9. Integrated Resource Plan and Risk Analysis

Highlights

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

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

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

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

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

9.1 Alternative Resource Plan Attributes[1]

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

Figure 9.1 Attributes of Alternative Resource Plans[2]

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

* With and without carbon capture

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

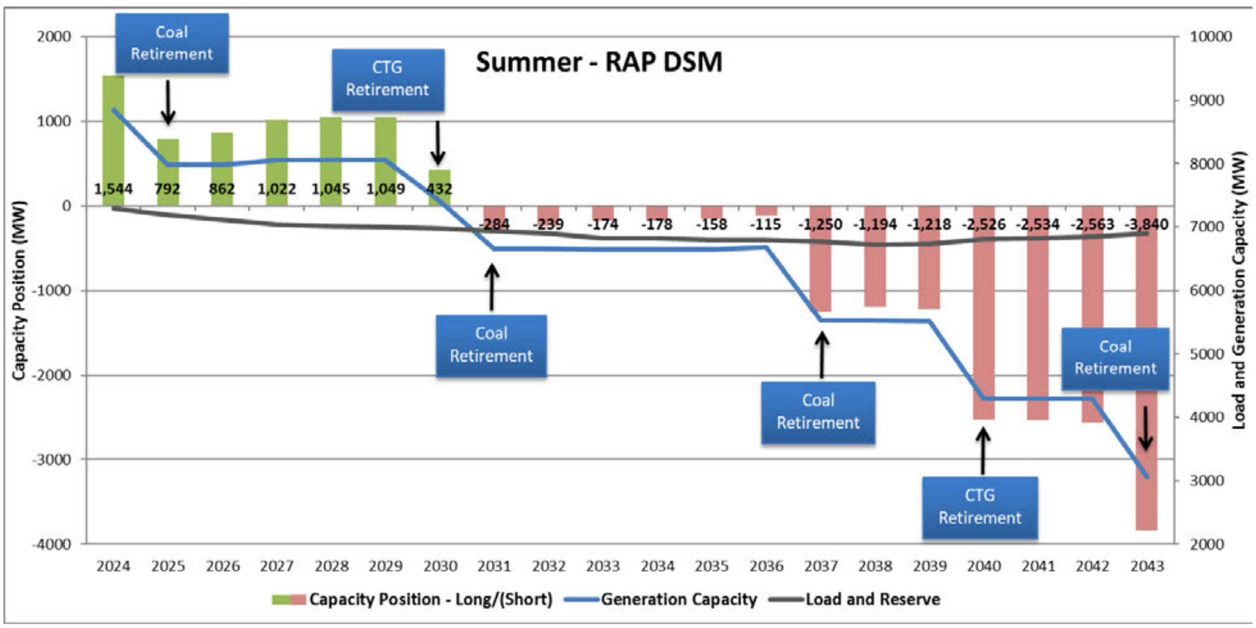
9.2 Capacity Position

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

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

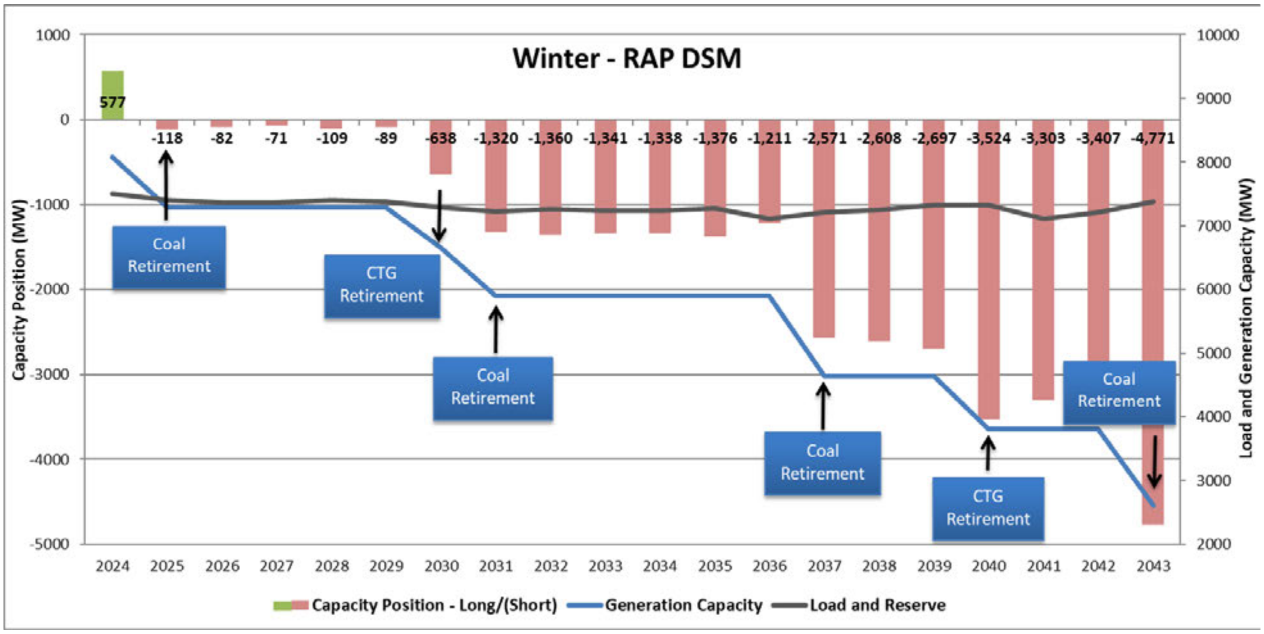
Figures 9.2 and 9.3 show Ameren Missouri's net capacity position with no new major generating resources for summer and winter.[3]

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



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

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



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

Retirements and Modifications

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

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

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

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

DSM Portfolios

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

Table 9.1 DSM Savings Summary

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

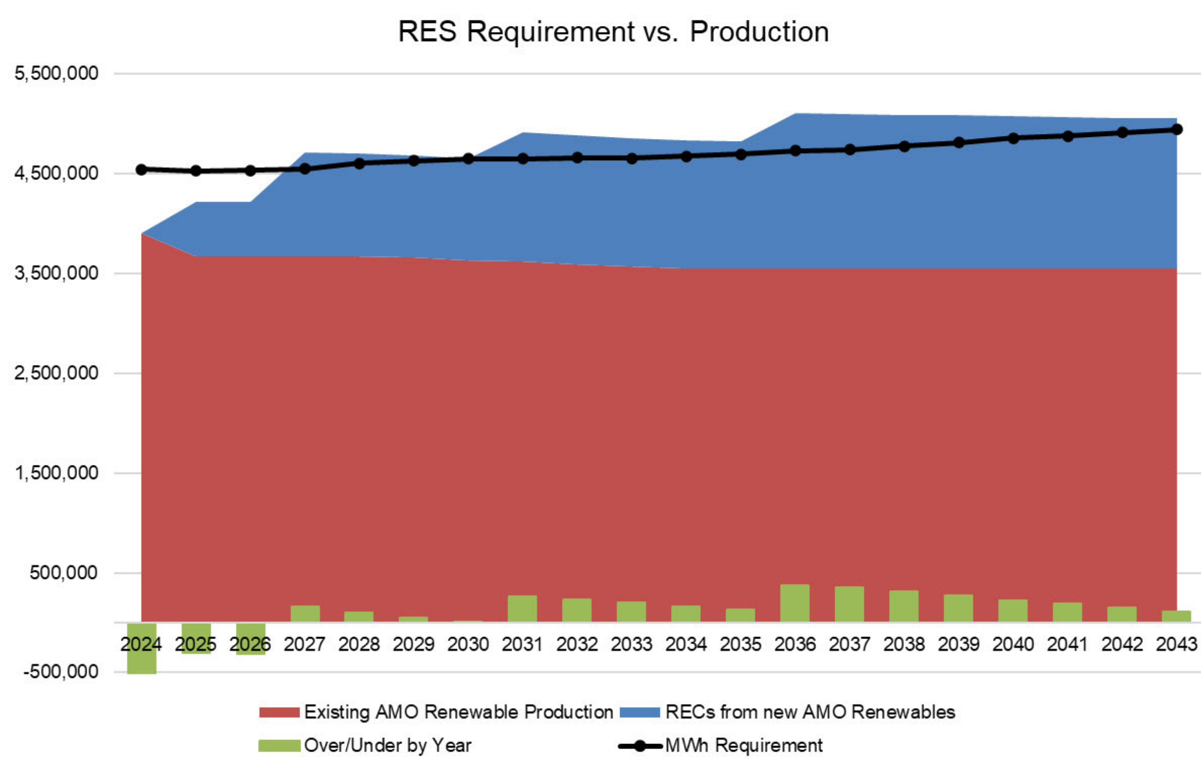
[5] An additional energy efficiency portfolio that achieves 80% of RAP level energy and demand savings.
[6] The extension of MEEIA Cycle 3 should not have a material impact on the analysis.

Renewable Portfolios[7]

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

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

Figure 9.4 Ameren Missouri's RES REC Positions



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

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

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

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

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

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

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

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

Table 9.2 Renewable Portfolios (Nameplate Capacity)

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

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

Table 9.3 Battery Additions (Nameplate Capacity)

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

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

Other Supply-side Resources

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

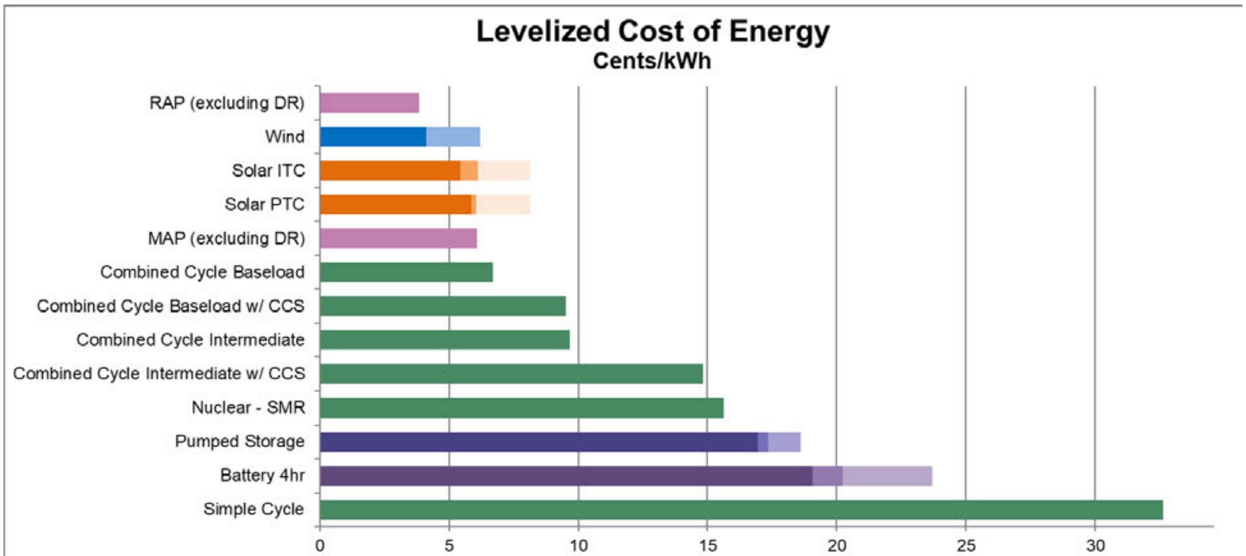
Table 9.4 Summer and Winter Capacity for Supply-Side Types[12]

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

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

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

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



Note: Wind costs are shown with and without PTC. Solar costs are shown with (including 10% adder) and without PTC, and 40%, 30%, with transfer and no ITC. Battery and pumped storage costs are shown with 40%, 30% and no ITC.

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

[13] 20 CSR 4240-22.010(2)(A)

9.3 Planning Objectives

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

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

Portfolio Transition

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

Financial/Regulatory

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

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

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

Customer Satisfaction

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

Economic Development

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

Cost

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

9.4 Pre-Analysis

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

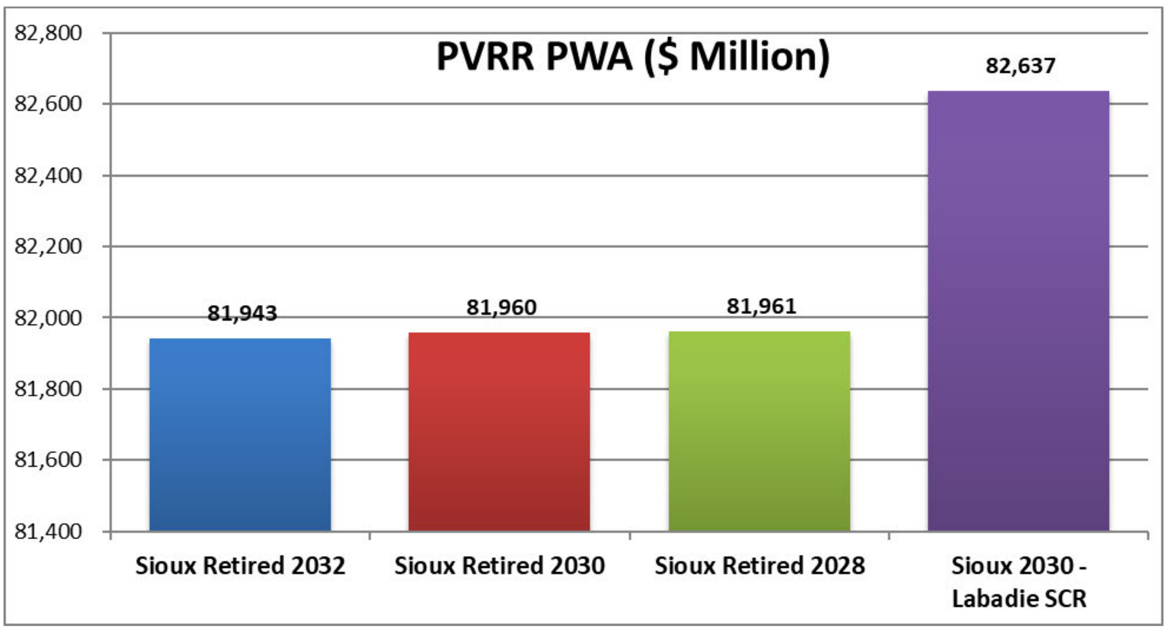
[16] 20 CSR 4240-22.060(2)(A)6
[17] 20 CSR 4240-22.060(2)(A)4
[18] 20 CSR 4240-22.060(2)(A)7
[19] 20 CSR 4240-22.060(2)(A)1; 20 CSR 4240-22.010(2)(B); 20 CSR 4240-22.060(2)(B)

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

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

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

Figure 9.6 Pre-Analysis PVRR Results



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

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

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

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

Table 9.5 Pre-Analysis – Difference in PVRR

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

9.5 Determination of Alternative Resource Plans[21]

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

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

[21] 20 CSR 4240-22.060(3)

- How do various supply-side resource options compare?

Table 9.6 provides a summary of the alternative resource plans.

Table 9.6 Alternative Resource Plans[22]

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

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

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

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

Does inclusion of DSM programs reduce overall customer costs?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

What is the impact of pursuing only new renewables?

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

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

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

How do various supply-side resource options compare?

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

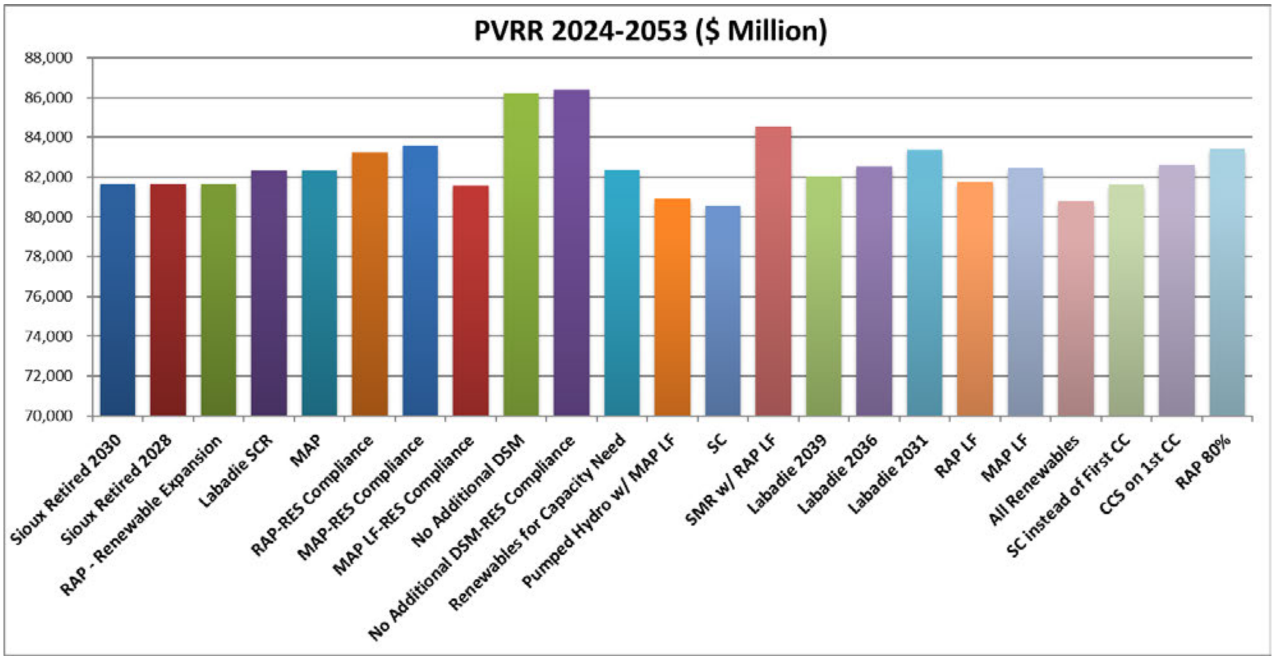
The type, size, and timing of resource additions/retirements for the alternative resource plans are provided in Appendix A and also in the electronic workpapers.[29]

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

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

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

Figure 9.7 Integration PVRR Results[31]



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

9.6 Sensitivity Analysis

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

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

9.6.1 Uncertain Factors[33]

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

Table 9.7 Uncertain Factor Screening

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

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

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

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

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

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

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

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

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

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

Uncertain Factor Ranges[34]

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

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

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

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

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

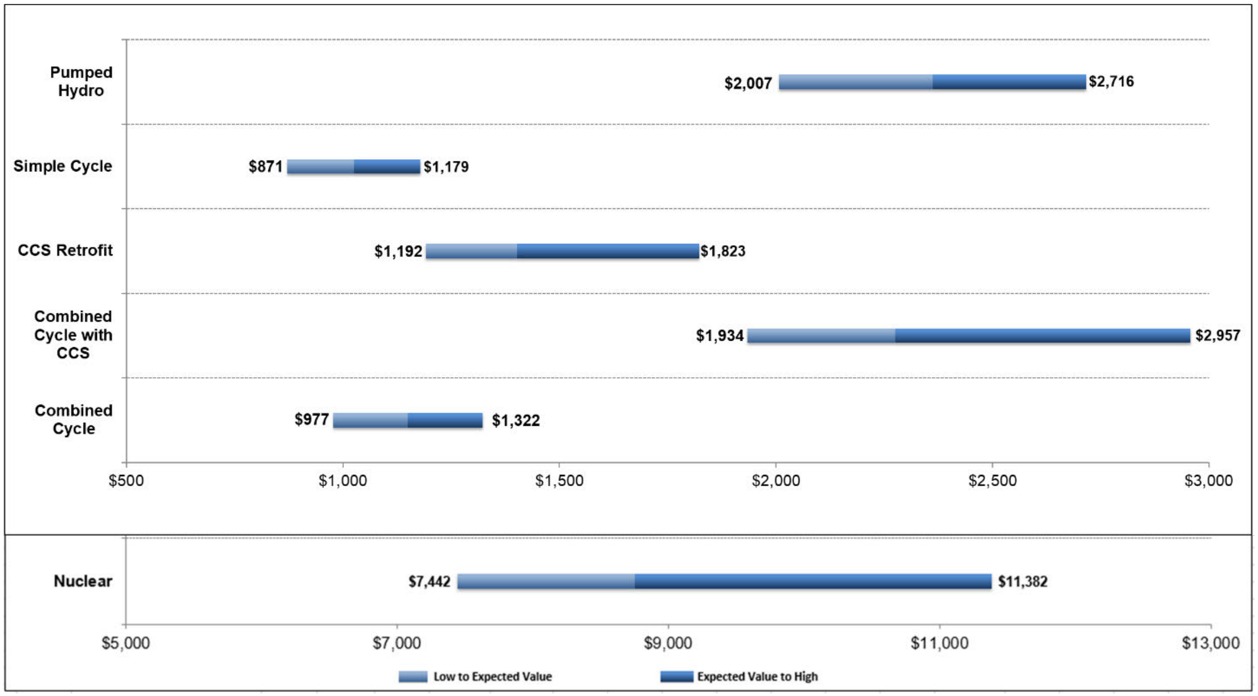


Figure 9.9 Solar, Wind and Battery Project Cost Ranges[35]

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

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

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Table 9.8 Resource-Specific Uncertain Factor Ranges

Uncertain Factor	Value	Probability	CC	CC with CCS	CCS Retrofit	SC	Pumped Hydro	SMR	Solar	Wind	Battery
Project Cost ($/kW) 2024 $	Low	10%	$977	$1,934	$1,192	$871	$2,007	$7,442	Cost curves change by year		
	Base	80%	$1,149	$2,275	$1,402	$1,025	$2,362	$8,756			
	High	10%	$1,322	$2,957	$1,823	$1,179	$2,716	$11,382			
Project Schedule (Months)	Low	10%	27	27	27	27	55	46	18	36	18
	Base	80%	36	36	36	36	73	61	24	48	24
	High	10%	48	48	48	48	95	79	32	63	32
Fixed O&M ($/kW-yr) 2024 $	Low	10%	$36.27	$74.23	$74.23	$7.14	$3.92	$107.02	$12.62	$31 93	$13.25
	Base	80%	$63.96	$109.85	$109.85	$8.39	$4.61	$125.91	$14.85	$37.56	$34.19
	High	10%	$108.60	$163.38	$163.38	$9.65	$5.30	$144.80	$17.07	$43 20	$61.43
Variable O&M ($/MWh) 2024 $	Low	10%	$2.34	$7.34	$7.34	$4.57	$3.18	$3.38	-	-	-
	Base	80%	$2.76	$8.64	$8.64	$5.38	$3.74	$3.98	-	-	-
	High	10%	$3.17	$9.93	$9.93	$6.19	$4.30	$4.57	-	-	-

Table 9.9 Project Cost Uncertainty Multipliers

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

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

Table 9.10 Non-Resource Specific Uncertain Factor Ranges

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

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

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

9.6.2 Sensitivity Analysis Results[36]

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

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

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

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

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

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

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

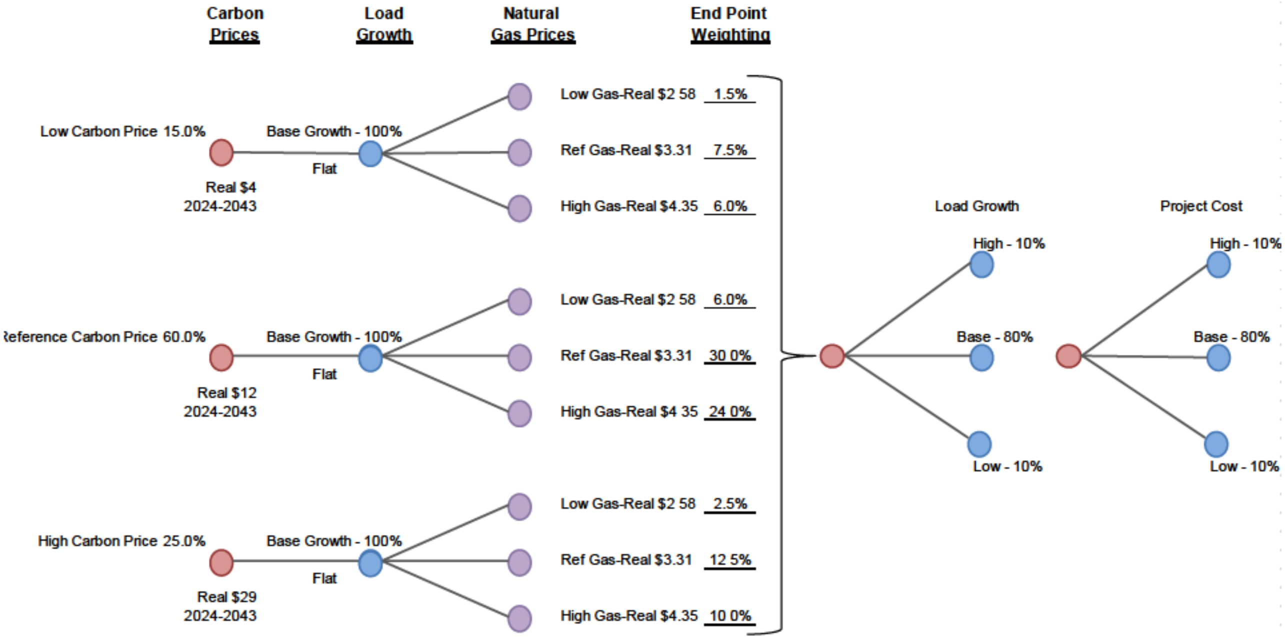
Table 9.12 Critical Independent Uncertain Factors – Change in PVRR (Million $)[38]

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

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

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

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



9.7 Risk Analysis[40]

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

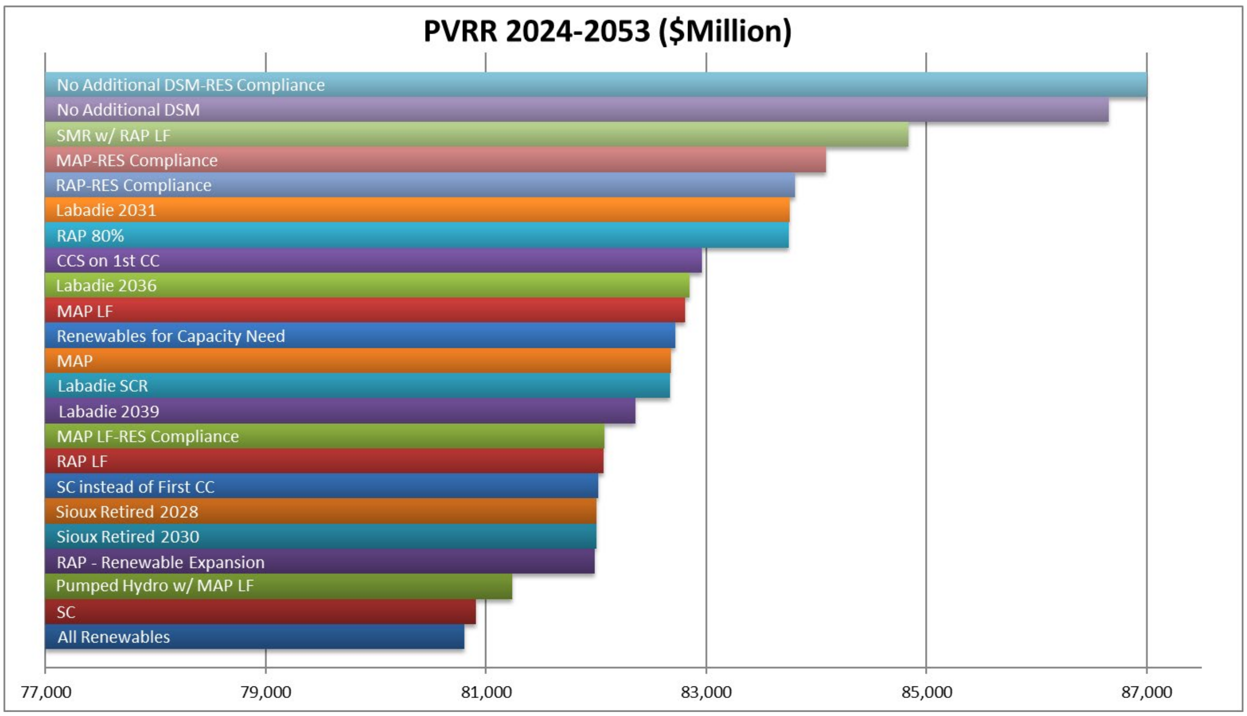
9.7.1 Risk Analysis Results

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

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

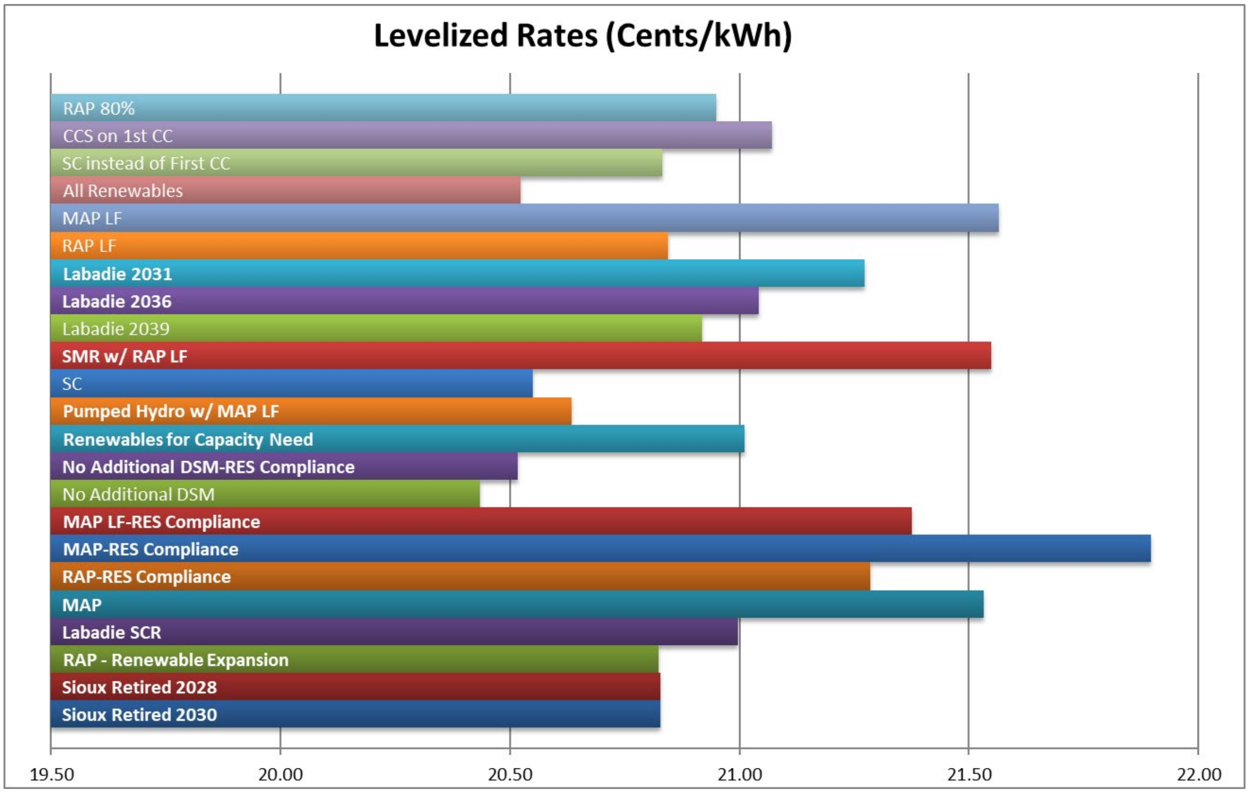
Plan T with Renewable Plus portfolio and RAP DSM has the lowest PVRR followed by Plan M, which includes Renewable Expansion portfolio, RAP DSM and an SC instead of a CC in 2040. Plan J with RES Compliance only renewable portfolio and no further DSM exhibits the highest PVRR and second to lowest levelized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

Figure 9.11 Probability-Weighted PVRR Results[41]



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

Figure 9.12 Probability-Weighted Levelized Rate Results



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

9.8 Conclusions from Integration and Risk Analysis

Below are several conclusions from the integration and risk analysis.

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

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

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

9.9 Resource Plan Model

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

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

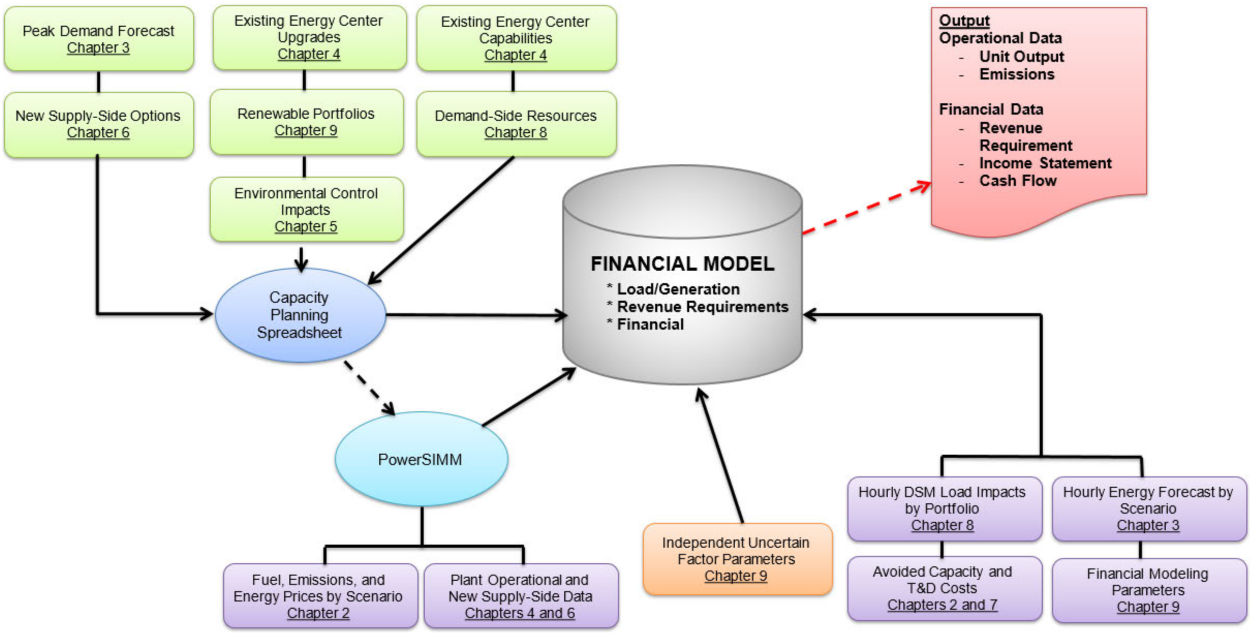
PowerSIMM simulates hourly dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The PowerSIMM model contains all unit operating variables required to simulate the units. These variables include,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

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

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

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

Figure 9.13 Resource Plan Model Framework[44]



Future Plans for Modeling Tools

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

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

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

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

9.10 Compliance References