9. Integrated Resource Plan and Risk Analysis

Highlights

- *Ameren Missouri has developed a robust range of alternative resource plans that reflect different combinations of energy efficiency, demand response, various types of new renewable and conventional generation, and conversion and/or retirement of each of its existing coal-fired generators.*
- *Ameren Missouri has evaluated several reasonable alternatives for its Meramec Energy Center, including conversion of units to natural gas-fired operation and retirement in either 2015 or 2022.*
- *In addition to the scenario variables and modeling discussed in Chapter 2, four critical independent uncertain factors have been included in the final probability tree for risk analysis: Financing Rates, Coal Prices, DSM Impacts and Costs, and Capital Project Costs.*

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

1. Identification of **alternative resource plan attributes**. These attributes represent the various resource options used to construct and define alternative resource plans – demand side resources, new renewable and non-renewable supply side resources, and existing supply side resource options such as retirement, conversion and environmental retrofits.
2. Development of the **baseline capacity position**, which reflects forecasted peak demand, reserve requirements and existing resources.
3. Pre-analysis was used to determine certain key base elements for alternative resource plans. This included analysis of various options for the Meramec Energy Center and expansion opportunities at our Keokuk hydroelectric facility.
4. Development of **planning objectives** to guide the development of alternative resource plans.
5. Development of the **alternative resource plans**. The alternative resource plans were developed using the plan attributes identified in step 1, the base capacity position developed in step 2, the results of the pre-analysis conducted in step 3, and the planning objectives identified in step 4.
6. Identification and screening of **candidate uncertain factors**, which are key variables that can influence the performance of alternative resource plans.

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

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

9.1 Alternative Resource Plan Attributes[1]

Development of alternative resource plans includes considering various combinations of demand-side and supply-side resources to meet future capacity needs. However, alternative resource plans may also include elements or attributes that serve the other planning objectives described in Section 9.4. Including these elements can significantly affect the capacity position that needs to be considered when developing alternative resource plans. Figure 9.1 includes the attributes considered during the development of resource plans. As has been mentioned, a pre-analysis was used to determine which Meramec and Keokuk options would be included in all alternative resource plans.

Figure 9.1 Attributes of Alternative Resource Plans

Meramec Retirement Options
- Retired 12/31/2015
- Retired 12/31/2022
- Convert Units 1&2 to Natural Gas 12/31/2015 and Units 3&4 Continue on coal; All Units Retired 12/31/2022

Retirements
- Labadie Retired 12/31/2023
- Rush Island Retired 12/31/2024
- Sioux Retired 12/31/2033

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

Keokuk Upgrade
- 50 MW Expansion
- None

Energy Efficiency
- Maximum Achievable Potential (MAP)
- Realistic Achievable Potential (RAP)
- Missouri Energy Efficiency Investment Act (MEEIA) Cycle 1 Only

Demand Response
- MAP
- RAP
- None

Renewable Portfolios
- Missouri Renewable Energy Standard (RES)
- Balanced

[1] 4 CSR 240-22.060(1); 4 CSR 240-22.060(3)

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9.2 Capacity Position

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

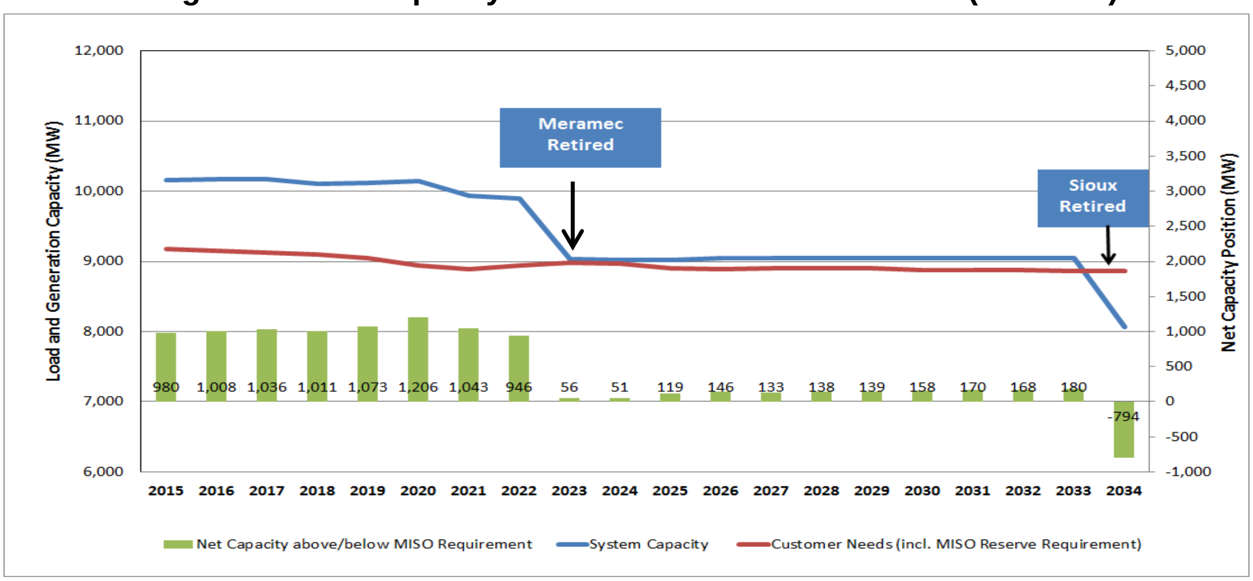
- Existing plant capabilities based on Ameren Missouri's annual generating unit rating update (i.e., July 2014 planned ratings)
- Existing obligations for capacity purchases and sales
- Peak demand forecast, as described in Chapter 3
- Planning reserve margin (PRM) requirement, based on MISO's Planning Year 2014 Loss of Load Expectation (LOLE) Study Report (November 2013). Table 9.1 shows the MISO System PRM from 2015 through 2023. The long-range PRM was assumed to continue at 17.3% through the remainder of the planning horizon.

Table 9.1 MISO System Planning Reserve Margins 2015 through 2023

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023
PRM Installed Capacity	14.9%	15.0%	15.1%	15.1%	15.6%	16.0%	16.4%	16.8%	17.3%

Figure 9.2 shows Ameren Missouri's net capacity position with no new major generating resources. The chart shows the system capacity, customer needs (including the MISO reserve requirement), and capacity above/below the MISO requirement (i.e., long/short position). The customer needs include peak load reductions due to RAP energy efficiency and demand response. The system capacity includes the capacity benefit of the RES Compliance portfolio.

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



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Existing Unit Upgrades

The capacity position reflects various upgrade projects for Ameren Missouri's existing generating units. Below is a list of the plant upgrade projects that were included in all resource plans.

- Keokuk Units 5 and 6 – 4 MW in 2016
- Keokuk Units 14 and 15 – 4 MW in 2018

The Keokuk unit upgrade projects listed above have been planned and budgeted based on Ameren Missouri's capital project justification process, which includes an evaluation of the costs and benefits of each project, including the value of energy and capacity provided or saved.

Retirements

Ameren Missouri is considering retirement of some or all of its eight older gas- and oil-fired CTG units – Kirksville, Howard Bend, Fairgrounds, Meramec CTG-1, Meramec CTG-2, Mexico, Moberly, and Moreau – with a total net capacity of 367 MW, over the next 20 years. Chapter 4 - Table 4.2 provides a summary of the planned CTG retirements. The CTG retirements were included in all resource plans.

Coal energy center retirements were also included in the capacity planning process. Sioux retirement by December 31, 2033, was common in all resource plans, based on prior analysis of Ameren Missouri's coal power plant life expectancy by Black and Veatch. Three different Meramec retirement options were considered: 1) retirement by December 31, 2015, 2) retirement by December 31, 2022, and 3) conversion of Units 1&2 to natural gas-fired operation by December 31, 2015, and Units 3&4 continuing to operate on coal with retirement of all four units by December 31, 2022. As discussed in Section 9.3, a pre-analysis was used to determine a single option for Meramec for inclusion in alternative resource plans. While the retirement dates for Labadie and Rush Island, as determined by the Black and Veatch life expectancy study, are beyond the 20-year planning horizon, we have evaluated potential early retirements for both energy centers. Retirement of Labadie by December 31, 2023 was evaluated as was retirement of Rush Island by December 31, 2024. The alternative retirement dates for Labadie and Rush Island were based on the ability to avoid significant costs associated with environmental compliance or environmental risk. In the case of Labadie, the expected need for a scrubber in the 2020-2025 timeframe was the primary driver for the alternative retirement date. In the case of Rush Island, the potential for an explicit price on carbon starting in 2025, included in the scenarios described in Chapter 2, was the primary driver for the alternate retirement date.

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Potential Keokuk Expansion

A potential Keokuk Energy Center expansion project was evaluated in the capacity planning process. As discussed in Chapter 4, Option 3 (3-5k)---the addition of five units to the spare bays---was the least cost option and was evaluated further in the integration analysis. The Keokuk expansion would provide 50 MW of additional capacity.

DSM Portfolios

DSM portfolios were included in capacity planning separately as energy efficiency and demand response. Energy efficiency (EE) and demand response (DR) programs not only reduce the peak demand but also reduce reserve requirements associated with those demand reductions. The following combinations of DSM portfolios were evaluated: 1) RAP EE and DR, 2) RAP EE Only, 3) MAP EE and DR, 4) MAP EE Only and 5) MEEIA Cycle 1 Only[2]. The MEEIA Cycle 1 Only DSM portfolio reflects completion of Ameren Missouri's current three-year program cycle with no further energy efficiency during the planning horizon and does not include DR.

Renewable Portfolios

Compliance with Missouri's renewable energy standard (RES) was updated to reflect current assumptions, including baseline revenue requirements, and an updated 10 year forward looking methodology which impacts the calculation of a 1% rate cap.

Ameren Missouri performed its RES compliance analysis with the *2014 IRP RES Compliance Filing Model* (model). The model is designed to calculate the retail rate impact, as required by the Commission's RES rules[3]. This model determines the quantity of renewable energy needed to meet both the overall RES portfolio standard and the solar portfolio standard "carve-out" absent any rate impact constraints. The model then determines the amount of renewable energy, both solar and non-solar that can be built without exceeding an average 1% revenue requirement increase over a ten-year period. Ameren Missouri's expected renewable energy credit (REC) position is presented in Figure 9.3.

[2] EO-2012-0142 12
[3] 4 CSR 240-20.100(5)

Figure 9.3 Ameren Missouri's RES REC Positions

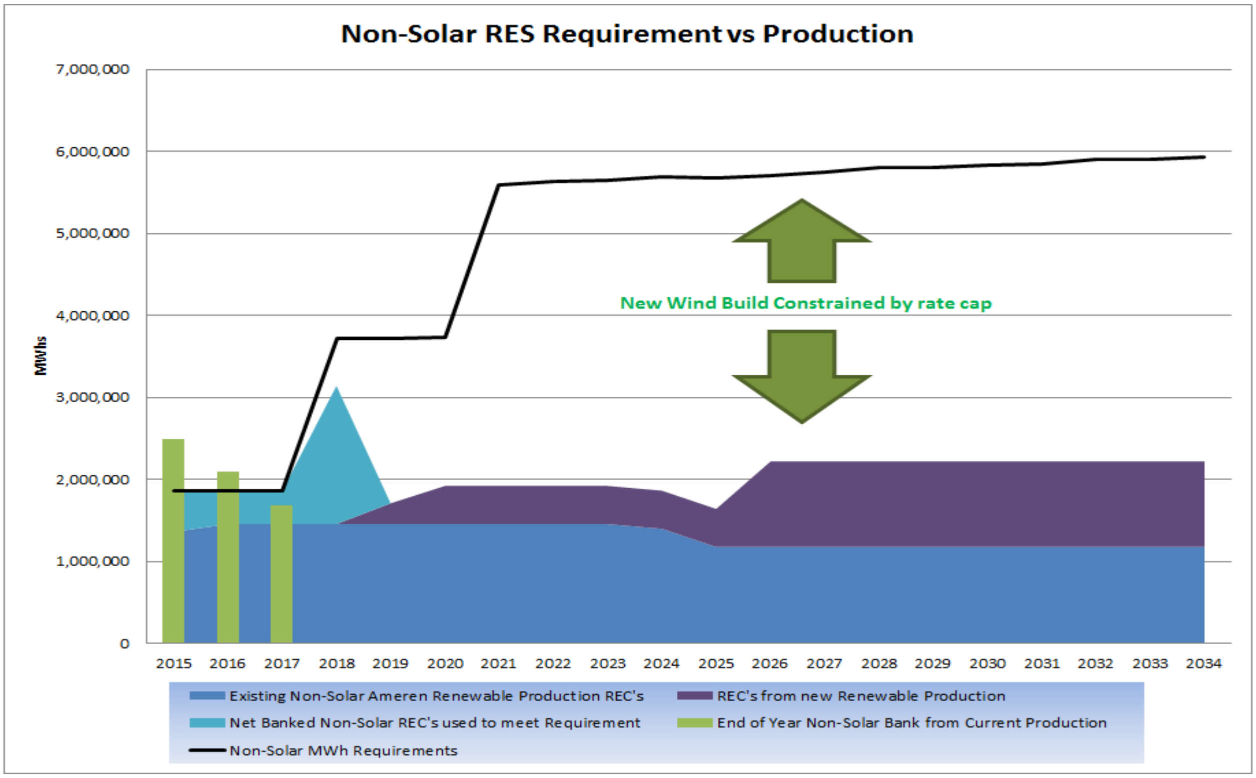

Figure 9.3 shows that Ameren Missouri expects to meet the overall REC requirement until 2018, without being constrained by the 1% rate impact limitation. Ameren Missouri is able to meet the overall standard until 2018 using RECs generated by its existing qualifying resources, including hydro, wind, and landfill gas, and banked RECs from prior years.

Once the standard increases to 10% in 2018, Ameren Missouri exhausts its remaining REC bank then places new wind generation into service starting in 2019. The model shows the amounts of planned new wind and solar resources needed to meet the standard subject to the 1% rate cap. In addition, the model is used to provide a view on RES compliance for both an unconstrained and constrained (i.e., 1% rate impact cap) view of compliance. Table 9.2 shows the unconstrained and constrained amounts of wind, landfill gas (LFG), and solar resources needed. This model was used to develop the RES compliance portfolios for the alternative resource plans. Appendix A shows the unconstrained and constrained amounts of wind, LFG, and solar resources needed in Term 1 (2014-2023) and Term 2 (2025-2034) by year.

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Table 9.2 2014 IRP Compliance Filing Model

Description	10 Year Sum TERM 1 (2015-2024)	10 Year Sum TERM 2 (2025-2034)	20 Year Sum (2015-2034)
Unconstrained Full RES REC Requirement met with new builds			
MW's Installed New Solar	5	54	59
MW's Installed New LFG	5	0	5
MW's Installed New Wind	1,003	110	1,114
RES Requirement within 1% Rate Cap Limit			
MW's Installed New Solar	16	10	26
MW's Installed New LFG	5	0	5
MW's Installed New Wind	100	142	242

Several renewable portfolios were evaluated in the capacity planning process using *2014 IRP RES Compliance Filing Model*: 1) RES compliance with RAP or MAP, 2) RES Compliance with MEEIA Cycle 1 Only, and 3) Balanced (i.e., 400 MW Wind, 45 MW Solar, and 20 MW Small Hydroelectric). The RES portfolios were developed using the described in Section 9.2.

When developing the RES compliance investment needs, consideration was given to the potential difference between RAP DSM investment vs a MAP DSM investment due to their differing impacts on customer sales, which is used as the basis for determining the amount of renewable energy needed to comply with the RES portfolio requirements. After modeling both, the difference in the level of renewable generation added was determined to be insignificant, primarily because of the effect of the 1% rate impact limitation on investment levels. Specifically, the difference was less than 1 MW of investment in solar for Term 1 and less than 4 MW's of wind investment for Term 2. Therefore MAP and RAP portfolios are accompanied by the same level of renewable investment when included in alternative resource plans.

Table 9.3 shows the timing of resources for renewable portfolios included in the alternative resource plans.

Table 9.3 Alternative Resource Plans - Renewable Portfolios

Renewable Portfolios		Nameplate Capacity (MW)																				
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	TOTAL
RES with RAP or MAP	Wind	0	0	0	0	50	50	0	0	0	0	0	142	0	0	0	0	0	0	0	0	242
	Solar	5	10	0	0	0	0	2	0	0	0	10	0	0	0	0	0	0	0	0	0	26
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RES with MEEIA Cycle 1	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	5	10	0	0	0	0	2	0	0	0	10	0	0	0	0	0	0	0	0	0	26
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Balanced	Wind	0	0	0	0	50	50	0	100	0	100	0	100	0	0	0	0	0	0	0	0	400
	Solar	5	10	0	0	0	0	10	0	0	0	10	0	10	0	0	0	0	0	0	0	45
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	10	0	0	0	20

Non-renewable Supply-side Resources

Non-renewable supply-side resource types were added last in the capacity planning process. If the capacity shortfall in a given year met or exceeded the build threshold, then supply side resources would be added to eliminate the shortfall. The build threshold was determined to be 300 MW (based on half the size of a combined cycle) regardless of the type of supply side resource under consideration. The full rated capacity and the build thresholds for each supply side type are shown in Table 9.4. Ameren Missouri has assumed reliance on short-term capacity purchases to cover shortfalls that are less than the build threshold and has assumed that any long capacity position would be sold into the market. The earliest in-service for each supply-side resource is also shown in Table 9.4. The in-service date constraints represent the expectations for construction lead time as well as the commercial availability of each technology.

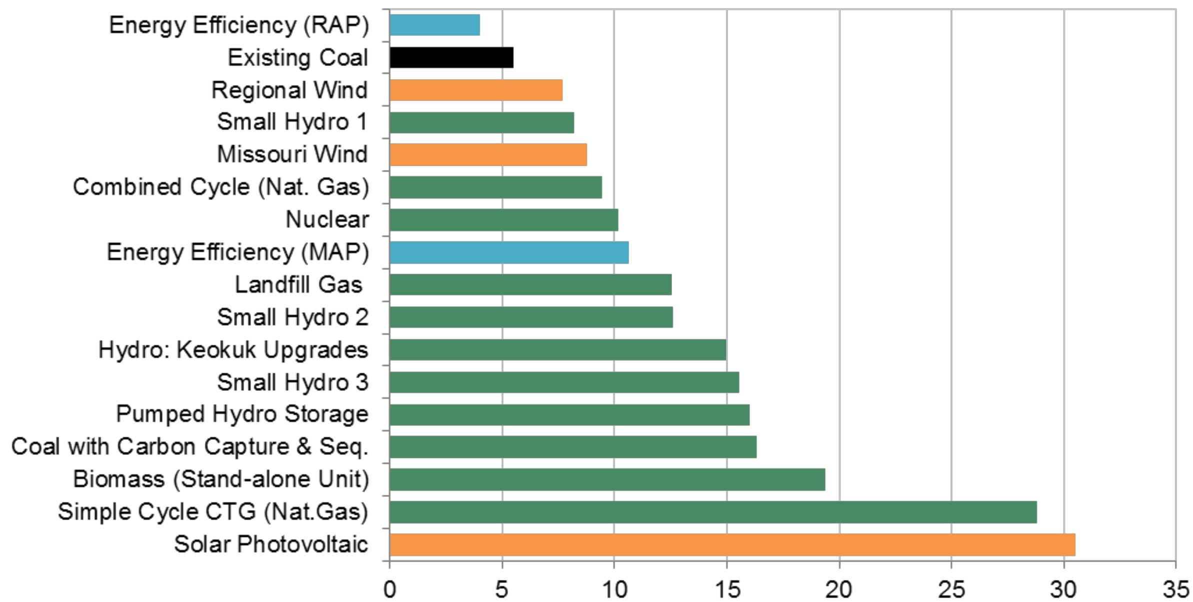
Table 9.4 Build Threshold for Supply Side Types

Supply Side Type	Capacity, MWs	Build Threshold, MWs	Earliest Year In-Service
CC-Natural Gas	600	300	2019
SC-Natural Gas	704	300	2019
Nuclear (100%)	225	300	2025
Nuclear (75%)	169	300	2025
Pumped Hydro	600	300	2020
Wind	465	300	2018
Wind and Simple Cycle	465	300	2020

The remaining net capacity position was modeled in the financial model as capacity purchases and sales priced at the avoided capacity costs as discussed in Chapter 2 and Chapter 8. The capacity purchases and sales were also adjusted for the various peak demand forecasts associated with each of the 15 scenarios and DSM impacts.

Figure 9.4 below summarizes the LCOE for all resources evaluated in the alternative resource plans.

Figure 9.4 Levelized Cost of Energy – All Resources[4]



Note: Does not reflect inclusion of tax incentives. Orange denotes intermittent resources. MAP energy efficiency reflects costs and energy savings incremental to RAP

9.3 Pre-Analysis

A pre-analysis consisting of two phases was conducted prior to development of the alternative resource plans to determine two key elements for inclusion in alternative resource plans. This included analysis of various options for the Meramec Energy Center and expansion opportunities at our Keokuk hydroelectric facility. Figure 9.5 provides a high-level overview of the alternative resource plan development process.

Figure 9.5 Alternative Resource Plan High-Level Overview

[4] 4 CSR 240-22.010(2)(A)

Meramec Energy Center Solution

The first phase was to determine a preferred retirement path for the Meramec Energy Center, our oldest coal-fired facility. Three different Meramec retirement options were considered: 1) retirement by December 31, 2015, 2) retirement by December 31, 2022, and 3) conversion of Units 1&2 to natural gas-fired operation by December 31, 2015, and continued operation of Units 3&4 on coal, with retirement of all four units by December 31, 2022. These plans were run against the scenario tree only (no independent uncertain factors) to determine the Meramec solution to be included in all other alternative resource plans.

In 2014, Burns & McDonnell completed a Condition Assessment for the Meramec Energy Center to determine ongoing costs to keep the plant operating safely and reliably through the planning horizon. The Condition Assessment was used to inform the development of the Meramec retirement options. The retirement dates for Meramec were also informed by the expectation for additional costs that would be incurred due to future environmental regulations and GHG regulations. In particular, and as discussed in Chapter 5, we would expect the need for a scrubber and other environmental mitigation investments at Meramec in the 2020-2025 timeframe.

Ameren Missouri conducted an internal preliminary evaluation for the potential conversion of the Meramec Energy Center Units 1-4 from coal to natural gas-fired operations. Units 1&2 were designed with the capability to operate on natural gas; however, these units have not operated at full load on natural gas since 1993. Therefore, restoration of devices and equipment is needed for Units 1&2 to operate fully on natural gas. The expected cost to restore Units 1&2 to natural-gas operations is estimated to be less than $2 million. Units 3&4 are currently capable of coal-fired operations only. The expected cost to convert Units 3&4 to natural-gas operations is expected to be over $40 million.

The PVRR results of the pre-analysis of the three Meramec options are shown in Figure 9.6. Conversion of Units 1&2 to natural gas-fired operation by December 31, 2015, and continued operation of Units 3&4 on coal, with retirement of all four units by December 31, 2022 result in the lowest PVRR and is the preferred solution.

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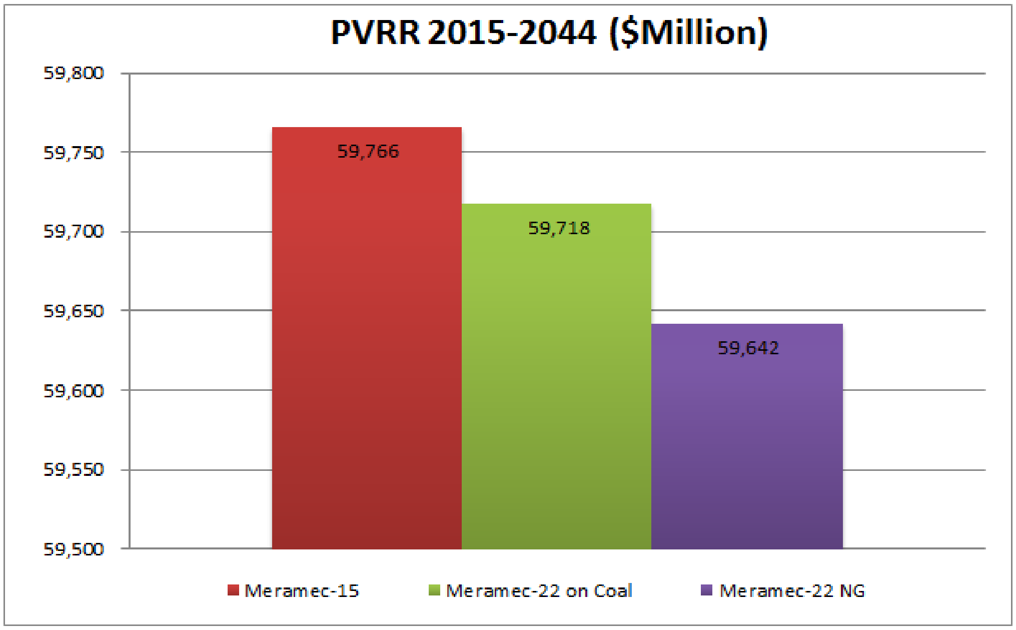
Figure 9.6 Integration PVRR Results: Meramec Pre-Analysis



Keokuk Energy Center Solution

The second phase of the pre-analysis was to determine whether or not the potential Keokuk expansion project would be included in all other alternative resource plans. As discussed in Section 4.3, seven of the 14 potential expansion options from the *Keokuk Hydroelectric Project Expansion Study Concept Report*[5] were evaluated further with approximate additional generating capacity ranging from 4.5 to 162 MW. Option 3 (3-5K) was determined to be the least cost option and was selected for further evaluation in the pre-analysis. Table 9.5 provides a summary of the operating and cost characteristics for Option 3 (3-5K).

Table 9.5 Keokuk Expansion Option: Operating and Cost Characteristics

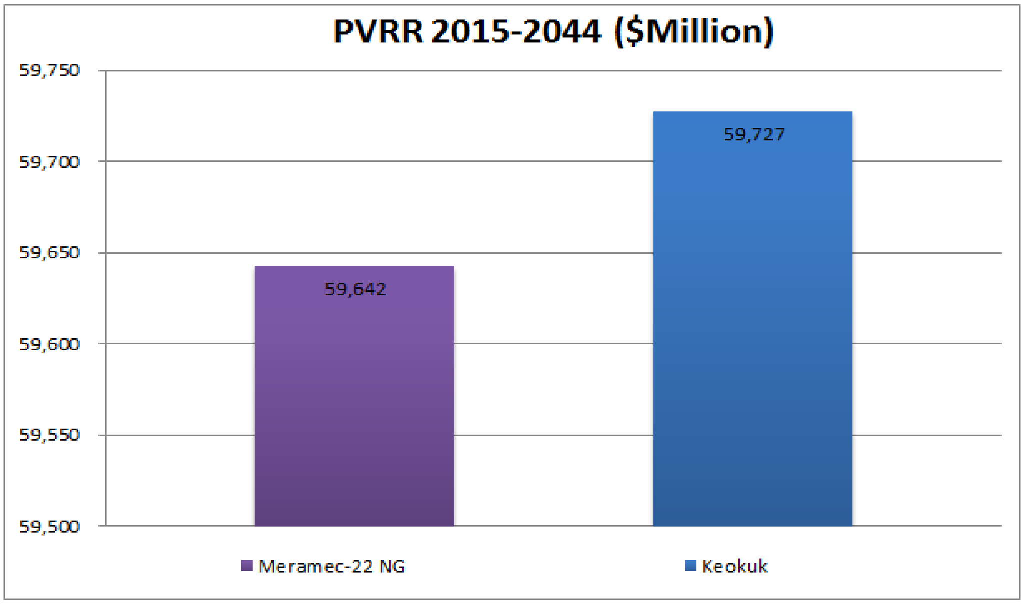
Option	Additional Capacity (MW)	Additional Average Annual Energy (MWh)	Project Cost ($1,000)	Annual Fixed O&M ($/yr), ($1,000)	Annual Variable O&M ($/yr), ($1,000)
3-5K New Units to Spare Bays (Add 5 Kaplan Units)	50	170,408	255,884	255	74

The Keokuk expansion was added to the preferred Meramec solution in the second phase. Figure 9.7 shows the PVRR results from the pre-analysis; adding Keokuk Expansion (50 MW) results in a higher PVRR than that resulting from the preferred Meramec solution without the Keokuk expansion.

[5] HDR Engineering, Inc. (HDR|DTA). *Keokuk Hydroelectric Project Expansion Study Concept Report.* April 20, 2011.

As discussed in Section 9.8, the results of the pre-analysis were validated by evaluating the same options under the full range of scenarios and critical uncertain factors used in risk analysis.

Figure 9.7 Integration PVRR Results: Keokuk Pre-Analysis



9.4 Planning Objectives

The fundamental objective of Missouri's electric resource planning process is to provide energy to its customers in a safe, reliable and efficient way, at just and reasonable rates while being in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.[6] Ameren Missouri considers several factors, or planning objectives, that must be considered in meeting the fundamental objective. Planning objectives provide a guide to decision making process while ensuring the resource planning process is consistent with business planning and strategic initiatives.

Five planning objectives were used in the development of alternative resource plans: Environmental/Renewable/Resource Diversity, Financial/Regulatory, Customer Satisfaction, Economic Development, and Cost. These planning objectives, which are the same as those discussed in Ameren Missouri's 2011 IRP, were selected by Ameren Missouri decision makers and are discussed below[7]:

[6] 4 CSR 240-22.010(2)
[7] 4 CSR 240-22.010(2)(C)

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Environmental/Renewable/Resource Diversity

Ameren Missouri has relied for many years on a portfolio that consists, in large part, of large, efficient coal-fired generators. Current and potential future environmental regulations may have significant impact on Ameren Missouri's coal-fired fleet and its selection of future generation resources. Ameren Missouri seeks to transition its generation portfolio to one that is cleaner and more diverse in a responsible fashion. To test various options for advancing this transition, alternative resource plans were developed to include MAP or RAP energy efficiency, renewables in addition to those required for RES compliance, new gas-fired generation, new nuclear generation, storage resources, and additional coal retirements.

Financial/Regulatory

The continued financial health of Ameren Missouri is crucial as it will need access to large amounts of capital for complying with renewable energy standards and environmental regulations, investing in new supply side resources, and funding continued energy efficiency programs while maintaining or improving safety and reliability. While making its investment decisions, it is important for Ameren Missouri to consider factors that may influence its access to capital markets. This includes measures of cash flow, profitability, and creditworthiness as well as assessment of risks associated with investment management and recovery.[8]

Customer Satisfaction

While there are many factors that can influence customer satisfaction, there are several that can be significantly affected by resource decisions. Ameren Missouri has focused on levelized annual rates, inclusion of energy efficiency and demand response programs, and inclusion of renewables to assess relative customer satisfaction expectations.[9]

Economic Development

Ameren Missouri assesses the relative economic development potential of alternative resource plans in terms of job growth opportunities associated with its resource investment decisions. Plans were rated on a relative scale based on direct jobs (FTE-years) including both construction and operation.[10] We have assumed that second and third level economic impacts would not significantly affect the relative economic development potential of alternative resource plans.

[8] 4 CSR 240-22.060(2)(A)6
[9] 4 CSR 240-22.060(2)(A)4
[10] 4 CSR 240-22.060(2)(A)7

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Cost

Ameren Missouri is mindful of the impact that its future resource choices will have on its customers' rate and bills. Maintaining reasonable costs while meeting its other planning objectives is of utmost importance to Ameren Missouri. Cost alone does not and should not dictate resource choices, but it is a very important factor in making resource decisions. Therefore, minimization of present value of revenue requirements was used as the primary selection criterion.[11]

9.5 Determination of Alternative Resource Plans[12]

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

- Does inclusion of Demand Response reduce overall customer costs?
- What level of DSM, RAP or MAP, results in lower costs?
- Is early retirement of Labadie Energy Center and replacement with MAP cost effective?
- Is early retirement of Rush Island Energy Center and replacement with MAP cost effective?
- What are the benefits of including renewables beyond those needed for RES compliance?
- What is the impact of pursuing only new renewables?
- How do various supply side resource options compare?
- How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?

Table 9.6 provides a summary of the alternative resource plans, including the results of the pre-analysis for Meramec and Keokuk.

[11] 4 CSR 240-22.060(2)(A)1; 4 CSR 240-22.010(2)(B)
[12] 4 CSR 240-22.060(3)

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Table 9.6 Alternative Resource Plans[13]

Pre-Analysis

	Plan Name	Meramec Option	Keokuk Expansion	Retirements	DSM	Renewables	Other New Supply
1	*Meramec Option 1*	Retired 12/31/22	None	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles
2	*Meramec Option 2*	U1-2 NG 12/31/15 Retired 12/31/22	None	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles
3	*Meramec Option 3*	Retired 12/31/15	None	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles
4	*Keokuk Expansion*	U1-2 NG 12/31/15 Retired 12/31/22	50 MW Expansion	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles

Alternative Resource Plans

	Plan Name	Meramec Option	Retirements	DSM	Renewables	Other New Supply
A	*Combined Cycle*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycle
B	*Nuclear*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	CC & Nuclear (450 MW)
C	*Simple Cycle CTGs*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	CTGs
D	*Pumped Hydro*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	Pumped Hydro
E	*Wind Plus CTGs*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	CC & Wind+CTGs
F	*No Demand Response - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE Only	RES Compliance	Combined Cycles
G	*Maximum DSM*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE&DR	RES Compliance	Combined Cycle
H	*Balanced Portfolio - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear (169 MW), Combined Cycle
I	*Balanced Portfolio - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Combined Cycle
J	*Balanced w/ No Further DSM After 2015 - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	MEEIA Cycle 1 only	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW), Combined Cycles
K	*Balanced w/ No Further DSM After 2015 - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	MEEIA Cycle 1 only	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Combined Cycles
L	*All Renewables*	U1-2 NG, Retired'22	Sioux 12/31/33	MEEIA Cycle 1 only	RES Compliance	Wind Only

[13] 4 CSR 240-22.010(2)(A); 4 CSR 240-22.060(3); 4 CSR 240-22.060(3)(A)1 through 8; 4 CSR 240-22.060(3)(B); 4 CSR 240-22.060(3)(C)1; 4 CSR 240-22.060(3)(C)2; 4 CSR 240-22.060(3)(C)3

Alternative Resource Plans

	Plan Name	Meramec Option	Retirements	DSM	Renewables	Other New Supply
M	*Add'l Coal Retirement - 1a*	U1-2 NG, Retired'22	Sioux 12/31/33 Labadie 12/31/23	MAP EE&DR	RES Compliance	Combined Cycles
N	*Add'l Coal Retirement - 2a*	U1-2 NG, Retired'22	Sioux 12/31/33 Rush Island 12/31/24	MAP EE&DR	RES Compliance	Combined Cycles
O	*Add'l Coal Retirement - 1b*	U1-2 NG, Retired'22	Sioux 12/31/33 Labadie 12/31/23	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW), Combined Cycles
P	*Add'l Coal Retirement - 2b*	U1-2 NG, Retired'22	Sioux 12/31/33 Rush Island 12/31/24	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW), Combined Cycles
Q	*Balanced Portfolio w/ Maximum DSM - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW)
R	*Balanced Portfolio w/ Maximum DSM - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Combined Cycle
S	*No Demand Response - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE Only	RES Compliance	Combined Cycle

Does inclusion of Demand Response reduce overall customer costs?

Plans F and S differ from plans A and G, respectively, only in that they do not include DR. Therefore, these plans can be compared to assess the impact on cost and other performance measures due to inclusion of DR.

What level of DSM, RAP or MAP, results in lower costs?[14]

Two alternative resource plans provide a comparison to evaluate the cost-effectiveness of RAP vs MAP energy efficiency. Plan F includes RAP EE only and Plan S includes MAP EE only. Additionally, plans with the same attributes except for the level of energy efficiency and demand response resources have been evaluated and provide a comparison for the DSM portfolios: Plans A and G, Plans H and Q, and Plans I and R.

Is early retirement of Labadie Energy Center and replacement with MAP cost effective?

Two alternative resource plans include the early retirement of Labadie Energy Center (i.e., Plans M and O). Plan M evaluates the cost effectiveness of early retirement of Labadie Energy Center and replacement with MAP.[15]

[14] Ameren Missouri added demand response programs to the alternative resource plans starting in 2019 and not only in years where there was a need to reduce peak demand due to shortfalls in Ameren Missouri's planning capacity reserve margins; EO-2012-0142 12; 4 CSR 240-22.060(3)(A)7

[15] EO-2011-0271 Order; 4 CSR 240-22.060(3)(A)7

Is early retirement of Rush Island Energy Center and replacement with MAP cost effective?

Two alternative resource plans include the early retirement of Rush Island Energy Center (i.e., Plans N and P). Plan N evaluates the cost effectiveness of early retirement of Rush Island Energy Center and replacement with MAP.[16]

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

Each alternative resource plan evaluated at least meets the minimum requirements of the RES. To assess the relative benefits of including additional renewable resources, several alternative resource plans were developed that exceed the level of renewable investment indicated by the RES compliance model. All alternative resource plans that are identified as "Balanced" (i.e., Plans H, I, J, K, O, P, Q, and R) include investment in renewable resources that are above and beyond needed for RES compliance. Also included are resource plans that feature wind as a major supply side resource (Plans E and L).

What is the impact of pursuing only new renewables?

Plan L is the all renewables alternative resource plan without DSM beyond MEEIA Cycle 1.[17]

How do various supply-side resource options compare?

The relative performance of the new supply-side resources can be determined by comparing Plans A through E.

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

Plans J, K, and L evaluate the impact if DSM cost recovery and incentive requirements are not met.

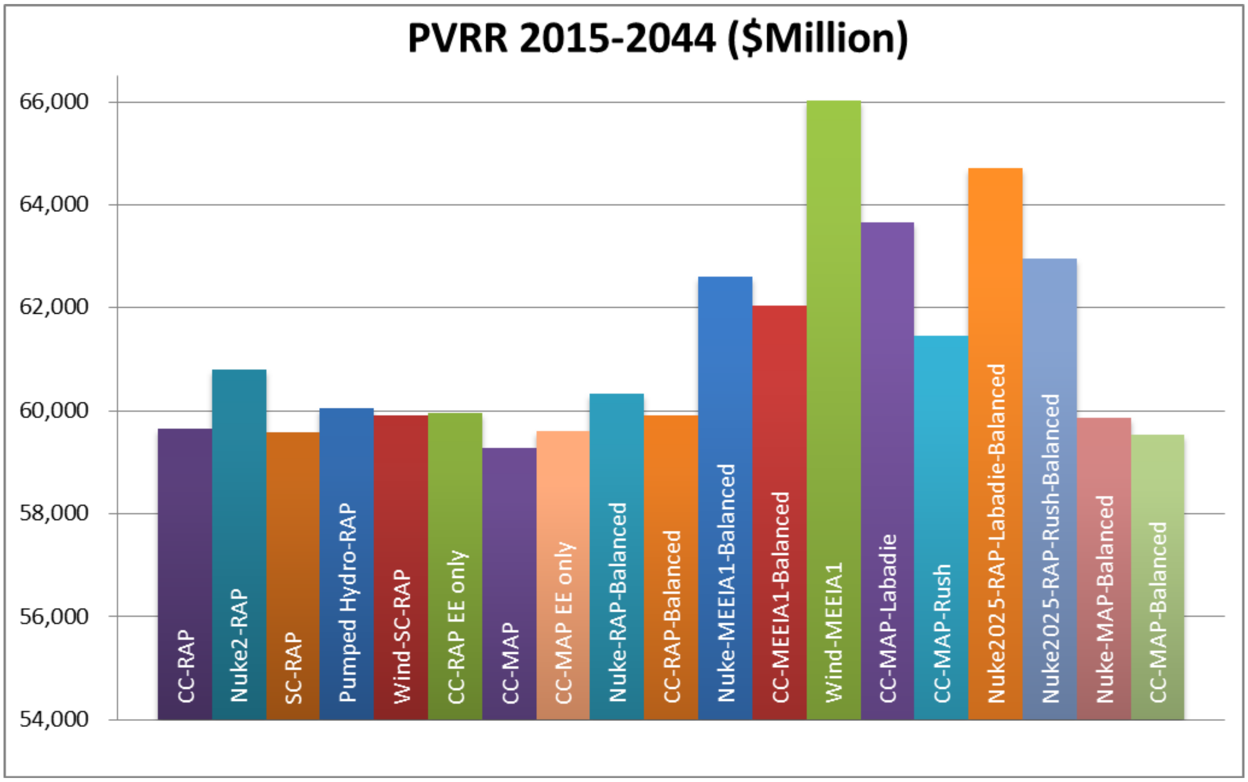
The type, size, and timing of resource additions/retirements for the alternative resource plans (i.e., Plans A-S) are provided in Appendix A and also in the electronic workpapers.[18]

Integration, sensitivity and risk analyses for the evaluation of alternative resource plans were done assuming that rates would be adjusted annually for the 20-year planning horizon and 10 additional years for end effects, and by treating both supply-side and

[16] EO-2011-0271 Order; 4 CSR 240-22.060(3)(A)7
[17] 4 CSR 240-22.060(3)(A)2
[18] None of the alternative resource plans analyzed include any load-building programs
4 CSR 240-22.060(3)(B); 4 CSR 240-22.080(2)(D); 4 CSR 240-22.060(3)(D)

demand-side resources on an equivalent basis. Integration analysis was performed on the most likely scenario of the probability tree (Scenario 8) as explained in Chapter 2. Integration analysis PVRR results are shown below in Figure 9.8 Results for the remaining performance measures for integration analysis are provided in the workpapers.[19]

Figure 9.8 Integration PVRR Results



It should be noted that all costs and benefits in all analyses were expressed in nominal dollars, and Ameren Missouri's current discount rate 6.46% was used for present worth and levelization calculations. Also, in all integration, sensitivity, and risk analyses, it was assumed that rates are adjusted annually (no regulatory lag).[20]

9.6 Sensitivity Analysis

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

[19] 4 CSR 240-22.060(4)
[20] 4 CSR 240-22.060(2)(B); EO-2011-0271 Order

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9.6.1 Uncertain Factors[21]

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

Table 9.7 Uncertain Factor Screening

Uncertain Factor	Candidates?	Critical?	Included in Final Probability Tree?
Load Growth	✓ **	--	✓
Interest Rates	✓	✗	✓ ‡
Carbon Policy	✓ **	--	✓
Fuel Prices Coal	✓	✓	✓
Natural Gas	✓ **	--	✓
Nuclear	✓	✗	✗
Project Cost (includes transmission interconnection costs)	✓	✓	✓
Project Schedule	✓	✗	✗
Purchased Power	✗	✗	✗
Emissions Prices SO_2	✗	✗	✗
NOx	✗	✗	✗
CO_2	✓ **	--	✓
Forced Outage Rate	✓	✗	✗
DSM Load Impacts	✓	✓ †	✓ †
DSM Cost	✓	✓ †	✓ †
Fixed and Variable O&M	✓	✗	✗
Return on Equity	✓	✗	✓ ‡
Nuclear Incentives	✓	✗	✗
Wind Capacity Factor	✓	✗	✗

** Included in the scenario probability tree
-- Not tested in sensitivity analysis
† DSM impacts and costs were combined
‡ Return on Equity and Long-term Interest rates were combined

[21] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5) (B) through (F)
4 CSR 240-22.060(5); 4 CSR 240-22.060(5) (A) through (M)

Chapter 2 describes how three of the candidate uncertain factors were determined to be critical dependent uncertain factors, which defined the scenarios. The three critical dependent uncertain factors are: load growth, environmental policy, and natural gas prices. Energy prices are an output of the scenarios and reflect a range of uncertainty consistent with the scenario definitions.

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

- Purchased Power – Purchased power is excluded since Ameren Missouri is a member of MISO and Ameren Missouri has employed planning criteria that minimize our dependence on the market.
- SO_2 and NOx Emissions Prices – SO_2 and NOx Emissions Prices were excluded as candidates because of the expectation for very low prices as a result of current and expected environmental regulations.

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

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

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

Uncertain Factor Ranges[22]

We use the sensitivity analysis to examine whether or not candidate independent uncertain factors have a significant impact on the performance of alternative resource plans, as measured by their impact on PVRR.

Most of the candidate uncertain factors are characterized by a 3-level range of values for this analysis, those 3 levels being low, base, and high values. One of the candidates, nuclear tax incentive, had a 2-level range of values, which were a low value and a high value.

[22] 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

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Unless the meaning of low, base, and high are treated in a standardized manner, the probability of occurrence for the value used for “low” for one uncertain factor could be significantly different than the probability of occurrence for the value used for “low” for other uncertain factors. Thus, for majority of the uncertain factors, Ameren Missouri standardized the meaning of low to be the value found at the 5th percentile of a probability distribution of values for an uncertain factor, the value at the 50th percentile to be the base value, and the value at the 95th percentile to be the high value. The probability distribution for each candidate uncertain factor was inferred from a series of estimated values produced by subject matter experts for each uncertain factor.

For the majority of candidate uncertain factors, probability distributions were used to obtain the values for low, base, and high. This process began with subject matter experts providing/revising estimates of (A) an expected value, (B) estimates of deviations from that expected value, and (C) the probabilities of those deviations from the expected value. That information was used to create the probability distribution collectively implied by that data. Values at the 5th, 50th, and 95th percentiles of those implied probability distributions were then obtained for use as the values for low, base, and high for the various candidate independent uncertain factors. Appendix A contains the standard value, estimated deviation and probabilities for project costs, project schedule, fixed operations & maintenance (FOM), variable operations & maintenance (VOM), equivalent forced outage rate (EFOR), environmental capital expenditures, and transmission-retirement expenditures.

Example

The standard value for Fixed Operations & Maintenance (FOM), for the greenfield Combined Cycle option is $7.62/kW-year (2013$). FOM and some other candidate uncertain factors are characterized by differing standard values among various supply-side types, while standard values for some other candidate uncertain factors are not uniquely correlated to each supply side type. For example the Long Term Interest Rates uncertain factor does not differ depending on the supply-side type; it is the same across all supply-side types.

The subject matter experts, in this example, members of Ameren Missouri’s generation organization, provided estimates of deviations from the standard value as well as the probabilities of those deviations. An example of that initial uncertainty distribution is shown in Table 9.8. In this example, the first of these estimates for FOM deviations was a -20% deviation from the FOM standard value with a 5% probability of occurring. These deviation estimates provide sufficient information to derive continuous

Table 9.8

CC Fixed O&M Uncertainty Distribution	
Deviation	**Probability**
-20%	5%
-10%	25%
0%	40%
15%	25%
30%	5%

probability distributions from which the low/base/high values can be derived.

The process of developing the probability distributions involved using Crystal Ball software. This software, when provided with a series of observations like these deviation estimates, can determine the probability distribution implied by the set of estimates. An example of the result of analyzing deviation estimates using Crystal Ball is shown Figure 9.9. From this distribution the values for the low, base, and high values ($6.32, $7.64, $9.59) are shown at the respective percentiles in Figure 9.9 and represent the 5th, 50th, and 95th percentiles.

Figure 9.9 Example of Probability Distribution---CC Fixed O&M

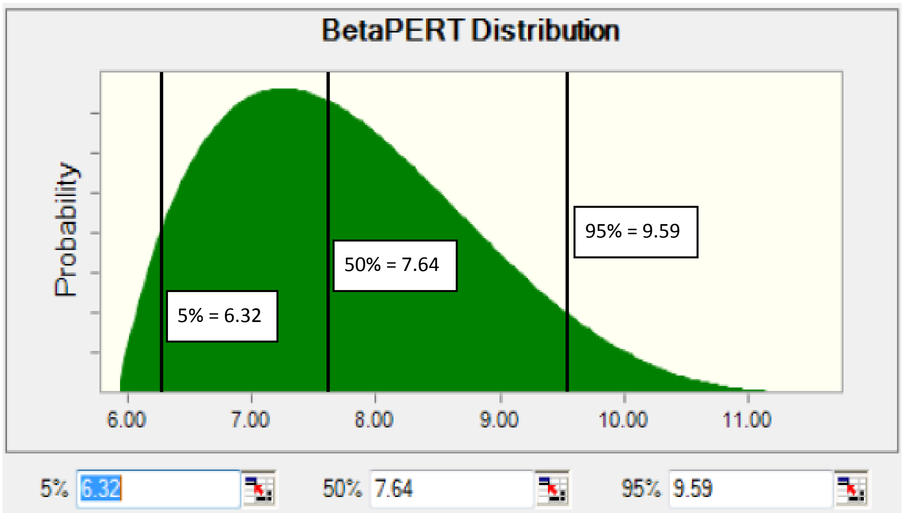

Figure 9.10 shows the resulting range of project costs, which also include interconnection costs estimates, for each new supply-side resource. For most of the technologies shown in Figure 9.10, base values found at 50th percentile were very close to their expected values. For nuclear technology, however, the base value inferred from the probability distribution was 27% higher than the expected value, $6,350/kW vs $5,000/kW.[23] Table 9.9 and Table 9.10 contain the uncertain factor ranges for the various candidate uncertain factors. It should be noted that, for the project schedule uncertainty, as the number of years in a project schedule change, the distribution of the cash flows was also updated to be consistent with those changes.

[23] EO-2011-0271 Order

Figure 9.10 Resource-Specific Project Cost Ranges ($/kW)

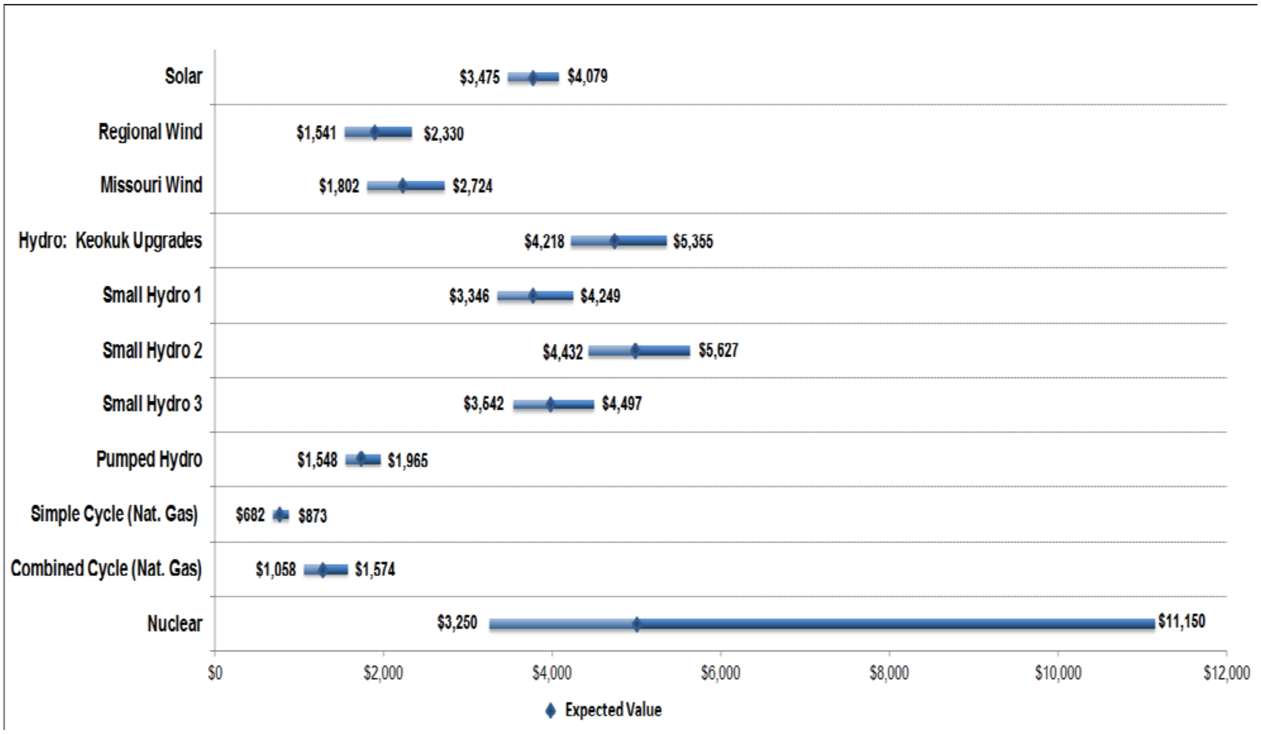

Table 9.9 Resource-Specific Uncertain Factor Ranges

Uncertain Factor	Value	Probability	CC (Nat. Gas)	SC (Nat. Gas)	Pumped Hydro	Hydro: Keokuk Upgrades	Nuclear (100%)	Small Hydro 1	Small Hydro 2	Small Hydro 3	Solar	Regional Wind	Missouri Wind
Project Cost ($/kW)	Low	10%	$1,058	$682	$1,548	$4,218	$3,250	$3,346	$3,542	$4,432	$3,475	$1,541	$1,802
	Base	80%	$1,297	$774	$1,756	$4,786	$6,350	$3,798	$4,020	$5,030	$3,777	$1,898	$2,219
	High	10%	$1,574	$873	$1,965	$5,355	$11,150	$4,249	$4,497	$5,627	$4,079	$2,330	$2,724
Project Schedule (months)	Low	10%	27	27	55	46	46	46	46	46	18	36	36
	Base	80%	36	36	73	61	61	61	61	61	24	48	48
	High	10%	48	48	95	79	79	79	79	79	32	63	63
Fixed O&M ($/kW-yr)	Low	10%	$6.32	$6.20	$2.81	$4.23	$111.38	$0.00	$0.00	$0.00	$20.76	$24.08	$24.08
	Base	80%	$7.64	$7.48	$3.39	$5.11	$136.89	$0.00	$0.00	$0.00	$25.06	$29.07	$29.07
	High	10%	$9.59	$9.36	$4.23	$6.41	$168.85	$0.00	$0.00	$0.00	$31.42	$36.44	$36.44
Variable O&M ($/MWh)	Low	10%	$1.52	$11.69	$2.82	$0.41	$1.75	$4.35	$4.35	$4.35	$0.00	$0.00	$0.00
	Base	80%	$3.94	$13.92	$3.50	$0.51	$2.17	$5.41	$5.41	$5.41	$0.00	$0.00	$0.00
	High	10%	$6.36	$16.15	$4.42	$0.65	$2.74	$6.83	$6.83	$6.83	$0.00	$0.00	$0.00
EFOR (%)	Low	10%	1%	0%	0%	*	1%	*	*	*	*	*	*
	Base	80%	2%	5%	5%	*	2%	*	*	*	*	*	*
	High	10%	5%	10%	10%	*	3%	*	*	*	*	*	*
Wind Capacity Factor (%)	Low	10%	---	---	---	---	---	---	---	---	---	33.4%	---
	Base	80%	---	---	---	---	---	---	---	---	---	38.5%	---
	High	10%	---	---	---	---	---	---	---	---	---	40.3%	---

Notes: * Assumed capacity factor includes effects of Forced Outage Rate

--- Not Applicable

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The Regional Wind capacity factors are based on the Black & Veatch Renewable Portfolio Study for Priority Development Areas 1, 2, 3, 11, 18, and 19 as mentioned in Chapter 6. The low and high capacity factor values are the lowest and highest values, respectively, among the specified priority development areas.

As discussed in Chapter 2, the long-range interest rate assumptions are based on the December 1, 2013, semi-annual Blue Chip Financial Forecast, a consensus survey of 49 economists. Ameren Missouri internal experts used this same set of data and process to develop a range of interest rate assumptions for use in the 2014 IRP. The high and low interest rate assumptions are based on the average of the 10 highest and 10 lowest forecasts from the survey. Additionally, the high and low forecasts for Treasury rates are used as inputs to the calculation of high and low ranges for allowed return on equity (ROE) using the same process as discussed in Chapter 2.

Table 9.10 Non-Resource Specific Uncertain Factor Ranges

Uncertain Factors	Low	Base	High
Probability -->>	10%	80%	10%
Nuclear Fuel Price	Varies By Year		
Coal Price	Varies By Year		
Long Term Interest Rates	5.8%	6.7%	7.6%
Return on Equity	11.0%	11.4%	11.8%
Probability -->>	50%		50%
Nuclear Incentives	No Incentive		$0.018/kWh
Probability -->>	45%	50%	5%
Energy Efficiency Load Impact			
MAP	82%	100%	100%
RAP	91%	100%	109%
Demand Response Load Impact			
MAP	21%	100%	286%
RAP	1%	100%	330%
Demand Side Management Cost			
MAP	78%	100%	113%
RAP	82%	100%	131%

One of the candidates, nuclear tax incentives, was characterized by a 2-level range of values, which were a low value (no incentives) and a high value. As a default, with a 50% probability, no nuclear tax incentives were included. As an alternative, with a 50% probability, a nuclear tax incentive of $0.018/kWh up to $125 million per year was included for the first eight years of operation for nuclear resources.

9.6.2 Sensitivity Analysis Results[24]

To conduct the sensitivity analysis, each of the 19 candidate resource plans was analyzed using the varying value levels (low/base/high or default/alternative) for each of the candidate independent uncertain factors, for the most likely scenario in the probability tree (Scenario 8). An uncertainty-probability weighted result (PVRR) was obtained for each plan for each relevant candidate uncertain factor. Finally, the results of using a “non-base” value were compared to the results of using an integration/base value for each plan for each candidate uncertain factor. The sensitivity analysis results for all of the candidate independent uncertain factors (resource-specific and non-resource specific) are presented in Appendix A.

The sensitivity analysis identified four critical independent uncertain factors: DSM Impacts and Costs, Project Costs, Coal Prices and ROE/Interest Rates. Table 9.11 shows the change in PVRR ranking (i.e., number of positions the plan moved in the ranking) for the four critical independent uncertain factors compared to the integration/base value. Table 9.12 shows the change in PVRR ($) for the four critical independent uncertain factors compared to the integration/base value.

Table 9.11 Critical Independent Uncertain Factors – Change in PVRR Ranking

			Critical Independent Uncertain Factors											
			DSM Impacts			Project Cost			Coal Price			ROE/Interest Rates		
Plan	Plan Description	Integration	DSM-PWA	DSM-Low	DSM-High	Prj Cost-PWA	Prj Cost-Low	Prj Cost-High	Coal Price-PWA	Coal Price-Low	Coal Price-High	ROE-PWA	ROE-Low	ROE-High
A	CC-RAP	5	0	(1)	(1)	0	1	0	0	0	0	0	0	0
B	Nuke2-RAP	12	0	0	0	0	(1)	1	0	0	1	0	0	0
C	SC-RAP	3	(1)	(1)	(1)	0	2	(1)	0	0	0	0	1	0
D	Pumped Hydro-RAP	10	0	(1)	(2)	0	2	(3)	0	0	0	0	0	0
E	Wind-SC-RAP	8	0	0	(2)	0	(1)	1	0	0	0	0	(1)	0
F	CC-RAP EE only	9	(3)	(4)	2	0	0	(1)	0	0	0	0	0	0
G	CC-MAP	1	0	0	0	0	0	0	0	0	0	0	0	0
H	Nuke-RAP-Balanced	11	0	0	(1)	0	(1)	0	0	0	0	0	0	0
I	CC-RAP-Balanced	7	0	0	(2)	0	1	(1)	0	0	0	0	1	0
J	Nuke-MEEIA1-Balanced	15	0	0	1	0	0	0	0	0	2	0	0	0
K	CC-MEEIA1-Balanced	14	0	0	0	0	0	0	0	(1)	0	0	0	0
L	Wind-MEEIA1	19	0	0	0	0	(2)	0	0	(1)	0	0	0	0
M	CC-MAP-Labadie	17	0	0	0	0	1	0	0	0	(1)	0	0	0
N	CC-MAP-Rush	13	0	0	0	0	0	(1)	0	1	(1)	0	0	0
O	Nuke2025-RAP-Labadie-Balanced	18	0	0	0	0	1	0	0	1	0	0	0	0
P	Nuke2025-RAP-Rush-Balanced	16	0	0	(1)	0	0	0	0	0	(1)	0	0	0
Q	Nuke-MAP-Balanced	6	3	4	1	0	(3)	4	0	0	0	0	0	0
R	CC-MAP-Balanced	2	2	4	1	0	0	2	0	0	0	0	0	0
S	CC-MAP EE only	4	(1)	(1)	5	0	0	(1)	0	0	0	0	(1)	0

[24] 4 CSR 240-22.060(5); 4 CSR 240-22.060(7)(A); 4 CSR 240-22.060(7)(C)1A

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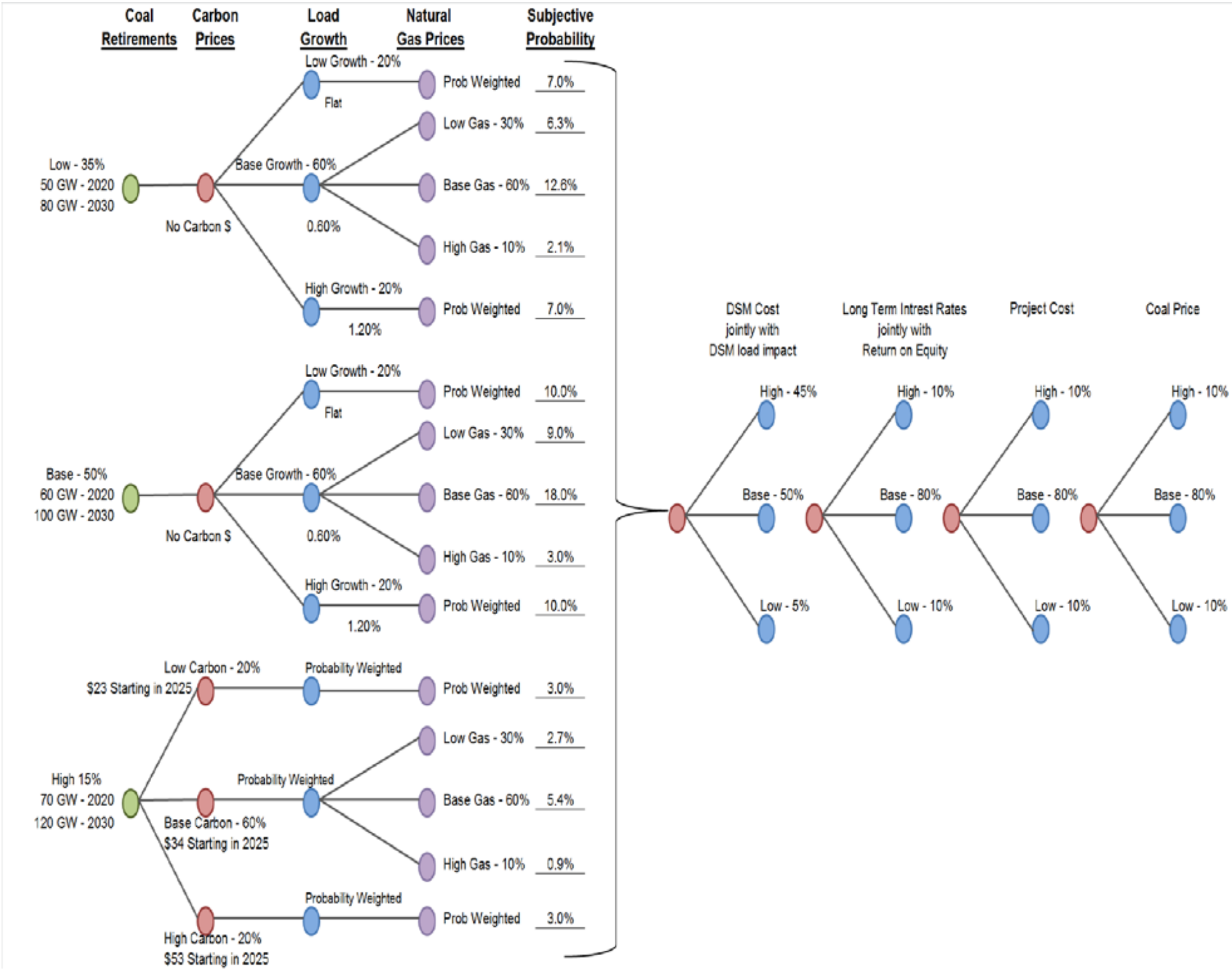
Table 9.12 Critical Independent Uncertain Factors – Change in PVRR ($)

			Critical Independent Uncertain Factors											
			DSM Impacts			Project Cost			Coal Price			ROE/Interest Rates		
Plan	Plan Description	Integration	DSM-PWA	DSM-Low	DSM-High	Prj Cost-PWA	Prj Cost-Low	Prj Cost-High	Coal Price-PWA	Coal Price-Low	Coal Price-High	ROE-PWA	ROE-Low	ROE-High
A	CC-RAP	59,642	129	349	(575)	29	(735)	1,022	(109)	(3,816)	2,729	(12)	(864)	748
B	Nuke2-RAP	60,778	129	349	(575)	75	(1,575)	2,322	(109)	(3,816)	2,729	(13)	(974)	844
C	SC-RAP	59,579	129	349	(575)	28	(690)	968	(109)	(3,816)	2,729	(12)	(857)	742
D	Pumped Hydro-RAP	60,036	129	349	(575)	27	(734)	1,008	(109)	(3,816)	2,729	(12)	(887)	768
E	Wind-SC-RAP	59,890	129	349	(575)	32	(918)	1,241	(109)	(3,816)	2,729	(12)	(905)	783
F	CC-RAP EE only	59,941	62	156	(156)	30	(816)	1,115	(109)	(3,816)	2,729	(12)	(887)	767
G	CC-MAP	59,266	242	588	(463)	29	(735)	1,022	(109)	(3,816)	2,729	(12)	(861)	745
H	Nuke-RAP-Balanced	60,331	129	349	(575)	47	(1,133)	1,607	(109)	(3,816)	2,729	(12)	(926)	801
I	CC-RAP-Balanced	59,888	129	349	(575)	30	(817)	1,119	(109)	(3,816)	2,729	(12)	(883)	764
J	Nuke-MEEIA1-Balanced	62,597	0	0	0	56	(1,469)	2,031	(109)	(3,816)	2,729	(14)	(1,011)	875
K	CC-MEEIA1-Balanced	62,029	0	0	0	34	(1,088)	1,432	(109)	(3,816)	2,729	(13)	(962)	832
L	Wind-MEEIA1	66,021	0	0	0	103	(4,238)	5,266	(109)	(3,816)	2,729	(22)	(1,554)	1,339
M	CC-MAP-Labadie	63,654	242	588	(463)	33	(1,262)	1,594	(65)	(2,194)	1,547	(13)	(936)	804
N	CC-MAP-Rush	61,433	242	588	(463)	30	(934)	1,236	(89)	(2,954)	2,062	(12)	(881)	762
O	Nuke2025-RAP-Labadie-Balanced	64,702	129	349	(575)	66	(1,856)	2,514	(65)	(2,194)	1,547	(14)	(1,018)	875
P	Nuke2025-RAP-Rush-Balanced	62,935	129	349	(575)	64	(1,608)	2,250	(89)	(2,954)	2,062	(13)	(984)	852
Q	Nuke-MAP-Balanced	59,846	242	588	(463)	46	(1,052)	1,514	(109)	(3,816)	2,729	(12)	(901)	780
R	CC-MAP-Balanced	59,512	242	588	(463)	30	(817)	1,119	(109)	(3,816)	2,729	(12)	(880)	762
S	CC-MAP EE only	59,582	161	358	0	29	(735)	1,022	(109)	(3,816)	2,729	(12)	(863)	747

DSM Impacts & Costs and Project Costs were selected as critical independent uncertain factors because of the variety in the change in PVRR ranking. Coal price was selected as a critical independent uncertain factor because of the high impact potential on relative results of early retirement plans compared to other plans. ROE/Interest Rates was selected as a critical independent uncertain factor as a degree of conservatism since it was selected as a critical independent uncertain factor in previous Ameren Missouri IRP's and since it can significantly influence the results of different levels of capital intensiveness between plans in combination with project cost uncertainty.

These four critical independent uncertain factors were added as nodes to the scenario probability tree that was developed in Chapter 2. The updated and expanded probability tree is shown in Figure 9.11, with the four critical independent uncertainty factors shown on the right-hand side.

Figure 9.11 Final Probability Tree Including Sensitivity Analysis Results[25]



9.7 Risk Analysis[26]

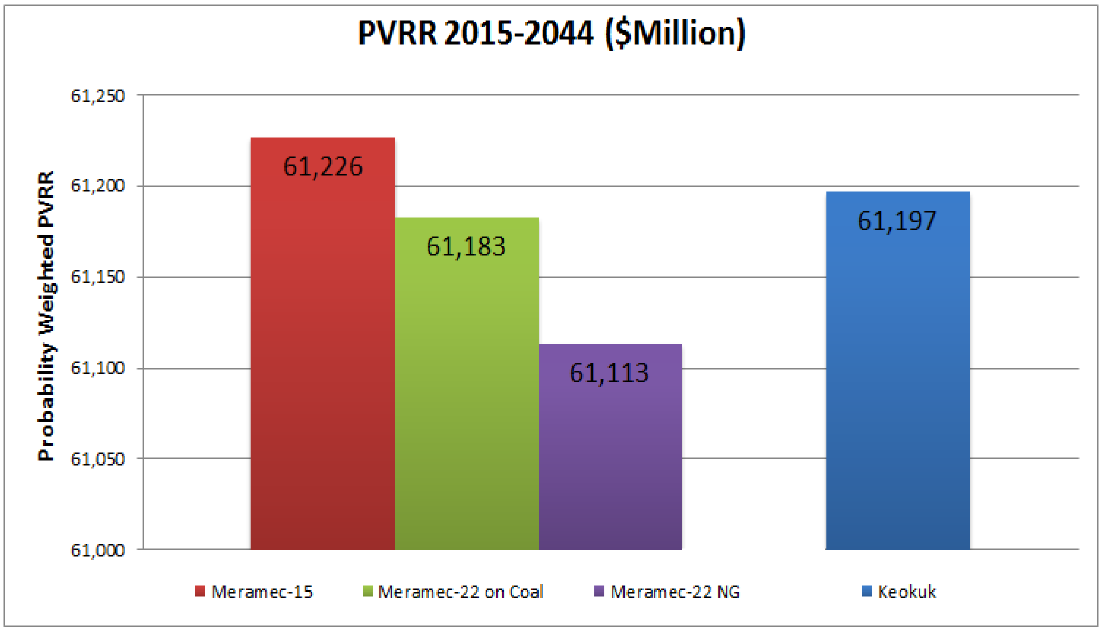
The Risk Analysis consisted of running each of the candidate resource plans (i.e., pre-analysis plans and Plans A-S) in Table 9.6 through each of the branches on the final probability tree shown in Figure 9.11. The probability tree consisted of 1,215 different branches. Each branch is the combination of different value levels among the fifteen scenarios, themselves defined by combinations of the three critical dependent uncertain factors (load growth, gas prices, and environmental regulations/carbon policy), and the four critical independent uncertain factors (DSM cost together with DSM load impacts, interest rates together with return on equity, project cost, and coal price). Each branch therefore represents a unique combination of the critical uncertain factors. Once all the combinations are calculated the sum of the individual branch probabilities equals 100%.

[25] 4 CSR 240-22.060(6)
[26] 4 CSR 240-22.060(6)

9.7.1 Risk Analysis Results

As mentioned in Section 9.3, the conclusions of the pre-analysis were tested by evaluating them under the full range of scenarios and critical uncertain factors used for risk analysis. The pre-analysis PVRR results from the risk analysis are shown in Figure 9.12. Figure 9.12 shows that the PVRR results under risk analysis are consistent with the initial findings for both Meramec and Keokuk and have therefore been appropriately included in all alternative resource plans.

Figure 9.12 Probability Weighted PVRR Results: Pre-Analysis



The PVRR results of the risk analysis of the 19 alternative resource plans are shown in Figure 9.13. The levelized rate results for the risk analysis are shown in Figure 9.14. It is important to consider both the PVRR and levelized rate impacts. The PVRR results are lower for plans with RAP or MAP DSM compared to the other plans. In addition, the plans with RAP or MAP exhibit lower levelized rates compared to the other plans. The additional coal retirement plans (i.e., Plans M through P) exhibit much higher PVRR results and much higher levelized rates compared to the other plans. Plan L (Wind-MEEIA1) exhibits the highest PVRR and the second highest levelized rates. Results for other performance measures can be found in Appendix A.

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Figure 9.13 Probability-Weighted PVRR Results: Alternative Resource Plans

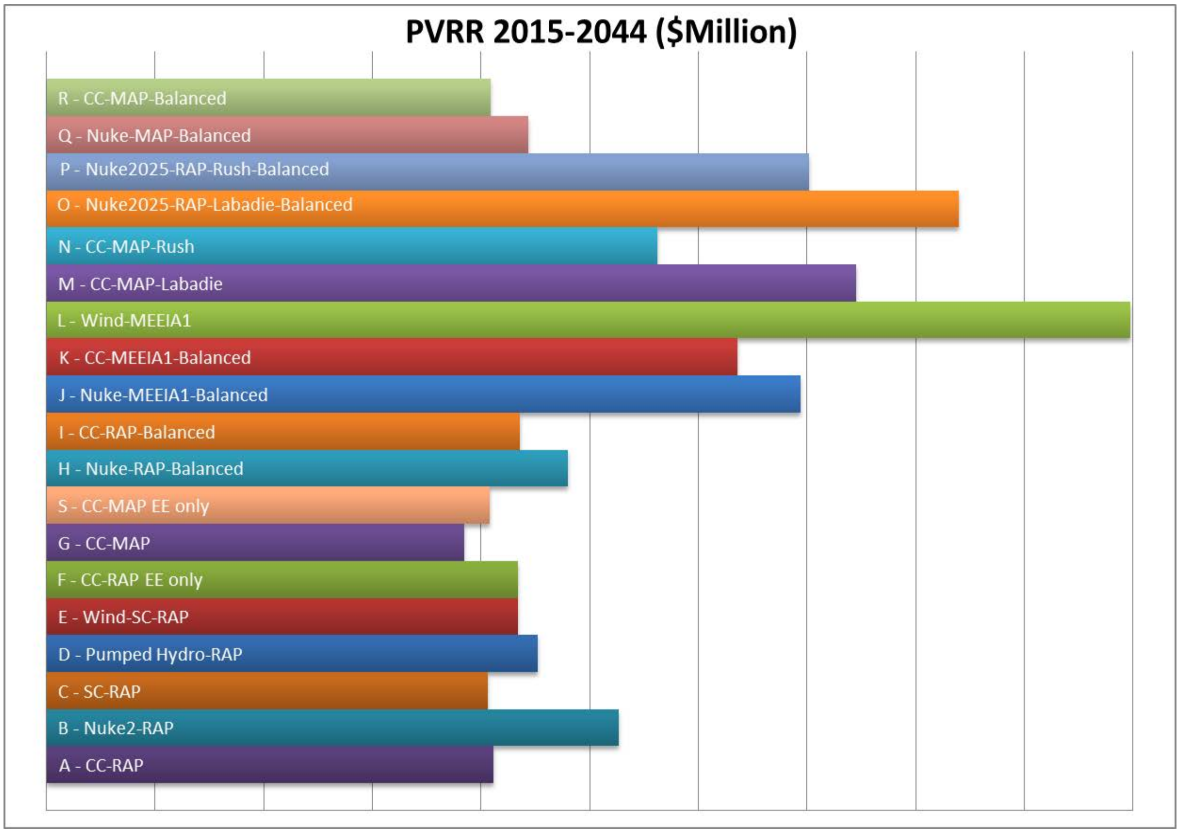
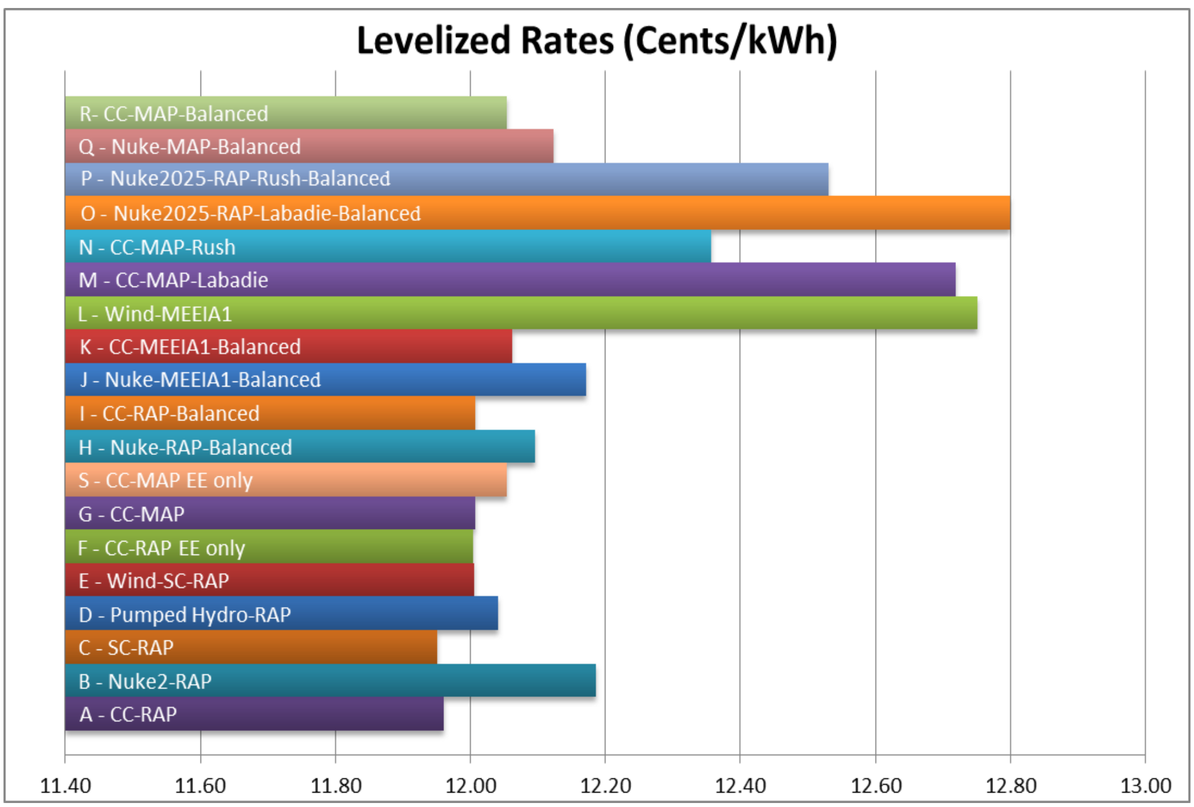


Figure 9.14 Probability-Weighted Levelized Rates: Alternative Resource Plans



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If decision making were solely based on PVRR and levelized rate impacts, then the analysis would be complete at this point. Since decision making is multi-dimensional, Ameren Missouri created a scorecard that embodies its planning objectives to evaluate the performance of alternative resource plans. With 19 alternative resource plans, Ameren Missouri can take a closer look at the performance of the plans by evaluating their relative strengths and weaknesses in meeting our planning objectives and whether other factors may be important in the selection of the preferred resource plan. Chapter 10 – Strategy Selection includes the additional analysis and decision-making considerations that lead to the selection of the Resource Acquisition Strategy.

9.8 Conclusions from Integration and Risk Analysis

Below are several conclusions from the integration and risk analysis.

- The risk analysis validates the Meramec Retirement Solution---conversion of Meramec Units 1&2 to Natural Gas December 31, 2015 and Units 3&4 continue on coal with retirement by December 31, 2022---is the solution for the candidate alternative resource plans.
- The risk analysis validates the exclusion of the potential Keokuk expansion from alternative resource plans.
- Inclusion of energy efficiency and demand response results in generally lower costs and rates
- Combined cycle resources are an attractive option for near-term development due to their competitive overall cost, relatively low capital cost and relatively short lead time.
- Meeting all future resource needs with renewable resources (Plan L) results in the highest PVRR and the second highest levelized rates.
- Plans with additional renewable resources beyond those included for RES compliance are competitive from a cost standpoint.
- Nuclear generation remains a competitive resource for future baseload capacity.
- Early retirement of coal generation, even if replaced with cost-effective demand side resources, results in significantly higher costs to customers and rates.

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9.9 Resource Plan Model

Ameren Missouri has used a modular approach to modeling for this IRP. Certain challenges associated with the use of the MIDAS model – financial modeling limitations, trouble-shooting difficulty, etc… – led us to reevaluate our modeling tools and approach. Discussions in recent years with Ventyx, the vendor that licenses MIDAS, have indicated that their long-term model plans do not include continued development of MIDAS. After identifying and assessing the capabilities of other "off-the-shelf" alternatives, Ameren Missouri elected to replace MIDAS for integration and risk analysis with a combination of stand-alone models for 1) production costing, 2) market settlements, 3) revenue requirements, and 4) financial statements. Items 2-4 on this list are collectively referred to as the "Financial Model." This approach permitted analysts maximum flexibility, customization and trouble-shooting capabilities. It also lends itself to greater transparency for stakeholders by limiting the use of proprietary third-party software.

Ameren Missouri used a generation simulation model from Simtec, Inc., typically referred to as RTSim (Real-Time Simulation) for production cost modeling.[27] RTSim provides a realistic simulation of an electric generating system for a period of a few days to multiple years. According to Simtec's marketing materials, RTSim finds higher profitability, lower risk, "free market" transactions, maintenance schedules, emission compliance strategies and fuel procurement schedules while maintaining reliable, reasonable cost service to the traditional regulated market sector.

RTSim simulates hourly chronological dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The model plans are based on a capacity planning spreadsheet, which was used to determine the timing of new resources. The RTSim model contains all unit operating variables required to simulate the units. These variables include, but are not limited to, heat rates, fuel costs, variable operation and maintenance costs, emission allowance costs, scheduled maintenance outages, and forced and partial outage rates. The generation fleet is dispatched competitively against market prices. The multi-area mode of the Ventyx Midas® model was used for the creation of forward price curves as described in Chapter 2.

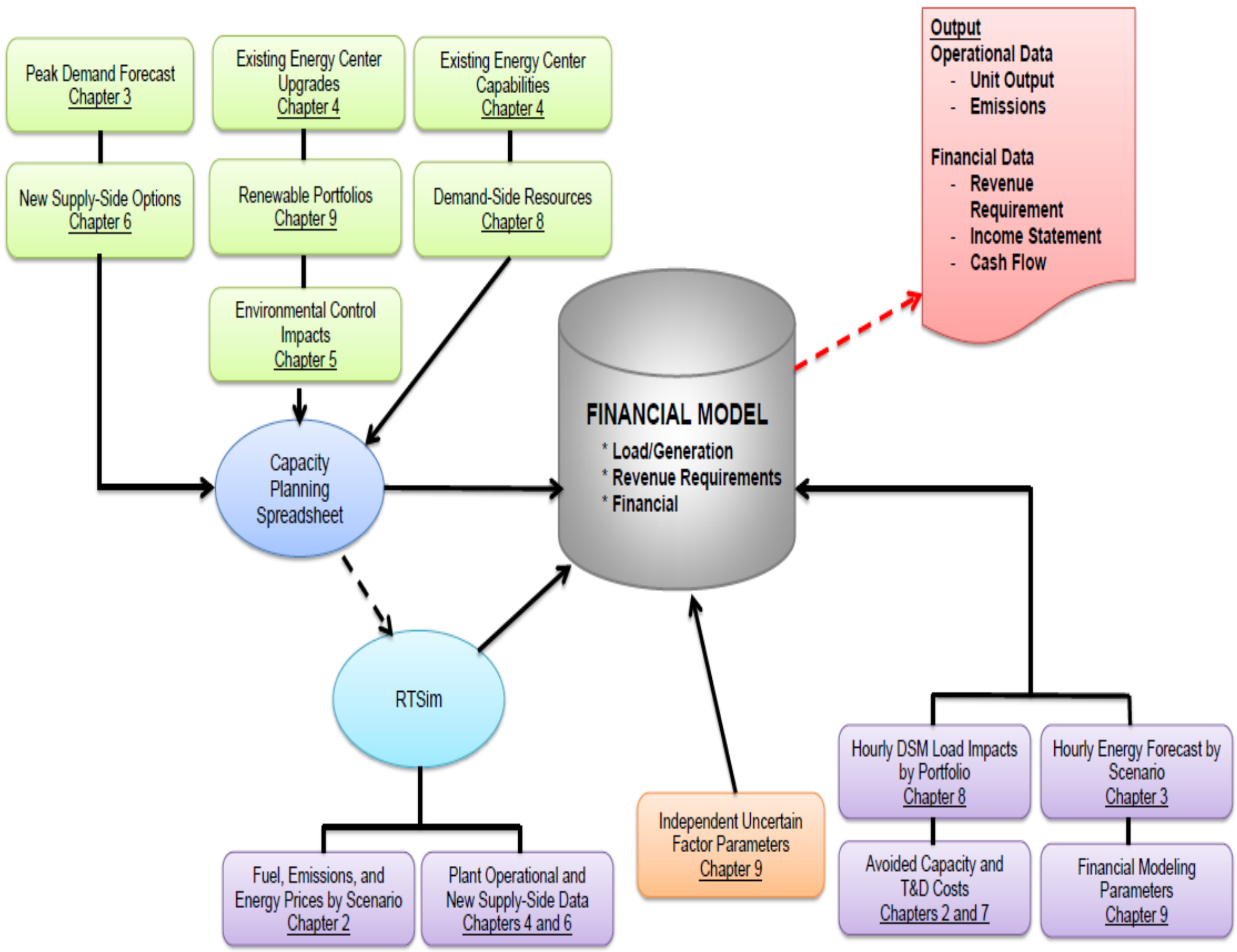
Ameren Missouri developed its own revenue requirements and financial model using Microsoft Excel. This model incorporates the capacity position and RTSim outputs, as well as other financial aspects regarding costs exterior to the direct operation of units and other valuable information that is necessary to properly evaluate the economics of a

[27] 4 CSR 240-22.060(4)(H); EO-2014-0062 d

resource portfolio. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts along with revenue requirement and various financial and credit metrics.

Figure 9.15 shows how the various assumptions are integrated into the financial model.

Figure 9.15 Resource Plan Model Framework[28]



[28] 4 CSR 240-22.060(4)(H)

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Future Plans for Modeling Tools[29]

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

We expect to continue our efforts to improve the efficiency, effectiveness and transparency of our modeling tools into 2015. The nature and timing of any changes we make will largely be a function of our assessment of the currently available options. As we consider these options, we plan to share thoughts with other Missouri utilities and with our stakeholder group. This may or may not provide opportunities to move to a common modeling platform. Ameren Missouri will remain open to such an outcome while ensuring that its own tools and processes are able to support our business needs and objectives.

[29] EO-2014-0062 e

9.10 Compliance References

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