ADOPTION SCORE

Direct willingness-to-participate questions are the starting point of measure/program-specific adoption curve calculations. For each item, respondents were asked to rate the likelihood that they would purchase the energy efficient version of the equipment, or participate in the DR program, at various incentive levels, including no incentive and an incentive that covers the full incremental (or total) cost. An example question from the residential online survey is provided below:

> *Now, please think about what actions you would take with respect to replacing a broken major appliance if incentives were available to cover some or all the cost. These incentives could come in the form of a rebate after purchasing.*
>
> *Again, one example of appliance costs is the cost of a standard versus high efficiency clothes washer. The cost of a typical standard efficiency clothes washer is about $450 while the cost of a high efficiency clothes washer is about $600. An energy efficient appliance like this would give you an energy saving of about $10-$15 a year compared to the stand efficiency model.*
>
> *If you had to replace a broken appliance, how likely would you be to purchase an ENERGY EFFICIENT model to replace this broken equipment, if there was…*
>
> *a. NO incentive?*
>
> *b. An incentive for ONE-QUARTER of the additional cost of an energy efficient model, compared to a standard model? (If the energy efficient model cost $600 and a standard model cost $450, the incentive would cover $38 of the additional cost of $150.)*

Responses to financial and non-financial barrier questions were then used to adjust the preliminary adoption score. Last, to reflect that some customers who might otherwise participate will not be aware of the program, survey respondents were also asked about their current awareness of Ameren Missouri programs/incentives. Key adoption rates are provided below. In addition, Section 3.1.7.1 has additional description regarding the utilization of the adoption rate research for assessing achievable savings potential.

3.1.7.3.1 Residential Sector Final Adoption Scores

Table 3-4 presents the final adoption scores (after all adjustments) based on responses by residential homeowners and tenants, segmented between market-rate and income-eligible customers. In general, market rate customers indicated a greater willingness to participate and install energy efficiency measures across all end-uses, particularly at lower incentive levels relative to income-eligible customers.

TABLE 3-4: HOMEOWNER/TENANT FINAL ADOPTION SCORES BY INCENTIVE LEVEL

Homeowners / Tenants	Annual Incentive (% of incremental measure cost)				
	0%	25%	50%	75%	100%
HVAC	26%	38%	46%	53%	59%
Water Heat	6%	11%	17%	21%	25%
Insulation	10%	22%	33%	43%	55%
Appliances	23%	30%	38%	44%	51%
Market Rate	0%	25%	50%	75%	100%
HVAC	31%	44%	53%	59%	64%
Water Heat	6%	12%	16%	21%	24%
Insulation	12%	26%	37%	48%	59%
Appliances	26%	33%	40%	46%	52%
Income-Eligible	0%	25%	50%	75%	100%
HVAC	17%	25%	33%	42%	50%
Water Heat	4%	10%	16%	22%	28%
Insulation	4%	13%	23%	32%	44%
Appliances	16%	25%	33%	40%	48%

Table 3-5 provides final adoption scores based on survey responses from multifamily property managers and/or building owners. For multifamily property manager and owner WTP (as well as in the business sector), incentives were described in the form of payback periods to better align with how purchasing decisions are likely to considered.

TABLE 3-5: MULTIFAMILY PROPERTY MANAGER/BUILDING OWNER FINAL ADOPTION SCORES BY PAYBACK PERIOD

MF Property Managers	Payback Years				
	10 Y	5 Y	3 Y	1 Y	0 Y
HVAC	18%	32%	42%	50%	57%
Water Heat	11%	21%	28%	36%	42%
Insulation	13%	26%	38%	50%	59%
Market Rate	10 Y	5 Y	3 Y	1 Y	0 Y
HVAC	16%	30%	40%	48%	56%
Water Heat	8%	16%	23%	29%	35%
Insulation	10%	24%	35%	47%	54%
Income-Eligible	10 Y	5 Y	3 Y	1 Y	0 Y
HVAC	24%	36%	47%	56%	60%
Water Heat	20%	33%	46%	54%	62%
Insulation	21%	34%	50%	65%	81%

Final adoption scores for residential direct load control (DLC) of central AC and water heating systems is shown in Table 3-6, depending on varying annual incentive levels. Current annual incentive offerings are $25 for direct load control of central air conditioning systems. Table 3-7 provides the final adoption score for a Time of Use (TOU) rate option based on a prescribed difference between peak and off-peak rates.

TABLE 3-6: DLC DEMAND RESPONSE FINAL ADOPTION SCORES BY INCENTIVE LEVEL

DR - DLC	Annual Incentive (% of incremental measure cost)				
	$0	$15	$25	$35	$50
Central AC	10%	15%	18%	21%	26%
Water Heat	5%	10%	14%	17%	22%
Market Rate	$0	$15	$25	$35	$50

Schedule MM-24

Central AC	11%	16%	20%	24%	28%
Water Heat	5%	11%	15%	18%	22%
Income-Eligible	$0	$15	$25	$35	$50
Central AC	8%	12%	15%	18%	22%
Water Heat	5%	10%	14%	17%	23%

TABLE 3-7: TOU DEMAND RESPONSE FINAL ADOPTION SCORES BY INCENTIVE LEVEL

DR - Rate	Peak: Off Peak Ratio[52]			
	3:1	4:1	6:1	8:1
DR-TOU	14%	19%	24%	30%
Market Rate	3:1	4:1	6:1	8:1
DR-TOU	19%	26%	33%	40%
Income-Eligible	3:1	4:1	6:1	8:1
DR-TOU	4%	7%	9%	10%

The final adoption scores related to select distributed energy resources are presented in Table 3-8. Survey questions asked participants about their likelihood to purchase and/or lease solar PV systems as well as electric vehicles assuming different incentive level amounts (or payback periods).

TABLE 3-8: RESIDENTIAL DER FINAL ADOPTION SCORES

Solar Purchase	Annual Incentive (% of incremental measure cost)				
	0%	25%	50%	75%	100%
Homeowners/Tenants	5%	19%	36%	52%	74%
Solar Purchase	Payback Years				
	10 Y	5 Y	3 Y	1 Y	0 Y
Multifamily Property Managers/Owners	10%	20%	34%	44%	56%
Solar Lease	Annual Incentive (% of incremental measure cost)				
	0%	25%	50%	75%	100%
Homeowners/Tenants	5%	14%	24%	33%	41%
Solar Lease	Incentive				
	$0	$1,250	$2,500	$3,750	$5,000
Multifamily Property Managers/Owners	5%	21%	33%	49%	55%
	Incentive				
	$0	$8,300	$12,500	$25,000	$33,300
Electric Vehicle	9%	23%	36%	47%	59%

[52] In the survey, peak rate was defined as $0.24/kWh. At a 3:1 peak to off-peak ratio, where the peak rate is $0.24/kWh, the off-peak rate is $0.08/kWh.

3.1.7.3.2 Business Sector Final Adoption Scores

Table 3-9 presents the final adoption scores (after all adjustments) for small business customers across several end-uses, depending on whether the investment is a minor or major investment. Small businesses indicated a minor investment to be approximately $4,000 or less. Final adoption scores were generally similar regardless of the initial investment amount.

TABLE 3-9: SMALL BUSNESS FINAL ADOPTION SCORES BY INCENTIVE LEVEL AND INVESTMENT TYPE

Small Business; Minor Inv.	Annual Incentive				
	0%	25%	50%	75%	100%
HVAC	14%	20%	25%	29%	32%
Lighting	14%	20%	25%	30%	33%
Refrigeration	12%	18%	25%	27%	30%
Water Heat	14%	20%	25%	29%	32%
Small Business; Major Inv.	**Annual Incentive**				
	0%	**25%**	**50%**	**75%**	**100%**
HVAC	15%	22%	29%	33%	36%
Lighting	16%	24%	29%	34%	37%
Refrigeration	14%	21%	26%	29%	32%
Water Heat	15%	23%	29%	33%	36%

Table 3-10 presents the final adoption scores (after all adjustments) for medium/large business customers depending on whether the investment is a minor or major investment. Medium/Large businesses indicated a minor investment to be roughly $20,000 or less. While final adoption scores were generally similar regardless of the initial investment amount, medium/large businesses indicated they were more likely to adopt efficiency measures than small businesses, regardless of incentive level.

TABLE 3-10: MEDIUM/LARGE BUSINESS FINAL ADOPTION SCORES BY INCENTIVE LEVEL AND INVESTMENT TYPE

Med/Large Business; Minor Inv.	Annual Incentive (% of incremental measure cost)				
	0%	25%	50%	75%	100%
HVAC	24%	35%	44%	53%	58%
Lighting	26%	38%	48%	55%	60%
Refrigeration	25%	36%	47%	53%	58%
Water Heat	25%	37%	48%	55%	60%
Med/Large Business; Major Inv.	**Annual Incentive (% of incremental measure cost)**				
	0%	**25%**	**50%**	**75%**	**100%**
HVAC	24%	35%	44%	51%	55%
Lighting	27%	39%	47%	53%	58%
Refrigeration	25%	36%	46%	52%	56%
Water Heat	25%	38%	47%	54%	57%

Final adoption scores for business sector demand response options are shown in Table 3-11, depending on varying annual incentive levels for direct load control as well as volunteer load reduction. The table also provides business sector responses for participation likelihood for a TOU DR rate program on a prescribed difference between peak and off-peak rates designs.

TABLE 3-11: BUSINESS SECTOR DEMAND RESPONSE FINAL ADOPTION SCORES

DR - DLC	Annual Incentive				
	$0	$15	$25	$35	$50
Central AC	6%	7%	9%	10%	12%
Water Heat	5%	8%	10%	11%	14%
DR – Capacity Bidding	**Incentive per kW**				
	$0	**$25**	**$50**	**$100**	
Custom DR-Large C&I Aggregator	8%	18%	27%	34%	
DR - TOU	**Peak: Off-Peak Ratio**				
	3:1	**4:1**	**6:1**	**8:1**	
DR-TOU	5%	7%	9%	12%	

Table 3-12 provides the final adoption scores for solar PV purchasing and/or leasing in the business sector. As with the energy efficiency measures, medium/large businesses indicate they are more likely to adopt DER measures across all incentive categories.

TABLE 3-12: BUSINESS SECTOR DER FINAL ADOPTION SCORES

Purchased Solar	15 YR+	10 YR	5 YR	3 YR	1 YR	0 YR
Small Business	4%	8%	14%	17%	21%	23%
Med/Lg Business	5%	9%	17%	22%	26%	30%
Solar Lease	**$0.00**	**Min (1/12 total cost)**	**Low (1/8 total cost)**	**High (1/4 total cost)**	**Max (1/3 total cost)**	
Small Business	2%	7%	10%	14%	17%	
Med/Lg Business	2%	8%	13%	17%	20%	

3.1.8 Program Potential

Program potential includes the allocation and bundling of individual measures into specific program concepts to support Ameren Missouri's program planning process. All cost-effective measures across all end-uses were bundled into programs based on a mapping to existing Ameren Missouri programs or new programs, if necessary.[53] Program potential cases were created based on the RAP and MAP achievable potentials.

3.1.8.1 Net to Gross (NTG)

All estimates of technical and economic potential, as well as measure level cost-effectiveness screening are conducted in terms of gross savings to reflect the absence of program design considerations in these phases of the analysis. The initial estimates of maximum and program achievable potential are also presented in the context of gross savings. Program Potential MAP and RAP are, however, presented in terms of net savings to reflect the importance of program design in overcoming market barriers to participation.

Net energy savings consider free-riders (participants who would have installed the high efficiency option in the absence of the program) and spillover customers (participants who install efficiency measures due to program activities, but never receive a program incentive). Measure net-to-gross ratios were based on the most recent

[53] 20 CSR 4240-20.050 (1)(B) and 20 CSR 4240-20.050 (3)(C)

Schedule MM-24

evaluation findings of Ameren Missouri's efficiency programs and mapped to individual measures in both the residential market rate and business sector. Assumed net to gross ratios for each measure are based on reported NTG ratios in the 2021 evaluation portfolio summary reports. The application of NTG ratios, as well as a shift in reporting from end-use detail to program offering, are the sole differences between the initial estimates of MAP/RAP and Program Potential MAP/RAP in this report.

3.2 RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

This section provides the potential results for technical, economic, MAP and RAP for the residential sector. Incremental and cumulative annual data is provided. Results are shown by end use and building type.

3.2.1 Scope of Measures & End Uses Analyzed

There were 185 total unique residential electric measures included in the analysis. Table 3-13 provides the number of unique measures by end-use. The measure list was developed based on a review of current Ameren Missouri programs, the Illinois TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 3-13: RESIDENTIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures	Number of Permutations
Appliances	12	73
Behavior	3	18
Building Shell	60	240
Custom	2	2
Electronics	4	37
HVAC	73	731
Lighting	15	62
Pool	4	34
Water Heating	10	60
New Construction	2	4
Total	**185**	**1,261**

3.2.2 Summary of Residential Electric Potential

Figure 3-5 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 20-year timeframes. The respective 20-yr technical and economic potential is 37% and 33% of residential sector sales. The MAP reaches 3.1% in three years and grows to 10.1% over ten years, while the RAP reaches 2.4% in three years and grows to 8.2% over ten years. The MAP and RAP reach 17% and 14% of residential sector sales, respectively, over the 20-yr timeframe of the study. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

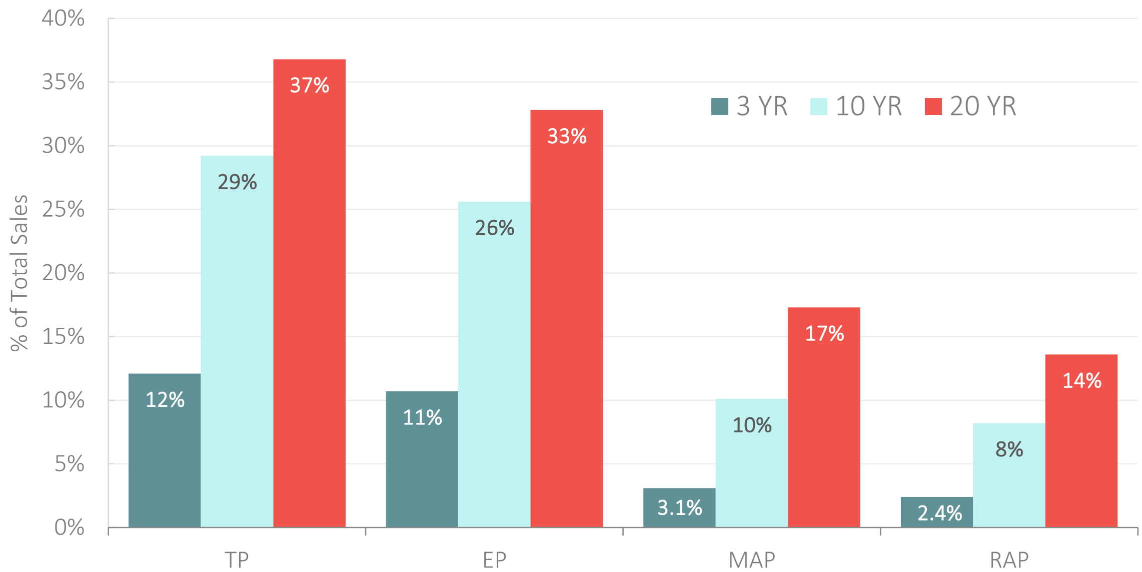


FIGURE 3-5: OVERVIEW OF RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

Table 3-14 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The MW demand savings for each level of potential are also provided. In 2024, the RAP is 0.8% of sector sales with more than 105,000 MWh in estimated energy savings and 47 MW in demand savings. By 2033, the estimated cumulative annual savings in the RAP scenario reaches 8.2% of sector sales at 1.2 million MWh and 418 MW in demand savings.

TABLE 3-14: RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2024	2025	2026	2033	2043
MWh					
Technical	621,001	1,178,484	1,680,446	4,363,340	6,134,445
Economic	552,293	1,048,092	1,491,718	3,835,712	5,474,181
MAP	135,879	277,386	425,110	1,508,303	2,878,344
RAP	105,159	216,057	333,390	1,223,770	2,262,238
Forecasted Sales	13,508,700	13,523,783	13,910,491	14,966,747	16,671,167
Technical	4.6%	8.7%	12.1%	29.2%	36.8%
Economic	4.1%	7.8%	10.7%	25.6%	32.8%
MAP	1.0%	2.1%	3.1%	10.1%	17.3%
RAP	0.8%	1.6%	2.4%	8.2%	13.6%
MW					
Technical	216	415	580	1,398	1,863
Economic	192	369	516	1,186	1,536
MAP	59	119	181	524	799
RAP	47	95	144	418	601

3.2.3 Detail of Residential Technical, Economic and Achievable Potential and Breakout by End Use

Table 3-15 provides cumulative annual technical, economic, and achievable potential results, by end-use, across the 20-yr study timeframe. The HVAC end use has the most potential in each scenario, with the Water Heating, Building Shell, and Appliances end uses also contributing a significant amount potential in each scenario.

Schedule MM-24

TABLE 3-15: RESIDENTIAL ELECTRIC POTENTIAL – DETAIL BY END USE AND SCENARIO (MWH)

End Use	Technical	Economic	MAP	RAP
Appliances	460,671	287,637	141,808	117,014
Behavior	237,407	252,088	58,823	57,189
Building Shell	770,221	584,082	305,625	178,749
Custom	81,294	4,755	3,035	2,763
Electronics	89,645	90,464	45,788	30,854
HVAC	3,462,501	3,253,587	1,868,685	1,529,090
Lighting	203,799	201,682	91,368	69,953
Pool	17,209	2,714	1,431	1,048
Water Heating	671,517	656,989	313,965	233,316
New Construction	140,182	140,182	47,816	42,261
Total	**6,134,445**	**5,474,181**	**2,878,344**	**2,262,238**
Savings as % of Forecast	**36.8%**	**32.8%**	**17.3%**	**13.6%**

Figure 3-6 provides the MAP and RAP across the 20-yr timeframe of the study. The green and orange bars provide the respective incremental annual MAP and RAP in MWh per year energy savings. The green and red lines provide the corresponding cumulative annual MAP and RAP as a percent of forecasted annual sales. The MAP rises to 17% by 2043 and the RAP rises to 14%.

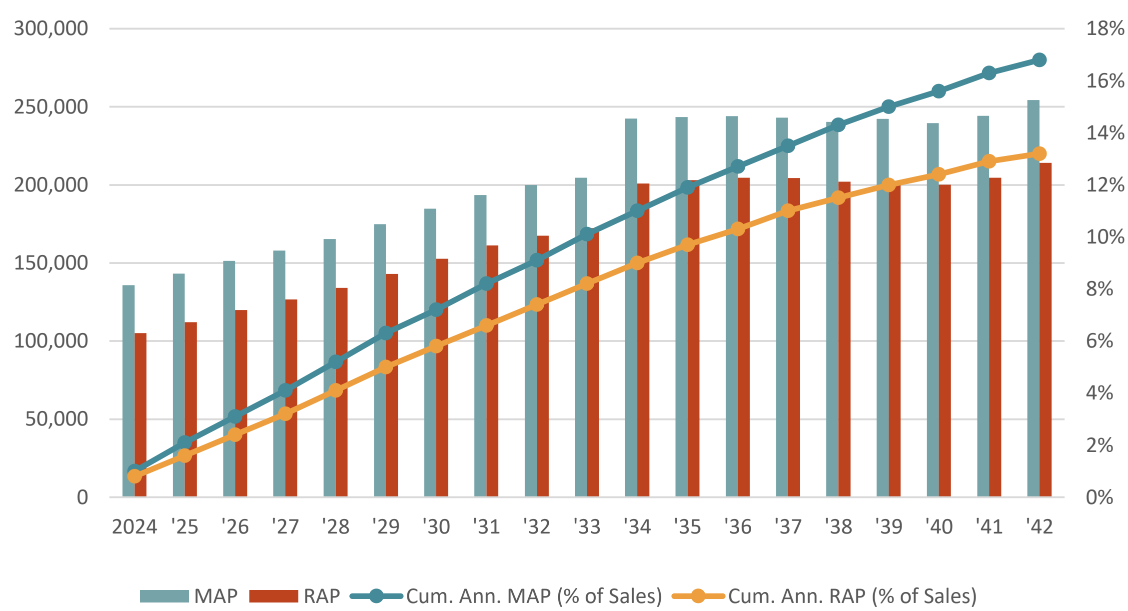


FIGURE 3-6: OVERVIEW OF ANNUAL RESIDENTIAL ACHIEVABLE POTENTIAL

Figure 3-7 provides a breakdown of the RAP potential in 2043 across end-uses and building type market segments. As in technical and economic potential, the HVAC Equipment is by far the leading end-use accounting for 68% of the total. Water Heating accounts for 10% and Building Shell accounts for an additional 8%. The remaining 14% is comprised of Lighting, Behavior, New Construction, Electronics and Custom measures. The single family and multifamily market rate housing sector represents 53% of the potential, while 41% is contributed by the low-income sector, and the remaining 6% is in the new construction housing market.

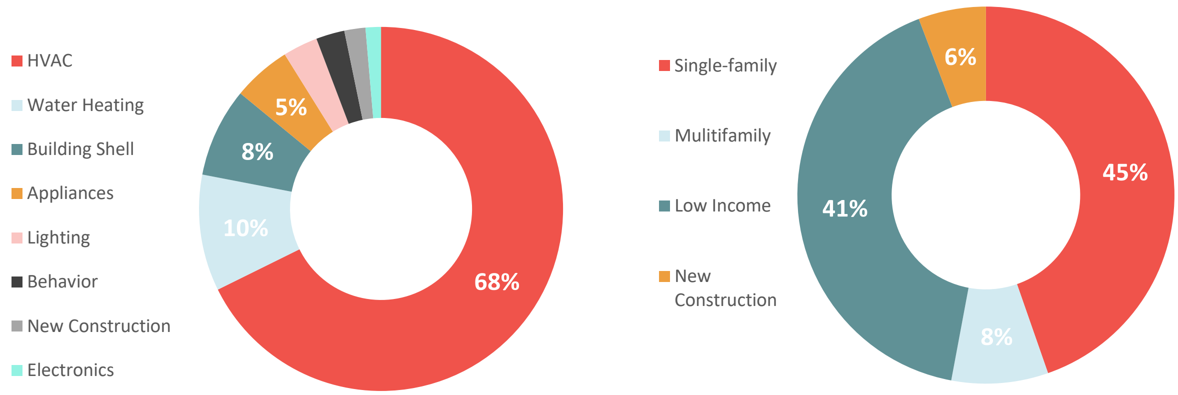


FIGURE 3-7: RESIDENTIAL REALISTIC ACHIEVABLE POTENTIAL BY END-USE AND BUILDING TYPE – 20-YR CUMULATIVE ANNUAL

Table 3-16 provides additional end-use level detail for the incremental annual residential MAP and RAP. On an incremental annual basis, the MAP ranges from 1.0% to 1.2% over the first six years of the study, with more than half of the savings from the HVAC end use. The RAP ranges from 0.8% to 1.0% of savings on an incremental annual basis. The RAP savings are also dominated by the HVAC end use, with sizeable contributions also from the Water Heating, Appliances, and Building Shell end uses.

TABLE 3-16: RESIDENTIAL INCREMENTAL MAP AND RAP – END USE DETAIL

	2024	2025	2026	2027	2028	2029
MAP Incremental Annual MWh						
Appliances	3,359	4,106	4,919	5,778	6,665	7,557
Behavior	1,941	2,763	3,351	4,016	4,894	7,093
Building Shell	33,316	34,298	33,343	31,517	29,506	27,928
Custom	536	508	457	393	325	259
Electronics	7,720	5,435	4,967	4,436	3,892	3,370
HVAC	79,781	85,908	92,344	97,971	104,019	109,613
Lighting	3,167	3,700	4,071	4,435	4,844	5,432
Pool	88	99	109	118	126	132
Water Heating	5,403	5,527	6,825	7,975	9,675	11,557
New Construction	567	797	1,005	1,207	1,459	1,819
Total	**135,879**	**143,142**	**151,390**	**157,846**	**165,405**	**174,762**
% of Forecasted Sales	**1.0%**	**1.1%**	**1.1%**	**1.1%**	**1.2%**	**1.2%**
RAP Incremental Annual MWh						
Appliances	2,452	3,024	3,659	4,344	5,066	5,806
Behavior	1,818	2,593	3,156	3,799	4,647	6,733
Building Shell	17,640	18,034	17,344	16,285	15,293	14,649
Custom	488	463	416	358	296	236
Electronics	5,155	3,458	3,272	3,016	2,715	2,369
HVAC	70,958	76,840	82,591	87,995	93,221	98,290
Lighting	2,719	3,078	3,372	3,671	3,997	4,409
Pool	70	77	84	90	95	100
Water Heating	3,356	3,898	4,984	5,947	7,354	8,870
New Construction	501	705	888	1,067	1,289	1,608
Total	**105,159**	**112,170**	**119,766**	**126,573**	**133,973**	**143,071**
% of Forecasted Sales	**0.8%**	**0.8%**	**0.9%**	**0.9%**	**0.9%**	**1.0%**

3.3 BUSINESS ENERGY EFFICIENCY POTENTIAL

This section provides the potential results for technical, economic, MAP and RAP for the business sector. Incremental and cumulative annual data is provided. Results are shown by end use and building type.

3.3.1 Scope of Measures & End Uses Analyzed

There were 195 total unique business electric measures included in the analysis. Table 3-17 provides the number of unique measures by end-use. The measure list was developed based on a review of current Ameren Missouri programs, the Illinois TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 3-17: BUSINESS ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures	Number of Permutations
HVAC	7	77
Lighting	10	110
Refrigeration	6	66
Office Equipment	44	473
Whole Building	34	374
Cooking	11	121
Process	5	55
Compressed Air	11	121
Behavioral	26	286
Miscellaneous	5	55
Hot Water	10	110
Motors	17	17
Agriculture	9	9
Total	**195**	**1,874**

3.3.2 Summary of Business Electric Potential

Figure 3-8 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 20-year timeframes. The respective 20-yr technical and economic potential is 35% and 32% of business sector sales. The MAP reaches 6.4% in three years and grows to 17.1% over ten years, while the RAP reaches 4.7% in three years and grows to 12.6% over ten years. The MAP and RAP reach 22% and 16% of business sector sales, respectively, over the 20-yr timeframe of the study. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

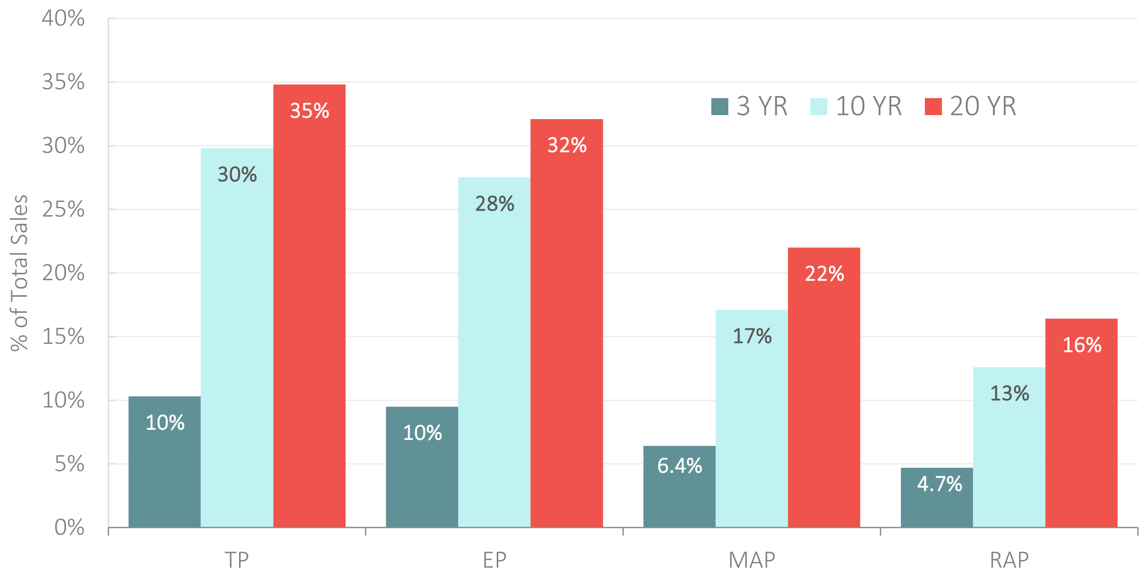


FIGURE 3-8: OVERVIEW OF BUSINESS ENERGY EFFICIENCY POTENTIAL

Table 3-18 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The MW demand savings for each level of potential are also provided. In 2024, the RAP is 1.6% of sector sales with more than 233,000 MWh in estimated energy savings and 63 MW in demand savings. By 2033, the estimated cumulative annual savings in the RAP scenario reaches 12.6% of sector sales at 1.9 million MWh and 557 MW in demand savings.

TABLE 3-18: BUSINESS CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2024	2025	2026	2033	2043
MWh					
Technical	468,422	963,866	1,483,470	4,458,691	5,462,287
Economic	436,911	897,084	1,380,145	4,116,578	5,036,977
MAP	316,388	623,887	921,943	2,554,287	3,452,685
RAP	233,465	458,816	678,451	1,885,518	2,573,513
Forecasted Sales	14,451,697	14,465,588	14,529,355	15,026,417	15,778,731
Technical	3.3%	6.7%	10.3%	29.8%	34.8%
Economic	3.0%	6.2%	9.5%	27.5%	32.1%
MAP	2.2%	4.3%	6.4%	17.1%	22.0%
RAP	1.6%	3.2%	4.7%	12.6%	16.4%
MW					
Technical	135	281	436	1,375	1,716
Economic	127	265	410	1,292	1,618
MAP	96	191	285	849	1,155
RAP	63	126	188	557	766

3.3.3 Detail of Business Technical, Economic and Achievable Potential and Breakout by End-Use

Table 3-19 provides cumulative annual technical, economic, and achievable potential results, by end-use, across the 20-yr study timeframe. The Lighting, HVAC and Whole Building / Behavioral end uses account for approximately 75%-80% of the potential each year, with Compressed Air, Hot Water, Motors, and Refrigeration each contributing a significant amount potential in each scenario.

TABLE 3-19: BUSINESS ELECTRIC POTENTIAL – DETAIL BY END USE AND SCENARIO (MWH)

End Use	Technical	Economic	MAP	RAP
Compressed Air	158,266	138,041	88,926	64,091
Cooking	8,678	8,747	5,003	4,092
Hot Water	163,436	157,009	92,955	70,327
HVAC	1,650,822	1,586,881	1,071,132	713,353
Lighting	1,394,182	1,382,401	1,018,288	818,856
Miscellaneous	197,593	163,803	85,548	60,947
Motors	594,309	580,925	370,759	275,404
Plug Loads / Office	153,743	136,763	82,032	58,271
Refrigeration	288,313	191,802	121,595	88,651
Whole Building / Behavioral	852,946	690,604	516,447	419,522
Total	**5,462,287**	**5,036,977**	**3,452,685**	**2,573,513**
Savings as % of Forecast	**34.6%**	**31.9%**	**21.9%**	**16.3%**

Figure 3-9 provides the MAP and RAP across the 20-yr timeframe of the study. The green and red bars provide the respective incremental annual MAP and RAP in MWh per year energy savings. The green and orange lines provide the corresponding cumulative annual MAP and RAP as a percent of forecasted annual sales. The MAP rises to 22% by 2043 and the RAP rises to 16%.

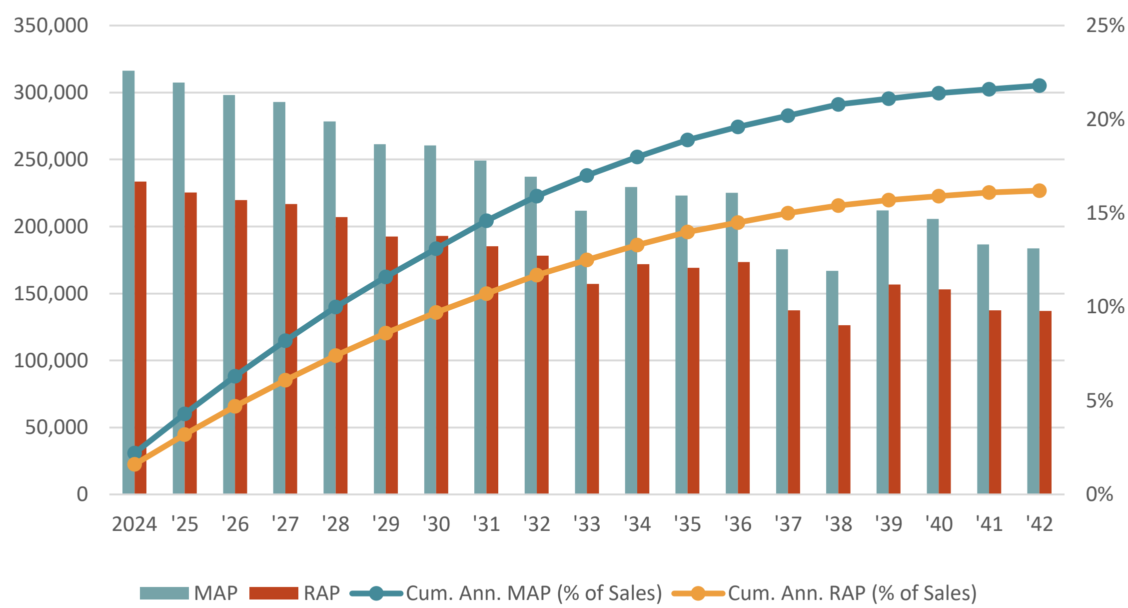
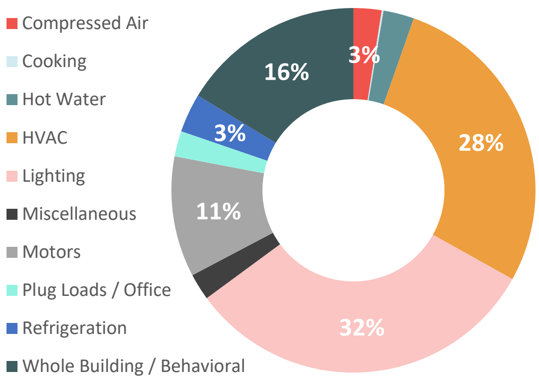


FIGURE 3-9: OVERVIEW OF ANNUAL BUSINESS ACHIEVABLE POTENTIAL

Figure 3-10 provides a breakdown of the RAP potential in 2043 across end-uses and building type market segments. In the RAP scenario, the HVAC, Lighting, Motors, and Whole Building / Behavioral end-uses combined to account for nearly 80% of the potential. Across building types, Office buildings, Industrial, and

Retail buildings provide close to 40% of the RAP. Food Service, Health, Lodging, Business Social Services, Assembly and Retail buildings account for between 4% and 8% of the RAP.



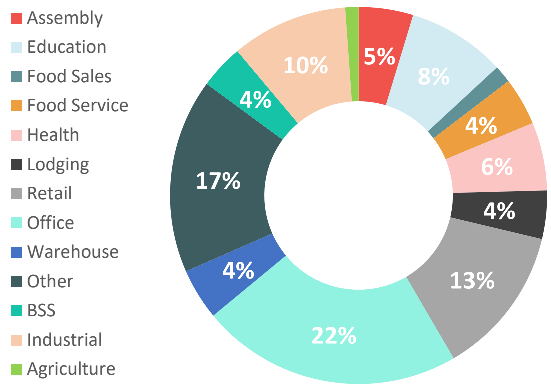


FIGURE 3-10: BUSINESS REALISTIC ACHIEVABLE POTENTIAL BY END-USE AND BUILDING TYPE – 20-YR CUMULATIVE ANNUAL

Table 3-16 provides additional end-use level detail for the incremental annual business MAP and RAP. On an incremental annual basis, the MAP ranges from 1.7% to 2.0% over the first six years of the study. The RAP ranges from 1.2% to 1.5% of savings on an incremental annual basis. The RAP savings have sizeable contributions also from the HVAC, Lighting, Motors, and Whole Building/Behavioral end uses.

TABLE 3-20: BUSINESS INCREMENTAL MAP AND RAP – END USE DETAIL

	2024	2025	2026	2027	2028	2029
MAP Incremental Annual MWh						
Compressed Air	12,166	11,771	11,018	10,669	9,555	12,332
Cooking	259	280	299	316	331	344
Hot Water	5,811	5,600	5,538	5,612	5,031	4,934
HVAC	65,323	72,142	75,014	81,315	82,036	85,118
Lighting	185,249	168,992	148,283	127,826	107,595	87,642
Miscellaneous	3,230	3,656	4,028	4,336	4,595	4,796
Motors	13,784	16,428	18,212	22,003	23,717	25,520
Plug Loads / Office	1,396	2,133	2,425	2,656	2,976	3,737
Refrigeration	2,563	3,830	4,264	4,580	5,133	6,881
Whole Building / Behavioral	26,605	22,667	29,021	33,566	37,543	30,145
Total	316,388	307,499	298,103	292,879	278,511	261,449
% of Forecasted Sales	2.0%	1.9%	1.9%	1.9%	1.8%	1.7%
RAP Incremental Annual MWh						
Compressed Air	8,813	8,525	7,980	7,740	6,931	8,822
Cooking	219	236	251	264	275	284
Hot Water	5,306	5,021	4,868	4,835	4,157	3,940
HVAC	40,113	45,126	47,537	52,921	53,811	56,719
Lighting	144,150	132,101	116,428	101,100	85,779	70,325
Miscellaneous	2,155	2,466	2,748	2,991	3,202	3,375
Motors	10,077	12,058	13,373	16,166	17,452	18,844
Plug Loads / Office	1,012	1,543	1,749	1,911	2,137	2,683
Refrigeration	1,862	2,783	3,099	3,329	3,731	4,986
Whole Building / Behavioral	19,757	15,493	21,638	25,419	29,540	22,615
Total	233,465	225,352	219,672	216,675	207,015	192,594
% of Forecasted Sales	1.5%	1.4%	1.4%	1.4%	1.3%	1.2%

Schedule MM-24

3.4 PROGRAM POTENTIAL

This section of the report provides an overview of the program potential. The cumulative annual savings are shown across the study timeframe, in aggregate as well as by program within each sector. The benefits and costs of program potential are also provided. The program potential scenarios are based off the achievable potential scenarios and are referred to as PP MAP (based off of MAP) and PP RAP (based off of RAP).

3.4.1 Program Potential Savings

Figure 3-11 below illustrates the cumulative annual program potential by sector over the next six years. The stacked bar chart shows the contributions of the residential and business sectors to the total program potential for the PP MAP and PP RAP scenarios. The gray portion of each bar shows the gap between the program potential and achievable potential, the latter of which is the basis for program potential scenario. This gap is created by estimated levels of free ridership in future programs which reduce the net-to-gross ratio to levels slightly below 100% and thereby reduce the program-level net savings estimates.

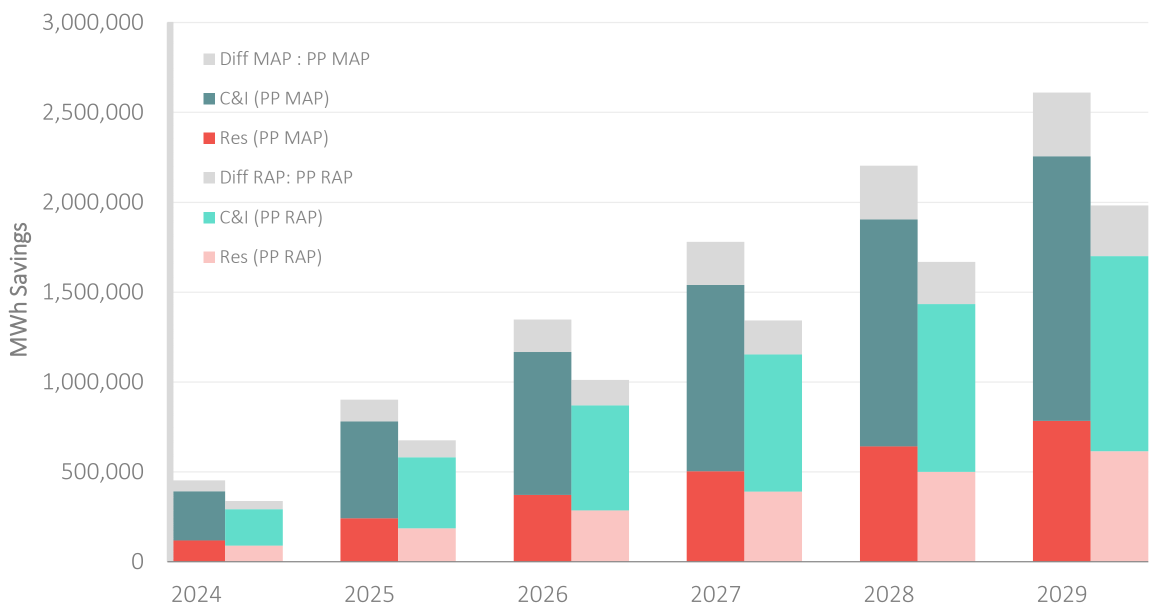


FIGURE 3-11: PROGRAM POTENTIAL BY SECTOR – PP MAP AND PP RAP

Figure 3-12 below illustrates the incremental annual energy savings in residential programs over the next six years. The HVAC, Efficient Products and Multifamily Market rate programs are the leading market rate programs, with the Single Family and Multifamily Income Eligible programs providing significant savings. The PAYS, Energy Efficiency Kits and New Construction programs provide some additional potential, with some measures not currently offered ("No program") providing some additional potential as well. The residential PP RAP ranges from 90,000 to 122,000 incremental annual MWh over the next six years.

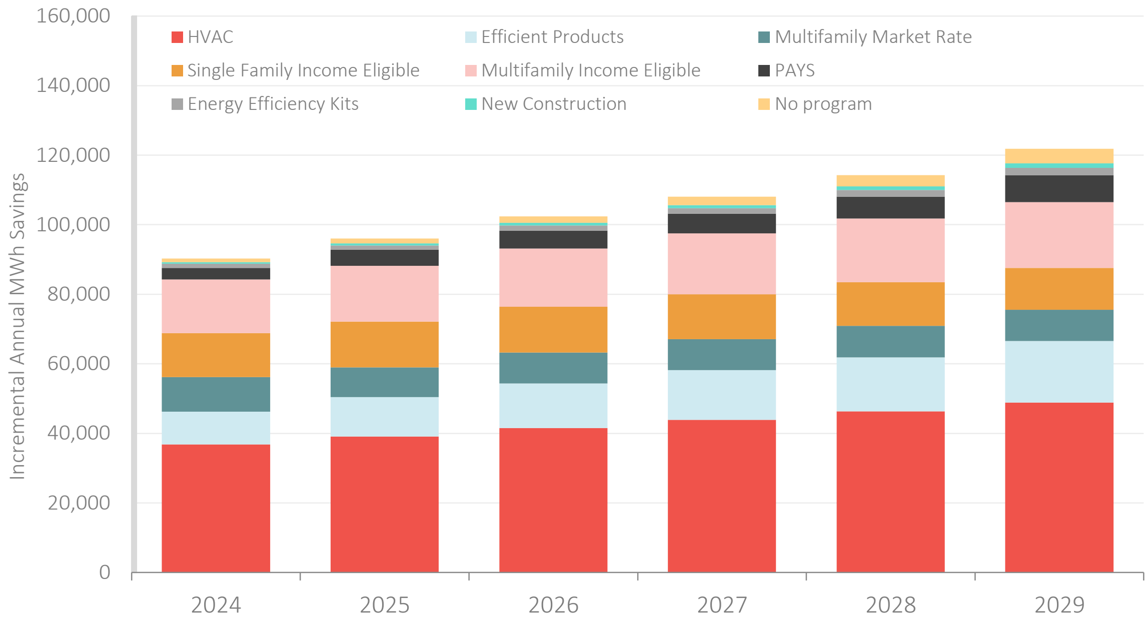


FIGURE 3-12: RESIDENTIAL SECTOR PROGRAM POTENTIAL – PP RAP

Figure 3-13 below illustrates the incremental annual energy savings in business programs over the next six years. The Standard, Small Business Direct Install and Custom programs are the leading business sector programs, with the Retrocommissioning, Strategic Energy Management, Agriculture and Business Social Services programs some additional potential as well. The business sector PP RAP ranges from 166,000 to 201,000 incremental annual MWh over the next six years.

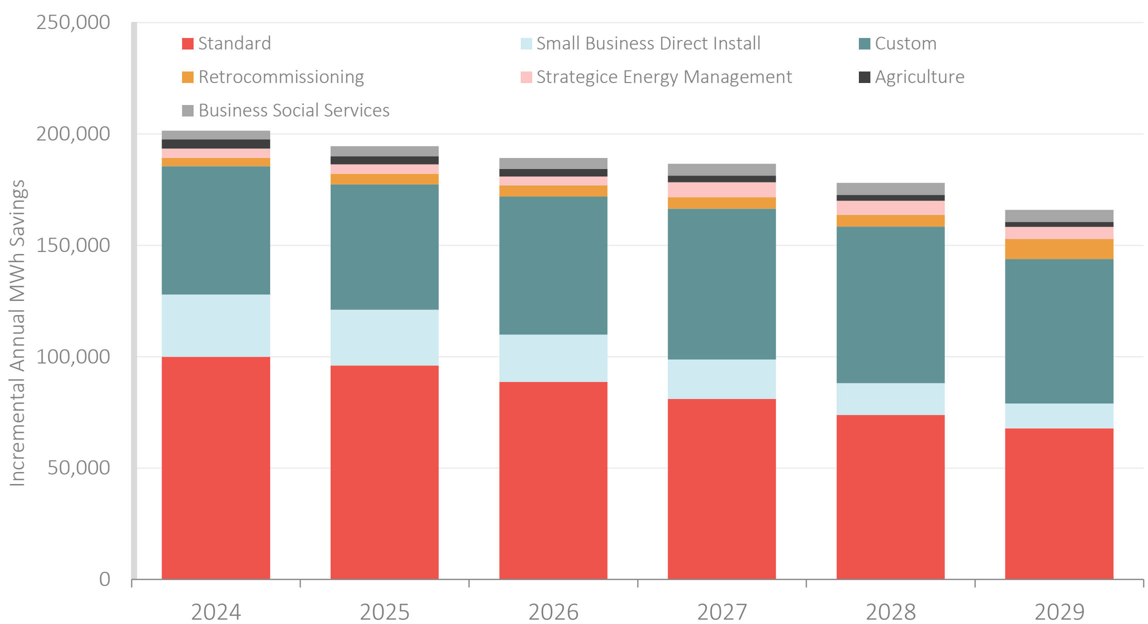


FIGURE 3-13: BUSINESS SECTOR PROGRAM POTENTIAL BY SECTOR – PP RAP

3.4.2 Benefits/Costs of Program Potential

Figure 3-14 shows the annual program budgets in the residential sector for the program RAP scenario. The budgets are broken out by incentives and admin costs. Total residential sector budgets range from $61 million in 2024 to more than $114 million by 2043.

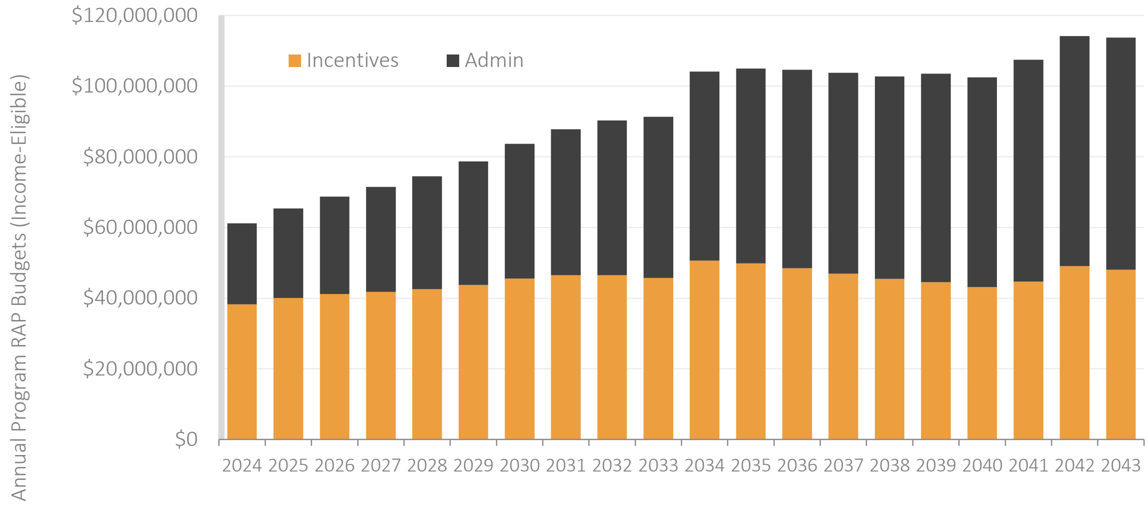


FIGURE 3-14: RESIDENTIAL SECTOR PROGRAM POTENTIAL BUDGETS – INCENTIVES AND ADMIN

Figure 3-15 shows the annual program budgets in the business sector for the program RAP scenario. The budgets are broken out by incentives and admin costs. Total business sector budgets start at nearly $36 million and remain steady for the next 10 years, with budgets decreasing in the second decade of the study timeframe.

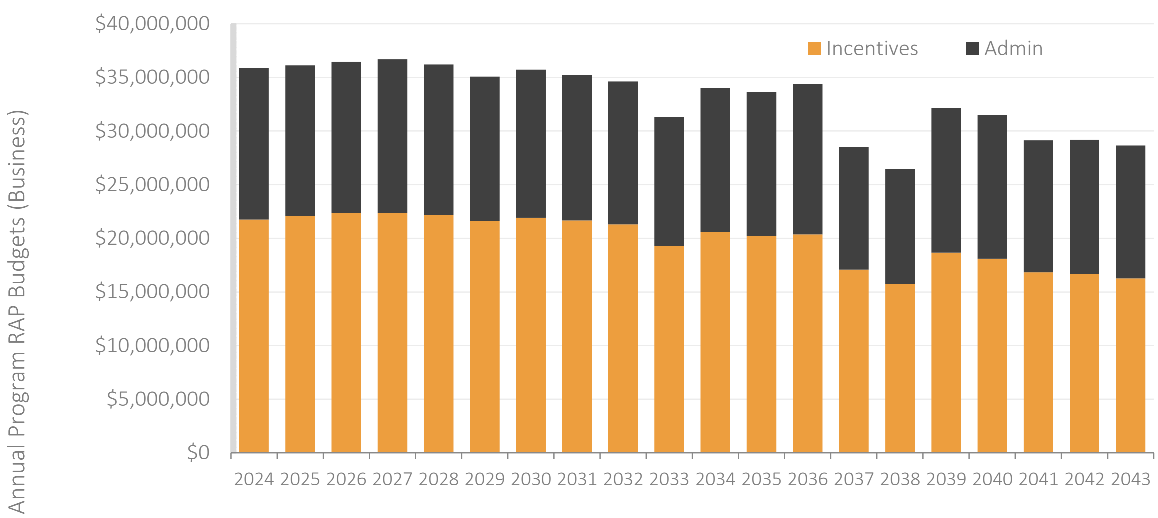


FIGURE 3-15: BUSINESS SECTOR PROGRAM POTENTIAL BUDGETS – INCENTIVES AND ADMIN

Table 3-21 below provides the net-present-value ("NPV") benefits and costs for each sector across the study timeframe and in total across all programs according to the TRC test. The overall TRC ratio is 1.7, with an estimated total of more than $1.3 billion in net benefits.

TABLE 3-21: PROGRAM RAP TRC NPV BENEFITS AND COSTS –BY 2043 ($, IN MILLIONS)

Sector	NPV Benefits	NPV Costs	TRC Ratio	NPV Net Benefits
Residential	$1,591	$1,137	1.40	$455
Business	$1,572	$707	2.22	$864
Total	$3,163	$1,844	1.72	$1,319

Table 3-22 below provides the net-present-value ("NPV") benefits and costs for each sector across the study timeframe and in total across all programs according to the UCT. The overall UCT ratio is 2.3, with an estimated total of more than $1.7 billion in net benefits.

TABLE 3-22: PROGRAM RAP UCT NPV BENEFITS AND COSTS –BY 2043 ($, IN MILLIONS)

Sector	NPV Benefits	NPV Costs	UCT Ratio	NPV Net Benefits
Residential	$1,591	$988	1.61	$604
Business	$1,572	$396	3.97	$1,175
Total	$3,163	$1,384	2.29	$1,779

3.5 SENSITIVITIES

3.5.1 Sensitivities Overview

In addition to the development of a base case for Program RAP potential, sensitivity analyses were performed surrounding several key assumptions in the study. The GDS team, Ameren Missouri, and stakeholders discussed multiple candidates for the sensitivity analysis that could either analyze the impact of uncertainty concerning customer participation and/or cost-effectiveness.[54] The following eight were ultimately selected for the residential market-rate and/or business sector energy efficiency analysis:

Avoided Costs. Avoided costs are the primary benefit in assessing the cost-effectiveness of DSM measures. Higher avoided costs will likely result in additional measures passing the TRC cost-effectiveness screen, leading to greater savings potential; while lower avoided costs will decrease the cost-effectiveness of measures and lead to lower savings potential.

High Sensitivities: (1) Increase avoided energy and generation capacity costs by 35%; no change to avoided T&D costs, and (2) Increase avoided T&D costs by 200%; no change to energy and capacity costs.
Low Sensitivities: (1) Decrease avoided energy and generation capacity costs by 50%; no change to avoided T&D costs, and (2) Reduce avoided T&D costs to $0 from 2024-2033, then apply base case T&D costs in second decade; no change to energy and capacity costs.
Impacted Sectors: *Residential / Business*

Prolonged Economic Downturn. GDS held constant economic factors in the Ameren Missouri load forecast, resulting in a negative impact on future energy sales. Adoption rates were also reduced to reflect concern over financial barriers. Population, households, and income are held constant at 2019 levels for residential. GDP, employment, and other rate class outputs were held constant in the business sector.

High Sensitivity: n/a
Low Sensitivity: (1) Residential: 10% decrease to forecast by 2040; 10% decrease to adoption levels; (2) Commercial: 5% decrease to forecast by 2040; 5% decrease to adoption levels; (3) Industrial: 8% decrease to forecast by 2040; 8% decrease to adoption levels

[54] 20 CSR 4240-20.050 (6)(C); 20 CSR 4240-20.050 (6)(C)1; 20 CSR 4240-20.050 (6)(C)2

Impacted Sectors: *Residential / Business*

COVID-19 Short/Long-Term Impacts. Sensitivity is expected to perform like the prolonged economic downturn, with a focus on changes in pre/post-COVID customer consumption and usage patterns. The forecast is assumed to already account for near-term COVID impacts. There are short-term impacts on lower adoption rates due to supply-chain concerns.

High Sensitivity: n/a
Low Sensitivity: Near-term adoption levels were adjusted (curve set back 2 years).
Impacted Sectors: *Residential / Business*

NTG Uncertainty (Attribution Case). The attribution sensitivity is relevant to Ameren in understanding the risk associated with changes in attribution that are outside the control of Ameren Missouri. In the case of DSM, attribution is the actual savings that are assigned to a program. One element in the transition from achievable potential to program potential includes the addition of the net-to-gross ratio assumed for each measure/program. The net-to-gross (NTG) ratio identifies the fraction of program participants who would not have purchased the energy efficient measures in the absence of a program. For the Program RAP reference case, the NTG ratios assigned to each measure/end-use/program were based on the latest evaluated DSM programs for MEEIA Cycle 2. However, changes to DSM measure mixes, costs, savings, program delivery methods, market forces, and other factors can significantly impact future NTG ratios.

High Sensitivity: 15% increase to current NTG ratios
Low Sensitivity: 30% decrease to current NTG ratios
Impacted Sectors: *Residential / Business*

High Touch Marketing. Intended to explore strategy of increasing marketing/high-touch administration to improve program delivery and increase program participation.[55] The high-touch marketing scenario is applied to RAP and produces a result between the current RAP and MAP levels.

High Sensitivity: Assume historical incentive levels but raises the program awareness threshold to the MAP level. Non-Incentive costs were estimated to be higher as well.
Low Sensitivity: n/a
Impacted Sectors: *Residential / Business*

Large Customer Opt-Outs. The base case excludes sales and savings from all eligible customers that currently opt-out of Ameren Missouri's energy efficiency programs. This sensitivity looks at the range of potential if no C&I customers were to opt-out, or if all eligible customers chose to opt-out.

High Sensitivity: Include currently opted-out customers in analysis of future potential.
Low Sensitivity: Exclude all eligible opt-out customers from analysis. For purposes of estimating sales from all eligible customers opt-out, GDS used the existing opt-out customers and included sales from all additional customers in the 11M rate (that are not currently designated as an opt-out customer).
Impacted Sectors: *Business Only*

Volatile Weather. Assessed impact of increasing Heating Degree Days and Cooling Degree Days, impacting measure savings and cost-effectiveness. GDS included a similar adjustment to heating and cooling load in the sales forecast (i.e. as HDD/CDD increased, the heating and cooling portion of the sector loads was similarly increased).

[55] 20 CSR 4240-20.050 (1)(E)2

High Sensitivity: Assumed heating and cooling degree days both increased by 25%.
Low Sensitivity: n/a
Impacted Sectors: *Residential / Business*

Improved Technology Savings/Costs. This sensitivity was included to assess the impact of improved technology savings and/or reduced technology costs.[56]

High Sensitivity: Assume program participation focuses on higher tier technologies regardless of current market acceptance; assume a 35% decrease in emerging technology/high tier equipment costs and incentives over the study horizon. For all other measures, reduced costs between 5%-20% based on current energy efficiency saturation assumptions. Shifted applicability to highest tier equipment (if cost-effective).
Low Sensitivity: n/a
Impacted Sectors: *Residential / Business*

Additional IQ-Funding Sensitivity. This sensitivity assumes 100% incentives of the full measure cost (rather than incremental) for income-qualified HVAC and Water Heating measures.

High Sensitivity: Increased adoption rates (MAP awareness factor). Modified measure costs and associated incentives.
Low Sensitivity: n/a
Impacted Sectors: *Residential Only*

PAYS Sensitivity. This sensitivity enhances the adoption of measures mapped to the PAYS program delivery channel. Model parameters adjusted include market adoption rates and net-to-gross assumption.

High Sensitivity: Adoption rates are based on assuming financing elements of PAYS yields adoption rates equal same assumed level as covering 100% of measure cost. NTG ratios for these measures are set to 100%. Market adoption curve accelerated to account for higher awareness.
Low Sensitivity: n/a
Impacted Sectors: *Residential Only*

Summer Planning Reserve Margin. This sensitivity assesses the impact of transitioning from MISO Planning Reserve Margin (PRM) Installed Capacity (ICAP) to Unforced Capacity (UCAP).

High Sensitivity: n/a
Low Sensitivity: Reduce summer planning reserve margin to 7.4%
Impacted Sectors: *Residential / Business*

3.5.2 Sensitivity Results

Figure 3-16 shows the program RAP based on the results of the sensitivity analysis, with the residential sector results in orange and the business sector results in black. The blue bars show the 20-yr cumulative annual MWh, and the orange line provides the corresponding 20-yr budget (in $ billions). Improved Technology, All Opt-Outs Included and High NTG provide the most savings, while the Low NTG, Economic Downturn, and Low Avoided Costs 1 sensitivities provide the least savings. 20-yr total budgets range from $2.1 billion to $3.9 billion with the low being the low being the Economic Downturn and the high being the Improved Technology sensitivity.

[56] 20 CSR 4240-20.050 (1)(E)1

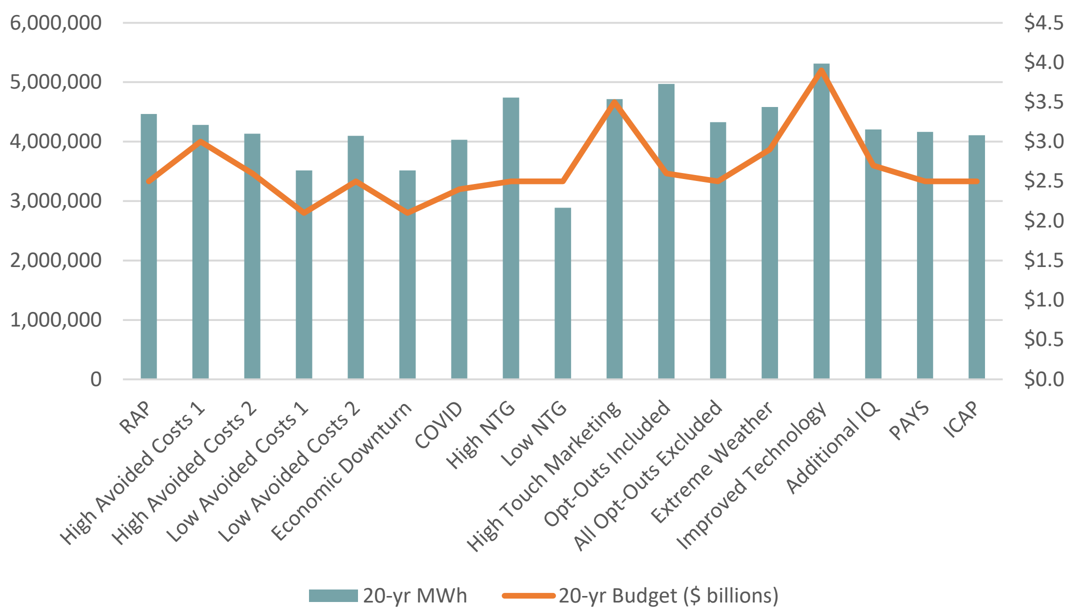


FIGURE 3-16: PROGRAM RAP SENSITIVITIES – CUMULATIVE ANNUAL SAVINGS AND 20-YR BUDGETS

Table 3-23 shows the NPV benefits and costs for the program RAP sensitivities. The sensitivity with high NTG has the highest TRC ratio of 1.97. The High Avoided Costs 1 sensitivity yields the greatest NPV net benefits. The sensitivity with low NTG has the highest TRC ratio of 1.30. The Additional IQ sensitivity yields the lowest NPV net benefits.

TABLE 3-23: SENSITIVITY PROGRAM RAP NPV BENEFITS AND COSTS –BY 2043 ($, IN MILLIONS)

Program	NPV Benefits	NPV Costs	NPV Net Benefits	TRC Ratio
RAP	$3,162,625,462	$1,843,863,501	$1,318,761,960	1.72
High Avoided Costs 1	$4,151,557,318	$2,178,765,606	$1,972,791,712	1.91
High Avoided Costs 2	$3,485,001,042	$1,961,843,037	$1,523,158,005	1.78
Low Avoided Costs 1	$2,453,317,946	$1,693,028,777	$760,289,169	1.45
Low Avoided Costs 2	$2,782,340,058	$1,579,864,467	$1,202,475,591	1.76
Economic Downturn	$2,663,118,557	$1,523,051,139	$1,140,067,418	1.75
COVID	$3,599,512,549	$1,901,849,142	$1,697,663,407	1.89
High NTG	$3,911,483,961	$1,988,226,045	$1,923,257,917	1.97
Low NTG	$2,793,356,030	$2,150,821,883	$642,534,147	1.30
High Touch Marketing	$3,543,376,873	$2,434,280,831	$1,109,096,041	1.46
Opt-Outs Included	$4,061,407,059	$2,592,380,468	$1,469,026,590	1.57
All Opt-Outs Excluded	$3,632,538,618	$2,395,042,045	$1,237,496,573	1.52
Extreme Weather	$3,565,579,338	$2,114,477,644	$1,451,101,694	1.69
Improved Technology	$3,819,673,057	$2,419,497,159	$1,400,175,898	1.58
Additional IQ	$1,653,173,884	$1,210,535,534	$442,638,351	1.37
PAYS	$1,722,046,691	$1,211,604,599	$510,442,092	1.42
ICAP	$3,074,301,271	$1,825,962,095	$1,248,339,177	1.68

4 DR POTENTIAL RESULTS

4.1 ANALYSIS APPROACH[57]

This section provides an overview of the demand response potential methodology. Summary results of the demand response analysis are provided in Section 4.2. Additional results details are provided in Appendix F.

4.1.1 Definition of Demand Response[58]

According to the Federal Energy Regulatory Commission (FERC), demand response is defined as changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. FERC's definition of demand response conforms to the North American Electric Reliability Corporation (NERC) definition developed by a consortium of utilities and end users – of which Ameren Missouri had a leadership role.

The Midcontinent Independent System Operator (MISO) defines demand response as the ability of a Market Participant to reduce its electric consumption in response to an instruction received from MISO. Market Participants can provide such demand response either with discretely interruptible or continuously controllable loads or with behind-the-meter generation. In short, resources must be dispatchable and measurable. Demand response rate options such as TOU or CPP don't meet these requirements. However, these rates can provide value for Ameren Missouri if they lower their peak demand requirements. That reduction in peak load can translate into lower capacity requirements. Utilities in MISO must demonstrate that they have enough capacity on a forward basis.[59]

This study uses the broader FERC definition of demand response so that all potential DR, including rate options, are identified. Ameren Missouri's integrated resource planning team will analyze and adjust as necessary the identified DR potential for what can be counted in the MISO market and/or how DR potential will be used to construct alternative resource plans.

4.1.2 Demand Response Program Options

Table 4-1 provides a brief description of the demand response (DR) program options that were considered as part of the base analysis and identifies the eligible customer segment for each demand response program to be considered in this study.[60] The list of DR options was determined based on a review of the 2020 Ameren MPS, Ameren's current and/or planned offerings, as well as DR programs run by other utilities in the region. The base case analysis includes direct load control (DLC), rate design, and aggregator options.[61] Additional demand response rate options were included as a sensitivity to the base case analysis.[62]

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57 20 CSR 4240-20.050 (3)(I)

58 EO-2023-0099 1F (Special Contemporary Issues)

59 20 CSR 4240-20.050 (4)(F)

60 20 CSR 4240-20.050 (1)(C)

61 EO-2023-0099 1B (Special Contemporary Issues)

62 20 CSR 4240-20.050 (3)(A)

Schedule MM-24