Exhibit No. 204

Staff – Exhibit 204
Sarah Lange Testimony
Rebuttal
File No. EO-2023-0136

Exhibit No.:	
Issue(s):	*Summary of MEEIA Avoided Revenue Mechanisms*
Witness:	*Sarah L.K. Lange*
Sponsoring Party:	*MoPSC Staff*
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MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

REBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. EO-2023-0136

Jefferson City, Missouri
April 2024

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EXECUTIVE SUMMARY

Q. Are you the same Sarah L.K. Lange, who prefiled Direct Testimony in this matter?

A. Yes.

Q. Your direct testimony and that of J Luebbert addressed foundational Missouri Energy Efficiency Investment Act (MEEIA) concepts. Can you explain additional concepts that are necessary to understanding Ameren Missouri's rebuttal testimony?

A. Yes.

I will briefly address the complexity of evaluating a MEEIA Application which includes a request for broad utility flexibility going forward. This is discussed in greater detail by Staff witness J Luebbert.

My testimony will demonstrate that Ameren Missouri has not presented reliable evidence that its conceptual MEEIA Cycle 4 is beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. I will explain some of the common cost/benefit tests, as well as Ameren Missouri's application of those tests in their Revised MEEIA Application. I will also explain the difficulty of achieving benefits through avoided energy costs, the difficulty of evaluating costs and benefits over time, and use of Net Present Value (NPV) calculations.

<u>HAS AMEREN MISSOURI'S REVISED MEEIA 4 APPLICATION SATISFIED THE STATUTORY REQUIREMENTS?</u>

Rate Impacts of MEEIA Cycle 4

Q. How much revenue will Ameren Missouri collect through its Rider Energy Efficiency Investment Charge (EEIC) – the MEEIA charge on customer bills - for Cycle 4, if they implement all programs exactly as modeled?

A. Based on Ameren Missouri's workpapers, Staff understands that Ameren Missouri anticipates recovering approximately $626,090,903 for MEEIA Cycle 4 through the Rider EEIC,[1] which is a 23% rate increase when compared to base rates.[2] The program costs alone (including incentive payments, administration costs, and other costs) would equate to an approximate 14% rate increase, Ameren Missouri's requested compensation for opportunities to build new ratebase in the future (the "Earnings Opportunity," or "EO") equates to an approximate 3% rate increase, and Ameren Missouri's requested Net Throughput Disincentive Mechanism ("NTD") for energy Ameren Missouri models it won't sell equates to an approximate 7% rate increase,[3] although the amount will vary by customer class and energy

[1] Ameren Missouri has requested flexibility in what programs it pushes and what measures programs include, and what incentives are available for the measures. There is also uncertainty as to whether the quantification of costs presented in Appendix A to the Revised Application or the inputs and outputs of Ameren Missouri's "DSMore" workpapers are the intended starting point for Ameren Missouri's requested flexibility, as quantifications vary between the two sources. Staff's best effort at quantifying the Rider EEIC cost is provided in the testimony of Marina Stever.

[2] In ER-2022-0337 the Commission authorized Ameren Missouri to recover approximately $2.7 billion from its ratepayers through its retail rate schedules.

[3] The sizing of the NTD costs will vary with actual program implementation and rate case timing.

usage. FAC impacts will also occur, though they cannot be quantified based on the information Ameren Missouri has provided to date. Further, Ameren Missouri requests significant flexibility in program implementation, so variances of up to 20% should be anticipated.[4]

Net benefits for all customers regardless of program utilization

Q. The MEEIA statute specifies:

> Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and are **beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers**….[5] **[Emphasis added.]**

Section 393.1075.5. further requires, "In setting rates the commission shall fairly apportion the costs and benefits of demand-side programs to each customer class."

Has Ameren Missouri's revised MEEIA 4 Application satisfied these statutory requirements?

A. No. Relying on Ameren Missouri's calculations, ratepayers in the Residential, Small General Service, and Large General Service classes will be worse off by the existence of a MEEIA Cycle 4 as requested by Ameren Missouri.

Ameren Missouri's Figure 43, at page 84 of the "Ameren Missouri 2025-27 MEEIA Plan (Revised),"[6] ("Revised Plan") illustrates Ameren Missouri's modeling of rate impact by customer class. The Revised Plan includes language noting "[t]he rate impacts also peak during the program years of 2025-2027 while costs are reflected in rates. After the programs end, rates

[4] The approximate Compound Annual Growth Rate of a 23% increase in rates over 5 years is approximately 5.2%, however, Rider EEIC is not included in the calculation of rate caps associated with election of Plant In Service Accounting.
[5] 393.1075.4.
[6] Attached to the Revised Direct Testimony of Antonio M. Lozano, as AML-D1.

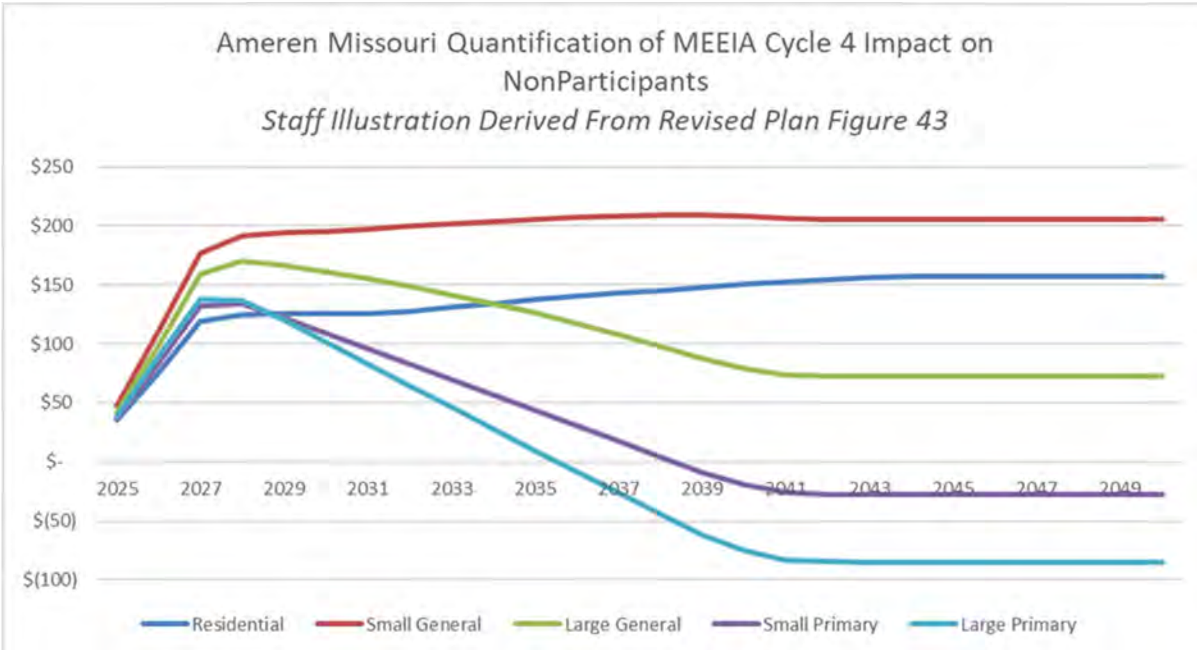
are higher because the fixed costs of the utility revenue requirement are spread over fewer kWh of usage due to the energy savings customers recognize."[7] The shortcoming of Ameren Missouri's application in complying with the statutory requirement is clear at page 83, in the statement "Keep in mind that, over time, customers receive bill savings even in the face of higher rates because the volumes of energy that they are purchasing at those rates are lower than they otherwise would have been." This caveat is simply not a reasonable assumption for evaluating the impact of MEEIA on "all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers," because necessarily, the usage of customers who do not participate in MEEIA will not change due to MEEIA participation, but the rate that they will pay, all else equal, will be higher to the extent the revenue requirement will be borne by fewer sales.[8]

Staff has taken the rate estimates prepared by Ameren Missouri for its preparation of Figure 43, and calculated Ameren Missouri's quantification for annual bills per 1,000 kWh per month of usage, which demonstrates that ratepayers in the Residential, Small General Service, and Large General Service classes will be worse off for by the existence of a MEEIA Cycle 4 as requested by Ameren Missouri:[9]

continued on next page

[7] This section also includes language that "It is imperative to recognize that despite higher rates, the total customer outlays for energy are fully expected to be lower with the implementation of the Plan programs, as shown previously on the bill impacts;" however, the referenced bill impacts figure does not assume consistent energy consumption, which is important in considering the effect of the proposal on non-participants.
[8] 393.1075.4.
[9] Ameren Missouri's workpaper provided rates expressed as a $/kWh value for each class. Staff has relied on this calculation and has not recalculated bills based on discrete rate structures. In his rebuttal testimony at page 38 - 41, Mr. Luebbert notes significant concerns with Ameren Missouri's valuation, allocation, and timing of avoided costs reflected in Figure 43, which overstates and accelerates the benefits that are reasonably expected.

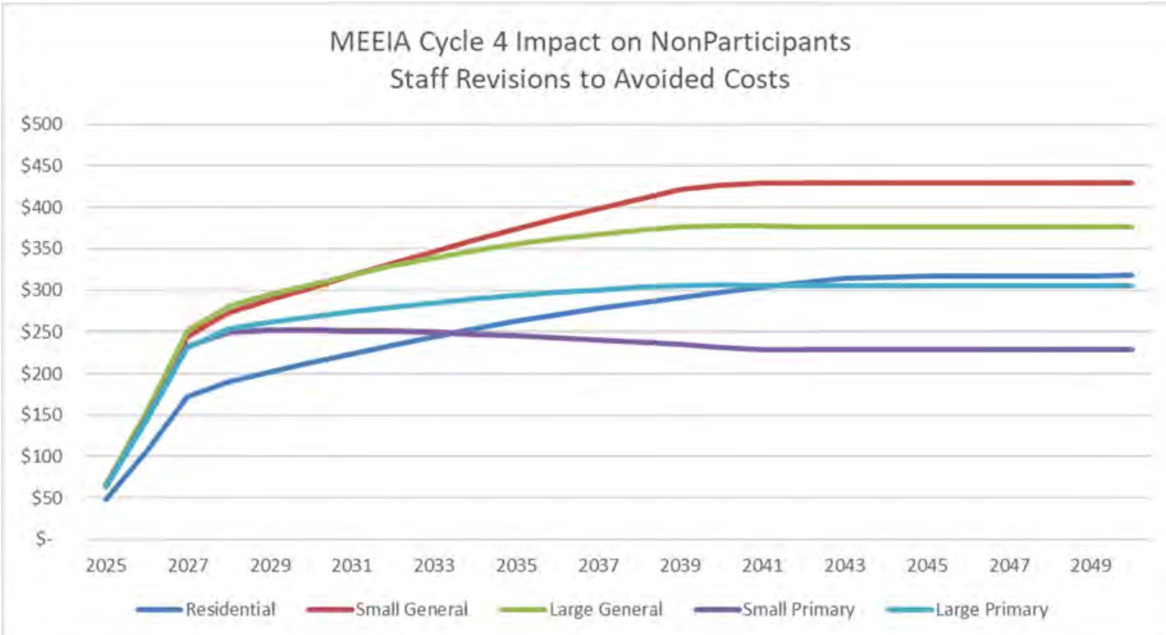
SLKL Figure 1



SLKL Figure 1 relies on Ameren Missouri's quantification of avoided costs. Staff witness J Luebbert has attempted to address some of Staff's concerns with quantification of avoided costs.[10] Using these values in place of those Ameren Missouri used to create Figure 43, Staff calculates that non-participants in all rate classes are worse off with Ameren Missouri's requested MEEIA Cycle 4, and significantly so. The cumulative bill impacts per 1,000 kWh of energy per month are illustrated below:

[10] In his rebuttal testimony at page 38 - 41, Mr. Luebbert also notes significant concerns with Ameren Missouri's timing and allocation of avoided costs reflected in Figure 43, which accelerates the benefits that are reasonably expected. Staff is unable to account for the timing and allocation issues in SLKL Figure 2, which adjusts only the overall level of benefits assumed by Ameren Missouri.

SLKL Figure 2



Q. Why does SLKL Figure 2 result in illustration of such drastic harm to ratepayers associated with MEEIA Cycle 4?

A. SLKL Figure 2 relies on Ameren Missouri's assumptions concerning erosion of retail sales, and relies on Ameren Missouri's assumptions concerning avoided energy costs. SLKL Figure 2 reflects Ameren Missouri's levels of costs to customers and customer energy savings, but provides less unreasonable estimates of the overall reduction in costs associated with production capacity, transmission, and distribution. Mr. Luebbert discusses the overestimation of production capacity, transmission, and distribution benefits associated with Ameren Missouri's Revised Application from Ameren Missouri's workpapers. SLKL Figure 2 demonstrates that ratepayers in all classes would paying higher bills for the same amount of usage under Ameren Missouri's modeling of MEEIA Cycle 4, with less unreasonable avoided cost assumptions.

The values underlying SLKL Figures 1 and 2 are attached as Schedules SLKL-r1.

Q. Why does SLKL Figure 1 demonstrate that ratepayers are worse off for MEEIA Cycle 4, while Ameren Missouri provides Benefit:Cost tests in Appendix A to its Revised Application that demonstrate the cycle should be a net benefit for ratepayers?

A. The chief differences between what Ameren Missouri presents in its Figure 43 within its Revised Plan, and Appendix A to its Revised Application is acknowledgement of the net margin gain or loss on each avoided kWh of energy sold. Ameren Missouri's Benefit:Cost test results in Appendix A to its Revised Application fail to account for this interaction.

Q. How can a proposed MEEIA Cycle be bad for ratepayers?

A. The basic premise of MEEIA is that it can make sense for a utility to facilitate programs where all customers pay the cost to help some customers reduce energy consumption, **if** that reduced energy consumption results in avoiding or delaying a costly supply-side resource,[11] or by enabling additional revenue from existing supply-side resources. However, the relationship between avoided energy costs and avoided retail revenue are factors in the overall cost effectiveness of even a seemingly sound portfolio, much less a portfolio with the unreasonable avoided cost assumptions found in Ameren Missouri's Revised Application. In this proceeding, Ameren Missouri has not designed programs to target hours driving capacity needs, hours with high energy or transmission costs, nor to target areas of the distribution system that are operating at or near capacity.

Q. If you ignore the requirements in the MEEIA statute that a MEEIA Cycle benefit all customers in a customer class, regardless of their participation, does the Revised MEEIA Cycle 4 Application produce benefits that exceed its cost?

[11] A supply-side resource refers to a new power plant.

A. No. MEEIA is incredibly complicated, and Ameren Missouri's application is opaque. Capturing the relationship between certain near-term costs, speculative future benefits, integrated market activities, generation and transmission planning, distribution rebuilding and expansion, participants and non-participants, load-building programs, and real and hypothetical revenue requirement recovery is complex and difficult under the best circumstances.

While costs are generally more certain to occur, the magnitude of the costs to be incurred are very uncertain given the flexibility that Ameren Missouri requests. Establishment of future benefits requires modeling a series of counterfactuals, and the reasonableness of assumptions varies significantly. As discussed in greater detail by J Luebbert, the creation of future benefits – let alone the quantification thereof – is incredibly uncertain.

Cost Quantification

Q. What level of program costs does Ameren Missouri request be passed on through the Rider EEIC for its Revised MEEIA Cycle 4?

A. Ameren Missouri's application and workpapers are unclear, and Ameren Missouri has requested significant flexibility. General information is provided below:

Based on Appendix A to the Revised Application, and not including the requested NTD or other compensation for avoided revenues, the costs to ratepayers are as set out below:[12]

[12] Appendix N includes an apparent math error in that the total "EO Maximum" provided near the top of the page does not include $3 million in additional requested "Performance Bonus" payouts indicated at the bottom of the page. The total EO Maximum that Ameren Missouri requests is $75 million. Ameren Missouri retains at least 110% flexibility for the program-related costs.

Summary of Revised Application Appendix A, with Requested EO			
	Millions	Dollars	Percent of Total
Customer Incentives	$ 205	$ 205,145,433	46%
Administrative Costs	$ 134	$ 133,802,225	30%
EM&V	$ 10	$ 10,168,430	2%
Other (Marketing, Potential Study, Data Tracking & Incremental Labor)	$ 21	$ 20,832,425	5%
Revised Appendix N Requested Earnings Opportunity	$ 75	$ 74,912,886	17%
Total Cycle 4 Costs	$ 445	$ 444,861,399	100%

Q. What dollar values does Ameren Missouri rely upon in its modeling?

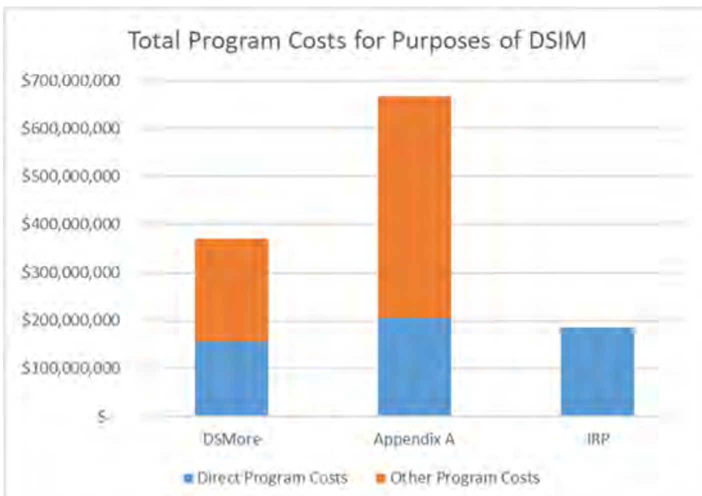
A. It varies. Staff inquired with respect to a particular workpaper for Ameren Missouri to "[p]lease clarify whether these values represent the highend, lowend, midpoint, or some other value within Ameren Missouri's proposed incentive range." Ameren Missouri's response was "We have not evaluated whether the incentives fall within the high end, low end, or midpoint of the incentive ranges."[13] Staff is concerned that Ameren Missouri cannot provide a reliable estimate of the program costs in its MEEIA Application, and is unsure how the Commission may lawfully approve an application without this information, even if there were no other issues.

Ameren Missouri's workpapers from DSMore[14] and its workpapers for Appendix A are incongruent. "Program Costs," as reflected in the Demand-Side Programs Investment Mechanism (DSIM) and billed through Rider EEIC will include direct program costs, and also administrative costs, EM&V[15] costs, education costs, and other costs which Staff understands

[13] Data Request No. 0145.
[14] DSMore is a modeling software.
[15] Evaluation, Measurement & Verification (EM&V)

may be difficult to classify on a given day as either program costs or other costs. Nonetheless, Ameren Missouri's workpapers do not provide consistent total costs:

	Program Costs in Appendix A	Program Costs in DSMore Files	Ameren Modeled Non-Program Costs Appendix A	Ameren Modeled Non-Program Costs DSMore Files
2025	$ 64,170,989	$ 49,439,919	$ 149,265,230	$ 69,356,699
2026	$ 68,476,802	$ 52,049,955	$ 153,952,197	$ 71,454,718
2027	$ 72,497,642	$ 54,391,750	$ 157,740,755	$ 73,255,398
	$ 205,145,433	$ 155,881,624	$ 460,958,182	$ 214,066,814



Q. Are the other cost components of Ameren Missouri's requested Rider DSIM more certain?

A. No. Cost uncertainty concerns also apply to Ameren Missouri's requested NTD, which as I noted in my Direct Testimony, is unlawful. It is also unreasonable, as discussed by myself and Staff witness Hari K. Poudel, PhD.

It is also difficult to reasonably estimate the net cost of an "Earnings Opportunity" mechanism, when, as here, the Commission cannot lawfully implement an "Earnings

Opportunity" if Ameren Missouri's investors do not avoid an investment opportunity. This result is likely given Ameren Missouri's Integrated Resource Plan (IRP) criteria, solar and wind will be deployed regardless of need, and those plant types do not result in avoidable costs to customers.[16] This is compounded by the facts that the portfolio in MEEIA 4 as modeled by Ameren Missouri is not consistent with the Realistic Achievable Potential (RAP) capacity modeled in Ameren Missouri's IRP,[17] and Ameren Missouri is actively engaging in load building at this time through economic development tariffs and subsidization of electric vehicle-related activities. Further, the Commission cannot lawfully implement a net benefit sharing mechanism if no net benefits occur, which is an expected outcome of Ameren Missouri's MEEIA 4 Application, as discussed in this testimony and that of J Luebbert and Brad J. Fortson.

Benefit Quantification

Q. How certain are benefits to occur, and when will they occur?

A. Benefits are far in the future and are based on modeling. As I will discuss in greater detail, near term benefits to non-participants of wholesale energy cost reductions can only occur if the wholesale cost of avoided energy is less than the retail revenue of energy avoided. As Mr. Luebbert and others will discuss:

[16] Ameren Missouri's IRP "Planning Objectives," are attached as Schedule SLKL-r2, but include Portfolio Transition, Economic Development (Direct Job Growth), and discusses the consistency of these planning objectives with Ameren's commitments to "Accelerating the transition to a cleaner and more diverse generation Portfolio," and "Strong long-term infrastructure investment pipeline." Staff witness Brad J. Fortson addresses Ameren Missouri's IRPs related to this issue at page 6, line 12 through page 14, line 3 of his rebuttal testimony.

[17] Ameren Missouri's energy efficiency programs in MEEIA Cycle 4 would have to have to impact peak capacity by a factor of 600% - 1,200% to reflect the level of Energy Efficiency and Demand Response reflected in the RAP Plans in Ameren Missouri's most recent IRP. Ameren Missouri has noted various issues with its 2023 IRP, while all workpapers concerning the corrections have not been received to date, the total RAP cost of $185 million is reflected in its IRP modeling, and the levels of DR and EE are as follows:

	2023	2024	2025	2026	2027
Energy Efficiency in RAP Plans		108	219	330	440
Demand Response in RAP Plans		198	223	250	271

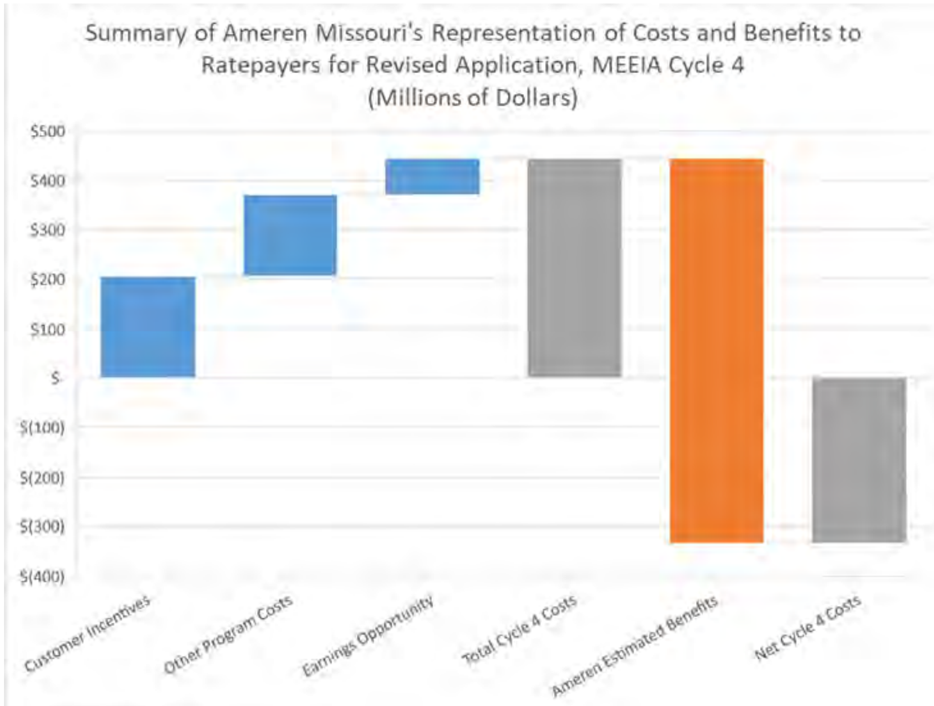
a. Near term benefits of avoided capacity investment will not occur.
b. Near term benefits of avoided Transmission & Distribution (T&D) investment will not occur.
c. Longer term avoided T&D is only reasonably possible with targeted deployment
d. Longer term avoided capacity benefit calculations must consider Ameren Missouri's willingness and likelihood to avoid capacity investments and to avoid capacity investments that can result in avoiding costs to customers.
e. Longer term avoided capacity benefit calculations must consider changes to capacity market and emerging capacity shortfalls outside of summer.
f. It is possible to avoid near term Midcontinent Independent System Operator, Inc. ("MISO") transmission charges and to enable near term MISO capacity revenues, but Ameren Missouri has not analyzed these costs and benefits, and Staff is unable to replicate or modify Ameren Missouri's modeling to account for them.

Q. What quantification of benefits does Ameren Missouri present in its Revised Application?

A. Ameren Missouri relies on estimated benefits of approximately $779 million NPV over the next 24 years for the Benefit:Cost test results presented in Appendix A. It bases this estimate on assumed benefits of $1,217,440,436 in nominal dollars.

Summary of Revised Application Appendix A, with Requested EO, and Ameren Estimated Benefits

	Millions	Dollars
Customer Incentives	$ 205	$ 205,145,433
Administrative Costs	$ 134	$ 133,802,225
EM&V	$ 10	$ 10,168,430
Other (Marketing, Potential Study, Data Tracking & Incremental Labor)	$ 21	$ 20,832,425
Revised Appendix N Requested Earnings Opportunity	$ 75	$ 74,912,886
Ameren Estimated Benefits	$ (779)	$ (779,305,697)
Total Cycle 4 Costs	$ (334)	$ (334,444,298)



Note, the estimated costs to ratepayers in this illustration do not include Ameren Missouri's requested NTD during the pendency of MEEIA Cycle 4, and the ongoing reallocation of revenue requirement.

Alignment of Costs and Benefits

Q. You have noted that the magnitude of costs may vary, but is it certain that ratepayers will bear costs for Ameren Missouri's MEEIA Cycle 4, if authorized?

A. Yes.

A. The incurrence of costs near, at, or above the magnitude (up to 110%) modeled by Ameren Missouri (including costs to nonparticipants related to avoided revenues) are almost certain to occur and will be borne by customers in the near term. In contrast, the benefits Ameren Missouri models are subject to layers of assumptions, and are spread to customers over decades, if at all. These issues with Ameren's application raise concern for unreasonable risk to ratepayers, as well as intergenerational inequity since customers today will be paying the costs for potential benefit to be enjoyed by future customers.

Q. Does Ameren Missouri's MEEIA 4 Application acknowledge the risk that benefits assumed for a MEEIA measure, program, and cycle may not materialize?

A. Ameren Missouri raises concerns for MEEIA implementers that assumed energy and demand savings may not materialize. Unfortunately, these concerns are not paralleled by its concerns for its captive ratepayers, nor does Ameren Missouri acknowledge the risk that the quantification of benefits that stem from a given level of assumed energy or demand were ultimately incorrect.

Q. In his January 25, 2024, Direct Testimony, at pages 29-30, Mr. Lozano references "Topic of Interest 5 – Ameren Missouri is proposing changes to EM&V as part of this new MEEIA cycle," and states "[b]enefits for moving in this direction include implementers reducing their costs due to lower risks from evaluation[.]" What support does Ameren Missouri include in its MEEIA 2024-2026 Plan filed March 27, 2003, concerning its request to authorize a MEEIA cycle which does not rely on measured, evaluated, and verified energy and demand reductions in implementation of its DSIM?

A. Ameren Missouri's Plan at page 53 includes the following paragraph:

> Ameren Missouri's prior MEEIA cycles have always used retrospective evaluation, where evaluation results are used to adjust the savings claimed by the implementers. This includes retrospective adjustments to deemed savings and net to gross ratios. This method of evaluation can be viewed as being punitive to implementers, who relied on historical net to gross ratios and deemed values as required in the TRM[18] to claim savings. As a result, implementers increase the administration costs to cover the amount they consider to be at risk from the evaluation.

[18] Technical Reference Manual (TRM).

> In comparison, prospective evaluation does not punitively impact the current year results. Instead, evaluation results are only used to update the deemed values for future years, including inputs to deemed savings algorithms and net to gross ratios. In this filing, Ameren Missouri is proposing to use prospective evaluation.

Q. What is Ameren Missouri characterizing here as "punitive?

A. Ameren Missouri's MEEIA Plan states that it is "punitive" for implementors who have voluntarily contracted to do business with Ameren Missouri to receive lower benefits (in the form of payment) for the work they perform if upon evaluation, measurement, and verification, it is determined that the work performed did not achieve the level of energy or demand savings desired.

Q. Did Staff conduct discovery related to this testimony?

A. Yes. Responses to Staff Data Request Nos. 0014 and 0016 are attached as Schedule SLKL-r3. Ameren Missouri's responses included the following explanations:

> Implementers develop program plans including targeting the number of measures or project completions using deemed savings values and historical net to gross ratios to meet energy and demand savings goals. When evaluations return realization rates or net to gross ratios that are lower than expected, implementers do not meet the energy and demand savings goals despite meeting the targeted number of measures or project completions. The evaluated realization rates and net to gross ratios are not available until after the program year is complete so implementers cannot make changes to program design to meet goals. Implementers typically have a performance-based contract that provides at least part of their compensation based on evaluated results. When evaluated results come in different than what had been expected, their compensation can be lower than what had been anticipated even though they may have incentivized the targeted number of projects or measures. To avoid this scenario, implementers may increase their performance-based pricing to reduce the risk of retrospective evaluation.[19]

[19] Ameren Missouri response to Staff Data Request No. 0016.

And

> Implementers typically have a performance-based contract that provides at least part of their compensation based on evaluated results. When evaluated results come in different than what had been expected, their compensation can be lower than what had been anticipated even though they may have incentivized the targeted number of projects or measures.[20]

Q. Please walk through a hypothetical example illustrating Ameren Missouri's concern that retrospective EM&V is "punitive" to implementers who have voluntarily contracted to do business with Ameren Missouri:

Step 1: Ameren Missouri requests and receives approval for a MEEIA Cycle that it modeled will cost ratepayers $1 million and save 20 million kWh of energy. Ameren Missouri estimates these energy savings will be worth $1.5 million to ratepayers.

Step 2: Ameren Missouri negotiates with an implementor to install 10,000 measures. Each measure is modeled to save 2,000 kWh of energy. Ameren Missouri's freely-negotiated contract with the implementor provides that the implementor will receive 5 cents per kWh of energy saved.

	Modeled/Assumed		
Total Energy Savings		20,000,000	kWh
Measures to Install		10,000	
Savings per Measure		2,000	kWh
Cost to Achieve Energy Savings	$	0.05	$/kWh
Program Costs	$	1,000,000	
Benefits per kWh Avoided	$	0.075	$/kWh
Total Benefits	$	1,500,000	

[20] Ameren Missouri response to Staff Data Request No. 0014.

Step 3: The implementor installs 10,000 measures. The program is then evaluated, and Ameren Missouri and stakeholders learn that each measure did not save 2,000 kWh, instead, each measure only saved 200 kWh.

Step 4: Ameren Missouri pays the implementor $100,000 for implementing 10,000 measures that each only saved 200 kWh, instead of paying the implementor $1,000,000 for implementing 10,000 measures that each saved 2,000 kWh, as Ameren Missouri had modeled and the implementor had hoped.

	Modeled/Assumed	Actual	
Total Energy Savings	20,000,000	2,000,000	kWh
Measures to Install	10,000	10,000	
Savings per Measure	2,000	200	kWh
Cost to Achieve Energy Savings	$ 0.05	$ 0.05	$/kWh
Program Costs	$ 1,000,000	$ 100,000	
Benefits per kWh Avoided	$ 0.075	$ 0.075	$/kWh
Total Benefits	$ 1,500,000	$ 150,000	

This is the point at which Ameren Missouri's direct testimony states that the implementor is being punished – it's not the implementors fault that the measures didn't perform as modeled. Perhaps the modeling was wrong, or perhaps the economy has changed. Ameren Missouri's solution is that the implementor receive the $1,000,000 as though the full 20,000,000 kWh had been avoided.

	Modeled/Assumed	Actual	Ameren Missouri Position	
Total Energy Savings	20,000,000	2,000,000	2,000,000	kWh
Measures to Install	10,000	10,000	10,000	
Savings per Measure	2,000	200	200	kWh
Cost to Achieve Energy Savings	$ 0.05	$ 0.05	$ 0.05	$/kWh
Program Costs	$ 1,000,000	$ 100,000	$ 1,000,000	
Benefits per kWh Avoided	$ 0.075	$ 0.075	$ 0.075	$/kWh
Total Benefits	$ 1,500,000	$ 150,000	$ 150,000	

Q. Is it understandable for Ameren Missouri to be concerned that implementors are not held responsible for shortcomings in Ameren Missouri's Technical Resource Manual and deemed savings tables?

A. It is understandable that Ameren Missouri recognizes that there is a risk that the energy and demand savings that they modeled may not materialize. However, this illustration considered only program costs. The costs to ratepayers are not limited to program costs and all program costs are not incurred on a simple $/kWh basis. Under this simple example, ratepayers are paying the $1 million that was supposed to produce benefits of $1.5 million, to instead produce benefits of $150,000. There is no net benefit for ratepayers under this outcome; in fact, ratepayers are worse off than if the program hadn't occurred. In reality, ratepayers will also be paying for avoided revenues through the NTD that were not actually avoided, and avoided shareholder return through the Earnings Opportunity that will not be actually avoided.

If Ameren Missouri is comfortable describing the reduction in the compensation of voluntary implementors as "punitive," then surely the erosion of modeled benefits to captive ratepayers is also "punitive." However, there are no safeguards proposed by Ameren Missouri to compensate captive ratepayers if and when modeled benefits fail to materialize.

Benefit:Cost tests, and Ameren Missouri's application of those tests in their Revised MEEIA Application

Q. Have you reviewed the Benefit to Cost tests Ameren Missouri provided in Appendix A to their Revised Application?

A. Yes.

Q. What do those test results reveal?

A. Ameren Missouri's Ratepayer Impact Measure test results support the overall conclusion that the benefits of MEEIA Cycle 4 do not outweigh the costs to ratepayers, even under Ameren Missouri's quantification of avoided costs. An analysis of Ameren Missouri's Total Resource Cost test results reveal Ameren Missouri used inconsistent quantification of costs and benefits. Correction of this inconsistency and of a mathematical error supports the overall conclusion that the benefits of MEEIA Cycle 4 do not outweigh the costs to ratepayers, even under Ameren Missouri's quantification of avoided costs.

Total Resource Cost Test

Q. Ameren Missouri bases its MEEIA application on an overall "TRC"[21] result of 1.64. Doesn't that mean that for every dollar Ameren Missouri ratepayers spend on MEEIA, they will receive $1.64 in benefits?

A. No. Staff has significant concerns with, among other things, the inputs to Ameren Missouri's cost tests.[22] However, this section will be focused on Ameren Missouri's execution of the test itself.

Ameren Missouri chose to model the actual program costs of MEEIA Cycle 4 as transfer payments, and further chose to model transfer payments incorrectly.

Q. What do you mean by "transfer payment"?

A. When resources – in this case ratepayer dollars – are redistributed by a government – or, in this case, a utility acting with the authority of the State – they are viewed

[21] 20 CSR 4240-20.092 (1) (WW) Total resource cost test or TRC means a test that compares the sum of avoided utility costs, including avoided probable environmental costs to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus utility costs to administer, deliver, and evaluate each demandside program and costs of statewide TRM or TRM and statewide TRM.
[22] See testimonies of Brad J. Fortson and J Luebbert.

as transferred without an exchange of value. The dollars billed through the EEIC for program costs are transferred from ratepayers as a whole to MEEIA participants, and Ameren Missouri neither contributes nor retains the program costs that are at the heart of MEEIA Cycle 4.

Q. Why does Ameren Missouri treat program costs as transfer payments?

A. Based on discussions with Ameren Missouri in prior MEEIA cycles, Ameren Missouri believes that dollars obtained from all ratepayers for provision to a subset of ratepayers are both costs and benefits to ratepayers, and can be ignored.

Q. If that is true, is that how math works?

A. No. Including a number in both a numerator and a denominator is very different than excluding a number in each.

The following relevant values are calculated from Ameren Missouri's Appendix A:

	Millions of $ NPV
Non-Program Costs	$ 446
Program Costs	$ 179
Total Costs	$ 625
Benefits	$ 729
Benefits and Program Cost	$ 909

To obtain a TRC result of 1.64, Ameren Missouri divided $729 million in benefits by $446 million in non-program costs. However, if program costs were being treated as a transfer payment, the proper math would be to divide $909 million in benefits by $625 million in costs, producing a TRC result of 1.45.

Ameren Missouri's math error is easily illustrated by the difference between the following two simple math problems:

2/1 = 2

But, adding another 1 to both the numerator and the denominator does not equal 2, instead it equals 1.5.

$$(2+1)/(1+1) = 3/2 = 1.5$$

Ameren Missouri cannot simply ignore the program cost, even if it is of the opinion that program costs are equally a cost and a benefit.

Q. For purposes of statutory compliance, is it reasonable to treat program costs as transfer payments?

A. No. The MEEIA allows approval of a DSIM only if the MEEIA Cycle is beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers.

Q. What are the TRC results if program costs are considered a cost, not a transfer payment?

A. $729 million in benefits divided by $625 million in costs produces a TRC result of 1.16.

Q. Is this calculation consistent with how Ameren Missouri calculated the TRC elsewhere?

A. Yes. In its workpaper "DSMore 2018 Aggregation Results – ALL – ALL – ALLwEO," Ameren Missouri calculated its TRC with program costs treated as a cost and not removed or treated as a transfer payment. However, the workpapers that feed into Appendix A and the calculations provided in the DSMore workpaper reflect different program costs, non-program costs, and benefits valuations, both of which are calculated from workpapers with hardcoded inputs. Ameren Missouri produced near-identical test results with very different inputs in two different workpapers. The similarity in test results and differences in inputs are obvious in the table provided below. The bolded numbers indicate the values considered in each test:

	Millions of $ NPV Depicted in Appendix A	Millions of $ NPV Depicted in DSMore Workpaper
Non-Program Costs	**$ 446**	**$ 275**
Program Costs	$ 179	**$ 201**
Benefits	**$ 729**	**$ 779**
TRC Test Results	1.63603	1.63624

Q. How did Ameren Missouri reflect the Earnings Opportunity in its test results in Appendix A?

A. The values provided in Appendix A assume that a total Earnings Opportunity of $47.89 million will be paid out. However, Ameren Missouri requests an Earnings Opportunity of $74.91 million. Ameren Missouri's inclusion of $47.89 million in program years 1-3 is a net present valuing of Ameren Missouri's receiving an Earnings Opportunity at its requested "Target" level in the future. The EO Target level is 80%, meaning Ameren Missouri's modeled benefits are exaggerated by 20% under Appendix A.

Q. What does that mean?

A. It means Ameren Missouri's modeling, as presented in Appendix A, assumes its programs will only produce 80% of their assumed energy and demand savings; however, Ameren Missouri included the full modeled benefit of programs. Correcting the overstated benefits to the 80% target level of $583 results in a TRC result of 0.93.

Q. In the alternative, what are the test results including the full cost of the requested earnings opportunity?

A. Correcting the $15.4 present value difference in the EO cost to correspond to Ameren Missouri's modeled level of benefits results in a TRC value of 1.07.

Q. At this point in your testimony you have corrected the Ameren Missouri MEEIA Cycle 4 TRC test result to a range of 0.93 – 1.07. Does this address any Staff concerns with the reasonableness of Ameren Missouri's avoided cost calculations, selection of a discount rate, relationship between the IRP and the Plan, relationship between the Plan and the measures, or any other Staff concern?

A. No. The correction of Ameren Missouri's MEEIA Cycle 4 TRC test result to a range of 0.93 – 1.07 reflects only including program costs as a cost to ratepayers, and addressing the level of performance Ameren Missouri expects to achieve with respect to its requested Earnings Opportunity.

Q. To the extent that your range does include some values greater than 1, do the TRC results modified as described above, and assuming the avoided cost calculations are accurate, show that Ameren Missouri's Revised Application is beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers?[23]

A. No. The TRC does not include either the cost to ratepayers of Ameren Missouri's requested NTD mechanism in the rider EEIC rate, nor the ongoing reduction in revenue as a result of diminished consumption. The Ratepayer Impact Measure[24] (RIM) incorporates these factors.

[23] 393.1075.4.

[24] 20 CSR 4240-20.092 (1) (NN) Rate Payer Impact Measure (RIM) test is a measure of the difference between the change in total revenues paid to a utility and the change in total cost incurred by the utility as a result of the

Ratepayer Impact Measure

Q. The RIM test results Ameren Missouri provides in Appendix A provide a portfolio total result of 0.70. Because the RIM result is less than one, does that mean that by Ameren Missouri's own modeling that the program costs customers more than it benefits them?

A. Yes, that is what Ameren Missouri's RIM test results mean.

Q. What costs and benefits did Ameren Missouri capture in its RIM test?

A. Ameren Missouri's RIM test results provided in Appendix A are linked to the RIM test results provided in the DSMore workpaper.[25] The calculation is reproduced below:

RIM Test		
Avoided Electric Production	$	397,858,977
Avoided Electric Capacity	$	309,766,262
Avoided Electric T&D	$	71,680,272
Total	$	779,305,511
Administration Costs	$	206,911,111
Other / Miscellaneous Costs	$	38,284,758
Incentives	$	145,780,892
Total	$	390,976,761
Electric Lost Revenue (Net Fuel)	$	721,023,457

Q. For its load building programs, such as the Charge Ahead program, what test does Ameren Missouri use, the TRC or the RIM?

implementation of demand-side programs. The benefits are the avoided costs as a result of implementation. The costs consist of incentives paid to participants, other costs incurred by the utility, and the loss in revenue as a result of diminished consumption, and the utility's earnings opportunity as a result of implementation of demand-side programs. Utility costs include the costs to administer, deliver, and evaluate each demand-side program and the costs of statewide TRM or TRM and statewide TRM.

[25] However, for the RIM test, "Administration Costs," are $30 million less than the TRC test Administration Costs, and the "Incentives," are $55 million less than the "Participant Cost," reflected in the TRC test. Because all values discussed are hard pasted, Staff has been unable to track the source of these discrepancies to date. Related discovery has not been productive.

A. The RIM. Ameren Missouri's position in the Charge Ahead cases is that selling more energy is good for all customers, and so in those cases it presents cost effectiveness tests that consider the overall impact on ratepayers regardless of participation in the program.

AVOIDED ENERGY COSTS AND REALLOCATION OF REVENUE REQUIREMENT

Q. Are avoided energy costs really avoided costs for purposes of analyzing a MEEIA program?

A. No. When a retail customer uses one less kWh, the company buys one less kWh at wholesale, and receives revenue for one less kWh at retail. What matters is whether the retail kWh avoided was one with high or low margin – meaning was the kWh purchase avoided at wholesale above or below average cost.

Q. Can you walk through an example?

A. Yes. Consider a vending machine. Leasing the vending machine costs $50 per month. Purchasing soda at Sam's to stock the vending machine costs $0.50 per can. If I sell 200 cans of soda per month at $0.75 per can, I will break even.

			Quantity	
Lease	$ 50.00	per month	1	$ 50.00
Wholesale Cost	$ 0.50	per can	200	$ 100.00
				$ 150.00
$150.00 divided by 200 cans, required price per can:				$ 0.75

Now, consider if my sales drop by 50 cans per month. If I only need to purchase 150 cans from Sam's, my wholesale cost of soda drops from $100 to $75 – I have avoided $25 in costs!

			Quantity	
Lease	$ 50.00	per month	1	$ 50.00
Wholesale Cost	$ 0.50	per can	150	$ 75.00
				$ 125.00
$125.00 divided by 150 cans, required price per can:				$ 0.83

But my lease cost of $50 hasn't changed, and I am now going to have to raise prices to $0.83 to continue to break even.

Obviously, electric pricing is more complicated than a soda vending machine. The cost of every kWh consumed at retail by an Ameren Missouri customer is obtained through an incomprehensibly complex integrated energy market, and the time at which that energy is purchased and the point on the transmission system at which it is obtained, and market and weather conditions for approximately half of the continental United States and a swath of Canada are factored into its pricing. And retail pricing is complex. Residential customers pay a different rate for energy depending on how much energy they've already used in that billing month, and where that billing month falls in the year, and many pay a different rate based on what time of day the energy is used. Outside of the residential class, customers are billed on multi-part rates which cannot be succinctly described in this testimony. So we'll consider an example with two soda brands.

			Quantity	
Lease	$ 50.00	per month	1	$ 50.00
Wholesale Cost Brand A	$ 0.80	per can	50	$ 40.00
Wholesale Cost Brand B	$ 0.40	per can	150	$ 60.00
				$ 150.00
$150.00 divided by 200 cans, required price per can:				$ 0.75

Notice we are losing 5 cents on every can we sell of Brand A. And our sales of Brand B have to cover not only our lease cost, but also the cost of our losses on Brand A.

			Quantity	
Lease	$ 50.00	per month	1	$ 50.00
Wholesale Cost Brand A	$ 0.80	per can	30	$ 24.00
Wholesale Cost Brand B	$ 0.40	per can	150	$ 60.00
				$ 134.00
$134.00 divided by 180 cans, required price per can:				$ 0.74

If I sell 20 fewer cans of Brand A, my wholesale costs have dropped by $16. Those 20 cans of soda I didn't sell would have cost me 80 cents to buy, but they also would have sold for 75 cents each, which would have increased my revenue by $15. The difference between these two values, $1.00, is what I will reflect when I drop my prices on the 180 cans of soda that are sold. Because I avoided $16 in wholesale costs, and $15 in revenues, I can drop my overall cost by $1.00, resulting in a new price of $0.74 per can.

However, if instead of selling fewer sodas of Brand A, I sell fewer sodas of Brand B, the opposite occurs.

			Quantity	
Lease	$ 50.00	per month	1	$ 50.00
Wholesale Cost Brand A	$ 0.80	per can	50	$ 40.00
Wholesale Cost Brand B	$ 0.40	per can	130	$ 52.00
				$ 142.00
$138.00 divided by 180 cans, required price per can:				$ 0.79

Notice my wholesale cost has again dropped. I have, without a doubt, avoided wholesale soda costs of $8 compared to where we started. However, I have also avoided $15 in revenue. The difference between those two values is $7, which is what I must reflect when I RAISE my prices by $0.04 per can to $0.79. Even though I avoided costs, my prices had to go up. The relationship between the wholesale and the retail cost – the margin – is what matters to the other soda purchasers. When analyzing avoided energy costs in MEEIA, avoiding the sale of high cost energy – especially if it is sold with little room for margin -- is good for customers. Avoiding the sale of low cost energy, when analyzing avoided energy costs in MEEIA, is not good for customers.

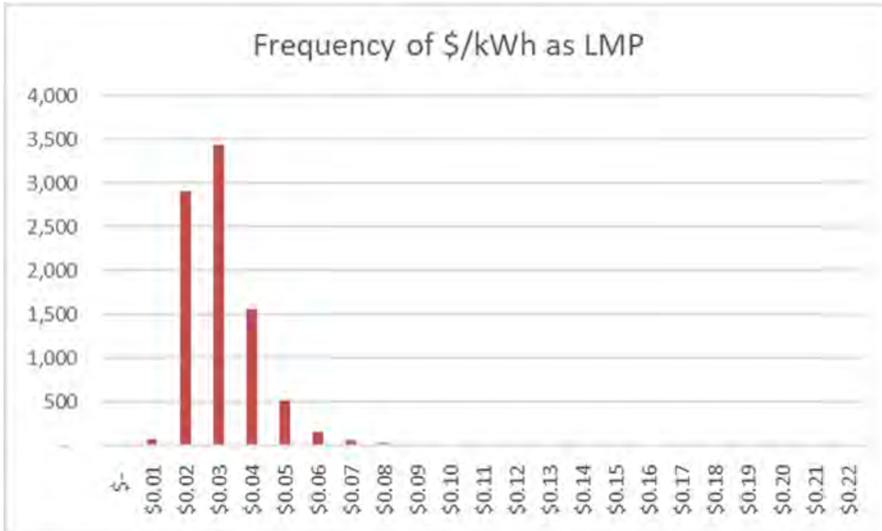
Q. Can you walk through an example using retail and wholesale rates?

A. Yes. Using the Large Power Service rate schedule as an example, for 8 months of the year the retail rate for energy is $0.0333 per kWh. For the non-summer months of calendar year 2023, there were 1,562 hours when the wholesale price of energy, plus an allowance for transmission costs, exceeded the LPS rate. However, there were 4,270 hours during this time period when the wholesale energy cost was less than the LPS energy rate. For the same time period, considering the Residential "Anytime," tail block rate of $0.0626, there were only 26 hours in which the wholesale cost of energy (plus an allowance for transmission) exceeded that retail rate, compared to 5,806 hours in which the retail rate exceeded the wholesale price.

Q. For calendar year 2023, for all months, what was the most common cost of electricity at wholesale, including an allowance for transmission expenses, for Ameren Missouri load?

A. As indicated in the distribution table below, in most hours the wholesale cost of energy with an allowance for transmission was between $0.015 and $0.044 per kWh.

Tranche	Count
$ -	-
$ 0.01	69
$ 0.02	2,908
$ 0.03	3,429
$ 0.04	1,551
$ 0.05	512
$ 0.06	150
$ 0.07	55
$ 0.08	30
$ 0.09	17
$ 0.10	11
$ 0.11	8
$ 0.12	4
$ 0.13	3
$ 0.14	1
$ 0.15	2
$ 0.16	2
$ 0.17	1
$ 0.18	3
$ 0.19	1
$ 0.20	2
$ 0.21	-
$ 0.22	1



Q. What does this mean for designing a reasonable MEEIA program?

A. This means that for most hours throughout the year, Ameren Missouri sells energy to retail customers for more than it costs Ameren Missouri to obtain the energy at wholesale. This makes sense. But, it also means that if Ameren Missouri avoids a sale of energy at retail when the cost of that energy at wholesale is lower than the retail rate, that a MEEIA program on the balance does not avoid energy costs, it avoids retail revenues.[26] This must be factored into the overall program evaluation.

Q. Is there a MEEIA program area that clearly illustrates the mismatch of avoided costs and energy particularly?

A. Yes. Air source heat pumps (ASHP) are an excellent illustration of the relationship between avoided wholesale retail energy and avoided retail revenue.

Assume a residential customer is using exactly 2,000 kWh in each non-summer month. That customer obtains an ASHP, enabling a reduction in energy consumed to 1,500 kWh in

[26] Further, as discussed in my direct testimony and that of J Luebbert, if a low-cost kWh is avoided, the average cost of fuel and purchased power increases, and ratepayers will bear that cost.

each of those months – a very aggressive energy savings level. Given the customer's level of usage, all energy consumption avoided is occurring at the residential non-summer tail-block rate of $0.0626, and to simplify the calculation, we will assume all kWh are priced at the tail-block rate.[27] For this first example, we will assume that the customer uses exactly the same amount of energy in every hour:

	October	November	December	January	February	March	April	May
Customer Usage before ASHP	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Customer Bill before ASHP	$ 125.20	$ 125.20	$ 125.20	$ 125.20	$ 125.20	$ 125.20	$ 125.20	$ 125.20
Wholesale Cost of Energy before ASHP (same amount used in every hour)	$ 58.91	$ 58.91	$ 58.91	$ 58.91	$ 58.91	$ 58.91	$ 58.91	$ 58.91
Revenue net of Wholesale Energy Costs	$ 66.29	$ 66.29	$ 66.29	$ 66.29	$ 66.29	$ 66.29	$ 66.29	$ 66.29

In this example, the wholesale cost of energy is less than the retail revenue for energy, and the customer contributes $66.29 per month to the overall revenue requirement of the utility.

Now, assume that the 500 kWh per month of energy savings occurs – again, assume the energy usage that remains occurs evenly in every hour. The resulting calculation of the customer's contribution to overall revenue requirement is provided below:

	October	November	December	January	February	March	April	May
Customer Usage after ASHP	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Customer Bill after ASHP	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90
Wholesale Cost of Energy after ASHP (same amount used in every hour)	$ 44.18	$ 44.18	$ 44.18	$ 44.18	$ 44.18	$ 44.18	$ 44.18	$ 44.18
Revenue net of Wholesale Energy Costs	$ 49.72	$ 49.72	$ 49.72	$ 49.72	$ 49.72	$ 49.72	$ 49.72	$ 49.72

The ratepayer now contributes less to overall revenue requirement. The customer's bill went down by more than the value of the wholesale energy the customer avoided. Other customers are worse off.

[27] Energy sales occurring in the higher-priced first block would only compound the adverse ratepayer impact to be discussed in this section.

Q. You noted above that there were 26 out of 5,832 hours when the wholesale value of energy exceeded the retail rate. What if the avoided energy occurred only in those hours?

A. The table below assumes that all energy savings occur in the high energy cost hours:

	October	November	December	January	February	March	April	May
Customer Usage after ASHP	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Customer Bill after ASHP	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90
Wholesale Cost of Energy after ASHP (**all savings occur in high cost hours**)	$ 22.93	$ 22.93	$ 22.93	$ 22.93	$ 22.93	$ 22.93	$ 22.93	$ 22.93
Revenue net of Wholesale Energy Costs	$ 70.97	$ 70.97	$ 70.97	$ 70.97	$ 70.97	$ 70.97	$ 70.97	$ 70.97

In this example we see that the participant's overall bill is lower ($93.90 per month, instead of $125 per month) and the customer is contributing more to the utility's overall revenue requirement ($70.97 per month, instead of $66.29 per month).

Q. How reasonable is it to assume that an ASHP program would produce the results in the second example?

A. It is not at all reasonable. ASHP are a good example of a measure that reduces overall energy consumption during mild winter weather, while maintaining usage during harsh weather conditions which coincide with peak energy prices. Essentially the heatpump quits working as a heatpump when the weather gets very cold, and instead functions as a resistance electric heater.[28] This example illustrates the lowest contribution to overall revenue requirement of any prior example:

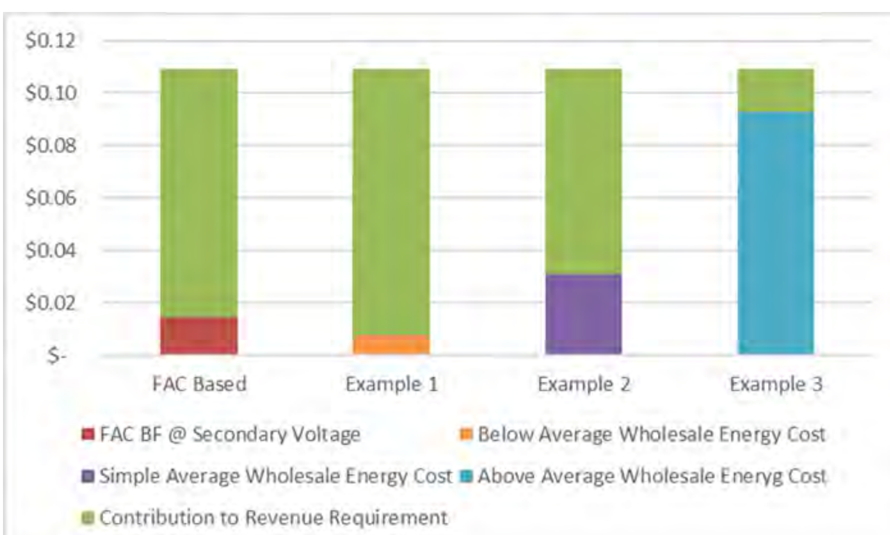
[28] For these reasons ASHP are also poor performers in utility capacity requirements under the MISO seasonal planning reserve auction. Resistance electric heaters rely on the inefficient conduction of electricity through a medium to produce waste heat which can be utilized for space heating.

	October	November	December	January	February	March	April	May
Customer Usage after ASHP	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Customer Bill after ASHP	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90	$ 93.90
Wholesale Cost of Energy after ASHP **(savings occur outside high cost hours)**	$ 44.28	$ 44.28	$ 44.28	$ 44.28	$ 44.28	$ 44.28	$ 44.28	$ 44.28
Revenue net of Wholesale Energy Costs	$ 49.62	$ 49.62	$ 49.62	$ 49.62	$ 49.62	$ 49.62	$ 49.62	$ 49.62

Relationship of FAC, NTD, and Contributions to Revenue Requirement

Q. Do these examples account for the interaction of MEEIA savings with the Fuel Adjustment Clause or the NTD?

A. No. I will attempt to demonstrate elements of these relationships, however the relationships are very complex. The current FAC Base Factor is $0.01403, which adjusted to secondary voltage by a factor of 1.0539 is $0.01479. Ameren Missouri represents that the average residential revenue per kWh is $0.10922, regardless of season or rate structure block. The simple average wholesale energy cost for calendar year 2023, with an allowance for Regional Transmission Organization (RTO) expense, adjusted to secondary voltage is $0.03103. The FAC Base Factor is less than half of the simple average wholesale energy cost for last year. The relationship of the FAC Base Factor to the average retail revenue per kWh, and the simple average wholesale energy cost per kWh are illustrated below:



As illustrated, between rate cases the FAC functions to ensure that the same amount of revenue is available to the revenue requirement in each kWh sold, whether the kWh sold was at a high, low, or average wholesale energy cost. However, the FAC then collects (or refunds) 95% of the difference between the experienced net energy function costs and revenues. Concurrently, Ameren Missouri's requested NTD Mechanism would charge ratepayers for the difference between the FAC base and the average revenue per kWh for the applicable month for each kWh sale assumed to have been avoided. The result is that whether a high cost kWh or a low cost kWh is avoided through a MEEIA program, Ameren Missouri requests compensation from ratepayers for the same avoided revenue requirement contribution. 95% of the energy cost difference is eventually billed to or refunded to ratepayers through the FAC, such that the FAC actually incents Ameren Missouri to target low-wholesale cost energy reductions.

Q. When a rate case occurs, what happens to the avoided revenue requirement contributions?

A. When a rate case occurs, the revenue requirement contributions are reallocated to other ratepayers.

Reallocation of Revenue Requirement

Q. What is the reallocation of revenue requirement?

A. A utility makes money by selling energy. When a utility uses ratepayer dollars to facilitate programs to reduce energy consumption, that utility is reducing the energy it sells, and ultimately, the money it makes, all else being equal. In other words, a utility has a financial disincentive to facilitating programs to reduce energy consumption, in general.

Collectively, ratepayers also have a financial disincentive to reduce the energy sold by their utility, to the extent that those sales were made above the marginal cost of the energy sold.

Decreased sales can reduce affordability, as avoided revenues do not displace the utility's need for retail electric service revenues required of the basic rate classes. Sales of energy effectively lost to energy efficiency programs can avoid revenues that cover some of the revenue requirement and contribute to overall affordability of basic electric service. Ameren Missouri has proposed and received authorization of economic development and electrification activities (including the Charge Ahead Electric Vehicle program approved by the Commission in 2019), all of which are designed to encourage new loads that provide revenues above the marginal cost of serving them, and therefore contribute to covering fixed costs and ultimately reduce rates for all customers from levels that would otherwise be required to cover those fixed costs.[29]

A poorly-designed MEEIA program can do the opposite of that. A poorly-designed MEEIA program may cause other customers to pay more to cover the revenue requirement that remains when a sale of energy is avoided. As discussed in the testimony of Staff witness J Luebbert, the operation of the fuel adjustment clause and Ameren Missouri's participation in an integrated energy and capacity market can further distort the typically-expected relationships for classes of customers and individual customers, even if a program appears reasonable at a total company level.[30]

Q. Is the reallocation of revenue requirement only a problem once a rate case occurs?

[29] See Direct Testimony of Steve Wills, File No.: ET-2021-0020, October 27, 2020 at page 5, lines 22 – 34.
[30] Because the overall program results are so poor, I have not included in this testimony modeling that the action of the FAC for reallocation of avoided energy cost benefits, and the importance of addressing the timing of energy consumption with regard to whether the avoided energy sale will actually increase or decrease the rates payed by all customers.

A. No. Prior to a rate case (and, in the short term, encompassed in a rate case normalization) the reallocation of revenue requirement occurs as a literal charge to customers – the Net Throughput Disincentive as proposed by Ameren Missouri. Staff witness Hari K. Poudel, PhD discussed the NTD in his direct testimony. If the Ameren Missouri NTD mechanism is used for MEEIA 4, it is likely that the cost to the NTD in the rates of ratepayers will exceed the reallocation of revenue requirement that occurs during the first several years of the program, contingent on rate case timing.

Q. Is the reallocation of revenue requirement a cost or a reduced benefit?

A. It would be reasonable to include an estimate of the cost of the NTD, at a minimum, as a cost in analyzing Ameren Missouri's MEEIA 4 Application, as these amounts will be paid directly by ratepayers. Rather than attempting to estimate rate case timing or make revisions related to net to gross assumptions, for convenience I will use the first 4 years of Ameren Missouri's calculation of "Lost Revenue (Net Fuel)" as a stand-in for the ratepayer impact of the requested NTD. As a conservative approach in this case, for the remainder of this testimony, where indicated, I will use Ameren Missouri's calculation of "Lost Revenue (Net Fuel)" as a stand-in for the reallocation of revenue requirement in years 5 and after.

Q. Why does it matter if something is modeled as a cost or an avoided benefit, all else being equal?

A. While it may seem trivial, the choice of whether to account for a given item as a cost or as an avoided benefit (or as an avoided cost versus an accrued benefit) has significant impact on benefit:cost test results. A simple illustration is provided below, in which a program with the same net impact has very different benefit:cost results depending on whether a cost of $1 is treated as a cost of $1, or as a reduction in benefit of $1.

	Scenario A	Scenario B	% Difference
Cost	$ 2.00	$ 1.00	100%
Benefit	$ 4.00	$ 3.00	33%
Net	$ 2.00	$ 2.00	0%
Test Result	**2.00**	**3.00**	-33%

Q. What is Ameren Missouri's calculation of "Lost Revenue (Net Fuel)"?

A. The values provided by Ameren Missouri are reproduced below, by year.

	Ameren Missouri Quantification of "Lost Revenue (Net of Fuel)"				
	Residential	**Business**	**Income Eligible**	**Demand Response**	**Total**
2025	$ 4,017,995	$ 8,841,802	$ 2,949,969	$ 363,869	$ 16,173,635
2026	$ 8,746,032	$ 19,338,869	$ 6,477,335	$ 404,227	$ 34,966,463
2027	$ 15,217,356	$ 33,359,870	$ 11,279,671	$ 472,822	$ 60,329,720
2028	$ 18,007,181	$ 38,385,010	$ 13,277,517	$ -	$ 69,669,709
2029	$ 18,887,650	$ 39,985,472	$ 13,772,418	$ -	$ 72,645,539
2030	$ 19,745,274	$ 42,124,438	$ 14,392,234	$ -	$ 76,261,946
2031	$ 18,316,574	$ 45,807,007	$ 14,601,583	$ -	$ 78,725,165
2032	$ 16,292,358	$ 48,657,263	$ 14,539,982	$ -	$ 79,489,602
2033	$ 14,154,642	$ 52,300,200	$ 14,713,790	$ -	$ 81,168,633
2034	$ 15,654,445	$ 57,809,275	$ 16,416,482	$ -	$ 89,880,203
2035	$ 14,656,112	$ 58,806,259	$ 15,717,847	$ -	$ 89,180,218
2036	$ 13,067,261	$ 58,344,749	$ 14,345,526	$ -	$ 85,757,537
2037	$ 11,371,322	$ 59,205,581	$ 13,061,777	$ -	$ 83,638,680
2038	$ 10,941,919	$ 59,707,056	$ 13,092,621	$ -	$ 83,741,596
2039	$ 10,338,990	$ 55,817,934	$ 12,843,361	$ -	$ 79,000,285
2040	$ 11,248,290	$ 40,786,815	$ 13,868,599	$ -	$ 65,903,705
2041	$ 11,283,513	$ 19,097,234	$ 13,618,391	$ -	$ 43,999,138
2042	$ 11,180,737	$ 1,188,536	$ 13,431,539	$ -	$ 25,800,812
2043	$ 8,585,858	$ 110,964	$ 12,943,530	$ -	$ 21,640,352
2044	$ 5,044,374	$ 82,781	$ 8,443,696	$ -	$ 13,570,851
2045	$ 1,130,425	$ 36,018	$ 3,573,444	$ -	$ 4,739,887
2046	$ 699,870	$ 18,276	$ 11,785	$ -	$ 729,931
2047	$ 470,441	$ -	$ 10,965	$ -	$ 481,406
2048	$ 468,453	$ -	$ 10,935	$ -	$ 479,387
Nominal Total	$ 259,527,071	$ 739,811,412	$ 257,394,997	$ 1,240,918	$ 1,257,974,399

Addressing Benefit Assumptions in Ameren Missouri's Analysis

Q. Ameren Missouri's quantification of avoided retail revenues net of fuel is provided in its DSMore workpapers. Can you use the DSMore workpapers to refine the benefits assumed in Ameren Missouri's cost analysis, while still relying on Ameren Missouri's models?

A. Yes. Below I present year-by-year costs to customers under Ameren Missouri's MEEIA Cycle 4 Revised Application?

	Residential Incentive Payments	Business Incentive Payments	Income Eligible Incentive Payments	Demand Response Incentive Payments	Administration	Other	Earnings Opportunity	NTD	Annual Costs to Ratepayers
2025	$ 11,931,015	$ 28,865,056	$ 8,643,847	$ -	$ 57,174,602	$ 12,272,149		16,173,635	135,060,305
2026	$ 12,737,742	$ 29,965,879	$ 9,346,334	$ -	$ 57,780,344	$ 13,674,374		34,966,463	158,471,136
2027	$ 13,683,676	$ 30,657,786	$ 10,050,289	$ -	$ 58,163,880	$ 15,091,517		60,329,720	187,976,867
2028	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,626,420	69,669,709	93,296,129
2029	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,712,893		24,712,893
2030	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,573,573		26,573,573

Q. Can you describe the relationship between benefits/avoided costs, and costs to ratepayers for Ameren Missouri's MEEIA Cycle 4 Revised Application, using Ameren Missouri's view of benefits and avoided costs?[31]

A. Yes. The following table shows ratepayers will pay $626,090,903 through the Rider DSIM for Ameren Missouri Cycle 4, if approved as-is, implemented exactly as modeled.

continued on next page

[31] As discussed by J Luebbert, these avoided cost estimates are not reasonable.

Cumulative	All Program Costs	NTD	Earnings Opportunity	Total Costs to Ratepayers in Rider DSIM	Ameren Assumed Avoided Energy	Ameren Assumed Avoided Capacity	Ameren Assumed Avoided T&D	Ameren Assumed Benefit Quantification	Running Benefit:Cost
2025	$ 118,886,670	$ 16,173,635	$ -	$ 135,060,305	$ (15,601,808)	$ (33,317,154)	$ (8,137,527)	$ (57,056,490)	**0.42**
2026	$ 242,391,343	$ 51,140,098	$ -	$ 293,531,441	$ (45,373,672)	$ (76,964,180)	$ (18,607,225)	$ (140,945,077)	**0.48**
2027	$ 370,038,490	$ 111,469,818	$ -	$ 481,508,308	$ (86,807,200)	$ (131,765,603)	$ (31,579,497)	$ (250,152,300)	**0.52**
2028	$ 370,038,490	$ 181,139,527	$ 23,626,420	$ 574,804,437	$ (127,915,455)	$ (160,153,052)	$ (37,958,175)	$ (326,026,682)	**0.57**
2029	$ 370,038,490	$ 181,139,527	$ 48,339,313	$ 599,517,330	$ (172,014,796)	$ (188,925,229)	$ (44,441,614)	$ (405,381,638)	**0.68**
2030	$ 370,038,490	$ 181,139,527	$ 74,912,886	**$ 626,090,903**	**$ (218,630,706)**	**$ (218,222,417)**	**$ (51,054,722)**	**$ (487,907,844)**	**0.78**
2031	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (264,538,200)	$ (245,891,306)	$ (57,311,532)	$ (567,741,039)	**0.91**
2032	$ 370,038,490	$ 181,139,527	$ 74,912,886	**$ 626,090,903**	**$ (308,647,475)**	**$ (271,706,037)**	**$ (63,152,931)**	**$ (643,506,442)**	**1.03**
2033	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (350,742,607)	$ (295,186,140)	$ (68,466,046)	$ (714,394,793)	**1.14**
2034	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (392,847,877)	$ (318,780,398)	$ (73,804,993)	$ (785,433,268)	**1.25**
2035	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (433,075,466)	$ (341,321,125)	$ (78,905,545)	$ (853,302,136)	**1.36**
2036	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (472,058,230)	$ (362,941,217)	$ (83,797,774)	$ (918,797,220)	**1.47**
2037	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (509,852,493)	$ (383,438,532)	$ (88,435,939)	$ (981,726,964)	**1.57**
2038	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (547,537,303)	$ (403,828,761)	$ (93,049,873)	$ (1,044,415,937)	**1.67**
2039	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (583,756,125)	$ (423,465,740)	$ (97,493,360)	$ (1,104,715,225)	**1.76**
2040	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (611,001,131)	$ (438,521,547)	$ (100,900,212)	$ (1,150,422,890)	**1.84**
2041	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (628,948,811)	$ (448,068,210)	$ (103,060,446)	$ (1,180,077,467)	**1.88**
2042	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (638,960,536)	$ (452,563,556)	$ (104,077,660)	$ (1,195,601,752)	**1.91**
2043	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (646,762,084)	$ (455,270,019)	$ (104,690,083)	$ (1,206,722,187)	**1.93**
2044	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (651,625,707)	$ (457,007,647)	$ (105,083,954)	$ (1,213,717,308)	**1.94**
2045	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,202,237)	$ (457,616,696)	$ (105,227,410)	$ (1,216,046,344)	**1.94**
2046	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,463,883)	$ (457,891,428)	$ (105,292,120)	$ (1,216,647,431)	**1.94**
2047	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,638,202)	$ (458,068,053)	$ (105,333,723)	$ (1,217,039,978)	**1.94**
2048	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,816,174)	$ (458,248,125)	$ (105,376,137)	$ (1,217,440,436)	**1.94**

Q. What does this table tell us?

A. Based on Ameren Missouri's modeling, ignoring reallocated revenue requirement not captured in the NTD, in the year 2032 Ameren Missouri's customers will have avoided over $308 million in energy costs, over $271 million in capacity costs, and over $63 million in T&D costs. At that point, the cost of the program –over time—and the benefits of the program – over time – will be essentially equal and an additional $573,933,994 in benefits will accrue to customers for an overall cost effectiveness score of 1.94.[32]

Q. What is a more realistic outcome?

A. If you assume that Ameren Missouri won't actually avoid capacity, transmission, or distribution costs until 2034, the program is not cost beneficial until 2038.[33]

[32] This value is based on Ameren Missouri's quantification of benefits, which are not reasonable.
[33] This value is based on Ameren Missouri's quantification of benefits, which are not reasonable.

Scenario 1									
Cumulative	**All Program Costs**	**NTD**	**Earnings Opportunity**	**Total Costs to Ratepayers in Rider DSIM**	**Ameren Assumed Avoided Energy**	**Assumed Avoided Capacity**	**Assumed Avoided T&D**	**Assumed Benefit Quantification**	**Running Benefit:Cost**
2025	$ 118,886,670	$ 16,173,635	$ -	$ 135,060,305	$ (15,601,808)			$ (15,601,808)	**0.12**
2026	$ 242,391,343	$ 51,140,098	$ -	$ 293,531,441	$ (45,373,672)			$ (45,373,672)	**0.15**
2027	$ 370,038,490	$ 111,469,818	$ -	$ 481,508,308	$ (86,807,200)			$ (86,807,200)	**0.18**
2028	$ 370,038,490	$ 181,139,527	$ 23,626,420	$ 574,804,437	$ (127,915,455)			$ (127,915,455)	**0.22**
2029	$ 370,038,490	$ 181,139,527	$ 48,339,313	$ 599,517,330	$ (172,014,796)			$ (172,014,796)	**0.29**
2030	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (218,630,706)			$ (218,630,706)	**0.35**
2031	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (264,538,200)			$ (264,538,200)	**0.42**
2032	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (308,647,475)			$ (308,647,475)	**0.49**
2033	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (350,742,607)			$ (350,742,607)	**0.56**
2034	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (392,847,877)	$ (23,480,103)	$ (5,313,115)	$ (421,641,096)	**0.67**
2035	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (433,075,466)	$ (47,074,361)	$ (10,652,062)	$ (490,801,890)	**0.78**
2036	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (472,058,230)	$ (69,615,088)	$ (15,752,614)	$ (557,425,931)	**0.89**
2037	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (509,852,493)	$ (91,235,180)	$ (20,644,843)	$ (621,732,516)	**0.99**
2038	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (547,537,303)	$ (111,732,495)	$ (25,283,008)	$ (684,552,806)	**1.09**
2039	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (583,756,125)	$ (132,122,724)	$ (29,896,942)	$ (745,775,791)	**1.19**
2040	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (611,001,131)	$ (151,759,703)	$ (34,340,429)	$ (797,101,263)	**1.27**
2041	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (628,948,811)	$ (166,815,510)	$ (37,747,281)	$ (833,511,602)	**1.33**
2042	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (638,960,536)	$ (176,362,173)	$ (39,907,515)	$ (855,230,224)	**1.37**
2043	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (646,762,084)	$ (180,857,519)	$ (40,924,729)	$ (868,544,333)	**1.39**
2044	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (651,625,707)	$ (183,563,983)	$ (41,537,152)	$ (876,726,842)	**1.40**
2045	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,202,237)	$ (185,301,610)	$ (41,931,023)	$ (880,434,870)	**1.41**
2046	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,463,883)	$ (185,910,660)	$ (42,074,479)	$ (881,449,021)	**1.41**
2047	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,638,202)	$ (186,185,391)	$ (42,139,189)	$ (881,962,783)	**1.41**
2048	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,816,174)	$ (186,362,016)	$ (42,180,792)	$ (882,358,982)	**1.41**

If you incorporate the reallocation of revenue requirement, the program is not cost beneficial at any time.

Scenario 2										
Cumulative	**All Program Costs**	**NTD**	**Earnings Opportunity**	**Total Costs to Ratepayers in Rider DSIM**	**Ameren Assumed Avoided Energy**	**Ameren Assumed Avoided Capacity**	**Ameren Assumed Avoided T&D**	**Reallocation of Revenue Requirement**	**Assumed Benefit Quantification**	**Running Benefit:Cost**
2025	$ 118,886,670	$ 16,173,635	$ -	$ 135,060,305	$ (15,601,808)	$ (33,317,154)	$ (8,137,527)		$ (57,056,490)	**0.42**
2026	$ 242,391,343	$ 51,140,098	$ -	$ 293,531,441	$ (45,373,672)	$ (76,964,180)	$ (18,607,225)		$ (140,945,077)	**0.48**
2027	$ 370,038,490	$ 111,469,818	$ -	$ 481,508,308	$ (86,807,200)	$ (131,765,603)	$ (31,579,497)		$ (250,152,300)	**0.52**
2028	$ 370,038,490	$ 181,139,527	$ 23,626,420	$ 574,804,437	$ (127,915,455)	$ (160,153,052)	$ (37,958,175)		$ (326,026,682)	**0.57**
2029	$ 370,038,490	$ 181,139,527	$ 48,339,313	$ 599,517,330	$ (172,014,796)	$ (188,925,229)	$ (44,441,614)	72,645,539	$ (332,736,099)	**0.56**
2030	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (218,630,706)	$ (218,222,417)	$ (51,054,722)	148,907,485	$ (339,000,359)	**0.54**
2031	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (264,538,200)	$ (245,891,306)	$ (57,311,532)	227,632,651	$ (340,108,388)	**0.54**
2032	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (308,647,475)	$ (271,706,037)	$ (63,152,931)	307,122,253	$ (336,384,189)	**0.54**
2033	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (350,742,607)	$ (295,186,140)	$ (68,466,046)	388,290,886	$ (326,103,908)	**0.52**
2034	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (392,847,877)	$ (318,780,398)	$ (73,804,993)	478,171,089	$ (307,262,180)	**0.49**
2035	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (433,075,466)	$ (341,321,125)	$ (78,905,545)	567,351,306	$ (285,950,830)	**0.46**
2036	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (472,058,230)	$ (362,941,217)	$ (83,797,774)	653,108,843	$ (265,688,377)	**0.42**
2037	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (509,852,493)	$ (383,438,532)	$ (88,435,939)	736,747,523	$ (244,979,441)	**0.39**
2038	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (547,537,303)	$ (403,828,761)	$ (93,049,873)	820,489,118	$ (223,926,819)	**0.36**
2039	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (583,756,125)	$ (423,465,740)	$ (97,493,360)	899,489,404	$ (205,225,821)	**0.33**
2040	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (611,001,131)	$ (438,521,547)	$ (100,900,212)	965,393,109	$ (185,029,781)	**0.30**
2041	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (628,948,811)	$ (448,068,210)	$ (103,060,446)	1,009,392,246	$ (170,685,221)	**0.27**
2042	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (638,960,536)	$ (452,563,556)	$ (104,077,660)	1,035,193,059	$ (160,408,693)	**0.26**
2043	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (646,762,084)	$ (455,270,019)	$ (104,690,083)	1,056,833,410	$ (149,888,776)	**0.24**
2044	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (651,625,707)	$ (457,007,647)	$ (105,083,954)	1,070,404,261	$ (143,313,047)	**0.23**
2045	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,202,237)	$ (457,616,696)	$ (105,227,410)	1,075,144,148	$ (140,902,196)	**0.23**
2046	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,463,883)	$ (457,891,428)	$ (105,292,120)	1,075,874,079	$ (140,773,352)	**0.22**
2047	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,638,202)	$ (458,068,053)	$ (105,333,723)	1,076,355,485	$ (140,684,493)	**0.22**
2048	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (653,816,174)	$ (458,248,125)	$ (105,376,137)	1,076,834,872	$ (140,605,564)	**0.22**

Q. Ameren Missouri provided the reduction to retail sales that they calculated, net of fuel. Is this information helpful to determine whether or not, as a whole, the wholesale energy purchases avoided will ultimately benefit customers?

A. Yes. This number is positive in every year. If the retail value of the energy sold was lower than the wholesale value of the energy purchased to make those sales, the "Lost Revenues (net of fuel)" would indicate it. Instead, the numbers reported by Ameren Missouri are that Ameren Missouri expects, at a portfolio level, that the retail value of the energy avoided exceeds the wholesale value of the energy avoided by 2 – 4 times. This is why the Direct Testimony of J Luebbert at pages 34 - 41 provides such an important guide to the process of how to proceed with development of a reasonable MEEIA program.

Q. What if the numbers Ameren Missouri provides as avoided cost are intended to reflect the cost of fuel and variable Operations & Maintenance Expenses ("O&M") for Ameren Missouri to generate energy?

A. In that case, the situation is worse. Ameren Missouri generally should not be operating its plants unless doing so produces a net profit. There may be isolated hours where a plant generates "out of the money" due to its ramp rate or other aspects of its design, but in the whole, a plant will only be "up" if it is "in the money."

Q. Can you show what the ongoing impact to ratepayers is if the Avoided Energy costs Ameren Missouri models should be largely ignored?

A. Yes. Scenario 3 incorporates the reallocation of revenue requirement as a cost to ratepayers.

continued on next page

Scenario 3									
					95%	0%	0%	= percent of Avoided Cost Variance	
Cumulative	**All Program Costs**	**NTD**	**Earnings Opportunity**	**Total Costs to Ratepayers in Rider DSIM**	**Ameren Assumed Avoided Energy**	**Ameren Assumed Avoided Capacity**	**Ameren Assumed Avoided T&D**	**Assumed Benefit Quantification**	**Running Benefit:Cost**
2025	$ 118,886,670	$ 16,173,635	$ -	$ 135,060,305	$ (780,090)	$ (33,317,154)	$ (8,137,527)	$ (42,234,772)	**0.31**
2026	$ 242,391,343	$ 51,140,098	$ -	$ 293,531,441	$ (2,268,684)	$ (76,964,180)	$ (18,607,225)	$ (97,840,088)	**0.33**
2027	$ 370,038,490	$ 111,469,818	$ -	$ 481,508,308	$ (4,340,360)	$ (131,765,603)	$ (31,579,497)	$ (167,685,460)	**0.35**
2028	$ 370,038,490	$ 181,139,527	$ 23,626,420	$ 574,804,437	$ (6,395,773)	$ (160,153,052)	$ (37,958,175)	$ (204,507,000)	**0.36**
2029	$ 370,038,490	$ 181,139,527	$ 48,339,313	$ 599,517,330	$ (8,600,740)	$ (188,925,229)	$ (44,441,614)	$ (241,967,582)	**0.40**
2030	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (10,931,535)	$ (218,222,417)	$ (51,054,722)	$ (280,208,674)	**0.45**
2031	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (13,226,910)	$ (245,891,306)	$ (57,311,532)	$ (316,429,749)	**0.51**
2032	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (15,432,374)	$ (271,706,037)	$ (63,152,931)	$ (350,291,341)	**0.56**
2033	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (17,537,130)	$ (295,186,140)	$ (68,466,046)	$ (381,189,317)	**0.61**
2034	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (19,642,394)	$ (318,780,398)	$ (73,804,993)	$ (412,227,785)	**0.66**
2035	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (21,653,773)	$ (341,321,125)	$ (78,905,545)	$ (441,880,443)	**0.71**
2036	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (23,602,911)	$ (362,941,217)	$ (83,797,774)	$ (470,341,902)	**0.75**
2037	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (25,492,625)	$ (383,438,532)	$ (88,435,939)	$ (497,367,095)	**0.79**
2038	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (27,376,865)	$ (403,828,761)	$ (93,049,873)	$ (524,255,499)	**0.84**
2039	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (29,187,806)	$ (423,465,740)	$ (97,493,360)	$ (550,146,906)	**0.88**
2040	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (30,550,057)	$ (438,521,547)	$ (100,900,212)	$ (569,971,815)	**0.91**
2041	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (31,447,441)	$ (448,068,210)	$ (103,060,446)	$ (582,576,097)	**0.93**
2042	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (31,948,027)	$ (452,563,556)	$ (104,077,660)	$ (588,589,243)	**0.94**
2043	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,338,104)	$ (455,270,019)	$ (104,690,083)	$ (592,298,207)	**0.95**
2044	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,581,285)	$ (457,007,647)	$ (105,083,954)	$ (594,672,886)	**0.95**
2045	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,660,112)	$ (457,616,696)	$ (105,227,410)	$ (595,504,218)	**0.95**
2046	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,673,194)	$ (457,891,428)	$ (105,292,120)	$ (595,856,742)	**0.95**
2047	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,681,910)	$ (458,068,053)	$ (105,333,723)	$ (596,083,686)	**0.95**
2048	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,690,809)	$ (458,248,125)	$ (105,376,137)	$ (596,315,070)	**0.95**

Q. Can you comment on what an appropriate scenario would be, relying on Ameren Missouri's inputs?

A. Yes. I would assume there are essentially no truly avoided energy costs. I would assume there are no avoided capacity costs until much further into the future, and that the level assumed by Ameren Missouri is greatly overstated, with the same assumption for T&D costs. I would also incorporate the reallocation of revenue requirement.

continued on next page

					Scenario 4					
					95%	50%	50%	= percent of Avoided Cost Variance		
Cumulative	**All Program Costs**	**NTD**	**Earnings Opportunity**	**Total Costs to Ratepayers in Rider DSIM**	**Avoided Energy**	**Avoided Capacity**	**Avoided T&D**	**Reallocation of Revenue Requirement**	**Assumed Benefit Quantification**	**Running Benefit:Cost**
2025	$ 118,886,670	$ 16,173,635	$ -	$ 135,060,305	$ (780,090)	$ -	$ -	$ -	$ (780,090)	**0.01**
2026	$ 242,391,343	$ 51,140,098	$ -	$ 293,531,441	$ (2,268,684)	$ -	$ -	$ -	$ (2,268,684)	**0.01**
2027	$ 370,038,490	$ 111,469,818	$ -	$ 481,508,308	$ (4,340,360)	$ -	$ -	$ -	$ (4,340,360)	**0.01**
2028	$ 370,038,490	$ 181,139,527	$ 23,626,420	$ 574,804,437	$ (6,395,773)	$ -	$ -	$ -	$ (6,395,773)	**0.01**
2029	$ 370,038,490	$ 181,139,527	$ 48,339,313	$ 599,517,330	$ (8,600,740)	$ -	$ -	$ 72,645,539	$ 64,044,799	**(0.11)**
2030	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (10,931,535)	$ -	$ -	$ 148,907,485	$ 137,975,950	**(0.22)**
2031	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (13,226,910)	$ -	$ -	$ 227,632,651	$ 214,405,741	**(0.34)**
2032	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (15,432,374)	$ -	$ -	$ 307,122,253	$ 291,689,879	**(0.47)**
2033	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (17,537,130)	$ -	$ -	$ 388,290,886	$ 370,753,755	**(0.59)**
2034	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (19,642,394)	$ (11,740,052)	$ (2,656,558)	$ 478,171,089	$ 444,132,085	**(0.71)**
2035	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (21,653,773)	$ (23,537,181)	$ (5,326,031)	$ 567,351,306	$ 516,834,321	**(0.83)**
2036	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (23,602,911)	$ (34,807,544)	$ (7,876,307)	$ 653,108,843	$ 586,822,081	**(0.94)**
2037	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (25,492,625)	$ (45,617,590)	$ (10,322,421)	$ 736,747,523	$ 655,314,887	**(1.05)**
2038	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (27,376,865)	$ (55,866,247)	$ (12,641,504)	$ 820,489,118	$ 724,604,502	**(1.16)**
2039	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (29,187,806)	$ (66,061,362)	$ (14,948,471)	$ 899,489,404	$ 789,291,765	**(1.26)**
2040	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (30,550,057)	$ (75,879,852)	$ (17,170,214)	$ 965,393,109	$ 841,792,986	**(1.34)**
2041	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (31,447,441)	$ (83,407,755)	$ (18,873,640)	$ 1,009,392,246	$ 875,663,410	**(1.40)**
2042	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (31,948,027)	$ (88,181,087)	$ (19,953,758)	$ 1,035,193,059	$ 895,110,188	**(1.43)**
2043	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,338,104)	$ (90,428,760)	$ (20,462,365)	$ 1,056,833,410	$ 913,604,182	**(1.46)**
2044	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,581,285)	$ (91,781,991)	$ (20,768,576)	$ 1,070,404,261	$ 925,272,408	**(1.48)**
2045	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,660,112)	$ (92,650,805)	$ (20,965,511)	$ 1,075,144,148	$ 928,867,719	**(1.48)**
2046	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,673,194)	$ (92,955,330)	$ (21,037,239)	$ 1,075,874,079	$ 929,208,316	**(1.48)**
2047	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,681,910)	$ (93,092,696)	$ (21,069,595)	$ 1,076,355,485	$ 929,511,284	**(1.48)**
2048	$ 370,038,490	$ 181,139,527	$ 74,912,886	$ 626,090,903	$ (32,690,809)	$ (93,181,008)	$ (21,090,396)	$ 1,076,834,872	$ 929,872,659	**(1.49)**

Q. Which of these scenarios are the best predictors of the future?

A. None are good predictors of the future. Even if everything was modeled as accurately and reasonably as possible, the future is uncertain, and Ameren Missouri has incredible freedom in how it implements its programs, and the actual behavior of those who receive incentives is not known. However, based on Ameren Missouri's modeling, I believe the reconfiguration in Scenario 4 is most likely. I think that MEEIA Cycle 4, as proposed, will cost rate payers over half a billion dollars through the DSIM. I think that MEEIA Cycle 4, as proposed, will produce no or little cost savings in the bills of nonparticipants, and I think it is entirely likely that it will cause cost increases in the bills of nonparticipants. This conclusion is consistent with Ameren Missouri's RIM test, reported in Appendix A.

<u>DIFFICULTY OF MODELING CUSTOMER IMPACTS OVER TIME</u>

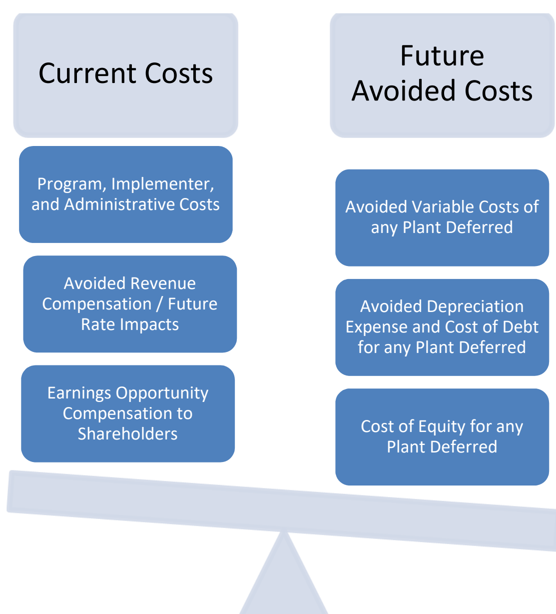
Intergenerational Equity

Q. What is intergenerational equity?

A. Intergenerational equity is the concept of striving for "fairness," between years of service and among a constant flux of new and dying ratepayers. The cheapest way to run a utility from a ratepayer perspective is to pay for all infrastructure in the year it is built – then there are no carrying costs and no return on ratebase to pay to shareholders or income tax to pay to governments. However, this arrangement would be fundamentally unfair. Consider if all the costs of the Callaway Nuclear facility had been paid in 1985. Ratepayers would have saved money in the long run, but since 1985 customers have been born and died, and it would not be fair for customers today to use a plant for free at a cost of billions of dollars to customers in 1985.

Q. Does MEEIA necessarily draw concerns of intergenerational equity?

A. Yes. The concept behind MEEIA is that all customers pay certain amounts today with an expectation that all customers will avoid potential costs in the future.



One of the potential costs to be avoided in the future is the return on equity portion of the capital costs of a potential generation facility.[34] The MEEIA statute allows a utility to be compensated today for the reduction in opportunity to earn a return on investment in the future. Ratepayer compensation of this "Earnings Opportunity" cancels out this element from each side of the balance.

Q. Does the level of certainty of benefits and the timeline for avoided capacity factor into the risk and intergenerational equity concerns of analyzing a MEEIA application to determine whether the MEEIA proposal is beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers?[35]

A. Yes. Year-to-year symmetry in incurring program costs to avoid capacity and operating costs is unlikely. But, if benefit assumptions require multiple MEEIA cycles and decades of implementation to slide the operational date of a far-off plant to a slightly further-off plant, the risk that current ratepayers will pay for benefits that may or may not be realized by future ratepayers increases.

Q. How are Ameren Missouri's estimated benefits comprised?

A. In nominal dollars, Ameren Missouri's estimated benefits can be broken out as approximately 20.5% related to the first three years of the MEEIA Cycle, and approximately 8% related to demand response.

[34] Renewable energy investments have very low variable costs. If the MEEIA program avoids or delays a renewable investment, few or any costs can be avoided.
[35] 393.1075.4.

	Avoided Energy Costs	Avoided Capacity Costs	Avoided T&D Costs	Total	%
First 3 Years	$ 86,807,200	$ 131,765,603	$ 31,579,497	$ 250,152,300	20.55%
Remainder of Estimate	$ 567,008,975	$ 326,482,522	$ 73,796,640	$ 967,288,136	79.45%

	Avoided Energy Costs	Avoided Capacity Costs	Avoided T&D Costs	Total	%
Demand Response	$ 2,086,222	$ 77,034,987	$ 19,287,010	$ 98,408,220	8.08%
Other Programs	$ 651,729,952	$ 381,213,137	$ 86,089,127	$ 1,119,032,216	91.92%

Q. What is significant about the first three years of the cycle?

A. While generally estimates that are closer in time are subject to fewer assumptions and therefore tend to be more reliable, in this instance Ameren Missouri's estimates for this close-in-time period are unreasonable. There is no reason to expect that Ameren Missouri will avoid a combined $163,345,101 in capacity, transmission, and distribution costs in the next three years.

- Ameren Missouri's distribution spend is spelled out in its PISA plan, and that spending will not be reduced in at least the near term due to any MEEIA savings
- Ameren Missouri's avoided capacity estimates and capacity planning are discussed by J Luebbert and Brad J. Fortson
- Ameren Missouri's modeling essentially ignores the MISO regional transmission organization and assumes that capital costs are avoidable, as opposed to expense.
- Nearly 40% of the savings modeled in the first 3 years are based on Demand Response (DR).

Q. Why is it not reasonable to estimate short term avoided cost based on DR?

A. Modeling DR is complicated. Essentially, in a well-administered DR program you use it when you need it, and you don't when you don't.

Q. From a capacity planning and distribution planning perspective, will DR reduce system needs in a mild year?

A. No. If a current year system peak is not on track to exceed prior years' peak, first of all, a DR event may not be called, but secondly, calling a DR event won't give rise to reducing existing system capacity, and will not change plans for future capacity.

Q. From a capacity planning and distribution planning perspective, will DR reduce system needs in an extreme year?

A. Probably not. Heat waves and winter storm events are growing more frequent, longer in duration, and more severe in impact. Not only does this mean that more DR events may be required than permitted under a program to actually avoid setting a new peak, but also customers may be less likely to engage in DR events if they are not mandatory but are more frequent, yielding a Catch 22.

Q. Is it possible to design DR to address these concerns?

A. I'm sure it is, but a program that does so is not contained in Ameren Missouri's Revised Application.

Q. Must DR be done through MEEIA?

A. No. Aggregator Retail Customers (ARCs) rate design are reasonable approaches to DR.

NPV in Costs Tests and Intergenerational Equity

Q. What discount rate does Ameren Missouri use in its modeling for MEEIA, where modeled benefits are in the future and costs are closer in time?

A. Ameren Missouri used its WACC (Weighted Average Cost of Capital) of 6.86% as a discount rate for NPV.

Q. What was Ameren Missouri's position concerning NPV discount rates in its solar Certificate of Convenience and Necessity (CCNs) in file No EA-2023-0286?

A. In its Solar Applications in EA-2023-0286, Ameren Missouri's witness Steven Wills, Ameren Missouri's Director of Regulatory Affairs, testified that customers' discount rates collectively are greater than the Company's WACC, and "it is absurd for Staff to conclude otherwise."[36] Mr. Wills testimony continues that:

> I am almost certain that the majority of business customers that are served by the Company have a very real cost of capital, (likely as high or higher than the Company's in most cases[fn]) and would prefer the Company to reflect a meaningful discount rate in our analysis that more closely acknowledges their opportunity cost of money. **They would almost certainly rather pay lower rates today even if there is a carrying cost that causes financing costs tomorrow**, as long as those carrying costs are at an interest rate, like the Company's WACC most likely is, that is less than their opportunity cost of money. **[Emphasis added.]**
>
> > Fn: Given that much of the Return on Equity testimony I have read over the years in rate cases indicates that a utility stock's "beta" is less than 1, suggesting that **utilities have risk below the market average and therefore a lower required return from investors than riskier stocks (i.e., the cost of capital for businesses like many of the Company's customers), and also given that small businesses likely cannot access capital on as favorable terms as larger enterprises like a utility due to issues of scale**. **[Emphasis added.]**

Mr. Wills continues at page 63:

> Over the past few weeks, the average 30-year mortgage rate has fluctuated roughly between six-plus percent to nearly 8 percent. Consumer debt (such as credit card debt) that Staff cites is almost certainly much, much higher than that. How 2% could possibly be considered the appropriate residential customer discount rate is beyond me. **Would a residential customer rather pay higher utility costs today to avoid carrying charges at the utility's discount rate of roughly 6-7% when it could use those dollars today to pay down their mortgage or credit card debt at a percentage interest rate in**

[36] Wills Surrebuttal in EA-2023-0286, at page 62.

> **the upper teens to lower twenties – or even to simply make ends meet? Certainly not. [Emphasis added.]**

At page 64, Mr. Wills continues:

> **Over the past decade I've been part of numerous rate cases and listened to customers' concerns about the burden requested rate increases could have on their lives. Never have I heard a willingness from customers, or really any party to any case – including Staff – to accept greater rate increases in the short run in order to defray the Company's carrying costs,** especially of any magnitude that would equate to a meaningful portion of the Company's approximately $11 billion investment in its rate base. **[Emphasis added.]**

Q. If you apply a discount rate as suggested by Mr. Wills to the TRC as modeled in Appendix A, what are the results?

A. Using Ameren Missouri's modeling (including its unreasonable treatment of EO level and benefits), but incorporating program costs as a cost, any discount rate at or over 10.5% results in the modeled benefits failing to meet or exceed program costs. The results at 10.5% are reproduced below:

	Millions of $ NPV Depicted in Appendix A	Millions of $ NPV Depicted in DSMore Workpaper	Millions of $ NPV Depicted in Appendix A, Wills' Discount Rate
Non-Program Costs	**$ 446**	**$ 275**	**$ 417**
Program Costs	$ 179	**$ 201**	**$ 168**
Total Costs	$ 625	$ -	
Benefits	**$ 729**	**$ 779**	**$ 583**
Benefits and Program Cost	$ 909		
80% of Benefits	$ 583		
Additional EO Cost	$ 57		
TRC Test Results	**1.636**	**1.636**	**0.997**

CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's 4th Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA	))))	Case No. EO-2023-0136

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Rebuttal Testimony of Sarah L.K. Lange*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L.K. Lange
SARAH L.K. LANGE

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 23rd day of April 2024.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin
Notary Public

	Ameren Avoided Cost Valuation - Customer Bill Impact of MEEIA 4 as Modeled by Ameren					Staff adjustment to Ameren Avoided Cost Valuation - Customer Bill Impact of MEEIA 4 as Modeled by Ameren				
	Residential	Small General	Large General	Small Primary	Large Primary	Residential	Small General	Large General	Small Primary	Large Primary
2025	$ 35.42	$ 47.83	$ 41.75	$ 36.62	$ 38.63	$ 47.82	$ 65.99	$ 66.35	$ 64.00	$ 63.41
2026	$ 75.92	$ 110.33	$ 98.69	$ 84.07	$ 89.31	$ 105.84	$ 151.02	$ 153.93	$ 146.31	$ 144.24
2027	$ 118.79	$ 176.88	$ 158.72	$ 131.72	$ 137.48	$ 172.04	$ 244.70	$ 251.01	$ 232.69	$ 232.26
2028	$ 124.97	$ 191.95	$ 170.24	$ 133.91	$ 136.53	$ 189.85	$ 272.88	$ 280.41	$ 250.15	$ 253.95
2029	$ 125.78	$ 194.13	$ 166.35	$ 121.94	$ 119.97	$ 202.17	$ 288.24	$ 294.49	$ 252.08	$ 261.59
2030	$ 125.25	$ 195.69	$ 160.82	$ 108.73	$ 101.60	$ 213.32	$ 303.00	$ 306.95	$ 252.20	$ 268.03
2031	$ 125.42	$ 197.58	$ 154.89	$ 95.62	$ 82.98	$ 223.71	$ 317.73	$ 318.50	$ 251.55	$ 274.01
2032	$ 127.19	$ 199.74	$ 148.58	$ 82.69	$ 64.55	$ 233.96	$ 332.43	$ 329.24	$ 250.67	$ 279.72
2033	$ 130.78	$ 201.98	$ 141.77	$ 69.83	$ 46.29	$ 244.16	$ 346.67	$ 338.75	$ 249.21	$ 284.70
2034	$ 134.21	$ 203.88	$ 134.09	$ 56.64	$ 27.82	$ 254.13	$ 360.57	$ 347.37	$ 247.53	$ 289.35
2035	$ 137.29	$ 205.69	$ 126.17	$ 43.89	$ 9.97	$ 263.09	$ 373.97	$ 355.18	$ 245.87	$ 293.80
2036	$ 140.21	$ 207.04	$ 117.49	$ 30.88	$ (8.01)	$ 271.08	$ 386.67	$ 361.91	$ 243.79	$ 297.66
2037	$ 142.99	$ 208.02	$ 108.11	$ 17.55	$ (26.13)	$ 278.11	$ 398.72	$ 367.54	$ 241.14	$ 300.76
2038	$ 145.57	$ 208.77	$ 98.17	$ 4.09	$ (44.30)	$ 284.78	$ 410.45	$ 372.47	$ 238.30	$ 303.58
2039	$ 148.07	$ 208.80	$ 87.69	$ (9.38)	$ (62.08)	$ 291.18	$ 420.94	$ 376.16	$ 235.12	$ 305.63
2040	$ 150.28	$ 207.82	$ 79.35	$ (19.52)	$ (74.97)	$ 297.26	$ 427.19	$ 377.58	$ 232.30	$ 306.18
2041	$ 152.58	$ 206.57	$ 73.87	$ (25.96)	$ (83.09)	$ 303.82	$ 429.94	$ 377.49	$ 229.73	$ 305.62
2042	$ 154.60	$ 205.78	$ 72.56	$ (27.44)	$ (84.63)	$ 309.65	$ 429.61	$ 376.80	$ 228.84	$ 304.83
2043	$ 156.17	$ 205.73	$ 72.47	$ (27.55)	$ (84.74)	$ 313.72	$ 429.59	$ 376.75	$ 228.77	$ 304.77
2044	$ 156.97	$ 205.68	$ 72.39	$ (27.64)	$ (84.84)	$ 316.13	$ 429.57	$ 376.70	$ 228.71	$ 304.71
2045	$ 157.17	$ 205.65	$ 72.35	$ (27.68)	$ (84.89)	$ 316.90	$ 429.55	$ 376.68	$ 228.68	$ 304.68
2046	$ 156.99	$ 205.64	$ 72.33	$ (27.71)	$ (84.91)	$ 316.99	$ 429.55	$ 376.67	$ 228.67	$ 304.68
2047	$ 156.97	$ 205.65	$ 72.33	$ (27.70)	$ (84.90)	$ 317.15	$ 429.56	$ 376.68	$ 228.67	$ 304.69
2048	$ 156.93	$ 205.66	$ 72.34	$ (27.69)	$ (84.90)	$ 317.30	$ 429.57	$ 376.69	$ 228.68	$ 304.70
2049	$ 156.89	$ 205.67	$ 72.35	$ (27.68)	$ (84.89)	$ 317.45	$ 429.58	$ 376.70	$ 228.69	$ 304.71
2050	$ 157.21	$ 205.68	$ 72.36	$ (27.67)	$ (84.88)	$ 317.76	$ 429.59	$ 376.71	$ 228.70	$ 304.71

Case No. EO-2023-0136
Schedule SLKL-r1

10. Strategy Selection

Highlights

- *Ameren Missouri is continuing the transformation of its generation portfolio over the next twenty years while also considering portfolio implications through 2050.*
  - *Our plan includes continued expansion of renewable wind and solar generation, bringing us to over 3,500 MW of wind and solar by the end of 2030 and over 5,400 MW by 2036. This allows us to replace energy no longer generated from coal-fired resources with the lowest cost alternative, clean, emission free renewable energy, while mitigating 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, customer programs for renewable energy, and retirement of nearly three-fourths of our remaining coal-fired generating capacity by 2040, which will be reaching the end of its useful life.*
  - *Our plan results in reductions in CO_2 emissions of at least 60% by 2030 from 2005 levels and 85% by 2040, with a goal of achieving Net Zero CO_2 emissions by 2045.*
- *Our implementation plan for the next three years includes steps necessary to add an additional 1,800 MW of solar generation and 1,000 MW of wind generation to our portfolio by the end of 2030, approval and implementation of energy efficiency and demand response programs beyond our current plan, steps to implement new simple cycle gas-fired generation by the end of 2027 and new combined cycle gas generation by the end of 2032, 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 new renewable and dispatchable generating resources.*
- *We will also continue to monitor prices for coal, 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 options 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 2024-2026 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 (PVRR) is our primary selection criterion.[2]

Costs alone do not and should not dictate resource decisions. Our other planning objectives are discussed below.

[1] 20 CSR 4240-22.010(2); 20 CSR 4240-22.010(2)(A)
[2] 20 CSR 4240-22.010(2)(B)

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 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: While Ameren Missouri has retired and will soon retire additional coal-fired generating resources, coal currently produces the majority of the energy it generates. 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, including reductions in energy consumption resulting from customer energy efficiency programs.

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 supporting 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 2023, Ameren Corporation released its corporate sustainability report – Powering a Smart, Sustainable Tomorrow. The report details Ameren's commitment to sustainability and environmental stewardship and offers a comprehensive view of the actions taken on key matters. In the report, Ameren addresses the following key topics:

- ✓ Environmental Stewardship
  - o Accelerating the transition to a cleaner and more diverse generation portfolio
  - o Significant transmission investment supporting cleaner energy
  - o Decade-long investment in gas infrastructure to reduce leaks
- ✓ Social Impact
  - o Delivered value to customers in 2022 while focused on safety
  - o Socially responsible and economically impactful financial support
  - o Supporting core value of DE&I both inside Ameren and in our communities
- ✓ Governance
  - o Diverse board of directors focused on strong oversight
  - o Board oversight aligned with ESG matters
  - o Executive compensation supports sustainable, long-term performance
- ✓ Sustainable Growth
  - o Constructive frameworks for investment in all jurisdictions

[3] 20 CSR 4240-22.060(2); 20 CSR 4240-22.060(2)(A)1 through 7

- Strong long-term infrastructure investment pipeline
- Expect future dividend growth to be in line with long-term EPS growth expectations

10.2 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.

10.2.1 Preliminary 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 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 scoring performed for all of our IRP filings since 2011.[5] The scoring approach for each planning objective is as follows:

Cost – The 23 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 2 points in the overall scoring for

[4] 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)

[5] 20 CSR 4240-22.010(2)(B)

Customer Satisfaction. Plans that yielded a score of 3 were given 1 point. 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)

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 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)
- ✓ Displacement of fossil resources with additional storage and/or renewables
- ✓ Addition of low-emission efficient gas generation

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 (i.e., less than 3 out of 5 points) were reduced by one point. Plan scores were also reduced by one point each for potential risks associated with:

- ✓ Lack of any DSM programs beyond currently approved programs
- ✓ Nuclear construction, financing, and operating risks
- ✓ Risks associated with a heavy concentration of gas-fired generation
- ✓ Risks associated with recovery of coal-fired generation investment (including those resulting from potential changes in environmental and climate policies and regulations)

Economic Development – Alternative plans were scored based on direct job creation, including construction and ongoing operation. 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 Preliminary Scoring Results[6]

Plan	Description	Composite Score
O	Labadie 2039	4.40
L	Pumped Hydro w/ MAP LF	4.30
B	Sioux Retired 2028	4.20
M	SC	4.00
P	Labadie 2036	3.90
A	Sioux Retired 2030	3.80
C	RAP - Renewable Expansion	3.80
R	RAP LF	3.80
H	MAP LF-RES Compliance	3.70
T	All Renewables	3.70
Q	Labadie 2031	3.70
D	Labadie SCR	3.50
U	SC instead of First CC	3.50
K	Renewables for Capacity Need	3.30
V	CCS on 1st CC	3.30
E	MAP	3.20
S	MAP LF	3.20
W	RAP 80%	2.80
N	SMR w/ RAP LF	2.60
F	RAP-RES Compliance	2.30
G	MAP-RES Compliance	2.30
I	No Additional DSM	1.70
J	No Additional DSM-RES Compliance	1.40

[6] Plans include RAP-level DSM and Renewable Expansion portfolio unless otherwise noted.

Table 10.2 shows the composite scores for each of the 23 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 3.7 were placed in the Top Tier. Plans with scores between 3.3 and 3.7 were placed in the Mid-Tier. Plans with scores below 3.3 were placed in the Bottom Tier. All Top Tier plans include energy efficiency and demand response at the realistic achievable potential (RAP) level and the Renewable Expansion portfolio discussed in Chapter 9.

10.2.2 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 and supplementing them with new dispatchable resources to partner with renewable resources to provide reliable and sustainable energy services at a reasonable cost.

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. **Aging Coal Fleet –** Ameren Missouri will need energy as well as capacity resources to meet customer demand and reserve margin requirements as its coal-fired generators are retired at the end of their useful lives. That need is also driven by the risk of reduced output from coal-fired generation due to existing or proposed environmental requirements or other causes even before the coal units retire. Due primarily to recent and expected coal unit retirements and these other risks, Ameren Missouri has a clear, present, and ongoing need to add energy resources to its generation portfolio to address the dramatic shift in the Company's energy position that will occur over the next several years and continue over the next twenty years. Ameren Missouri expects to experience an energy shortage as early as 2029 assuming normal loads and generation, a dramatic change from the approximately 15-20% energy buffer from which customers have typically benefited, although at times that buffer has been a high as approximately 10 million

MWhs. Such a shift could expose our customers to reliability challenges and high market price risk.

2. **Low Cost, Emission-Free Energy –** Renewable resources represent the lowest cost, and emission-free, sources of replacement energy, as shown in Chapter 6.

3. **Increasing Environmental Regulations –** The large-scale expansion of renewable resources provides significant risk mitigation to Ameren Missouri's portfolio, particularly with respect to additional environmental regulations that could become law, other changes in climate policy and carbon dioxide (CO_2) prices, and other factors that may significantly affect the operating costs and benefits of its existing coal-fired resources. The industry is actually seeing these risks come to fruition now with the effectiveness of new rules regulating emissions of nitrous oxides (NO_x), plus additional proposed regulations targeted specifically at CO_2, among others.

4. **Reliability and Resilience –** Ameren Missouri's addition of diverse new renewable resources during continued operation of its existing fleet, and addition of new dispatchable resources, is a prudent approach and ensures reliable, resilient, and affordable energy for our customers under varying scenarios during the transition.

5. **The Risk of Inaction –** Delaying the inevitable shift to renewables creates significant implementation risk. The transition will require a very large-scale expansion of renewable generation at the same time that other utilities and states are pursuing the same. A task of this magnitude must be implemented over time to be successful. This is the case since each renewable energy project takes 5 to 8 years to develop and construct, requires geographical diversity of projects for reliability, and requires navigating several implementation risks, such as delays in the development or completion of projects, lost opportunities for more viable projects, and the potential for financing constraints and increases in financing costs.

6. **Availability of Significant Tax Credits -** Initiating renewable resource builds in the nearer term provides the ability to realize significant tax incentives for customers and thus lower the overall cost of adding needed renewables, making addition of these necessary resources more affordable for all customers. Because federal law and policy can change, taking advantage of such incentives sooner and while the better projects are available provides greater certainty of benefits to customers.

Ameren Missouri's Need for Energy Resources

Ameren Missouri's existing generation fleet has a total net capability of 9,986 MW. Of this, 45% is coal, 12% is nuclear, 15% is hydroelectric and other renewables, and 28% is gas or oil-fired peaking generation. In contrast, coal currently provides approximately 66% of the energy produced by our fleet, with nuclear providing roughly 23% and renewables providing another 10%. Gas and oil-fired resources provide approximately 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 current coal-fired energy assets will remain relatively low in the future 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, along with new dispatchable resources, does allow Ameren Missouri to maintain reliability as increasing amounts of renewable energy is integrated into the system to meet customer needs.

Figure 10.1 Energy Position With and Without Renewable Transition – Low CO_2 Price

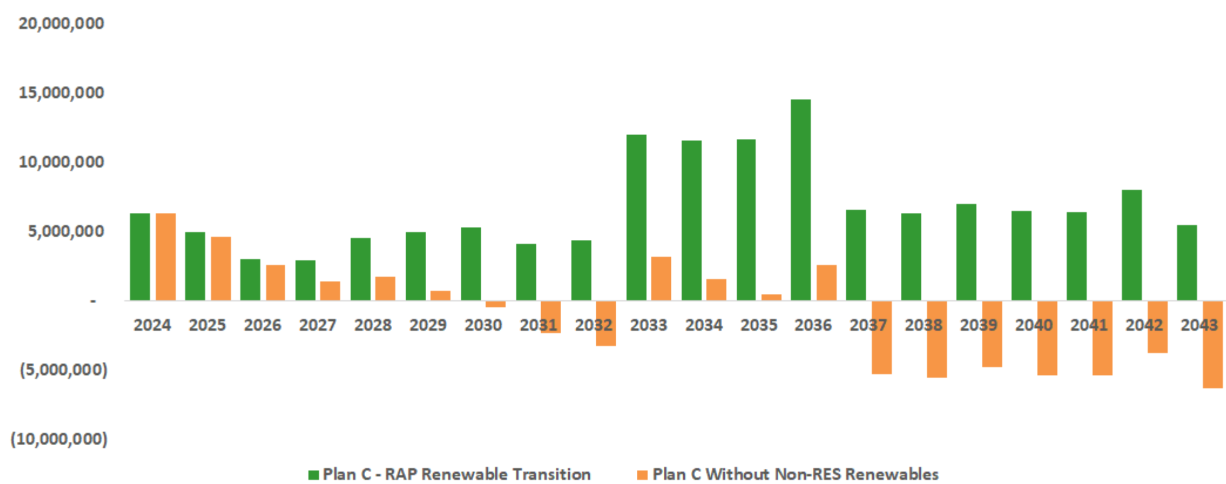


Figure 10.1 shows a comparison of the Company's expected energy position (generation minus sales) with and without renewable transition under our Low CO_2 price scenario. Figure 10.2 shows a similar comparison of energy production for several alternative plans under our High CO_2 price scenario, which results in reduced levels of generation from coal resources (and also gas to a lesser extent) compared to the levels of production under the Low CO_2 price scenario. The chart shows that for Plan C (RAP – Renewable Transition) without renewable resources beyond those needed for renewable energy

standard (RES) compliance, Ameren Missouri would be generating less energy than its customers use by 2028 and that this shortfall would grow to over one-third of total load by 2038. Any acceleration of coal energy center retirements would further exacerbate this issue. This is also true if retail sales are higher, as shown in Figure 10.3.

Taken together, the charts in Figures 10.1, 10.2, and 10.3 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 factors 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 increase in reliance on fossil-fueled generation like natural gas combined cycle, and potentially deferring or displacing some renewable resource additions.

Figure 10.2 Energy Position With and Without Renewable Transition – High CO_2 Price

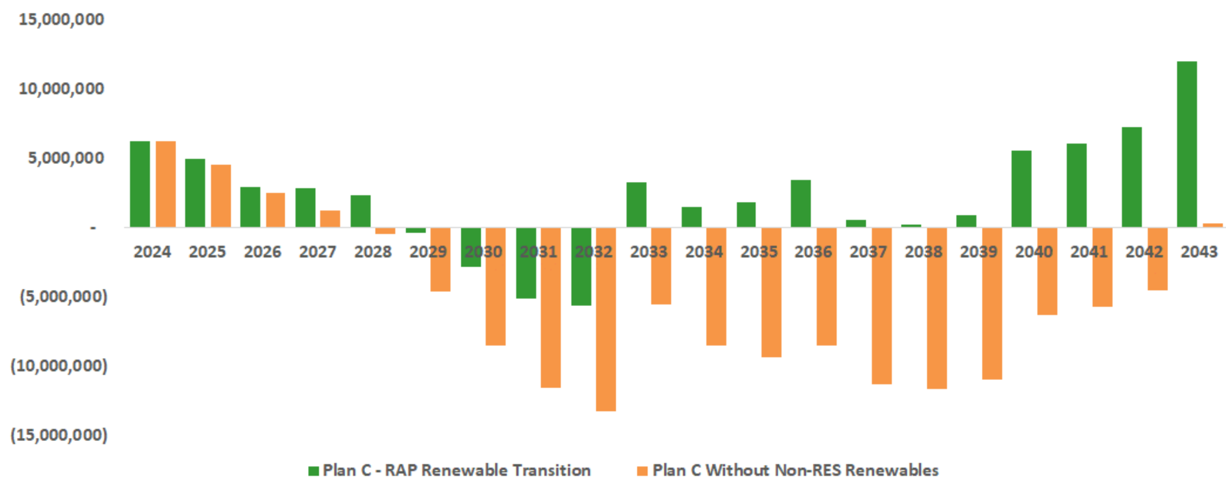
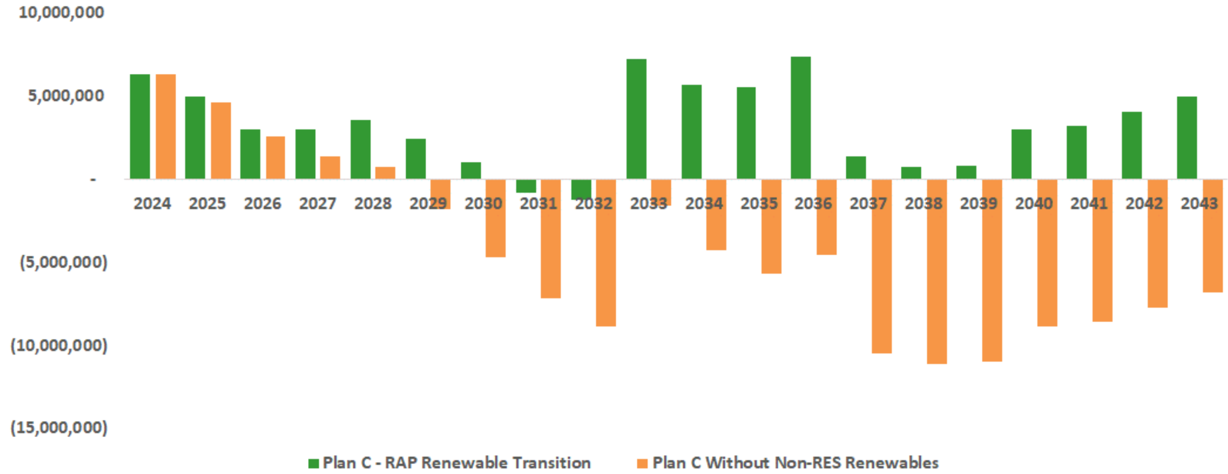


Figure 10.3 Energy Position With and Without Renewable Transition – High Load



The energy position charts in Figures 10.1-10.3 represent "economic" energy, or energy generated based on economic dispatch in the MISO market. This is important because it does not represent a constraint to the ability for units to generate at any given time, which means there is some flexibility to operate at higher levels if needed.[7] At the same time, Ameren Missouri's fleet is increasingly subject to constraints in its ability to operate units across seasons or across the year. This mainly affects the Company's remaining fleet of coal-fired generation at the Sioux and Labadie Energy Centers. In addition to assumed prices on CO_2 emissions, our modeling assumes allowance prices for NO_x emissions consistent with US EPA's Good Neighbor Rule, described in Chapter 5. As a result, forecast coal generation declines beginning in the latter part of this decade and continues to decline until units are retired. In addition, the natural gas combined cycle generators included in the PRP are forecast to run at high-capacity factors (80% or more). When added to our portfolio of high capacity factor nuclear generation and weather-dependent hydro, wind and solar generation, the ability to generate significantly more energy is somewhat limited. This further highlights the importance of the energy position analysis presented above and the vital role of new renewable additions in ensuring sufficient energy to meet customer needs. While assumptions for key variables, like CO_2 price and customer load, and constraints of further environmental regulation may change, and almost certainly will, planning to meet energy needs under such assumptions is vital to ensure reliable energy supply under a range of potential future conditions.

Risk Mitigation Benefits of Renewable Expansion

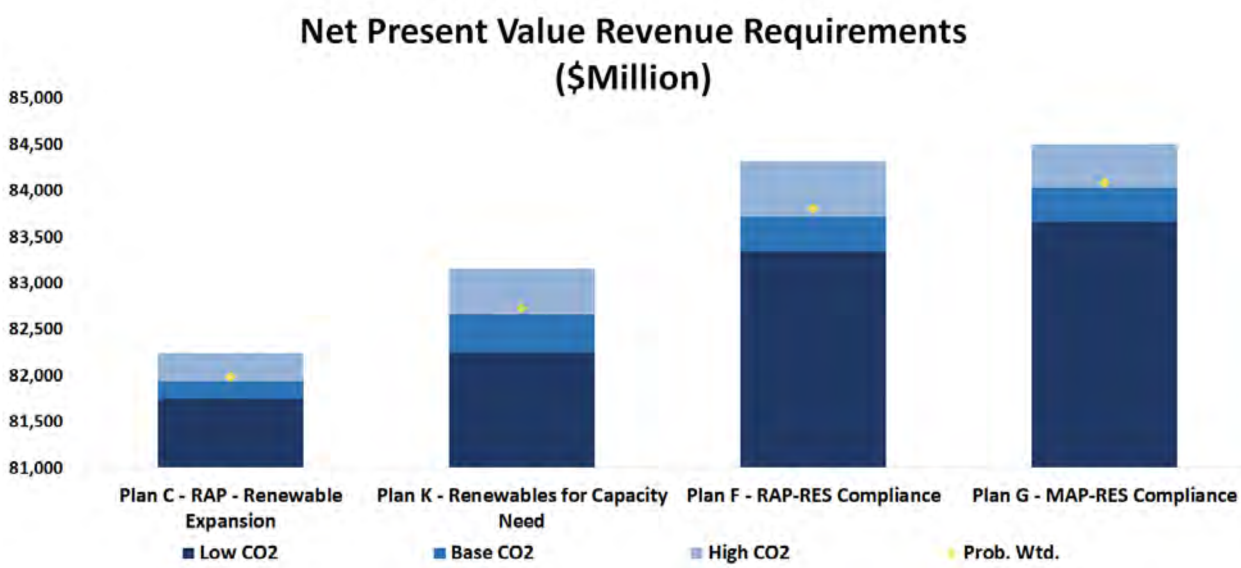
Our analysis shows that higher CO_2 prices have a beneficial impact on the economics of renewable resources and a detrimental effect on the economics of coal-fired resources,

[7] Ameren Missouri would expect to be compensated by the market in such instances.

a decidedly unsurprising result. 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.

By expanding the share of renewable resources in our portfolio, we improve 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 10.4 shows the PVRR results for several plans with different levels and timing of renewable energy resources under the three different scenarios for CO_2 price used in our risk analysis.

Figure 10.4 PVRR Results for Selected Plans by CO_2 Price Scenario



As the chart in Figure 10.4 shows, the steady addition of wind and solar resources represented by Plan C provides not only the lowest PVRR among the plans, but also provides risk mitigation around the range of CO_2 prices used for risk analysis, with the range of costs to customers across the different CO_2 price scenarios being significantly narrower than for those without the steady buildout. In fact, PVRR for Plan C under all scenarios for CO_2 price is lower than the lowest cost to customers for any of the other plans shown. This CO_2 price risk mitigation 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.

Customers continue to express 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. Ameren Missouri has done just this with the implementation of its Renewable Solutions Program, approved by the Missouri Public Service Commission (MPSC) in April 2023, which will provide 150 MW of solar generation to some of the Company's largest customers. The Company also has completed projects to support its Neighborhood Solar and Community Solar programs, as described in Chapter 4. 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 continues to implement the resources necessary to comply with the full requirement of the RES, having received MPSC approval for the planned 200 MW Huck Finn solar project, which follows the Company's acquisition of 700 MW of wind generation projects in Missouri in 2020 and 2021. The passage of the Inflation Reduction Act (IRA) in 2022 has also provided unprecedented incentives to enhance customer affordability for both the deployment of renewable resources and the development of domestic industry to support that deployment. While the advancement of further policies supporting renewable energy development remains uncertain, the trend in recent years has been one of greater and greater support for the use of renewable energy resources.[8]

Reliability and Resiliency Benefits of Renewables

The Company's plan to transition to a "new fleet," featuring renewable and low-carbon resources, reflects some meaningful operating overlap with the "old fleet" resources, comprised of primarily coal-fired resources. The term "old fleet" refers to Ameren Missouri's existing (and legacy) coal-fired generation resources. These resources have served as the backbone of Ameren Missouri's generation fleet for several decades but are now approaching the end of their useful lives, with increasing maintenance challenges for key equipment (such as energy piping, boilers, and turbines) and increasing pressure from existing and new environmental regulations. Three of the Company's four coal-fired energy centers will be retired within the next ten years: the Meramec Energy Center in 2022, the Rush Island Energy Center by 2025 and the Sioux Energy Center by 2032.

[8] File No. EO-2023-0099 1.C; File No. EO-2023-0099 1.E

These retirements will result in a dramatic swing in the Company's energy position over the next few years, from its historically abundantly long position (as many as 10 million MWhs annually) to having a shortage of energy starting in 2029, assuming normal generation and load, absent the addition of new energy resources. The shortage grows steadily thereafter. A significant shift in the Company's energy position is already underway with the recent retirement of the Meramec Energy Center, and it will continue to shift when the Rush Island Energy Center is retired. The term "new fleet" refers to the Company's planned future resource portfolio, which includes a diverse mix of zero or low-carbon resources, primarily renewable resources like solar, wind and hydroelectric, along with zero-carbon nuclear and supported by dispatchable energy storage and natural gas resources.

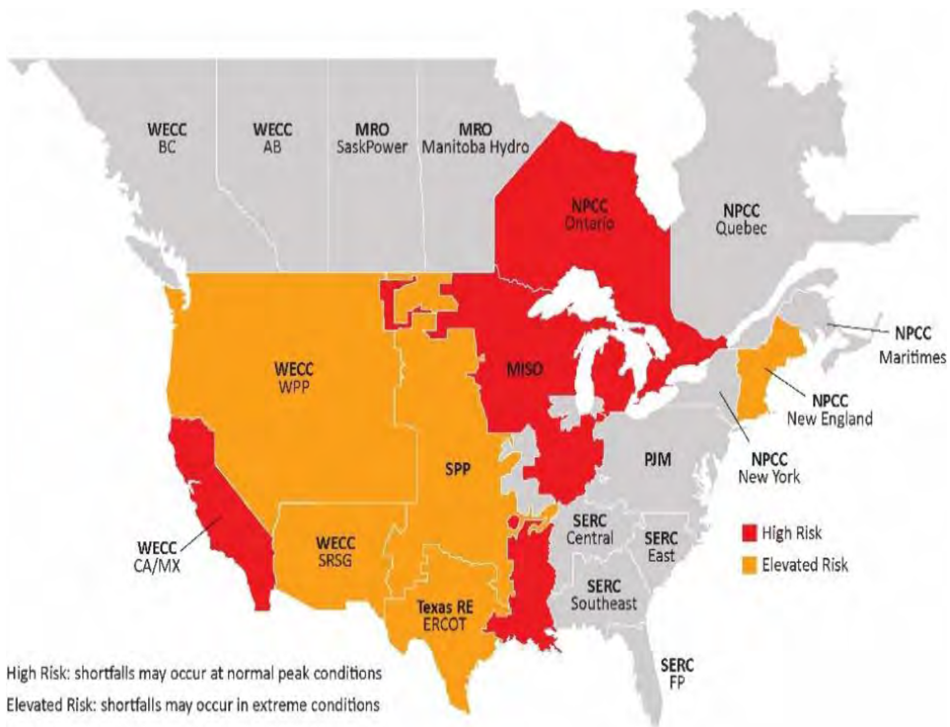
The overlap between the old fleet and the new fleet is necessary to address reliability risks during the transition period between the old fleet coming offline, and the new fleet being fully implemented. These risks are driven by myriad planning uncertainties, such as:

- Uncertainty in system load, including as industry and transportation electrify, and also driven by the potential for more frequent and intense severe weather;
- Uncertainty in the energy or demand savings, or both, from planned energy efficiency and demand-response programs;
- Uncertainty in whether and to what extent Ameren Missouri can expect to (or should) rely on the MISO market to meet customers' reliability needs;
- Uncertainty in the reliability contribution of new renewable resources;
- Ever increasing environmental regulations for existing fossil generation;
- Unplanned generation outages or other unanticipated events; and
- Material variances between our optimized generation forecasts or weather-normalized loads used for planning purposes and what happens in reality.

Taken as a whole, it is unwise to wait until some predetermined amount of capacity of coal-fired generation retires to add corresponding capacity of renewables to plug the capacity gap, or to wait until that coal capacity can no longer provide significant energy. Over the last five years, the Company's customers have benefited from an annual energy buffer of approximately 5 million MWhs. This energy buffer has mitigated the risk that the Company's customers face from reliability related emergency conditions resulting in energy shortages on the electric system. The buffer over the past roughly 5 years translates to an energy position approximately 15-20% above our retail customers' needs, which mitigates customers from the risk of adverse MISO reliability and market conditions as well as price spikes (price risk), while generating meaningful excess market revenues for the benefit of customers.

Likewise, it would not be prudent to rely on the MISO market more heavily for near-term energy needs. Just like Ameren Missouri, the entire MISO footprint is undergoing a transition from dispatchable fossil resources to a much greater reliance on renewable resources; in fact, MISO's modeling indicates that MISO as a whole is expected to move at a faster pace than Ameren Missouri. Therefore, it has become riskier to rely on the MISO market in moments of system stress than it has been in the past.

Figure 10.5 NERC Risk Area Summary, 2023-2027



As detailed in the North American Reliability Corporation's (NERC's) 2022 Long-Term Reliability Assessment, MISO's anticipated capacity reserves are alarmingly low and energy risks are expected to increase starting in 2024, especially in June through August when MISO's demand peaks. The NERC report lists MISO as a "high risk" region of the country in terms of resource adequacy, defined as an area that does not meet resource adequacy criteria, such as the 1-day-in-10-year load loss metric, during periods of the assessment horizon. Figure 10.5 highlights the regions considered high or elevated risk. MISO's "high risk" status indicates that without a concerted effort to begin and sustain our plan to add replacement energy resources, Ameren Missouri and MISO will both be "skating on the edge" from an energy and capacity perspective, putting customer reliability and affordability at risk. As discussed above, although MISO's 2023-2024 Planning Resource Auction results indicate that the North/Central region is expected to have adequate capacity to meet the Planning Reserve Margin during the current planning year, those results do not reflect a "fix" for all long-term capacity concerns. And similarly, NERC's 2023 Summer Reliability Assessment suggested that although the risk of meeting load in MISO was reduced for summer 2023 as compared to 2022, MISO was "at risk of operating reserve shortfalls during periods of high demand or low resource output."

Adding new renewable generation while the Company's coal-fired resources are still online is the ideal approach to ensure continued system reliability during the transition to cleaner energy resources while still enabling the Company to gain critically needed experience with renewable resources. Without that experience, Ameren Missouri risks being unable to reliably manage and operate its renewable generation fleet, and unable to fully understand the backup resource needs that may be required to ensure a reliable supply. Transitioning to renewable energy while more of our coal-fired generation and gas-fired peaking capacity is still in operation will allow us to gain this necessary experience with minimal risk of continuing to provide reliable service to our customers.

By continuing to add new renewable energy in a staged and continuous manner while a significant portion of Ameren Missouri's existing generation fleet remains online, the Company will gain invaluable experience in two areas:

1) The ability to assess when and to what extent renewable energy is truly available over a wide range of weather conditions, which is dependent in large part on the location of the renewable resource, and

2) An understanding of how the existing Ameren Missouri generation fleet may need to be dispatched differently than historical dispatch patterns to provide critical back-up generation during hours that intermittent renewable generation is not available.

By understanding the operational aspects of a significant portfolio of renewable energy resources under different weather conditions over a long period, the Company can also determine the optimal amount of renewable capacity needed to ensure a secure energy supply, ensuring we are not adding too much or too little new renewable energy generation. The Company may also learn how to increase generation through planned and preventative maintenance approaches, and how to optimize equipment selection based on project site characteristics. In addition, the Company can determine the amount of dispatchable generation and battery storage to maintain the reliability of least cost renewable energy. Said simply, by adding significant new renewable generation resources while the Company's coal-fired generation is still operational, Ameren Missouri can learn how to optimally plan and operate its generation fleet in a high renewables future without putting system reliability at risk.

Another important factor to ensure long-term system reliability and resiliency is to pursue a geographically diverse portfolio of renewable energy resources to ensure energy is always available to meet our customers' needs, even during peak energy time periods. Since solar and wind generation are dependent on weather conditions which vary by geographical location, a regionally diverse renewable resource portfolio will be more reliable under varying weather conditions. Over time, as ideal project sites are developed and land availability declines, it will become more challenging to achieve a regionally diverse portfolio of projects. This is another key reason the Company needs to continue to transition to clean energy now and sustain it.

The Risk of Inaction

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 continue 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, and there are significant risks of inaction or delays in implementation. Renewable energy development is a difficult, lengthy process with successful projects taking five to eight years to reach commercial operation. With each stage of the project lifecycle there is a risk that the project can be delayed, and at times cancelled altogether. The most significant implementation risks are likely to emerge in siting the project location, completing extensive transmission studies, evaluating transmission upgrade costs and completion schedules, completing environmental studies, conservation plans, and compliance requirements, acquiring real estate, obtaining local county permits and community support, qualifying for federal tax credits, evaluating technology options, obtaining financing, receiving regulatory approvals, procuring key equipment in a timely manner, and designing, engineering, and finally constructing, commissioning, and testing of the new renewable energy center. A challenge, delay, or misguided decision can delay and potentially terminate the project. Given the number of renewable energy projects that are needed for a successful transition combined with the length and potential risks within the full lifecycle, it would be impractical, and frankly, irresponsible for the Company to continue to take a "capacity when needed" approach – as there is never a guarantee that each renewable energy project being pursued will come to fruition. We must start and sustain the transition to account for any potential delays. The key project implementation risks include the following:

- Land (i.e., renewable site) availability
- Project permitting and construction
- Supply chain constraints
- Transmission interconnection
- Technology costs
- Financing costs
- Financing constraints

One of the most critical reasons for Ameren Missouri to pursue a controlled but sustained transition that starts immediately is to ensure the Company can acquire the best available project sites in our region. The lengthy development, permitting, regulatory approval and construction cycle challenges described above, along with the myriad of development risks involved to successfully develop a good renewable energy project site, means that the best renewable energy sites are the first to be developed. Ameren Missouri is now also in competition with large technology firms from outside its service territory who are purchasing renewable energy projects in and around Missouri and Illinois for their announced sustainability goals and are equally as eager to find the best available project sites. An ideal project site will feature good renewable resource, favorable topography, good community relations, access to a favorable transmission interconnection point, and minimal environmental risk. This means that as the availability of suitable land declines, both the cost of the planned facility and the risks of not being able to obtain necessary permissions or not being able to construct the project at all are likely to increase.

Placing a renewable energy project into service requires a series of preceding permits – these include but are not limited to environmental, construction, county, state, federal and other governmental permits. These activities require a great deal of lead time and if not obtained, could delay project construction, or even terminate a project. For example, to obtain the appropriate environmental permits, we must first complete several environmental studies to determine and mitigate any potential adverse impacts to the environment (e.g., water, land, natural habitat, etc.). These studies can take years to complete as they require extensive data collection and analysis. In some cases, the studies might indicate a fatal flaw in the project site. A fatal flaw would result in a change in project site – making it important to pursue a pipeline of potentially suitable projects simultaneously to pivot to a more suitable project site from an environmental permitting perspective.

Prior to starting construction, local and county permits might be required. If there is a delay in receiving these permits, the construction schedule can be put at risk. A delay in schedule can jeopardize the in-service date, ultimately impacting the Company's ability to receive federal tax incentives or at times, preventing project implementation altogether.

Building community support and engaging with key stakeholders early in the project development lifecycle will allow the Company to quickly identify potential delays and adjust accordingly. But navigating these permitting issues takes a great deal of time, and navigating them simultaneously with the large number of projects that would be needed all at once if we wait to add renewable capacity when the capacity need is here would be extremely difficult, if not completely impractical.

Once all necessary environmental and local government permits have been received, projects must be designed, engineered, and then constructed in a manner to provide at least 30 years of reliable energy. The design and engineering phase typically takes about a year. While recently performing due diligence on a solar project in an advanced stage of development (land acquisition, permitting and environmental assessment were all completed), Ameren Missouri discovered that the project was sited on land above a historical mine that potentially may be unsuitable for construction. Ameren Missouri had to place the project on hold until suitable geotechnical due diligence could be completed to ensure that the project can be constructed and operated in a reliable manner.

The construction phase itself for solar and wind projects can take one to two years to complete. During this time there is heavy construction traffic on smaller local county roads that can be subject to weather delays. The supply chain for solar and wind generation is global and there are numerous opportunities for delays in manufacturing, shipment, and delivery. As with any large construction projects, actual construction may face challenges from an electric and mechanical component perspective, and therefore testing of the final project after completion of construction is critical. For the High Prairie and Atchison Renewable Energy Centers, the Company experienced several months of delay before achieving successful testing and commissioning and ultimately bringing the projects online.

Supply chain constraints can occur due to labor shortages, political upheaval (globally or otherwise), commodity supply and price changes, transportation challenges, or quality control issues. Challenges in the supply chain can lead to project delays, cost increases, or ultimately an inability to construct a project at all. Since supply chain problems can meaningfully disrupt the timing and costs of renewable energy projects, it is important to have a long implementation timeframe to maintain flexibility in the generation transition. By developing long-term strategic partnerships with key renewable equipment manufacturers as well as established renewable energy developers, we ensure a greater certainty of supply of key renewable project equipment. But to develop such strategic partnerships, we need a long-term and defined transition plan with a known stream of projects for which equipment can be acquired in a timely manner. The same dynamic exists when we have ongoing relationships with national renewable energy developers for new projects, so they can plan ahead for completing projects in a timely manner. Given the 5- to 8-year life cycle for successful renewable energy project development, such partnerships are much more difficult to develop if a transition plan is not defined at least 10 years in advance to ensure certainty of equipment supply.

Transmission interconnection and upgrade costs remain one of the most important and, it is fair to say, challenging aspects of renewable energy development. This includes the challenge of navigating MISO's Generator Interconnection Queue. The larger utility scale renewable energy projects must go through a transmission interconnection queue to determine the timing and cost of transmission upgrades that may be required for interconnection. This is not only challenging, but time-consuming. In MISO, generator interconnection at the transmission level is a three-phase process that can generally take up to three years to complete. The transmission upgrade costs are a function of the number of projects in the queue, and the location and size of the projects. Generally, projects that are earlier in a queue can interconnect at a lower cost. It is also important to note that after Phase 2, a non-refundable 20% payment is due for expected transmission upgrades for a renewable energy project. As such, only the best projects with the most favorable locations and queue positions make it to the final Phase 3. Other projects are rejected due to high transmission costs in Phase 2, or at times even in Phase 3, as cost estimates can change throughout the process until it is clear which projects will proceed to construction.

At any point in the process, projects that the Company may be relying on could be terminated due to exorbitant interconnection costs, forcing the Company to start the 3-year cycle once again. Over the last ten years, generally less than a third of the projects that enter the MISO Generator Interconnection Queue make it to start of construction. Ameren Missouri has first-hand experience with projects in which a great deal of time and effort was expended only to see the project fail due to no fault of the Company. The Brickyard Hills wind project, for which the Commission granted Ameren Missouri a CCN in 2019 and which had likely been under development for approximately 10 years, ultimately had to be terminated due to unacceptably high transmission costs. As future queues get more and more constrained with new renewable energy projects, new transmission buildout will be needed. However, building new transmission lines to interconnect new renewable energy projects is generally a 6- to 10-year endeavor, if not longer. Although ideally transmission buildout will keep pace with renewable energy project buildout, projects later in the queue may have significantly higher transmission interconnection costs or may not be able to operate at full output. This poses a real risk caused by delay because the energy from the generation we will ultimately place in service may be more costly or less reliable.

The Company can best manage transmission interconnection risks, first and foremost, by continuing to proceed with the planned renewable transition now and sustaining it. Second, we must act on good projects when they are available, including smaller utility-scale projects like the Vandalia and Bowling Green Projects currently before the MPSC, which were not required to navigate the difficult and lengthy MISO generation interconnection queue since they will connect to the distribution system. Third, we must be flexible regarding the best renewable project acquisition approach for each specific project – whether we use a build-transfer, development-transfer, or self-development approach. The Company needs to maintain a renewable project pipeline with at least twice the number of projects needed for the inevitable transition to renewable energy and use the most appropriate acquisition approach for each project. To have a pipeline of twice the number of projects needed for our generation transition, we need to constantly be looking for – and acting on – good renewable projects in Missouri and surrounding states. Without a large pipeline and a phased approach, we are likely to face delays in project interconnection to the grid, significantly higher costs, or both, thus rendering our generation transition less reliable and more costly than it would have been had we obtained good project earlier in the transition process.

Although Ameren Missouri hopes that renewable technology costs will ultimately decline, the last several years served as a reminder that cost declines are far from a guarantee. It is tempting to point to some possible declining cost curve forecasts for wind and solar and recommend the Company wait until such declines materialize before proceeding with renewable development. But it is critical to remember that declines that are forecasted by some are not certain. Waiting for costs to decline is also a risky approach, because if those declines do not materialize customers could be exposed to higher costs for less ideal sites later. By adding investments steadily over time, we engage in a form of "dollar cost averaging" similar to that used in financial investing, while continuing to progress towards a prudent energy buffer.

Financing costs are also a key risk. Investors are increasingly focused on concerted efforts by utility companies to transition their portfolios to cleaner and more sustainable resources as they make decisions about which companies to invest in and what kind of return on investment they expect based on their assessment of risk. This increased focus is expected to result in differences in cost of capital between those utilities that are making concerted and consistent efforts to transition their portfolios and those that are not. Deferring implementation of renewable resources may require that Ameren Missouri invest huge amounts of capital in a short period of time, risking substantial deterioration to our credit metrics and impairment of our ability to cost-effectively and timely finance investments in the renewable generation we need when we need it. Staging the transition with a steady stream of additions over several years therefore reduces the expected financing costs associated with the renewable resources the Company needs to add.

Capturing the Value of Available Tax Credits

In 2022, Congress passed the IRA. Among its many impacts, the IRA extensively modifies provisions of the tax code for renewable energy projects. The IRA extends both the investment tax credit (ITC) and production tax credit (PTC), creates additional wage and apprenticeship requirements that projects must meet to qualify for the full ITC or PTC value, and adds additional bonus credit amounts for domestic content and project location. The IRA enables solar projects to utilize the PTC or the ITC (previously solar projects could only elect the ITC) and allows taxpayers the ability to transfer tax credits to unrelated parties for cash. Certain projects may be eligible for bonus tax credits, such as the energy community bonus incentive, which increases the value of the ITC from 30% to 40% or increases the PTC credit value in a given year by 1.1 times. Projects that are located in a community with a retired coal mine or coal generating facility are eligible.

While the benefits of the IRA are significant and expected under the law to apply for projects completed into the next decade, it is important to avoid complacency with regard to securing these benefits for customers. Although the IRA extends available tax incentives for renewable resources into the early 2030s, they are still not expected to be available forever. If the Company were to wait to add renewable resources, these new and enhanced tax benefits could be unavailable. Moreover, there is no guarantee that Congress may not change the law in such a way that the tax credits under the IRA become unavailable earlier than 2032. Implementing a sustained and planned transition to renewable resources enables the Company to capture the IRA incentives and pass them back to customers, helping maintain customer affordability while transitioning to a cleaner generating fleet.

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 provides us with valuable risk mitigation regarding CO_2 prices and other factors, and valuable flexibility in managing the transformation of our generation portfolio.

10.2.3 Reliability Needs and New Dispatchable Generation

While renewable wind and solar resources are vitally important to meet customers' energy needs, we also need dispatchable resources that are available on demand to partner with those renewable resources and ensure reliable and affordable service, both now and as we continue to transition our resource portfolio. As explained in Chapter 2, the nature of resource planning has changed from one in which we plan for meeting the annual peak demand (typically in the summer) with dispatchable resources that can meet energy needs in any hour to one that is far more complex. Resource planning must account for the need to blend non-dispatchable, intermittent energy resources like wind and solar with the need for dispatchable capacity to ensure reliability in all hours, and it must do so for all seasons and under the most extreme weather conditions. The need for energy resources is discussed in section 10.2.2.

To assess capacity needs, we must account for both the expected operation of resources in the real world and also how those resources will be compensated in MISO's capacity market. MISO's seasonal resource adequacy (RA) construct aims to promote reliability and ensure fair value for resources that are available when they are needed to meet load. In doing so, MISO has designed a process for capacity accreditation that accounts for each generator's historical performance in each season, including the degree to which each generator was available at time when it was needed most to ensure reliability. MISO establishes planning reserve margin (PRM) requirements for each season that accounts for generator performance as well as load forecast uncertainty under normal conditions. While this framework is necessary and important for promoting reliability and fair value for resources across the MISO footprint, it is not by itself sufficient for examining resource adequacy needs at the utility level over all timeframes.

Capacity Positions – Operating View

To examine resource adequacy needs more rigorously, Ameren Missouri has used what it has learned about reliability needs from its work with Astrapé Consulting, from trends in the industry, and from the operation of its own units in MISO under real operating constraints such as those imposed by the Climate and Equitable Jobs Act (CEJA) in Illinois. We have done this by also examining capacity needs under what we call an "Operating View." This view accounts for the real-world constraints like those of CEJA and is defined by the following characteristics:

- Most Illinois CTGs are limited to a short period of operation (rolling 12 months) and/or emergencies; unit capacity is therefore set to zero – Units in this category are Pinckneyville Units 5-8, Venice Units 2-4, and all units at the Goose Creek, Racoon Creek, and Kinmundy Energy Centers.
- All gas-only CTGs are subject to fuel availability constraints during cold weather, including at time of normal winter peak demand; gas-only CTG unit capacity is therefore set to zero for winter capacity position – Units in this category are Pinckneyville 1-4, Venice Unit 5, and all units at the Audrain Energy Center.
- Wind, solar and storage set to ELCC values (current MISO transitioning to calculated ELCC)[9]
- All other units set to full unit capability by season based on Ameren Missouri's most recent assessment of monthly unit capabilities.[10]

[9] See discussion of wind and solar capacity credits in Chapter 2.
[10] Monthly unit capabilities are reviewed and revised annually based on unit testing and operation.

- Planning reserve margin requirement set to output of largest unit (Callaway) – Approximately 1,200 MW, which corresponds to ~17% of summer peak demand and ~20% of winter peak demand.

It should be noted that MISO's new seasonal construct, which took effect with the 2023-2024 planning year, results in an interdependent set of unit accreditations and planning reserve margins. As a result, the planning reserve margins determined by MISO for use in its seasonal capacity construct cannot be applied in the Operating View described here. As a reasonableness check, it is useful to compare the planning reserve margin requirements for the Operating View describes above with historical planning reserve margin requirements based on an installed capacity (ICAP) view, which similarly uses unit capabilities unadjusted for availability. The ICAP-based planning reserve margin requirements used by Ameren Missouri, and previously set by MISO under its annual RA construct, were typically in the range of 15-20%. The planning reserve margin requirements for the Operating View are comparable to this historical range.

Using the Operating View described above, Ameren Missouri has examined the capacity position for its PRP as well as variations from the PRP to assess the contribution of certain resource additions. These variations include the following and correspond to the subsequent figures as noted:

- Winter operating view capacity position with no new simple cycle generation, batteries or non-RES renewables – Figure 10.6
- Winter operating view capacity position for the PRP – Figure 10.7
- Summer operating view capacity position with no new solar resources beyond those for which the Company has received a CCN (i.e., the Boomtown and Huck Finn projects) – Figure 10.8
- Summer operating view capacity positions for the PRP – Figure 10.9

Figure 10.6 Winter Operating View Capacity Position Without New Simple Cycle, Batteries, or Non-RES Renewables

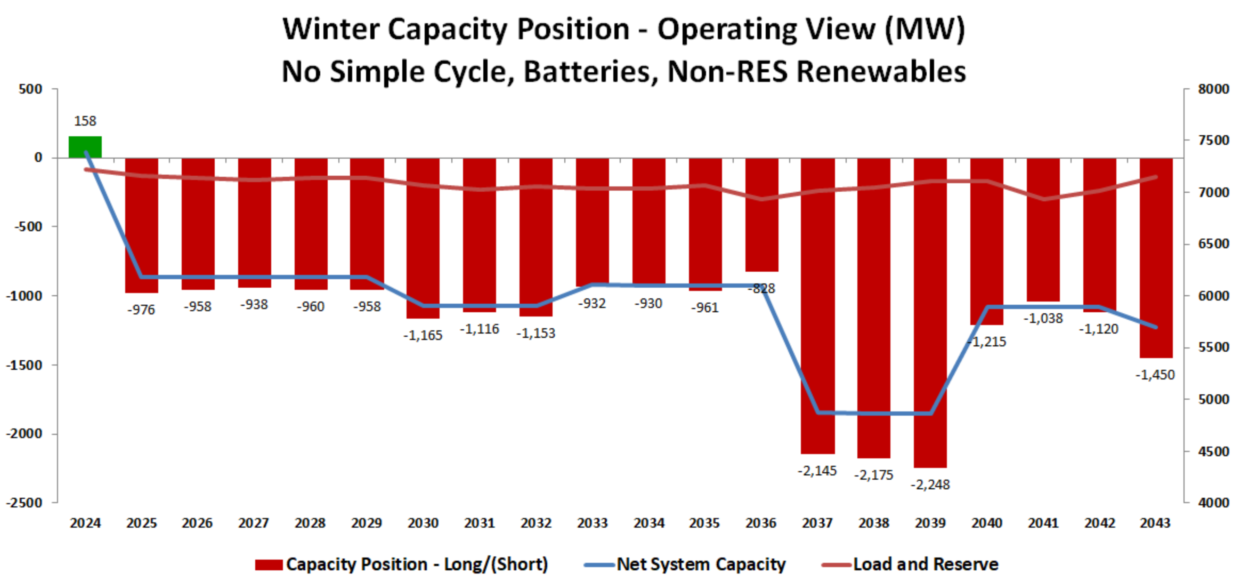


Figure 10.7 Winter Operating View Capacity Position – Preferred Resource Plan

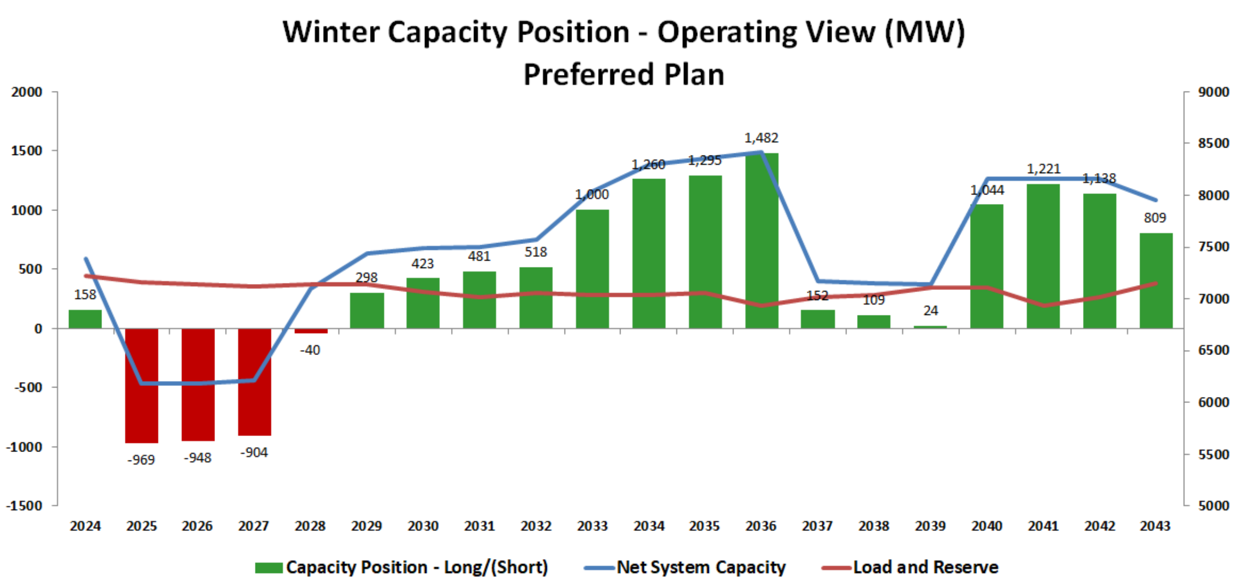


Figure 10.6 shows that without new simple cycle generation, batteries and non-RES renewables, Ameren Missouri would be roughly 1,000 MW short of its PRM in most years and roughly 2,000 MW short for the three years following the retirement of the first two units at Labadie Energy Center. Including the simple cycle generator, batteries, and planned wind and solar resources in the PRP results in Ameren Missouri achieving its PRM in all years starting in 2029, with only a slight shortfall in 2028 following the addition

of the new simple cycle generation. For the years 2025-2027, Ameren Missouri expects to be dependent on MISO to meet demand and/or the ability to operate CTG units in Illinois under emergency conditions.

Figure 10.8 shows Ameren Missouri's summer capacity position without new solar resources beyond those for which it has received a CCN, and Figure 10.9 shows Ameren Missouri's summer capacity position with additional new solar resources. Figure 10.9 shows how near-term capacity needs are reduced with the addition of additional new solar projects, such as those for which the Company is currently seeking CCNs, particularly in 2027. As with the winter capacity position shown in Figure 10.7, Ameren Missouri expects to be dependent on MISO to meet some of its near term needs and/or the ability to operate CTG units in Illinois under emergency conditions.

Figure 10.8 Summer Operating View Capacity Position With No Additional Solar

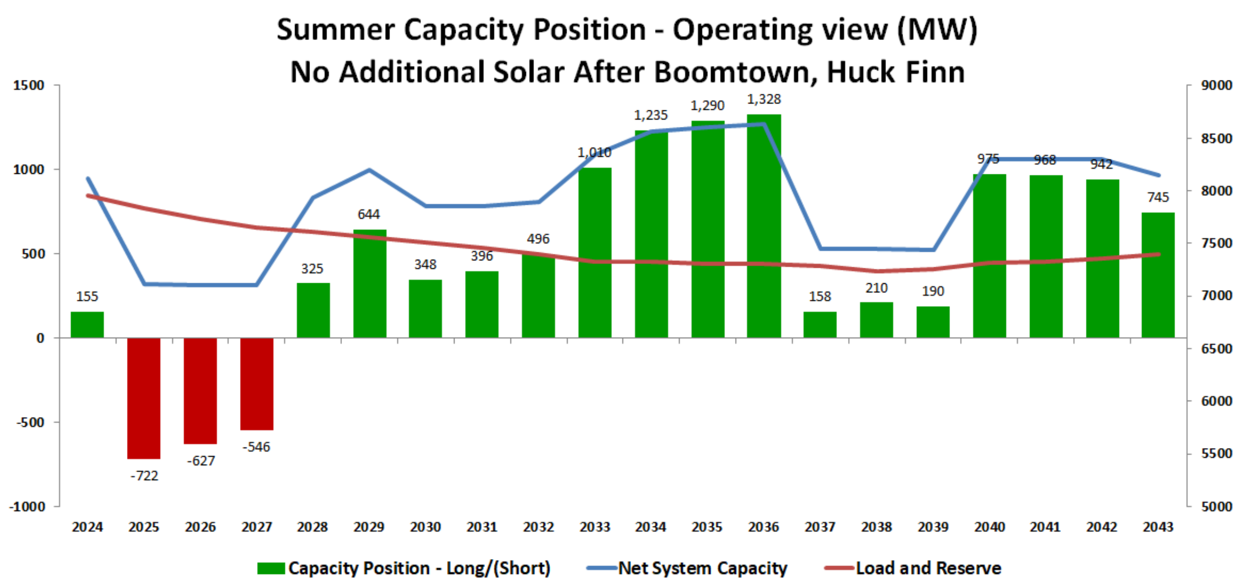
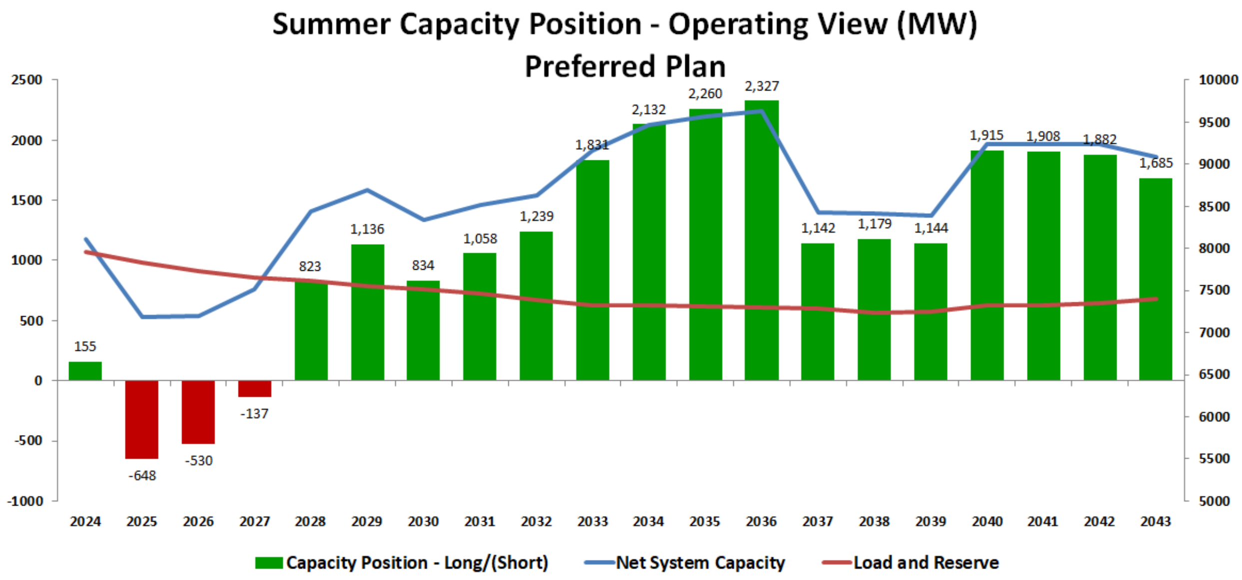


Figure 10.9 Summer Operating View Capacity Position – Preferred Resource Plan



Capacity Positions – MISO Resource Adequacy View with Extreme Weather[11]

In addition to the Operating View capacity positions shown above, Ameren Missouri has also examined its capacity position under MISO's seasonal construct and under extreme weather conditions. For convenience, and to distinguish this view from the Operating View, we refer to this as the "MISO RA View." The MISO RA View is characterized by the following:

- All units reflected at MISO seasonal accredited capacity (SAC) values
- Planning reserve margins set to MISO seasonal values[12]
- Assessment with extreme weather assumes limited use units (i.e., Illinois CTGs) are available for emergencies only
- Extreme weather reflects incremental peak demand of 600 MW in winter and 800 MW in summer based on recent extreme weather events[13]

Using the MISO RA View described above, Ameren Missouri has examined the capacity position for its PRP as well as variations from the PRP to assess the contribution of certain

[11] 20 CSR 4240-22.070(1)(D); 20 CSR 4240-22.030(8)(B)
[12] See Chapter 2 for a full discussion of seasonal PRM requirements.
[13] Summer peak load addition of 800 MW based on approximate midpoint of values calculated and presented in the extreme weather sensitivity analysis in Chapter 3. Winter peak load addition of 600 MW based on approximate increase in peak demand above normal peak experienced during winter storm Elliott in December 2022.

resource additions. These variations include the following and correspond to the subsequent figures as noted:

- Winter capacity position with no new simple cycle generation, batteries or non-RES renewables – Figure 10.10
- Winter capacity position for the PRP – Figure 10.11
- Summer capacity position with no new solar resources beyond those for which the Company has received a CCN (i.e., the Boomtown and Huck Finn projects) – Figure 10.12
- Summer capacity positions for the PRP – Figure 10.13

Figure 10.10 Winter MISO RA View Capacity Position Without New Simple Cycle, Batteries, or Non-RES Renewables

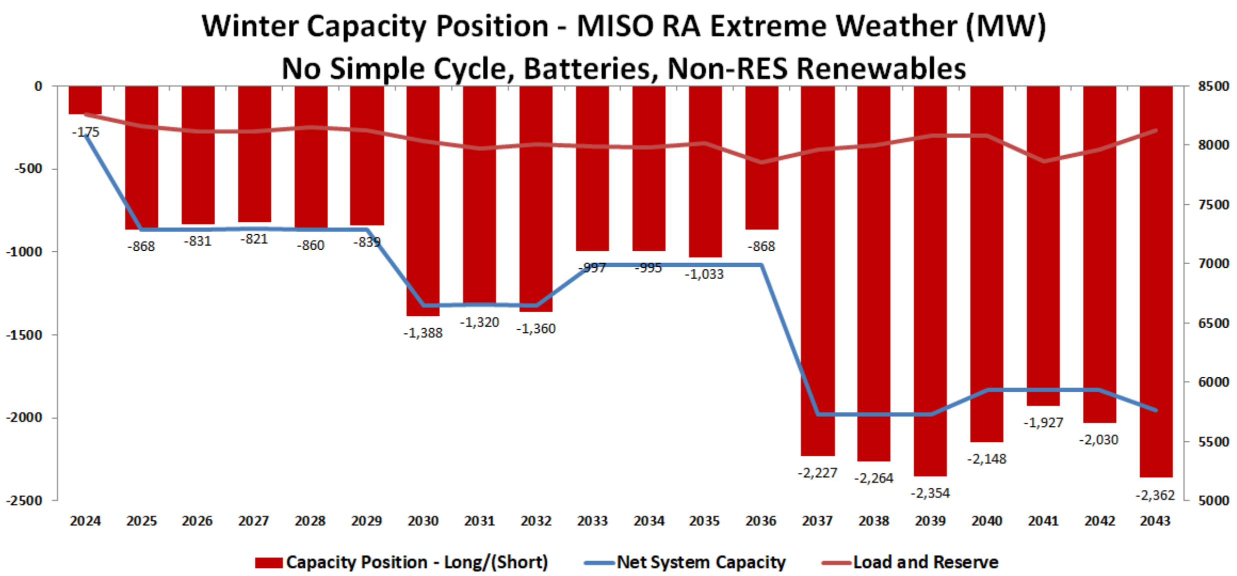
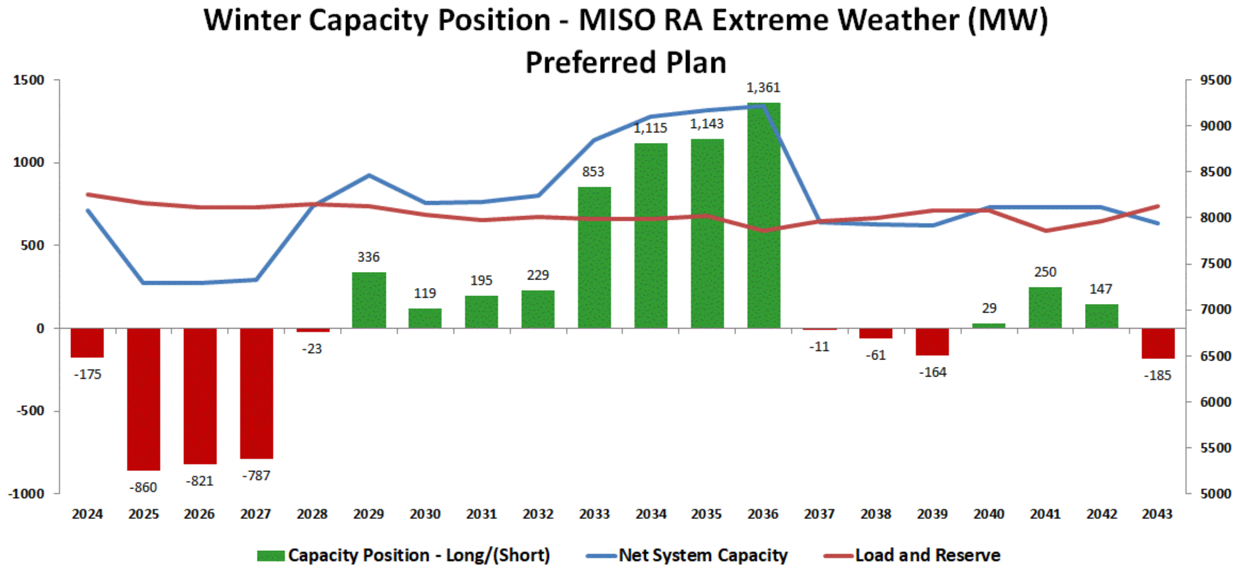


Figure 10.11 Winter MISO RA View Capacity Position – Preferred Resource Plan



Under extreme weather conditions, the MISO RA view for winter shows a capacity shortfall in all years absent the simple cycle generation, batteries and non-RES renewable additions included in the PRP, as shown in Figure 10.10. With those resources, as shown in Figure 10.11, Ameren Missouri expects to have sufficient resources in most years beginning in 2029, with a slight deficit in 2028 and relatively small deficits beyond 2036, following the retirement of the first two units at the Labadie Energy Center. Ameren Missouri could be dependent on MISO for capacity under extreme weather conditions between now and 2027.

Figure 10.12 shows that Ameren Missouri expects a relatively small capacity deficit in the summer under extreme weather conditions in 2024 and 2026 in the absence of additional solar resources. Figure 10.13 shows that this near-term deficit is resolved by the inclusion of additional solar resources, including those for which the Company is currently seeking CCNs.

Figure 10.12 Summer MISO RA View Capacity Position With No Additional Solar

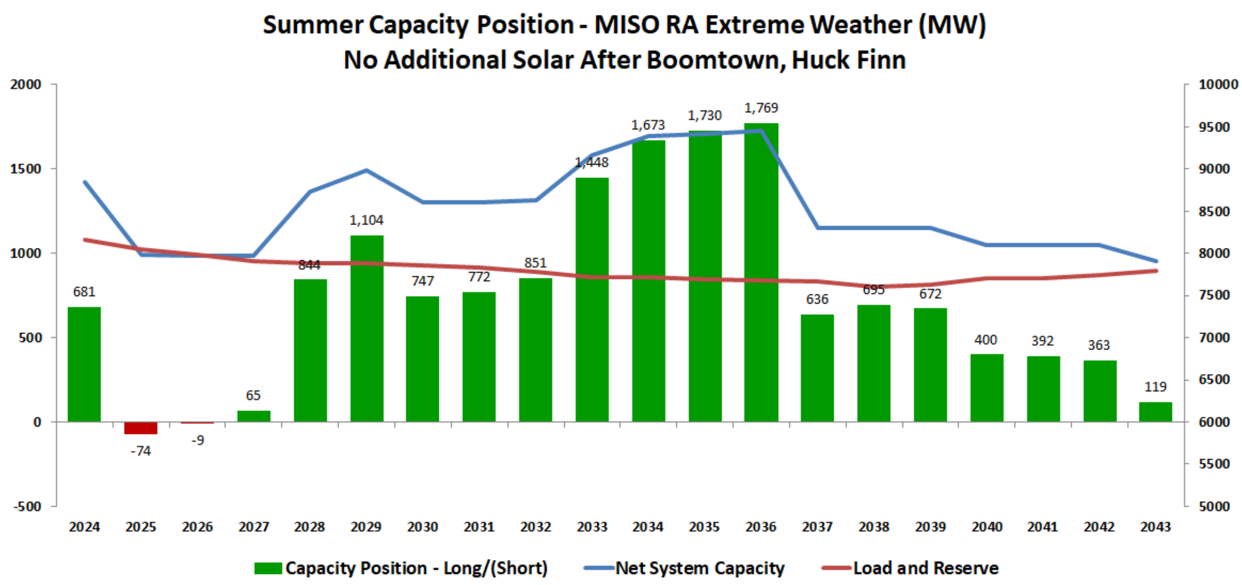
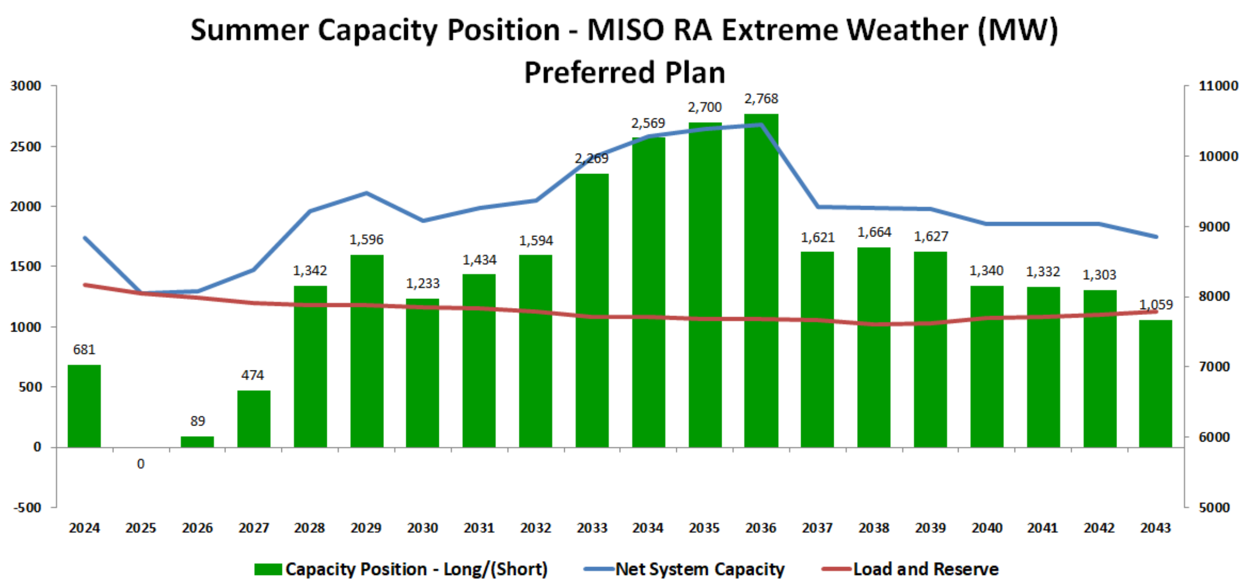


Figure 10.13 Summer MISO RA View Capacity Position – Preferred Resource Plan



Additional Reliability Analysis

As discussed previously, Ameren Missouri will need new dispatchable resources that can produce at any hour to partner with new renewable resources and other dispatchable resources in Ameren Missouri's fleet to ensure reliable energy for customer. Wind and solar resources are not dispatchable. Batteries can provide dispatchability over short periods, but they need to be charged, and therefore their value on the grid is determined by finding an optimal charging and discharging cycle over time. Gas-fired resources, on the other hand, can generate on demand in any given hour and ensure reliability of the overall portfolio in a way that renewables and storage alone cannot.

To illustrate this, the Company used Astrapé Consulting to analyze three different portfolios at or near the end of the Company's 20-year planning horizon. In each of these portfolios, all of Ameren Missouri's existing coal-fired resources are assumed to have been retired. One portfolio (marked as Case 2 in Table 10.3 below) reflects renewable resources included in the Company's PRP. Case 1 shows an alternative portfolio in which no further renewables (or battery storage) are added beyond the Company's existing and approved wind and solar resources (including the Huck Finn and Boomtown solar projects). That portfolio shows the need for 1,800 MW of additional natural gas-fired generation to achieve the same level of reliability, shown in terms of the Loss of Load Expectation (LOLE) – 0.04 in both cases. Case 3 shows an alternative portfolio in which no new gas resources are added. Case 3 includes a combination of wind (7,400 MW), solar (6,500 MW), and battery storage (4,000 MW) to attempt to achieve the same LOLE as Case 2. As the table shows, this still falls short from a reliability perspective, with an LOLE of 0.14. Further increments of wind, solar, and storage could be added to achieve the 0.04 LOLE achieved by Cases 1 and 2 but would simply result in even higher (and more unrealistic) levels of such resources. As discussed previously in this chapter, there are significant, but not insurmountable, challenges to implementing the renewable resources in the Company's PRP. To attempt to pursue the levels of renewable resources and battery storage shown in Case 3 would simply not be realistic, and even if they were available, it would require a much quicker pace of implementation in the near term than what the Company is currently seeking to execute.

Cases 4-7 show portfolios with and without further renewable resources under the PRP in 2026 and 2031, which each follow the retirement of significant coal-fired generation – Rush Island by 2025 and Sioux by 2030.[14] Cases 4 and 6 shown years 2026 and 2031, respectively, including the renewable additions in the PRP, and cases 5 and 7 show those same years, respectively, without renewable additions beyond those already approved. Differences from the PRP are highlighted in green.

[14] Note that this analysis was completed prior to the final selection of the Company's PRP.

Table 10.3 Astrapé Reliability Analysis Results

Year	2043	2043	2043	2026	2026	2031	2031
Case	*1*	*2*	*3*	*4*	*5*	*6*	*7*
Rush Island	-	-	-	-	-	-	-
Sioux	-	-	-	974	974	-	-
Battery Storage	-	800	4000	-	-	-	-
CCGT	4200	2400	-	-	-	1200	1200
Labadie	-	-	-	2372	2372	2372	2372
CT Gas	788	788	-	2711	2711	2058	2058
DR	704	704	704	704	704	704	704
Hydro	370	370	370	370	370	370	370
Nuclear	1236	1236	1236	1236	1236	1236	1236
PSH	440	440	440	440	440	440	440
Purchases	2200	2200	2200	2200	2200	2200	2200
Solar	350	2700	6500	900	350	1800	350
Wind	400	2400	7400	400	400	1400	400
LOLE	0.04	0.04	0.14	0.09	0.13	0.01	0.08

For 2026, the addition of 550 MW of solar resources, which is the total combined capacity of the solar projects currently before the MPSC, results in an improvement in LOLE from 0.13 (Case 5) to 0.09 (Case 4). For 2031, the addition of 1,450 MW of solar and 1,000 MW of wind resources results in an improvement in LOLE from 0.08 (Case 7) to 0.01 (Case 6). While renewable resources are intermittent and alone cannot provide all the necessary capacity to ensure a reliable system, they are integral to meeting reliability needs throughout the near, intermediate, and long term in partnership with existing and new dispatchable resources in the Company's fleet.

Hourly Energy Contribution of Renewable Resources

In addition to the annual energy analysis described previously in this chapter, Ameren Missouri has analyzed hourly energy needs and expected generation during key times of the year, which highlights the value of the Company's renewable additions in meeting customer energy needs.[15] This was done by taking the Company's 2023 IRP load forecasts and showing an explicit build-up of energy resources compared to the load.

[15] More granular hourly and sub-hourly analysis is among the recommendations made by NERC in its 2022 Long-term Reliability Assessment, as discussed in Chapter 2.

Specific time periods were evaluated, including summer and winter peak conditions, for several key timeframes during the 20-year planning horizon.

The hourly analysis shows that renewable resources are expected to contribute significantly to meeting customer energy needs in the short-, intermediate- and long-term and that the Company's planned solar projects in particular are valuable in meeting customer energy needs in the near term, especially during the summer. The importance of the value provided by the solar projects in the near term is further heightened by the CSAPR rule changes affecting coal generation during the summer months and proposed rules regulating CO_2 emissions.

Figure 10.14 shows peak day energy resources and load for July 5, 2026. The solar resources, shown in yellow on the chart, are contributing energy production primarily during the peak period, while wind resources, shown in green generate primarily in the off-peak period. Figure 10.15 shows a similar view for December 23, 2026. This shows much higher production from wind resources in winter than in summer, and primarily in the early morning hours, while solar resource still generate during the middle of the day. Note that in both summer and winter, there is still a need for other energy to meet load, as is the case in the annual energy positions discussed previously. This could be met by a combination of resources, including peaking resources in the Company's fleet and other available resources within MISO and the broader market.

Figure 10.14 Summer Peak Day Energy – PRP 2026

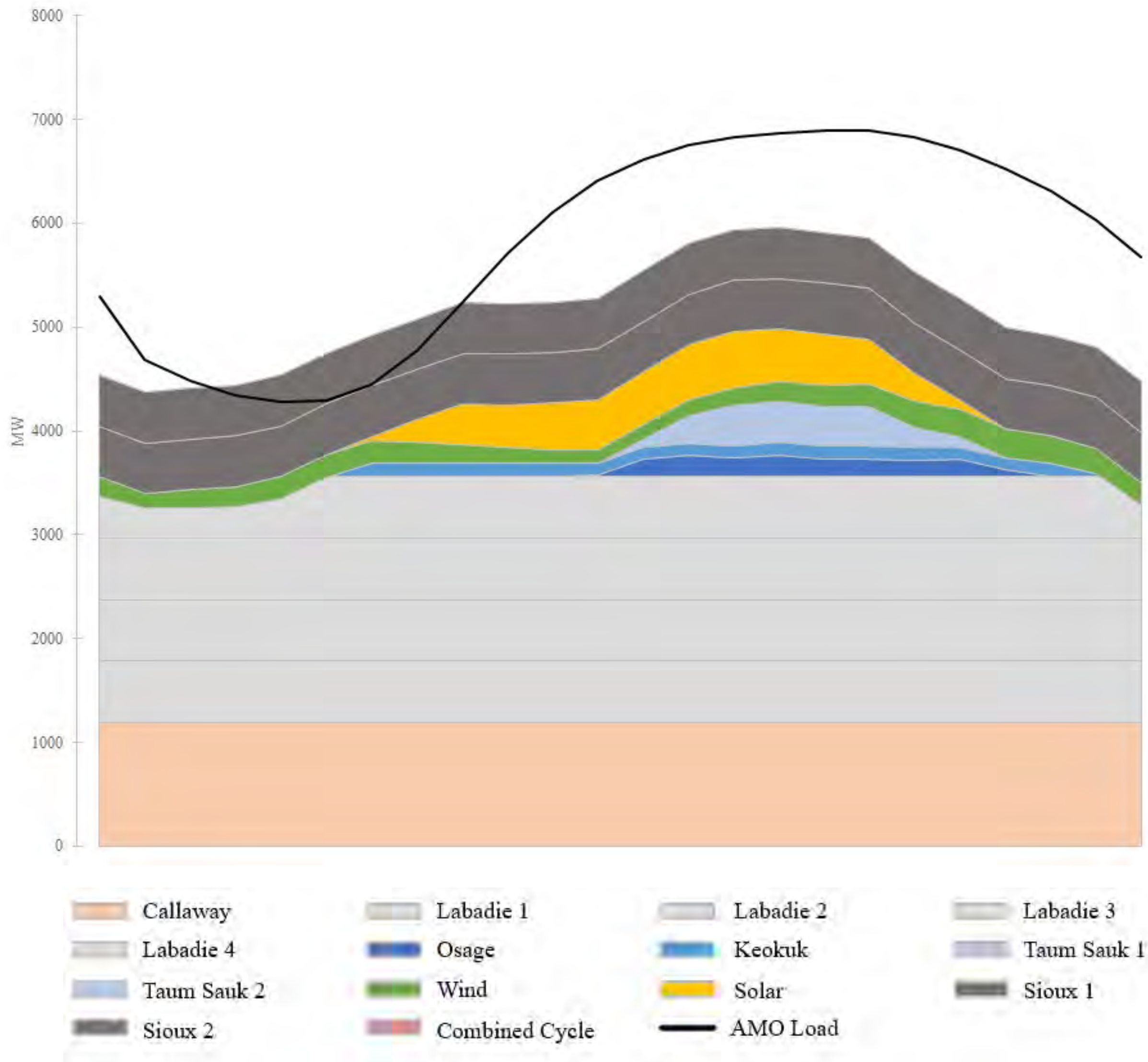
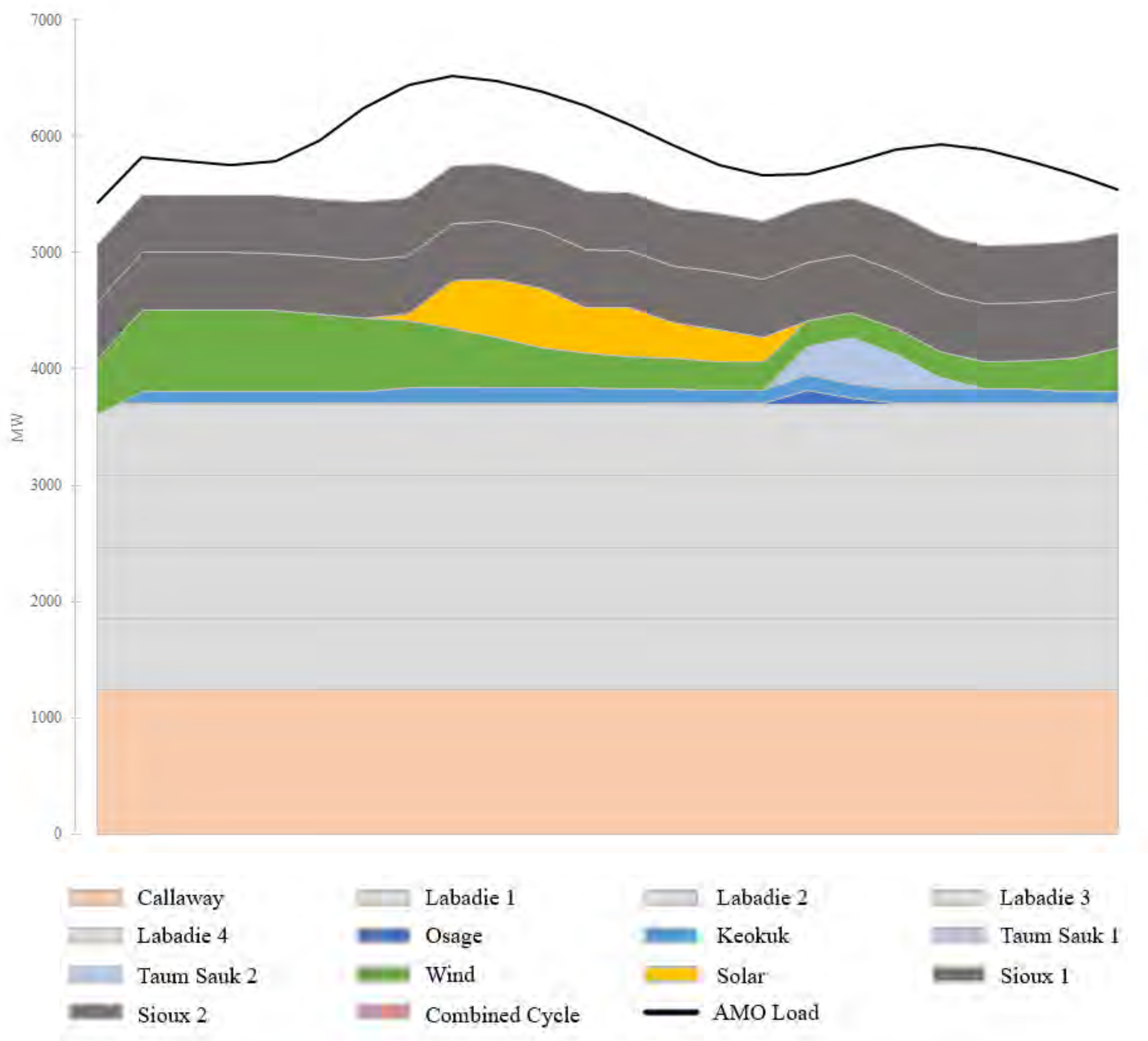


Figure 10.15 Winter Peak Day Energy – PRP 2026



Figures 10.16 and 10.17 similarly show the summer and winter, respectively, energy production and load for the same days in 2033, following the retirement of Sioux Energy Center, the addition of 1,200 MW of combined cycle gas generation and renewable additions that bring total wind generating capacity to 2,100 MW and total solar generating capacity to 2,200 MW. These charts show the higher contribution of solar during the summer and wind during the winter, while also showing that both provide generation during both seasons. The charts also demonstrate the important role of new dispatchable generation in meeting customer energy needs when total wind and solar generation are lower.

Figure 10.16 Summer Peak Day Energy – PRP 2033

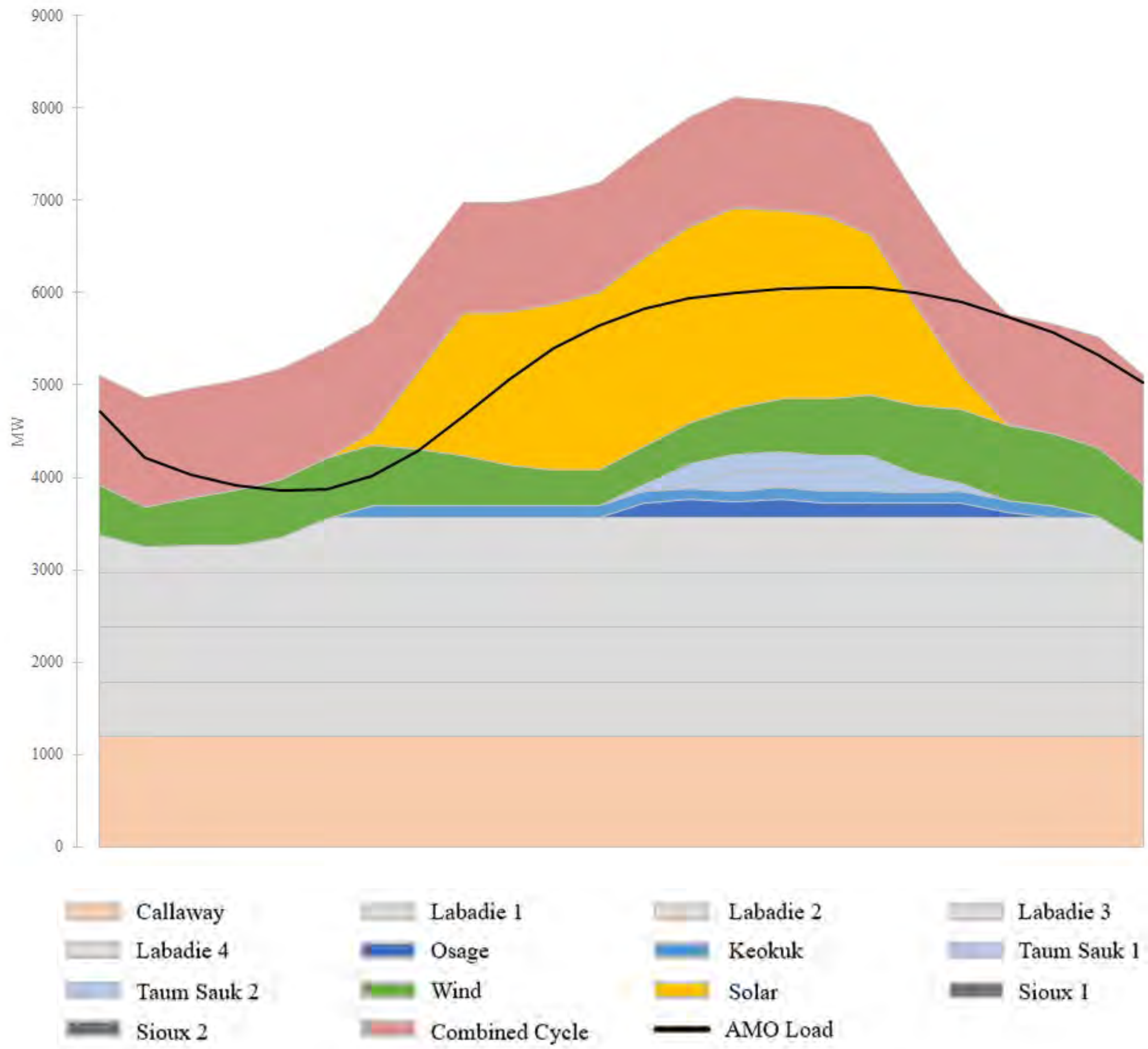
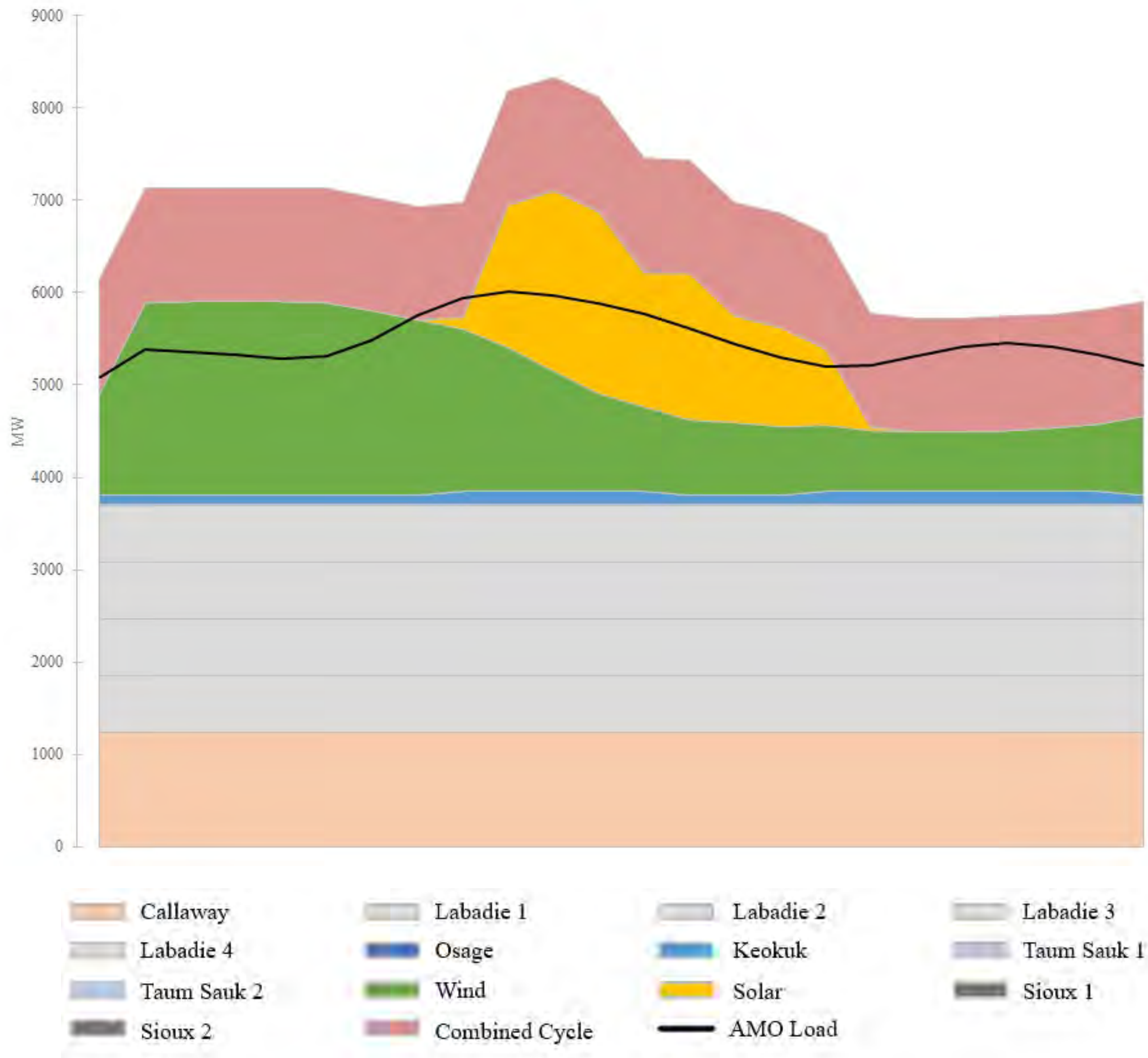


Figure 10.17 Winter Peak Day Energy – PRP 2033



Following the retirement of two Labadie units in 2036, renewable additions bring total wind and solar generating capacity to 5,400 MW. The charts in Figures 10.18 and 10.19 again show summer and winter peak days, respectively, and the generation needed to serve load in 2040, following the addition of 1,200 MW of clean dispatchable generation.[16] Once again, these charts show the important role of renewable resources in producing energy to meet load and the role of dispatchable resources to partner with renewables and ensure reliability in all hours.

[16] For analysis purposes, the clean dispatchable resource is modeled as combined cycle gas. However, the Company plans to make the decision in the future as to exactly what type of clean dispatchable generation is ultimately deployed.

Figure 10.18 Summer Peak Day Energy – PRP 2040

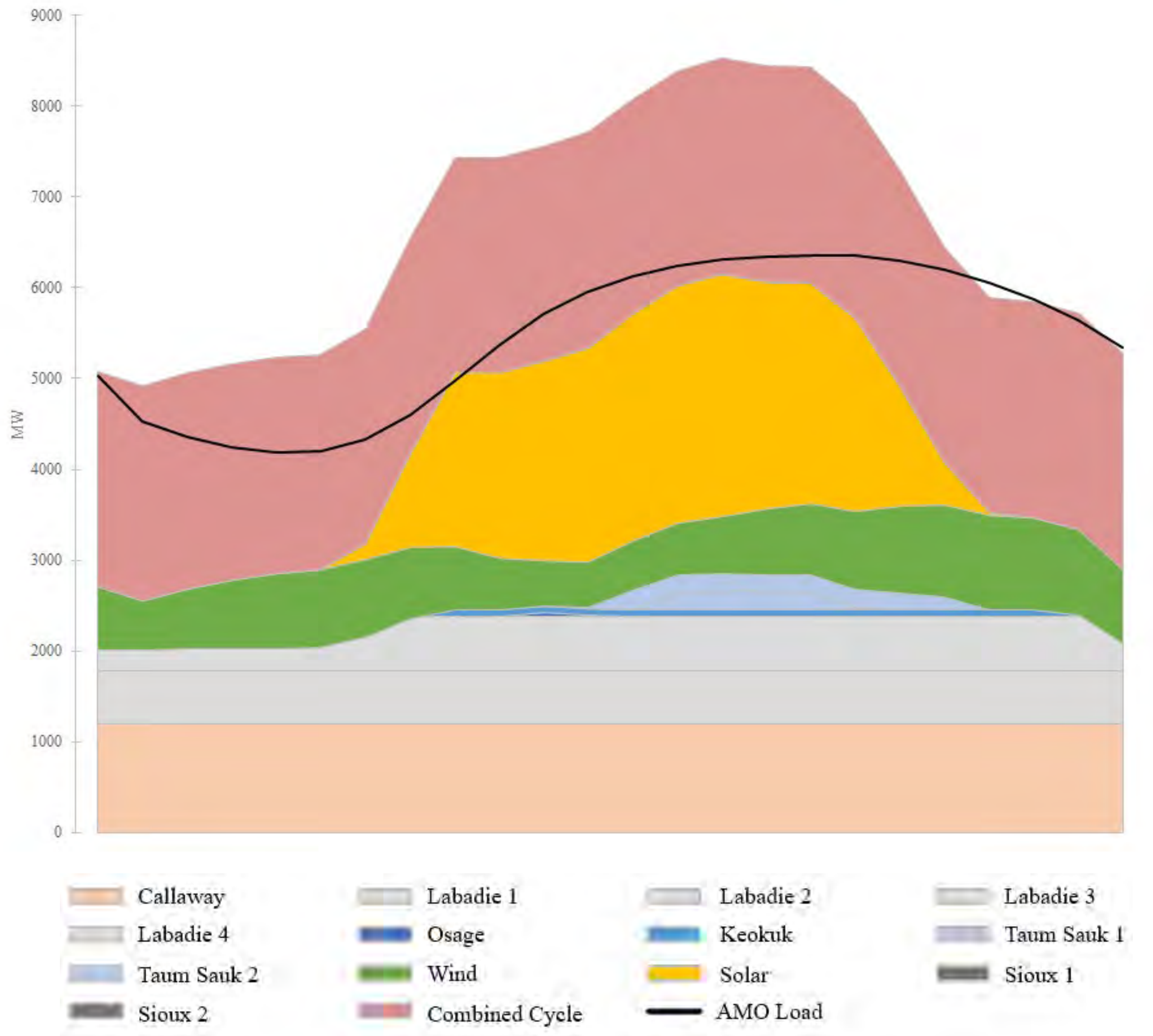
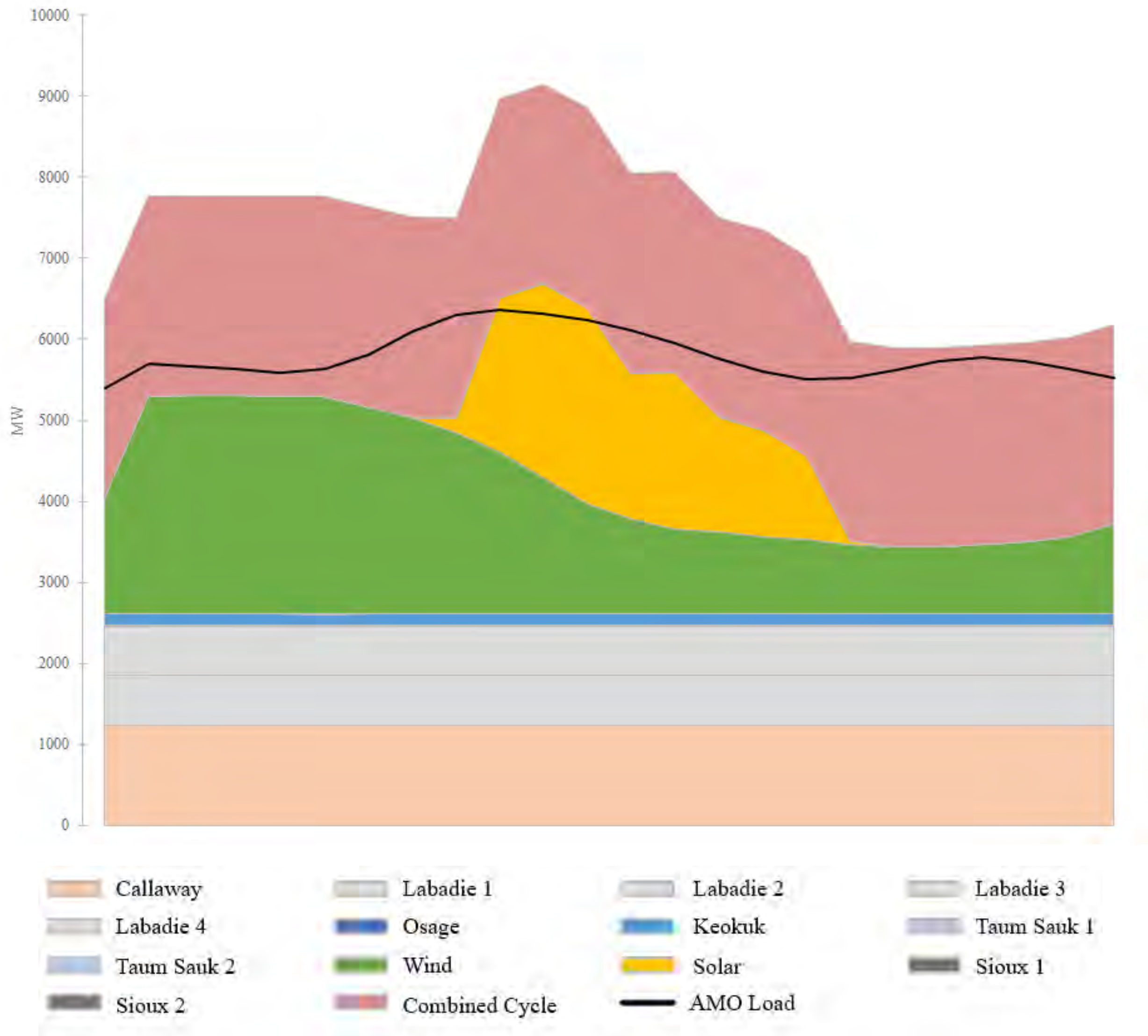


Figure 10.19 Winter Peak Day Energy – PRP 2040



10.2.4 DSM Portfolio Considerations

The continued transition from our old fleet to our new fleet has placed an even greater emphasis on the potential role of demand-side resources, which compete directly with supply-side resources in the alternative plans described and analyzed in Chapter 9. We have seen the gap between the costs of the RAP and MAP portfolios increase in terms of the cost per kWh saved. As a result, the incremental cost of the MAP portfolio does not result in savings from the deferral of supply side resources that justify this cost, as evidenced by our PVRR analysis. At the same time, achievement of energy savings at levels less than that reflected in the RAP portfolio give rise to the need for more supply side resource additions, also resulting in higher costs for customers. For these reasons, the Company believes it is appropriate to continue to target energy and demand savings based on the RAP portfolio.

In addition to its traditional evaluation of demand side programs, the Company also evaluated the potential for additional load flexibility, as described in Chapter 8. While inclusion of this potential (see Plan R in Chapter 9) results in higher PVRR, it may still prove to be a useful contingency option for meeting reliability needs, particularly in the winter. The Company will continue to evaluate the potential for additional load flexibility.

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 in Chapter 8, 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[17]

In selecting its Preferred Resource Plan, Ameren Missouri decision makers[18] relied on the planning objectives discussed earlier in this chapter and the considerations reflected in the scoring and comparison of alternative plans highlighted in the previous sections. As was noted previously, the Top Tier plans identified through scoring include the RAP DSM portfolio, a significant expansion of renewable and storage resources, and the addition of dispatchable resources in the selection of the preferred resource plan.

[17] 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)

[18] Names, titles and roles of decision makers are provided in Appendix B.

Figure 10.20 Comparison of Top Tier Plans

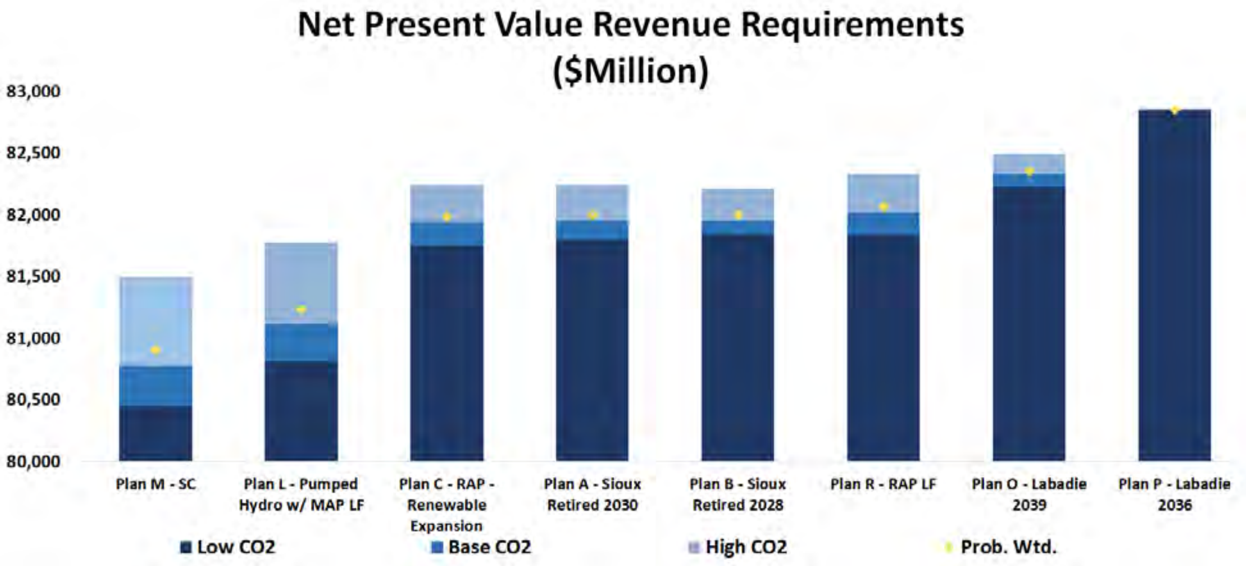
Performance Objectives	Customer Cost (PVRR) (30%)	Customer Sat. (incl. Reliability) (20%)	Financial and Regulatory (20%)	Resource Diversity (20%)	Econ. Dev. (Direct Jobs) (10%)
Plan C – Sioux Retired 2032; Clean Dispatchable (CC-CCS) 2040/2043	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage	Relative Advantage	No Relative Advantage/Disadvantage
Plan A – Sioux Retired 2030; Clean Dispatchable (CC-CCS) 2040/2043	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Disadvantage	Relative Advantage	No Relative Advantage/Disadvantage
Plan B – Sioux Retired 2028; Clean Dispatchable (CC-CCS) 2040/2043	No Relative Advantage/Disadvantage	Relative Disadvantage	Relative Disadvantage	Relative Advantage	Relative Disadvantage
Plan R – Sioux Retired 2032; Clean Dispatchable 2040/2043; Additional Load Flexibility	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage	Relative Advantage	No Relative Advantage/Disadvantage
Plan M – Sioux Retired 2032; Simple Cycle 2040; Clean Dispatchable 2043	Relative Advantage	No Relative Advantage/Disadvantage	Relative Advantage	No Relative Advantage/Disadvantage	Relative Disadvantage
Plan L – Sioux Retired 2032; Pumped Hydro 2040; Clean Dispatchable 2043	Relative Advantage	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage
Plan O – Sioux Retired 2032; Labadie Retired 2039; Clean Dispatchable 2040x2	Relative Disadvantage	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage	Relative Disadvantage
Plan P – Sioux Retired 2032; Labadie Retired 2036; Clean Dispatchable 2037/2039	Relative Disadvantage	Relative Disadvantage	Relative Disadvantage	Relative Advantage	Relative Disadvantage

Relative Advantage No Relative Advantage/Disadvantage Relative Disadvantage

To facilitate the selection of the preferred plan, an additional assessment was made of the top tier resource plans. Figure 10.20 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 10.2 do not constrain this comparison. Following is a description of the consideration of each planning objective for the top tier plans.

PVRR – Figure 10.21 summarizes the PVRR results for the top tier plans by CO_2 price scenario and for the probability weighted average. Based on these results, Plans M and L were rated as having a relative advantage compared to the other plans. Plans O and P were rated as having a relative disadvantage. All other plans were rated as having no relative advantage or disadvantage.

Figure 10.21 Results for Top Tier Plans[19]



Customer Satisfaction – Plans B and P were judged to have a relative disadvantage due to risks to the accelerated need for gas-fired generation and risks to reliability if new generation is delayed. Plan P also reduces flexibility to take advantage of new clean resource technology development. The other plans were judged to have no relative advantage or disadvantage. While Plan A also results in a slight acceleration of coal generation retirement (i.e., Sioux Energy Center), the risks to reliability are not elevated as with Plan B.

Financial and Regulatory – Plans A, B, and P were judged to have a relative disadvantage given the acceleration of retirement for coal-fired energy centers and the resultant accelerated need for gas-fired generation. The potential implications of EPA's proposed rule for greenhouse gas emissions under Section 111 of the Clean Air Act weighs significantly in the consideration of regulatory risk since they affect not only coal-fired generation, but also new gas-fired generation. Should the proposed rule take effect in a form other than that proposed, or not take effect at all, this risk would be reconsidered. Plan O was judged to have no relative advantage or disadvantage. While Plan O carries regulatory risk associated with the licensing and permitting of new pumped hydro generation, the risk is far enough in the future as to not constitute a relative disadvantage. Should policy changes reduce the regulatory risk associated with licensing and permitting new pumped hydro generation, this risk would be reconsidered. Plan L was judged to have no relative advantage or disadvantage. Like Plans A, B, and P, Plan L carries some risk associated with accelerating gas-fired generation. However, this risk is far enough in

[19] Plans include RAP-level DSM unless otherwise noted.

the future so as not to constitute a relative disadvantage. All other plans were judged to have no relative advantage or disadvantage.

Portfolio Transition – Plans L and M were judged to have no relative advantage or disadvantage since the alternative resources that differentiate them – simple cycle gas and pumped hydro – would not be expected to provide replacement energy for retiring coal. This could also result in the need to retain remaining coal-fired generation and/or operating coal and gas-fired generation at higher levels to meet energy needs. Because this risk is far in the future, this did not result in a finding that they exhibited a relative disadvantage. All other plans were judged to have a relative advantage in that they result in significant energy transition. It should be noted that changes in technology and other factors may diminish the relative advantages of various resources in the period 2040 and beyond. Ameren Missouri will continue to monitor such developments as part of its ongoing planning process.

Economic Development – Plan L was judged to have a relative advantage based on the jobs associated with pumped hydro resource construction. Plans B, O and P were judged to have a relative disadvantage based on the earlier elimination of jobs at coal-fired energy centers. Plan M was also judged to have a relative disadvantage due to the reduced labor intensity of simple cycle gas. All other plans 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.

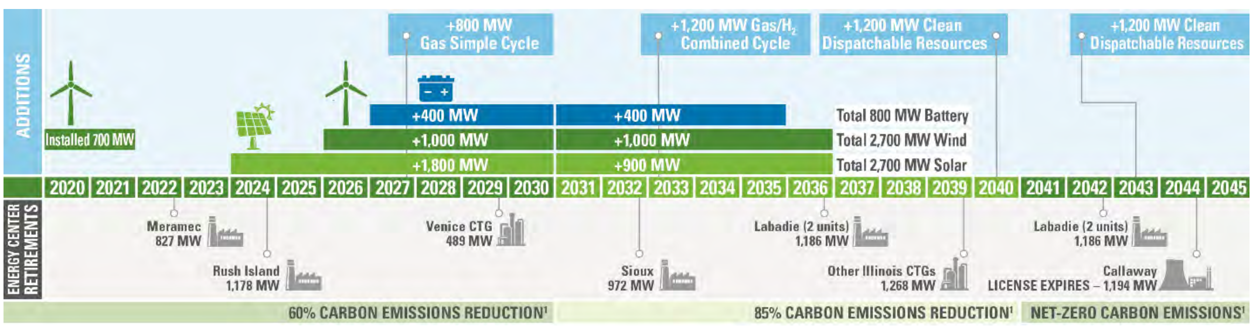
DSM Portfolio – Including energy efficiency and demand response based on RAP DSM potential in our preferred resource plan allows us to continue to offer highly cost-effective programs to customers at a reasonably aggressive level of annual spending while also allowing the potential for increased savings 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 this chapter, we believe that the appropriate course of action is to continue the transition to greater levels of renewable energy today in a sustained and controlled manner. 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 and Replacements – We evaluated various alternatives for earlier retirement of coal-fired generation as well as a delay of the retirement of Sioux Energy Center. Delaying the retirement of Sioux Energy Center to 2032 yields benefits in terms of customer costs while also addressing risks associated with potential policy changes and changes in market conditions that affect not only coal generation economics but also the economics and risk associated with replacement gas-fired generation. In particular, EPA's proposed GHG rule introduces risks associated with new gas fired generation, particularly non-peaking gas-fired generation. 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.

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 C as our preferred resource plan. Figure 10.22 shows the major resource additions and retirements defined by Plan C.

Figure 10.22 Preferred Resource Plan



10.4 Contingency Planning[20]

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.

10.4.1 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

[20] 20 CSR 4240-22.070(4)

energy more efficiently. In September 2023, the MPSC approved the third one-year extension of 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 an amended multi-year MEEIA 4 application with the MPSC for approval of a new portfolio of demand-side programs that would become effective starting in 2025. 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 Renewable Subscription Program

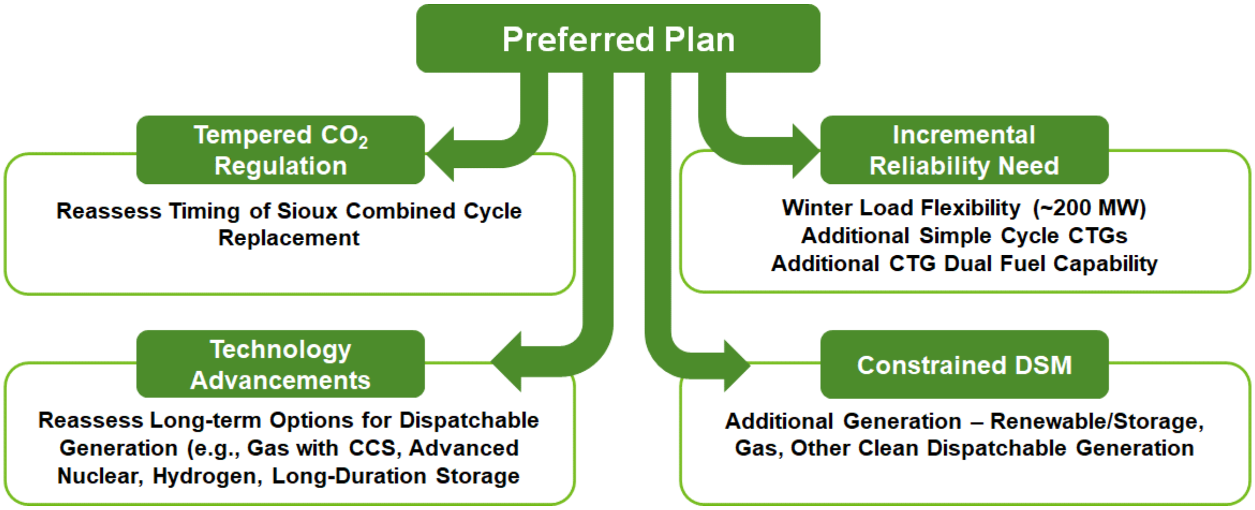
Our preferred plan includes our Renewable Solutions Program to offer commercial and industrial customers and communities the means by which they can source more of their electric energy needs from renewable resources. While further resources have not been designated for this program, some planned resources may be designated for the program in the future depending on customer demand and project economics.

10.5 Resource Acquisition Strategy[21]

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. Figure 10.23 shows the contingency options the Company has considered 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, 2024-2026.

[21] 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)

Figure 10.23 Contingency Options



10.5.1 Preferred Plan

As discussed in Section 10.3, our Preferred Resource Plan includes energy efficiency programs based on the RAP portfolio potential discussed in Chapter 8, 4,700 MW of wind and solar generation by 2036, 800 MW of battery storage by 2035, retirement of the Fairgrounds, Mexico, Moberly, Moreau and Venice Energy Centers by the end of 2029, retirement of Rush Island Energy Center by the end of 2024, retirement of Sioux Energy Center by the end of 2032, retirement of two of the four units at Labadie Energy Center by the end of 2036, retirement of the remaining CTG energy centers in Illinois by the end of 2039, and retirement of the remaining two units at Labadie Energy Center at the end of 2042. It also includes the addition of 800 MW of simple cycle gas generation by the end of 2027, 1,200 MW of combined cycle gas generation by the end of 2032, and 1,200 MW of clean dispatchable resources in each of 2040 and 2043.

Demand-Side Resources

The preferred plan includes energy efficiency and demand response programs based on the RAP portfolio potential discussed in Chapter 8. Program spending for the 20-year planning horizon (after the current cycle of MEEIA programs) is approximately $2.5 billion. Cumulative peak demand reductions approaching 1,600 MW by 2043 (not including planning reserve margin), and cumulative annual energy savings (at the customer meter) over 4.1 million MWh.

Renewables and Storage

We are continuing a transformation of our generation portfolio, and one of the key components of that transition is the continued significant expansion of renewable wind and solar generation resources, with a total of 4,700 MW of new wind and solar generation by 2036 and 2,800MW by 2030, and the addition of 400 MW of battery storage by 2030 and another 400 MW by 2034. As discussed earlier in this chapter, these renewable energy resources will be necessary to ensure the energy supply that our customers need and do so in a way that is environmentally responsible and ensures affordability for our customers. Battery storage resources, along with other dispatchable resources in our fleet, will partner with these renewable resources to ensure reliable energy supply during and after the transition of our portfolio.

Supply-Side Resources

The Preferred Resource Plan calls for the retirement of Rush Island by the end of 2024, retirement of Sioux Energy Center by the end of 2032, retirement of two of the four units at Labadie Energy Center by the end of 2036, and retirement of the remaining units at Labadie Energy Center by the end of 2042. It also calls for the retirement of four older oil-fired CTGs and the gas-fired Venice Energy Center by the end of 2029 and the remaining Illinois gas-fired units at the Goose Creek, Racoon Creek, Pinckneyville and Kinmundy Energy Centers by the end of 2039. To ensure sufficient dispatchable resources to partner with the above-mentioned renewable and storage resources, we also plan to add 800 MW of gas-fired simple cycle combustion turbine generation by the end of 2027, 1,200 MW of gas-fired combined cycle generation by the end of 2032, and 1,200 MW of additional clean dispatchable generation in each of 2040 and 2043.

10.5.2 Contingency Plans[22]

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 option that reflects a discontinuation of demand side programs after our current MEEIA cycle programs expire. The contingency option therefore also includes acceleration of 2033 combined cycle gas generation, the installation of an additional 1,150 MW simple cycle gas generation in 2037 and another 1,200 MW of clean dispatchable generation in 2043. Should the EPA's current proposed regulation of CO_2 take effect in a different form or not take effect at all, the Company may reevaluate the timing of the retirement of its Sioux Energy Center and the planned addition of combined cycle gas replacement generation. Should the development of clean dispatchable resource technologies advance more quickly or result in resource options that provide a more favorable combination of reliability and affordability, Ameren Missouri will reevaluate its planned generation additions. This could also include further consideration of simple cycle gas generation and/or pumped hydro energy storage resource, which scored well in our assessment of alternative plans. Should additional resources be needed for ensuring reliability, the Company will reassess the role of additional load flexibility resources.

[22] 20 CSR 4240-22.070(4)

10.5.3 Expected Value of Better Information

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 10.4 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. Plan M results in the lowest PVRR under certain values for critical uncertain factors – low CO_2 prices, low or base gas prices, and high project costs. Because the difference between the preferred plan and Plan M is the addition of simple cycle gas in 2040 instead of the placeholder clean dispatchable resource, incurring additional expenditures for the better information needed is not expected to resolve that choice. Instead, we have time to monitor conditions and engage in continued planning analysis until a decision must be made. For all other values of critical uncertain factors, Plan T results in the lowest PVRR. For the reasons discussed in Section 10.3, Plan T is not considered to be a feasible or desirable path. As a result, procuring better information, regardless of the cost, would not bear on plan selection.

Table 10.4 EVBI Analysis Results

	Alternative Resource Plans	PVRR Without Better Info	Carbon Price			Natural Gas Price			Load Growth			Project Cost		
			Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
A	Sioux Retired 2030	82,002	81,799	81,953	82,241	81,358	81,821	82,388	80,603	82,040	83,286	80,434	81,922	84,209
B	Sioux Retired 2028	82,003	81,839	81,955	82,215	81,341	81,810	82,409	80,604	82,041	83,287	80,416	81,923	84,226
C	RAP - Renewable Expansion	81,985	81,748	81,937	82,243	81,353	81,814	82,356	80,586	82,023	83,269	80,434	81,905	84,178
D	Labadie SCR	82,668	82,426	82,619	82,931	82,041	82,499	83,037	81,269	82,707	83,953	81,008	82,581	85,025
E	MAP	82,680	82,541	82,633	82,879	82,027	82,512	83,054	81,281	82,719	83,965	81,129	82,600	84,873
F	RAP-RES Compliance	83,807	83,344	83,711	84,314	82,537	83,439	84,583	82,407	83,845	85,091	82,129	83,724	86,147
G	MAP-RES Compliance	84,087	83,657	84,023	84,499	82,861	83,750	84,815	82,688	84,125	85,371	82,514	83,991	86,429
H	MAP LF-RES Compliance	82,080	81,352	81,933	82,870	80,960	81,791	82,721	80,681	82,118	83,364	80,814	82,012	83,891
I	No Additional DSM	86,182	85,960	86,145	86,406	85,288	85,915	86,740	84,783	86,220	87,466	84,090	86,047	89,358
J	No Additional DSM-RES Compliance	87,002	86,618	86,972	87,305	85,573	86,554	87,919	85,603	87,041	88,286	84,961	86,891	89,932
K	Renewables for Capacity Need	82,721	82,248	82,658	83,157	81,894	82,516	83,184	81,322	82,759	84,005	81,178	82,634	84,964
L	Pumped Hydro w/ MAP LF	81,238	80,819	81,118	81,778	80,648	81,100	81,559	79,839	81,277	82,522	79,803	81,181	83,135
M	SC	80,907	80,448	80,777	81,493	80,296	80,756	81,248	79,508	80,945	82,191	79,507	80,849	82,768
N	SMR w/ RAP LF	84,840	84,584	84,775	85,148	84,442	84,762	85,037	83,440	84,878	86,124	82,784	84,714	87,903
O	Labadie 2039	82,356	82,226	82,331	82,495	81,693	82,167	82,759	80,957	82,394	83,640	80,759	82,271	84,634
P	Labadie 2036	82,848	82,853	82,852	82,837	82,137	82,633	83,294	81,449	82,886	84,132	81,199	82,757	85,226
Q	Labadie 2031	83,758	83,985	83,767	83,599	82,923	83,468	84,330	82,359	83,796	85,042	81,978	83,689	86,093
R	RAP LF	82,067	81,834	82,016	82,331	81,421	81,894	82,445	80,668	82,106	83,352	80,516	81,987	84,260
S	MAP LF	82,813	82,679	82,760	83,020	82,136	82,641	83,197	81,414	82,851	84,097	81,262	82,733	85,006
T	All Renewables	80,808	80,816	80,767	80,901	80,945	80,953	80,592	79,409	80,846	82,092	78,895	80,708	83,516
U	SC instead of First CC	82,020	81,507	81,892	82,635	81,404	81,887	82,341	80,621	82,058	83,304	80,367	81,907	84,576
V	CCS on 1st CC	82,963	82,725	82,916	83,219	82,336	82,794	83,331	81,564	83,001	84,247	81,254	82,869	85,430
W	RAP 80%	83,749	83,680	83,756	83,773	83,008	83,534	84,202	82,350	83,787	85,033	81,967	83,648	86,340
	Minimum PVRR among plans		80,448	80,767	80,901	80,296	80,756	80,592	79,409	80,846	82,092	78,895	80,708	82,768
	Plan with Minimum PVRR		M	T	T	M	M	T	T	T	T	T	T	M
	Subjective Probability		15%	60%	25%	10%	50%	40%	20%	60%	20%	10%	80%	10%
	Expected Value of Better Info		1,300	1,170	1,342	1,057	1,059	1,764	1,177	1,177	1,177	1,539	1,196	1,410

10.5.4 Implementation Plan[23]

As mentioned earlier, the implementation plan outlines the major activities to be completed during the next three years, 2024-2026. 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 2024. Ameren Missouri expects to file an updated multi-year MEEIA 4 application with the MPSC in the first quarter 2024 for approval of demand-side programs and associated cost recovery and incentive mechanisms to be implemented beginning in 2025. Such a proposal will be consistent with the preferred resource plan which includes the RAP portfolio.

Renewables

Our preferred resource plan includes the addition of 2,800 MW of new wind and solar generation by the end of 2030. 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 new request for proposal process for wind resources will be initiated by the first quarter of 2024. CCN applications are currently before the MPSC for four solar projects totaling 550 MW. Additional solar project CCN applications are expected to be filed with the MPSC in the second quarter of 2024. Concurrently, Ameren Missouri continues with implementation of the Huck Finn solar project to satisfy RES requirements and the Boomtown solar project to support the Company's Renewable Solutions program, with each resource also contributing to meeting the Company's energy and capacity needs apart from the RES or the Renewable Solutions Program. Both projects were granted CCNs by the MPSC earlier in 2023, and the Renewable Solutions program was approved in that same timeframe.

New Simple Cycle Gas Generation

Our preferred resource plan includes the addition of 800 MW of simple cycle CTG generation with dual fuel (natural gas and oil) capability by the end of 2027 to provide periodic generation during times of peak demand or when wind and solar generation are diminished. The Company will be taking steps to implement this new dispatchable resource starting in 2023 and over the next few years. These include site selection, permitting, engineering, and procurement, as well as steps to secure interconnection within MISO. The Company expects to seek approval by the MPSC for a CCN for this resource sometime in 2024.

[23] 20 CSR 4240-22.070(6); 20 CSR 4240-22.070(6)(A) through (D)

New Combined Cycle Gas Generation

Our preferred resource plan also includes the addition of 1,200 MW of natural gas-fired combined cycle generation by the end of 2032 to replace the existing coal-fired generation at the Sioux Energy Center. The Company will begin taking steps to implement this new dispatchable resource over the next few years. These include site selection, permitting, engineering, and procurement, as well as steps to secure interconnection within MISO.

Rush Island and Sioux

Ameren Missouri will be taking steps to retire the units at Rush Island Energy Center by the end of 2024, including construction of new transmission facilities to ensure grid reliability. Ameren Missouri continues to operate the units at Rush Island pursuant to an SSR agreement with MISO until the units are retired. While the retirement of Sioux Energy Center has been delayed to 2032, the Company will continue to prepare for its retirement and thereby maintain flexibility to further revised retirement plans in the event conditions warrant a review of the current plans and Ameren Missouri management decides it is appropriate to make a change.

Competitive Procurement Policies[24]

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.[25]

[24] 20 CSR 4240-22.070(6)(E)
[25] 20 CSR 4240-22.070(6)(G)

10.5.5 Monitoring Critical Uncertain Factors[26]

Ameren Missouri will be monitoring the critical uncertain factors that would help determine whether the Preferred Resource Plan is still appropriate 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 its Environmental Services organization will continue to monitor and evaluate developments on efforts to regulate greenhouse gas emissions, including EPA's current proposed rule, as well as state and industry efforts aimed at reducing greenhouse gas emissions. The Company reviews its assumptions for climate policy and CO_2 prices as part of its IRP annual update process.

Natural Gas Prices

Ameren Missouri evaluates natural gas prices at least annually, and a review of natural gas price assumptions is included as part of its IRP annual update process.

Generation Project Costs

Ameren Missouri will continue to monitor project pricing for various resources through industry sources and through its own resource acquisition activities, such as RFPs and competitive bidding. This includes wind, solar, storage, and natural gas-fired resources (both simple cycle and combined cycle) as well as environmental controls such as SCRs, and carbon capture and sequestration. Evaluation of project costs will continue to be included as part of the Company's IRP annual update process.

[26] 20 CSR 4240-22.070(6)(F)

10.6 Compliance References

Ameren Missouri's
Response to MPSC Data Request - MPSC
EO-2023-0136
Ameren Missouri's 3rd Filing to Implement Regulatory Changes in Energy Efficiency by MEEIA

No.: MPSC 0014

On pg. 53 of the confidential MEEIA 2024-26 report, in regards to retrospective EM&V, the Company states that “This method of evaluation can be viewed as being punitive to implementers, who relied on historical net to gross ratios and deemed values as required in the TRM to claim savings. As a result, implementers increase the administration costs to cover the amount they consider to be at risk from the evaluation.” Please provide a detailed explanation of: 1) how retrospective EM&V can be viewed as being punitive to implementers, 2) a detailed description of the correlation between increased administration costs and risk from evaluation, 3) the amount of administration cost increase that can be expected for each potential risk from evaluation, and 4) a detailed description of Ameren Missouri’s firsthand experience with this. Brad Fortson (brad.fortson@psc.mo.gov <mailto:brad.fortson@psc.mo.gov>)

RESPONSE

Prepared By: Laureen Welikson
Title: Senior Consultant Energy Efficiency & Demand Response
Date: April 11, 2023

Subject to the objection provided on April 20, 2023, Ameren Missouri states as follows:

1) Implementers develop program plans including targeting the number of measures or project completions using deemed savings values and historical net to gross ratios in order to meet energy and demand savings goals. When evaluations return realization rates or net to gross ratios that are lower than expected, implementers do not meet the energy and demand savings goals despite meeting the targeted number of measures or project completions. The evaluated realization rates and net to gross ratios are not available until after the program year is complete so implementers cannot make changes to program design to meet goals.
2) Implementers typically have a performance-based contract that provides at least part of their compensation based on evaluated results. When evaluated results come in different than what had been expected, their compensation can be lower than what had been anticipated even though they may have incentivized the targeted number of projects or measures. To avoid this scenario, implementers

may increase their performance-based pricing to reduce the risk from retrospective evaluation.

3) A response to this question calls for speculation and subject to the Company's objection, Ameren Missouri states as follows: Ameren Missouri cannot speculate on each potential risk from evaluation for the amount of administration cost increase. Such speculative risk might not arise or other risks might not be foreseen or quantified.
4) Program implementors have told Ameren Missouri anecdotally that evaluation risk is causing implementers to increase their pricing to cover the risk of retrospective evaluation. Program implementors have not provided any detailed impact data to support the observation.

Ameren Missouri's
Response to MPSC Data Request - MPSC
EO-2023-0136
Ameren Missouri's 3rd Filing to Implement Regulatory Changes in Energy Efficiency by MEEIA

No.: MPSC 0016

On pg. 54 of the confidential MEEIA 2024-26 report, the Company states, "Prospective evaluation allows implementers to reduce their costs due to lower risks from evaluation. It would allow the State Auditor to focus their efforts during the draft report review period and potentially reduce issues in finalizing evaluation reports. This would allow evaluation reports to be finalized faster and reduce the chances of Change Requests being filed, saving all Stakeholders both time and costs involved in the litigation of disputed evaluation results." Please provide a detailed explanation further substantiating each of the Company's statements. Brad Fortson (brad.fortson@psc.mo.gov <mailto:brad.fortson@psc.mo.gov>)

RESPONSE

Prepared By: Laureen Welikson
Title: Senior Consultant Energy Efficiency & Demand Response
Date: April 12, 2023

Implementers develop program plans including targeting the number of measures or project completions using deemed savings values and historical net to gross ratios to meet energy and demand savings goals. When evaluations return realization rates or net to gross ratios that are lower than expected, implementers do not meet the energy and demand savings goals despite meeting the targeted number of measures or project completions. The evaluated realization rates and net to gross ratios are not available until after the program year is complete so implementers cannot make changes to program design to meet goals. Implementers typically have a performance-based contract that provides at least part of their compensation based on evaluated results. When evaluated results come in different than what had been expected, their compensation can be lower than what had been anticipated even though they may have incentivized the targeted number of projects or measures. To avoid this scenario, implementers may increase their performance-based pricing to reduce the risk of retrospective evaluation.

The move to prospective evaluation would allow parties to agree upfront to deemed values including net to gross ratios. The review of free ridership and spillover calculations have historically been a focus of draft report review and Change Requests that have been filed. Because these values would be agreed to upfront, there would be no disagreements during the review of the draft evaluation reports on these values. This would allow the review process to be streamlined by focusing only on values that are not deemed. There would still be ample opportunity to review any values proposed to be deemed going forward that would be agreed to in a collaborative process, but this review and discussion would not need to occur during the specific draft evaluation report review period.