2022 Change in Preferred Plan

INTEGRATED RESOURCE PLAN

Ameren MISSOURI

Schedule MM-R9

Notification of Change in Ameren Missouri's Preferred Resource Plan

Executive Summary

Ameren Missouri's senior management has concluded that the Preferred Resource Plan presented in its 2020 Triennial Integrated Resource Plan ("IRP") (File No. EO-2021-0021) is no longer appropriate and should be revised. This conclusion was reached as a result of several key events and changes in the planning environment:

- Rush Island NSR Litigation – An appellate court decision resulted in a subsequent decision by Ameren Missouri to retire the coal units at Rush Island Energy Center within the next few years rather than install expensive pollution control technology.
- Illinois Energy Legislation – Legislation passed by the Illinois General Assembly to transition away from carbon-emitting electric generation shortens the operating life of simple cycle gas combustion turbine generators ("CTGs") owned by Ameren Missouri and operated in Illinois.
- Winter Capacity Needs – In the wake of Winter Storm Uri, Ameren Missouri has placed additional focus on winter reliability. The Midcontinent Independent System Operator ("MISO") has also filed a proposal with the Federal Energy Regulatory Commission ("FERC") to include consideration of seasonal capacity needs and capabilities as part of proposed resource adequacy reforms.
- Enhanced Reliability Focus – In addition to considering winter capacity needs, Ameren Missouri has engaged Astrapé Consulting to evaluate long-term reliability implications of the Company's resource decisions through rigorous reliability modeling and has incorporated insights from this analysis into the development of its revised Preferred Resource Plan.

In addition to the above factors, Ameren Missouri has revisited key assumptions affecting the performance of its Preferred Resource Plan – natural gas prices, carbon prices, and costs for wind, solar, storage and gas-fired generation technologies. Ameren Missouri continues to consider its resource planning decisions in the context of a comprehensive generation strategy, which includes the following objectives:

- Operate Energy Centers safely, economically, and in an environmentally responsible fashion while transitioning the generation fleet.
- Ensure overall energy (supply and grid) reliability and affordability.
- Create and capitalize on investment opportunities that are beneficial to customers, shareholders, the environment, and our communities.
- Maintain financial, technical, regulatory, and environmental flexibility.

Ameren Missouri also strives to ensure specific objectives are met by its Preferred Resource Plan. These objectives include:

- Minimize customer costs (Present Value Revenue Requirements or "PVRR").

- Customer Satisfaction (including rate impacts and reliability).
- Portfolio Transition (clean energy expansion and carbon reduction).
- Mitigate Financial/Regulatory Risk.
- Economic Development.

Given these objectives and the planning environment changes noted above, Ameren Missouri has updated its Preferred Resource Plan as shown in Figure 1. Figure 2 shows Ameren Missouri's actual 2021 generation mix and its expected future generation mix under the new Preferred Resource Plan.[1]

Figure 1: Preferred Plan Resource Timeline

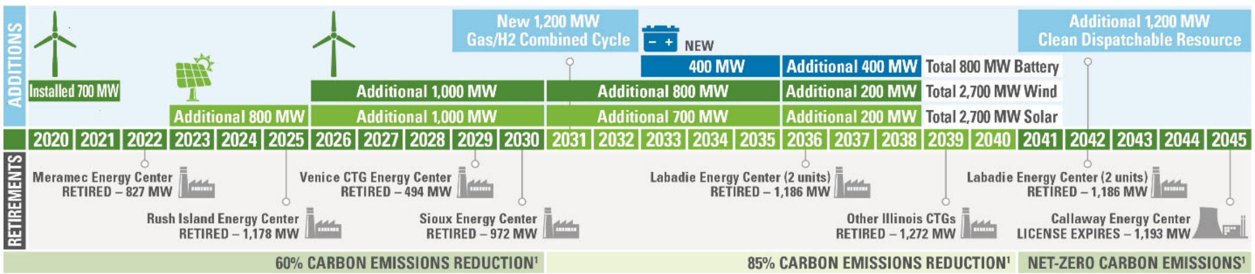
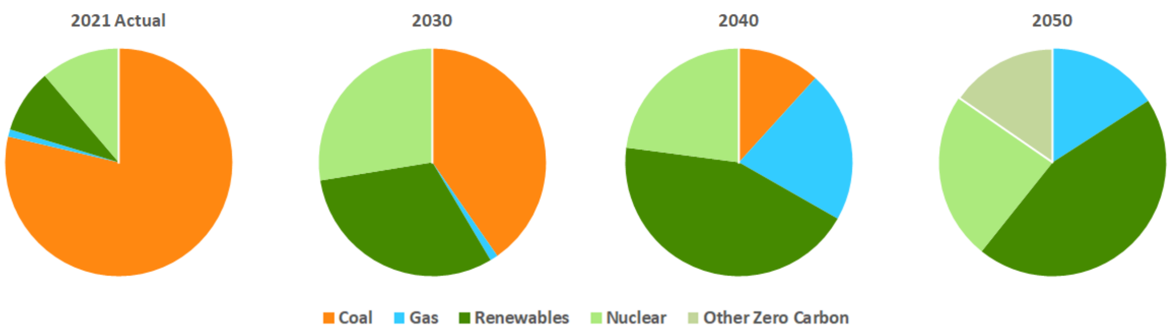


Figure 2: Preferred Plan Generation Mix



The Preferred Resource Plan reflects the following key changes from the 2020 IRP preferred plan:

- Acceleration of the retirement of Rush Island Energy Center from 2039 to 2025[2].
- Retirement of Venice Energy Center by the end of 2029.
- Delay in the retirement of Sioux Energy Center by two years from 2028 to 2030.

[1] Gas generation in 2050 is assumed to include a combination of hydrogen blending and carbon capture and sequestration to eliminate CO_2 emissions that might otherwise result. Other zero carbon generation may be a combination of gas-fired generation with hydrogen blend and carbon capture, utilization and storage ("CCUS"), advanced nuclear, renewables with long-duration storage, or other new zero-emitting technologies. 2021 actual generation reflects a prolonged outage of the Callaway Energy Center.

[2] At the time of preparation of this notification, final resolution of the retirement date for the Rush Island Energy Center had not been reached. Changes in the retirement date are expected to have no material impact on other resource decisions represented in the updated Preferred Resource Plan.

- Addition of 1,200 MW of natural gas-fired combined cycle ("NGCC") generation in 2031, with plans to switch to hydrogen fuel and/or blend hydrogen fuel with natural gas and install carbon capture technology by 2040.
- Changes in the timing of wind and solar additions, still resulting in total renewable generation additions of 5,400 MW[3].
- Addition of 800 MW of battery storage resources.
- Retirement of the remaining Illinois CTGs by the end of 2039 – Goose Creek, Raccoon Creek, Pinckneyville, and Kinmundy Energy Centers.
- Increase from 800 MW to 1,200 MW of clean dispatchable resources in 2043.

Ameren Missouri's new Preferred Resource Plan represents an acceleration of the Company's portfolio transition that results in the retirement of approximately 3,000 MW[4] of coal-fired generation by the end of 2030, accelerated retirement of approximately 1,800 MW of gas-fired generation, total renewable generation of 3,500 MW by 2030, the addition of flexible battery storage, and the deployment 1,200 MW of clean-burning NGCC generation, with an expectation for technology development to eliminate remaining carbon emissions in the long term. This accelerated transition allows Ameren Missouri to achieve greater reductions in carbon emissions by 2030 – 60% compared 2005 levels versus the previous goal of 50% – maintain the goal of an 85% reduction in carbon emissions by 2040, and accelerate the Company's net zero emissions goal to 2045 from 2050.[5] Table 1 shows the acceleration of the transition by comparing key elements of the new Preferred Resource Plan to the 2020 IRP preferred plan.

Table 1: Transition Timing Comparison

	2022 Preferred Plan	2020 IRP Preferred Plan
Coal Retirement Acceleration	**3,000 MW by 2030** 5,400 MW by 2042	1,800 MW by 2030 5,400 MW by 2042
Natural Gas Retirement Acceleration	**500 MW by 2030** **1,800 MW by 2040**	None
Renewable Additions	**3,500 MW by 2030** **5,000 MW by 2035** 5,400 MW by 2040	3,100 MW by 2030 4,300 MW by 2035 5,400 MW by 2040
Battery Storage Additions	**400 MW by 2035** **800 MW by 2040**	None
Carbon Emission Reduction (CO_2e)	**60% by 2030** 85% by 2040 **Net Zero by 2045**	50% by 2030 85% by 2040 Net Zero by 2050
Natural Gas Additions	**1,200 MW (2031)**	None
Other Clean Dispatchable Additions	**1,200 MW (2043)**	800 MW (2043)

[3] Includes 700 MW of wind generation resources added in 2020 and 2021.

[4] Includes 240 MW of generation at Meramec Energy Center that was switched from coal-fired operation to gas-fired operation in 2016.

[5] Ameren Missouri's carbon reduction goals are focused on CO_2 equivalent (CO_2e) emissions, including methane, nitrous oxide and sulfur hexafluoride and include both Scope 1 and Scope 2 emissions. Achieving net zero is contingent on the availability of some combination of developing technologies, such as CCUS, hydrogen fuel/energy storage, advanced nuclear, long-duration battery storage, and other developing or potential technologies.

As mentioned above, Ameren Missouri is accelerating its carbon reduction goals to achieve a 60% reduction from 2005 levels by 2030, 85% by 2040, and net zero emissions by 2045. This accelerated reduction in carbon emissions means that cumulative emissions over the planning horizon will be substantially reduced compared to the 2020 IRP preferred plan. As was the case with the previous 2050 net zero goal announced in 2020, the 2045 net zero goal depends on the development of new clean energy technologies that will allow the Company to ensure reliability while eliminating carbon emissions. Figure 3 shows the decline in total carbon emissions under the new Preferred Resource Plan. Figure 4 shows expected carbon intensity, carbon emissions per MWh generated, for the new Preferred Resource Plan compared to the prior preferred plan.

Figure 3: Expected Carbon Emissions

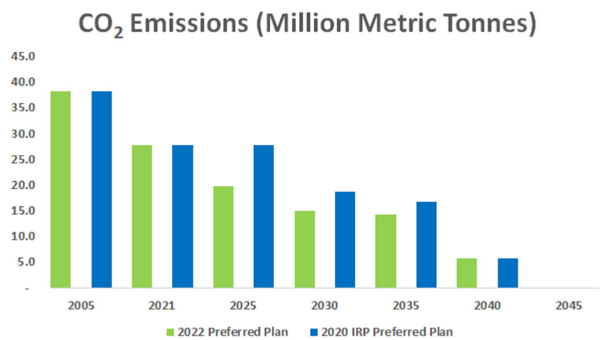
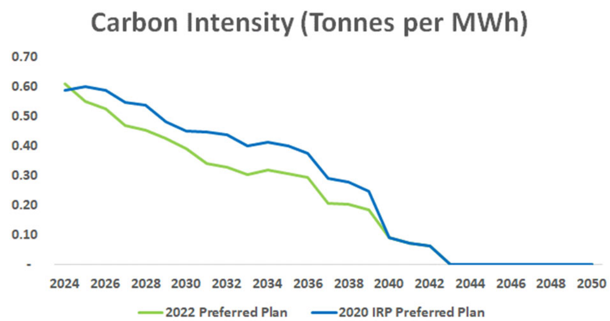


Figure 4: Expected Carbon Intensity



It should be noted that Ameren Missouri has updated its plan to include the cost to Ameren Missouri of expected future transmission system investments in MISO to integrate a significantly higher penetration of renewable wind and solar generation resources based on MISO's Long Range Transmission Planning ("LRTP") effort, the first iteration of which was published by MISO in early 2021. These investments will be critical to achieving broader decarbonization across the economy, including the electrification of transportation, industrial processes, and other uses of fossil fuels.

The Company has also performed rigorous analysis to ensure that its new Preferred Resource Plan will deliver the reliable service customers count on. This includes ensuring that the plan meets the expected requirements of MISO's proposed seasonal capacity construct, which considers differences in customer demand and electric resource capabilities on a seasonal basis in addition to the annual summer peak that has traditionally been the focus of resource adequacy. This is particularly important as the Company reflects on the challenges that were presented by Winter Storm Uri in early 2021. It also includes insights gained through the analysis of Ameren Missouri's system performed by Astrapé Consulting. This analysis looks specifically at Ameren Missouri's system and its expected reliability with different mixes of resources, accounting for the intermittent nature of wind and solar resources, operating constraints for other resources in Ameren Missouri's fleet, and support from MISO, as well as the benefits of energy efficiency and demand response. While MISO's proposed seasonal capacity construct has not yet been adopted, a focus on seasonal reliability will be critical to ensuring reliable service to customers under a wide range of weather and system conditions and constraints.

One of the hallmarks of Ameren Missouri's planning process is maintaining flexibility and developing prudent long-term plans to mitigate energy supply and reliability risks. This often ensures preferred plan provisions that reduce risk to customers and investors alike. The portfolio transition represented by the new Preferred Resource Plan is designed to maintain flexibility and mitigate risks that could otherwise result in increased costs to customers, particularly if the addition of renewable resources were delayed until a specific need for capacity was imminent. In December 2021, Ameren Missouri filed with the Missouri Public Service Commission ("MPSC") its analysis of the relative risks to customers and shareholders of the planned renewable transition in the 2020 IRP preferred plan when compared to a planned transition that reflects renewable additions only when a need for new capacity is identified. To further quantify these risks and to assist with updating the Company's assessment based on the revised timing of renewable additions in the new Preferred Resource Plan, Ameren Missouri engaged Roland Berger. Roland Berger's analysis identified a number of key risks associated with a delayed renewable transition. Certain of these risks – those that were determined to be quantifiable and significant – were quantified and included in the results of the Company's plan analysis.

Over the next two years, Ameren Missouri will be carrying out specific actions to execute on the new Preferred Resource Plan. These include:

- Submitting applications for Certificates of Convenience and Necessity ("CCNs") to the MPSC for solar generation projects.
- Applying for the creation of a Renewable Solutions program to help communities and large customers meet their sustainable energy goals.
- Issuing a new Request for Proposals ("RFP") to identify additional wind and solar project opportunities to support planned additions.
- Finalizing plans for the retirement of Rush Island Energy Center:
    - Completing the Attachment Y process with MISO.
    - Receiving a revised decision from the U.S. District Court reflecting early retirement as the means of compliance.
    - Finalizing plans for operation of the units until retirement.
    - Completing transmission system upgrades necessary to ensure reliability after retirement of the units.
- Adjusting depreciation expense for Sioux Energy Center to reflect retirement by the end of 2030 as part of the Company's next rate review.
- Filing an application with the MPSC to securitize the remaining balance in rate base and other transition costs associated with the Rush Island Energy Center.
- Conducting preliminary work for the development of new NGCC generation, including site studies, permitting, and engineering[6].

[6] Ameren Missouri intends to seek a CCN for the new NGCC generation at some time after the filing of the Company's 2023 triennial IRP, which is due by October 1, 2023.

- Continuing to provide energy efficiency and demand response programs to customers to help them manage their energy costs and reduce the need for new generation resources.

As Ameren Missouri considers new wind and solar projects to fulfill the resource needs identified in the new Preferred Resource Plan, it will be focused on ensuring a regionally diverse portfolio to mitigate any potential impacts on energy supply due to variations in weather conditions across geographical locations. With strategic and proper siting, geographic diversity allows for a smoothing effect across variable energy resources, allowing for improved reliability. Further, a geographically diverse energy portfolio is more resilient during unplanned events that would otherwise negatively impact the electrical system. With a host of viable solar generation projects currently under consideration, Ameren Missouri will also be focused on wind generation additions after 2025 to ensure a balanced portfolio designed to mitigate the variations in generating performance of wind and solar technology. This variation is due to the times when renewable energy resources are available in Missouri and surrounding states. Wind is typically available more at night and during non-summer months while solar is typically available more during the day and summer months. This difference in availability allows for more hours that energy is produced when wind and solar are combined to provide a more predictable energy generation profile. The Company will also continue to look for opportunities to pair storage resources with renewable resources to enhance reliability and flexibility.

With respect to demand-side resources, Ameren Missouri continues to evaluate the potential for additional energy efficiency and demand response resources to help customers better manage their energy consumption and to ensure that the Company is able to meet all customers' electric energy needs reliably and affordably. The Company recently commissioned a new market potential study to identify further potential for energy efficiency and demand response. As part of that market potential study, Ameren Missouri will also be evaluating the benefits of load flexibility to further enhance and ensure reliability at a reasonable cost.

As Ameren Missouri begins the initial work to add new natural gas-fired generation, it will continue to ensure that it maintains flexibility that allows the Company to alter plans as new and better information becomes available. This includes new information regarding technology, energy policy, market conditions, and changes in expected demand.

In making changes to the preferred plan, the Company's management is mindful of how the many variables that can influence long-term resource planning may change over time. These variables include power prices, carbon prices, fuel prices, environmental regulations, load growth, generation technology costs, transmission infrastructure costs, interest rates and allowed returns on equity, retirements of generators in the U.S. power markets, and other economic and market conditions that affect the various resource alternatives. While the Company conducts robust risk analyses to account for potential changes in such variables, sometimes changes are of such a magnitude that they fall outside the expected range and could result in a significant change in the Company's preferred plan in the future. There are also other factors that must be considered, such as the presence of an enabling regulatory cost recovery framework or expectations for environmental regulation that impact the cost-effectiveness of Ameren Missouri's existing generation fleet and necessitate the consideration of options such as unit retirement or conversion. Ameren Missouri must periodically consider all these factors as it makes and adjusts its long-term resource plans.

Planning Environment

A key element of Ameren Missouri's resource planning process is monitoring the planning environment and assessing the potential impact of changes in various factors on the preferred resource plan. Since the filing of Ameren Missouri's 2020 IRP, a number of factors that may influence the complexion and performance of the Company's preferred resource plan have emerged or changed. These include policy changes, market changes, and the outcome of litigation involving Ameren Missouri generating units. Following is a discussion of each of the factors that have been considered in the Company's change to its preferred resource plan.

Rush Island NSR Litigation

In August 2021, the U.S. Court of Appeals for the Eight Circuit upheld in part a U.S. District Court finding that Ameren Missouri had violated the New Source Review ("NSR") provisions of the Clean Air Act and that a portion of the associated remedy ordered by the lower court was lawful. Specifically, the appellate court upheld the lower court's order to install flue gas desulfurization ("FGD") equipment, commonly referred to as "scrubbers" on the Rush Island coal units. The appellate court subsequently denied petitions for rehearing submitted by both the Company and the United States. In December 2021, the Company announced in a filing with the Securities and Exchange Commission its intent to seek a modification to the District Court order, allowing the Company to retire the Rush Island coal units in lieu of adding scrubber technology. That process is ongoing at the time of this filing. While the final resolution of the case is still pending, the Company expects the units to be retired within the next few years and has assumed retirement of the units at the end of 2025 for purposes of this new Preferred Resource Plan. The final retirement date will depend in part on the completion of the Attachment Y process with MISO, which is used to determine the need for new transmission infrastructure necessary to ensure reliability upon retirement of generating units and to determine the need for continued operation of generating units until such transmission infrastructure has been placed into service. Ameren Missouri does not expect any differences in the final timing for unit retirement to affect other resource decisions included in its new Preferred Resource Plan. The Company expects to file an application with the MPSC to securitize the remaining balance for the Rush Island Energy Center and other appropriate energy transition costs in the second half of 2023. Because the details of such a filing have yet to be determined, the economic impact of securitization has not been included in the Company's planning analysis. Since such an assumption would be common to all plans evaluated, this would not result in relative differences in economics between the plans evaluated.

Illinois Legislation

In September 2021, the Illinois General Assembly passed Senate Bill 2408, the Climate and Equitable Jobs Act ("CEJA"), and Governor Pritzker signed it into law on September 15, 2021. Among other things, CEJA provides for the elimination of fossil-fueled generation in Illinois by 2045. This includes approximately 1,800 MW of gas-fired simple cycle CTGs owned and operated by Ameren Missouri within the state of Illinois. While the headline date of 2045 applies to some fossil-fueled generators, Ameren Missouri's Illinois CTGs are subject to specific provisions that are expected to result in retirement of these units more quickly. First, the law requires generators owned by investor-owned utilities to be retired by January 1, 2040. Second, the law requires generators to reduce CO_2 equivalent emissions by half starting January 1, 2035. Third, the timeline for retirement is accelerated for generators in close proximity to statutorily designated Environmental Justice Communities. Of Ameren Missouri's CTG facilities in Illinois, Venice Energy Center is the only facility that is subject to this requirement. As a result, the Company expects Venice to be retired by January 1, 2030. In addition to the accelerated retirements, the Illinois CTGs are subject to emission limits in any rolling 12-month period equal to the average annual actual emissions during the calendar years 2018-2020. These limits are included in the reliability modeling performed by Astrapé Consulting and described later in this report.

Seasonal Capacity Needs

In the wake of Winter Storm Uri, the electric power industry has placed increased focus on seasonal reliability. Ameren Missouri has included consideration of seasonal capacity needs as part of its analysis supporting the selection of its new Preferred Resource Plan. On November 30, 2021, MISO filed with FERC proposed reforms to its resource adequacy construct, including the establishment of seasonal capacity accreditation and capacity auctions for each of four distinct seasons. Ameren Missouri has reviewed the proposed framework and included evaluation of the Company's capacity position for both winter and summer seasons, including assumed differences in seasonal capacity accreditation for its existing fleet of generators, using the framework proposed by MISO as an appropriate basis for consideration. For example, Ameren Missouri's CTG fleet frequently experiences gas supply constraints during the winter season that result in lower assumed capacity accreditation for those units during the winter. Capacity positions were not developed for fall and spring given the expectation that those seasons could be adequately covered if summer and winter requirements were met. FERC is expected to act on MISO's proposed reforms by the end of 2022. Ameren Missouri will continue to monitor the proceedings at FERC and incorporate any changes to the Company's resource planning process as appropriate. It is important to note that regardless of the outcome of proceedings at FERC regarding MISO's proposed seasonal capacity construct, seasonal capacity needs will continue to be a vital consideration in Ameren Missouri's resource planning process.

Capacity Prices

In April 2022, MISO released the results of its capacity auction for planning year 2022-2023, indicating that capacity prices were set to the cost of new entry ("CONE") for the North and Central regions. In the development of its 2020 IRP, Ameren Missouri adopted an approach to estimating annual market prices for capacity based on a long-term expectation for "residual pricing" that reflects the predominantly vertically integrated nature of the MISO membership. That is, because MISO members are predominantly vertically integrated utilities with IRP or other planning mechanisms designed to ensure sufficient capacity to meet resource adequacy requirements, market prices for capacity will typically reflect prices for capacity that is in excess of the aggregate demand and reserve margin requirement. These assumed market capacity prices are used to monetize long and short capacity positions in the alternative resource plans evaluated through the Company's integration and risk analysis. It is important to note that this approach does not presume that periodic spikes in capacity prices of the kind experienced in the recent MISO auction cannot occur, but rather reflects an expectation that high capacity prices will not be the norm. It is also important to note that with imminent generator retirements in Ameren Missouri's fleet, that long capacity positions are expected to be lower than they have been historically and that the Company's resource planning process is designed to minimize any short positions to less than 300 MW. As a result, assumed capacity prices are not expected to have as significant a potential impact on the relative economics of alternative resource plans as they have in the past. Ameren Missouri will continue to evaluate the potential for changes to its approach for developing assumptions for market capacity prices.

MISO Long-Range Transmission Planning

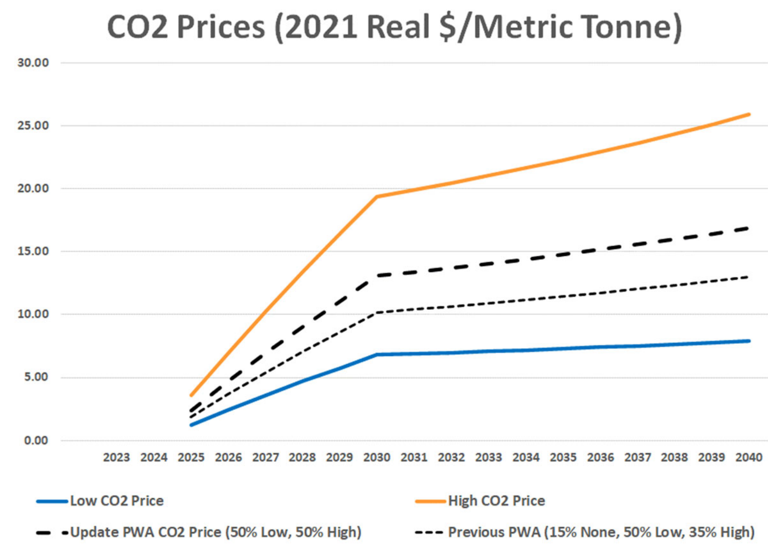
In early 2021, MISO published results of its LRTP effort, which evaluated the need for transmission infrastructure to support high levels of penetration of renewable wind and solar resources within MISO. Given expectations for continued policy direction at the state and federal levels to support greater levels of decarbonization and greater levels of renewable resources, Ameren Missouri has included estimated costs associated with the transmission infrastructure needs identified by the LRTP in its planning model assumptions. This assumption reflects an expectation that Ameren Missouri will be allocated a share of the costs of this transmission infrastructure in a manner similar to that used to allocate costs of Multi-Value Projects ("MVPs") over the last decade. As a result, this assumption is common to all the plans evaluated in the analysis and does not result in differences in costs between plans. However, it is important to recognize the potential impact of these costs on future rates, which are included in the results highlighted in this report.

CO_2 Prices

As part of the analysis to support the preferred plan change, Ameren Missouri revisited the assumptions for carbon pricing used in the 2020 IRP. In the 2020 IRP, the Company's management had assigned a 15% probability to the scenario with no carbon price, a 50% probability to the low carbon price scenario and a

35% probability to the high carbon price scenario. Following management review and discussion, management has revised the probabilities to reflect a 50% probability on each of the high and low carbon price scenarios with zero probability for the no carbon price scenario. The carbon price scenarios and the probability weighted average price under the prior and updated probabilities are shown in Figure 5.

Figure 5: Carbon Dioxide Emission Price Assumptions

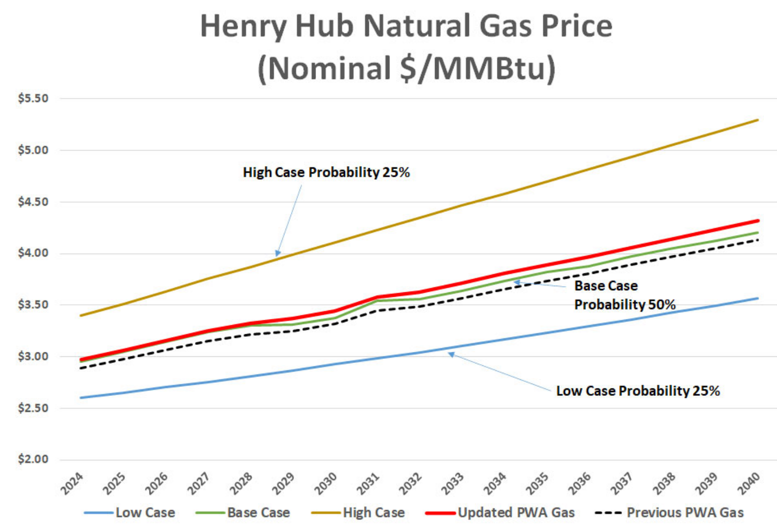


Note that as described in the 2020 IRP, the assumptions for carbon price do not presume a particular mechanism (e.g., carbon tax, cap-and-trade program, etc.) by which the carbon price is implemented. It can be explicit or implicit and may reflect expectations regarding potential regulations, including those that target other emissions associated with carbon-emitting resources. Ameren Missouri continues to monitor policy proposals and developments that may affect assumptions for carbon pricing.

Natural Gas Prices

Ameren Missouri has also revisited it assumptions for natural gas prices, particularly in light of recent price increases. Based on management review of supply and demand fundamentals and the risk of a shift in market dynamics due to recent geopolitical events, Ameren Missouri's management has shifted the probabilities for the high, base and low gas price scenarios. Figure 6 shows the three price scenarios, the revised probabilities, the new probability-weighted average price, and the prior probability-weighted average price. Ameren Missouri continues to monitor factors that may affect assumptions for natural gas prices.

Figure 6: Natural Gas Price Assumptions



The changes in probabilities for natural gas prices and carbon prices carry through to joint probabilities for resultant power prices and are reflected in the analysis of plans described later in this report.

<u>Other Potential or Emerging Factors</u>

In addition to the planning environment factors described above, Ameren Missouri continues to monitor other factors that may influence plan performance and planning decisions. One such factor is the potential for federal energy legislation. During 2021, a number of proposals were considered in Congress to support the decarbonization of the electric industry. These included proposals for carbon taxes, clean energy standards with varying timelines and penalties/incentives, incentive programs for expansion of clean energy, and extension and expansion of tax credits for clean energy projects. While such proposals have not yet been passed by Congress, the Company continues to monitor potential legislative policies.

On the federal regulatory front, Ameren Missouri also continues to follow efforts to promulgate changes in regulation of power plant emissions. This includes the Environmental Protection Agency's ("EPA") recently proposed changes to the Cross-State Air Pollution Rule ("CSAPR") with respect to ozone season NOx emissions. The Company is closely following this proposed change through the review and comment period and is evaluating the potential impact of requirements on its existing fleet and the potential options for mitigation. Upon the release by EPA of a final rule, the Company will determine whether and to what extent further changes to its preferred resource plan may be warranted. As described later in this report, the Company's planned addition of solar generation provides a measure of mitigation for potential impacts to coal-fired generation during the summer ozone season, when expected solar production is higher.

Supply Side Resources

Ameren Missouri continues to monitor changes and potential changes in the market for renewable energy projects, both through its own engagement with developers and through evaluation of secondary information sources. Based on the most recent such information, Ameren Missouri has updated the assumptions for wind and solar project costs. For its updated cost assumptions, Ameren Missouri used the most recent Annual Technology Basis ("ATB") assumptions from the National Renewable Energy Laboratory ("NREL"), starting with the moderate cost scenarios for each technology and shifting the cost curves to ensure consistency with current market costs. The updated assumptions for wind and solar resources are shown in Figures 7 and 8, respectively, along with the assumptions that were used in the 2020 IRP for comparison. Both show a relatively consistent long-term cost path after 2030, with higher prices in the near term. While the assumptions for both wind and solar show an expected decline, future costs are subject to certain risks. These risks have been described and quantified by Roland Berger, as explained later in this report.

Figure 7: Wind Project Cost ($/kW)

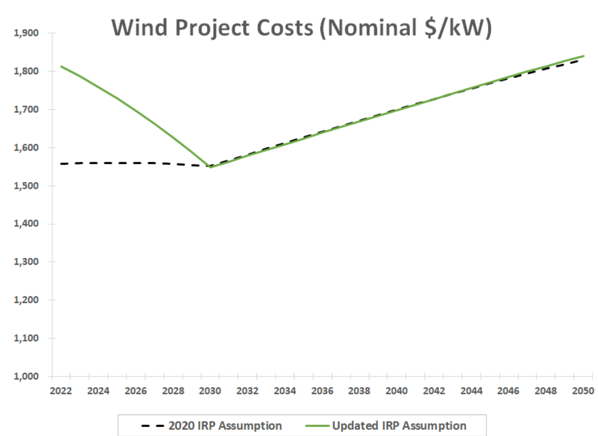
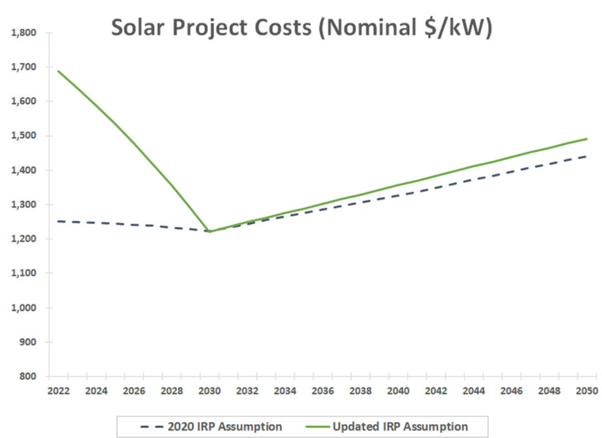


Figure 8: Solar Project Cost ($/kW-AC)



The Company also reviewed its assumptions for battery storage costs and performance and determined that the 2020 IRP assumptions were still appropriate. In addition to changes in the assumptions for the cost of renewable resources, Ameren Missouri has also updated its assumed overnight cost for NGCC generation to $1042/kW from $1245/kW in the 2020 IRP (both in 2019 dollars).[7] This cost change reflects expectations for design and scale optimization based on review by internal subject matter experts. The alternative plans analysis described later in this report also reflects the cost of firm gas transportation to ensure reliable operation of the units in all seasons. In considering the addition of NGCC generation during the planning horizon, Ameren Missouri is mindful of the benefits and risks associated with this resource type. Following is an overview of the benefits and risks associated with NGCC generation.

[7] The 2020 IRP assumed NGCC capacity of 824 MW. Updated analysis reflects 1,200 MW.

Benefits

- Proven highly efficient technology that can produce on demand.
- Superior flexibility to fill in gaps in wind/solar production and respond to rapid changes in load and renewable production.
  - Lower minimum operating levels than coal.
  - Faster ramping response than coal – 75 MW per minute for a new H Class combined cycle plant vs. 5 MW per minute for the existing Sioux coal units.
- Less than half the carbon emissions per MWh produced compared to coal – 0.34 metric tons per MWh for a new combined cycle plant vs. 1.0 metric tons per MWh for the Sioux coal units.
- Capability to burn hydrogen blended with natural gas (20-30% hydrogen by volume today with increases expected).
- CO_2 emissions may be mitigated in the future through addition of CCUS (currently in demonstration phase).

Risks

- Exposure to regulation of CO_2 emissions (absent hydrogen and/or CCUS).
- Permitting may become more challenging over time (can be mitigated with early start).
- Requires firm fuel transportation (i.e., pipeline capacity) to ensure reliability.
- Fuel price volatility.

Depending on the continued development of low and no-carbon technologies, changes in fuel and power markets, and changes in climate and environmental policy, the level of operation of new NGCC and its resultant emissions could vary significantly in the future. Regardless of such potential variations in the planning environment and expected outcomes, the reliability and flexibility benefits of firm, dispatchable resources are critical to ensuring reliable and affordable electric service. The next section discusses the Company's latest analysis of reliability needs and the relative benefits of different types of resources in the context of Ameren Missouri's system.

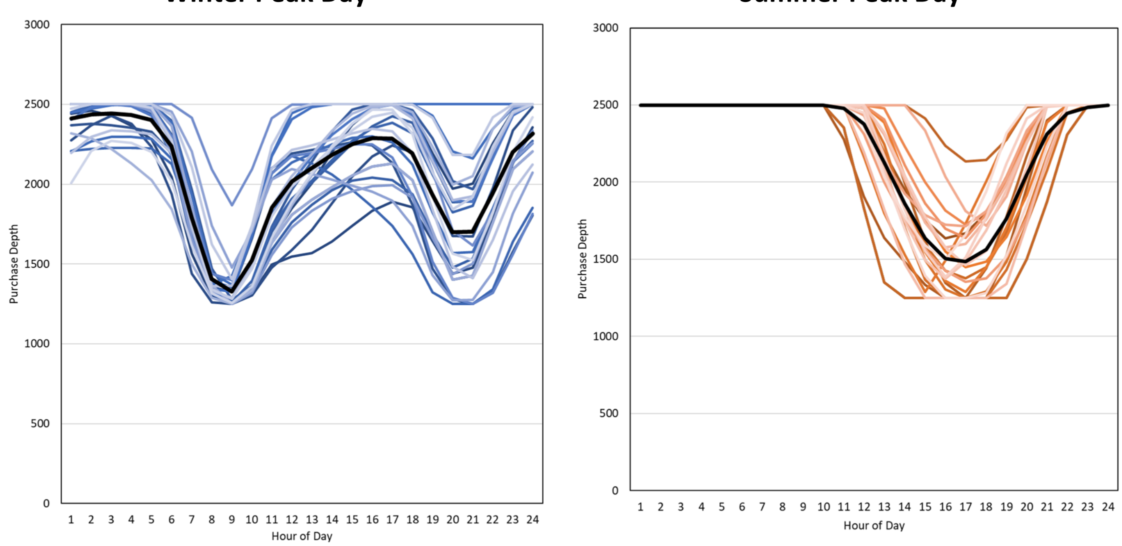
Reliability Analysis

As dispatchable coal and gas-fired resources continue to be retired and actual and expected additions of intermittent wind and solar resources continue to rise, it has become increasingly important in resource planning to conduct more rigorous analyses of expected system reliability. To help Ameren Missouri evaluate and consider the reliability implications of resource decisions, it has engaged Astrapé Consulting to evaluate the reliability of different mixes of resources and any potential associated risks or gaps. Astrapé uses its proprietary Strategic Energy Risk Valuation Model ("SERVM") to evaluate reliability in terms of the loss-of-load expectation ("LOLE"). The SERVM model is based on a resource adequacy framework which uses history as a guide for estimating future reliability. It uses up to 40 synthetic weather scenarios developed using neural networks, Monte Carlo generator outage draws, and economic commitment and dispatch on hourly or sub-hourly (5-minute) time steps. Astrapé has provided consulting and modeling services using SERVM in multiple Regional Transmission Organizations ("RTOs") and regions across the U.S. and Canada, including MISO, Southwest Power Pool, Tennessee Valley Authority, and the California Independent System Operator.

For its analysis, Astrapé modeled the Ameren Missouri system with planned loads, including energy efficiency and demand response and an assumed level of available resource support from the rest of MISO. Ameren Missouri supplied assumptions regarding the performance characteristics of its existing resources, including forced outage rates and constraints on emission and fuel supply. Fuel constraints are most notably applied to the operation of Ameren Missouri's CTG fleet during the winter heating season when gas may not be available on the coldest days when winter peaks are highest. CTGs were assumed to be unavailable for dispatch below 20 degrees Fahrenheit. Emission constraints include the constraints on Ameren Missouri's Illinois CTG fleet pursuant to CEJA, which limits emissions of each generator during any 12-month period to the actual annual average emissions during the calendar years 2018-2020. All cases analyzed reflect market support from MISO of up to 2,500 MW off peak and 1,500 MW on peak, with separate shapes for market support in winter and summer periods as illustrated in Figure 9. Market support varied as a function of weather – summer or winter extreme days saw lower periods of external support, whereas mild weather benefitted from greater amounts. The black line in each chart represents the average market support.

Figure 9: Summer and Winter Peak Day Market Support

Winter Peak Day | **Summer Peak Day**



A base case, Case 0, was calibrated to achieve an LOLE of 0.1, which corresponds to the standard of one day in ten years used by RTOs and other reliability organizations as the basis for establishing resource adequacy metrics such as MISO's planning capacity reserve margin. This was done to provide a baseline of reliability against which to measure reliability risks for other cases and does not necessarily indicate an absolute measure of current reliability for Ameren Missouri's system.

To isolate the reliability implications of anticipated resource decisions for Ameren Missouri's resource portfolio, Astrapé evaluated ten cases, with each case focused on a given year during the planning horizon and variations of resource mix in that year. Table 2 lists the ten cases that were evaluated. Cases were designed to evaluate relative reliability risks associated with different combinations of resources and determine the magnitude of additional resources that would be needed to achieve an LOLE of 0.1. Unless stated otherwise, all incremental battery additions were assumed to be 4 hours in duration.

Table 2: Cases Evaluated for Reliability Risks

Case Name	System Year	
Case 0	2022	Current System (Callibrated to 0.1 LOLE)
Case 1	2025	Rush Island Retired; 1,200 MW Solar Added
Case 2	2025	Rush Island Retired; No Solar Added
Case 3	2030	Sioux and Venice Retired; 1,200 MW Combined Cycle; 3,100 MW total Wind and Solar
Case 4	2030	Venice Retired (Sioux Operating, No CC); 3,100 MW total Wind and Solar
Case 5	2035	Sioux and Illinois CTGs Retired; 1,200 MW CC; 4,200 MW total Wind and Solar
Case 6	2040	Sioux, 2 Labadie Units and IL CTGs Retired; 1,200 MW CC; 354 MW Batteries; 5,400 MW total Wind and Solar
Case 7	2040	Sioux, 2 Labadie Units and IL CTGs Retired; 1,800 MW CC; 354 MW Batteries; 5,400 MW total Wind and Solar
Case 8	2040	Sioux, 4 Labadie Units and IL CTGs Retired; 2,400 MW CC; 354 MW Batteries; 5,400 MW total Wind and Solar
Case 9	2040	Sioux, 4 Labadie Units and IL CTGs Retired; 3,000 MW CC; 354 MW Batteries; 5,400 MW total Wind and Solar
Case 10	2040	Sioux, 4 Labadie Units and IL CTGs Retired; 1,200 MW CC; 1,540 MW Batteries; 5,400 MW total Wind and Solar

Cases 1 and 2 were designed to test the reliability contribution of adding solar generation to Ameren Missouri's portfolio in the near term. Cases 3 and 4 were designed to test the relative reliability contributions of the existing Sioux coal units and new NGCC generation, which the Company's capacity position analysis indicated are needed upon the retirement of Sioux. Case 5 examines the incremental impact on reliability of retiring the remaining Illinois CTGs beyond Venice and adding incremental renewable generation, relative to Case 3. Cases 6 and 7 were designed to examine the further reliability implications of retiring two Labadie units and adding incremental renewables and storage to the portfolio. Finally, cases 8, 9 and 10 were designed to examine reliability contributions of different combinations of storage and NGCC generation once all coal is retired, and the full renewable buildout is complete.

The results of Astrapé's modeling are summarized in Table 3. For each case, results are shown for LOLE as well as the "Deficit Found" – i.e., the magnitude of continuously available, fully dispatchable generation, or "perfect resources,", needed to achieve 0.1 LOLE – and, alternatively, the amount of 4-hour battery storage that would be needed to achieve 0.1 LOLE. It is important to note that conditions and assumptions may change that would alter the absolute LOLE results, so the Company focuses primarily on the comparative results across cases for each timeframe. Alternative plans continue to be designed to meet capacity reserve margin requirements, including consideration of winter capacity needs under MISO's proposed seasonal capacity construct. The absolute LOLE results do, however, serve as a measure of potential reliability risk for a given case and set of assumptions.

Table 3: Astrapé Analysis Summary

Year	2022	2025	2025	2030	2030	2035	2040	2040	2040	2040	2040
Case	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Rush Island	-	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178
Sioux	-	-	-	-974	-	-974	-974	-974	-974	-974	-974
Battery Storage	-	-	-	-	-	-	354	354	354	354	1,540
CCGT	-	-	-	1,200	-	1,200	1,200	1,800	2,400	3,000	1,200
Labadie	-	-	-	-	-	-	-1,186	-1,186	-2,372	-2,372	-2,372
CT Gas	-	-	-	-491	-491	-1,765	-1,765	-1,765	-1,765	-1,765	-1,765
Solar	-	1,205	5	1,605	1,605	2,000	2,700	2,700	2,700	2,700	2,700
Wind	-	700	700	1,499	1,499	2,200	2,700	2,700	2,700	2,700	2,700
LOLE	**0.1**	0.7	1.2	0.3	1.3	0.7	1.5	0.4	1.0	0.2	2.1
Deficit Found	-	696	858	346	999	488	907	417	709	196	817
4-Hr Battery Equivalent	-	766	963	346	1,195	488	1,458	488	1,178	196	N/A

In comparing the results of Cases 1 and 2, one can see that the inclusion of 1,200 MW of solar generation provides a measure of reliability risk mitigation, reducing LOLE from 1.2 in Case 2 to 0.7 in Case 1 and reducing the need for perfect resources by 162 MW. This implies an effective load carrying capability ("ELCC")[8] of 13.5% (162 MW divided by 1,200 MW) for the 1,200 MW of solar added in Case 1. This result reflects the fact that Ameren Missouri's system is subject to potential reliability challenges during winter morning and evening periods, as illustrated in Table 4, which presents a "heat map" of LOLE by month (horizontal axis) and hour (vertical axis) under normal conditions with Ameren Missouri's fleet as constituted in 2020.[9]

Table 4: LOLE by Month and Hour (2020)

	Month											
2020	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

[8] ELCC is a measure of the dependable capacity output associated with a resource and is commonly used by MISO and other RTOs to determine capacity credit values assigned to wind and solar resources.
[9] The values shown in Table 4 represent the contribution to total LOLE of each hour for all days in each month.

The heat map also shows potential reliability challenges during summer peak conditions. While the addition of solar resources does improve reliability, the benefits during winter peaks is limited. Note that this limitation is also reflected in the capacity credit assigned to solar resources in the winter capacity position.

Turning to Cases 3 and 4, one can see a significant reliability benefit from the replacement of the Sioux coal units with new NGCC generation, with LOLE improving from 1.3 in Case 4 to 0.3 in Case 3. This improvement can be attributed to a combination of the greater output capability of the gas generation (1,200 MW vs. 974 MW) and better reliability (equivalent availability over 95% for gas vs. 65% for the Sioux coal units by 2030). The new gas units also provide significantly greater flexibility, with the ability to ramp output up and down more quickly than the coal units, which becomes increasingly valuable as more intermittent wind and solar generation are added to Ameren Missouri's fleet and within MISO. The results for Case 5 indicate a potential increased risk associated with the retirement of the remaining Illinois CTG fleet as more wind and solar generation are added.

Cases 6 and 7 provide an indirect comparison of gas-fired generation with battery storage resources. Case 7 starts with the same portfolio analyzed in Case 6 and adds 600 MW of NGCC generation. The result is an improvement in LOLE – 0.4 for Case 7 vs. 1.5 for Case 6. The amount of perfect resources needed is reduced by 490 MW (417 MW in Case 7 vs. 907 MW in Case 6), and the equivalent amount of incremental 4-hour battery storage is reduced by 970 MW (488 MW in Case 7 vs. 1,458 MW in Case 6). This indicates that the ELCC for additional batteries beyond the 842 MW (354 MW plus 488 MW) included in Case 7 is roughly 50% (490 MW divided by 970 MW) of the maximum rated output for the batteries. This highlights an important consideration with respect to the deployment of battery storage, the reliability benefit of which depends on the net load shape (load less wind and solar generation) for a given system.

Figure 10 shows net load for a summer day and a winter day for the modeled 2030 renewable portfolio (~3,100 MW of wind and solar) with variations in output based on 39 historical weather years. The expected net load is indicated by the solid black line in each chart. The winter net load shape indicates a more limited role for storage resources than is indicated by the summer net load shape, with a relatively flatter net load, and thus a reduced opportunity to shift load to other times of day. As a result, one can see diminishing returns in terms of reliability for additional battery storage past a certain point. These diminishing returns are illustrated more explicitly in Figure 11, which shows the marginal and average ELCC for battery storage as a function of installed 4-hour battery capacity with a total of 5,400 MW of wind and solar resources. Figures 12 and 13 show samples of the variations in solar and wind production, respectively, for the first week in August across 39 weather years that underlie the summer and winter peak day net loads shown in Figure 10.

Figure 10: Summer/Winter Day Net Load with ~3100MW Renewables (2030)

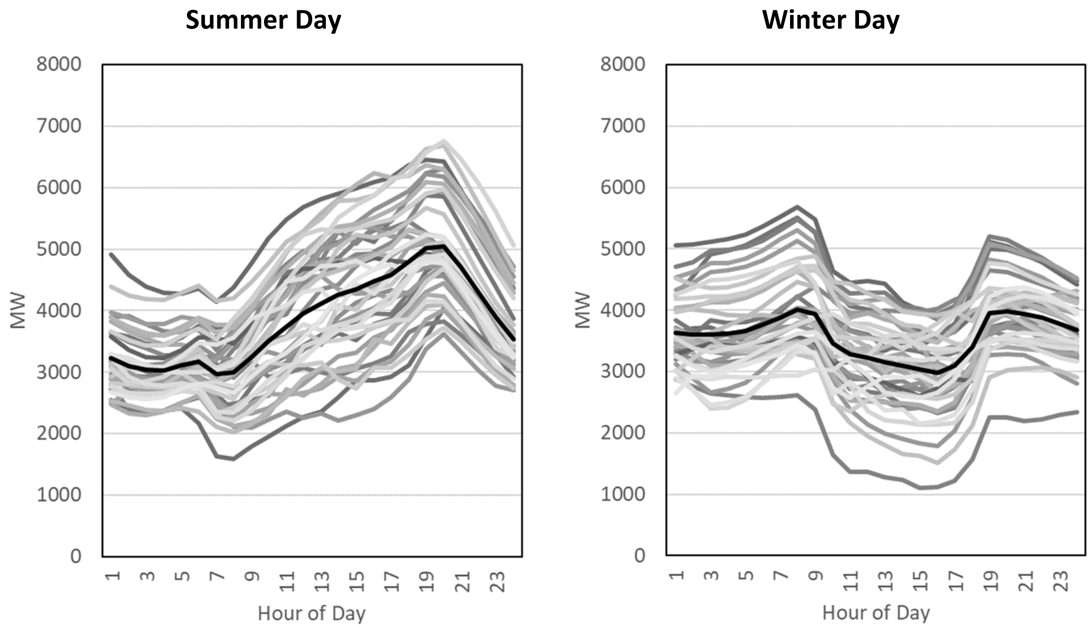
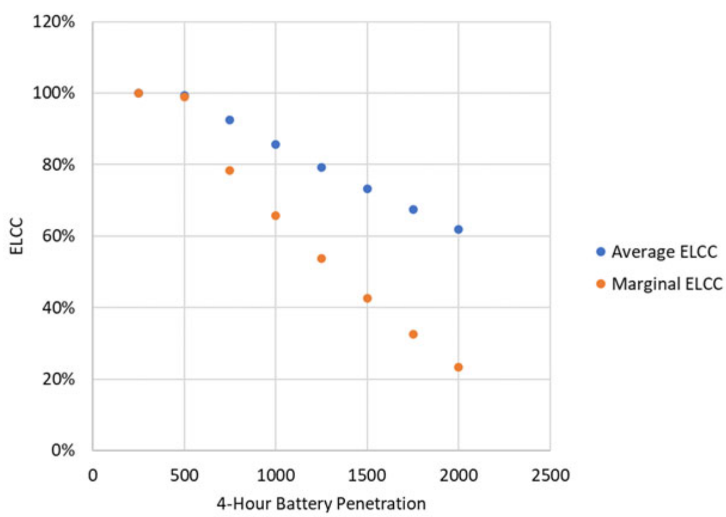


Figure 11: Benefit from Additional Battery Storage



As Figure 11 shows, once aggregate battery capacity reaches about 500 MW, the marginal benefit of additional battery storage begins to decline. As a result, meeting further reliability needs with battery storage as additional renewable resources are added and dispatchable resources are retired becomes increasingly more costly and/or dependent on significant improvements in battery storage technology. The insights discussed here on the diminishing returns of battery storage can also be applied to the incremental benefits of demand response and rate structures like time-of-use rates. These insights also indicate the potential for benefits of such programs and rate structures, along with battery storage resources, to "cannibalize" one another. That is, deployment of one such resource may reduce the potential benefits of other similar resources. This will be a focus area for continued resource planning efforts.

Figure 12: Solar Generation – First Week of August

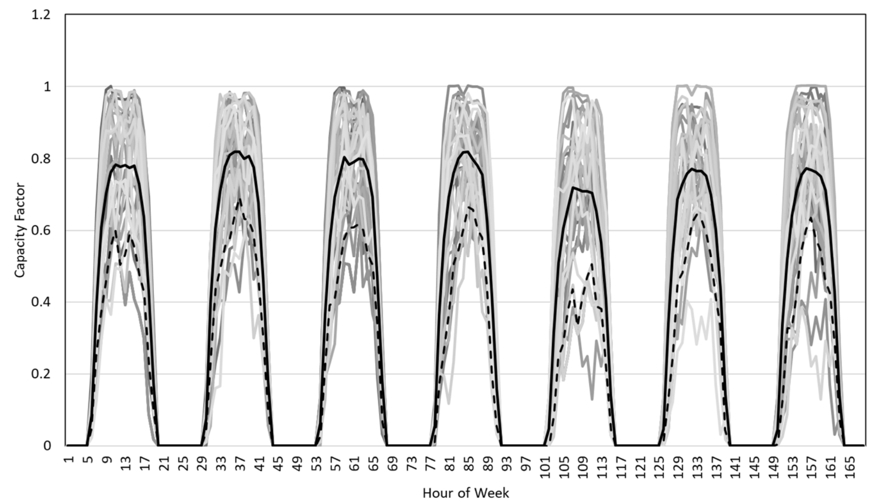
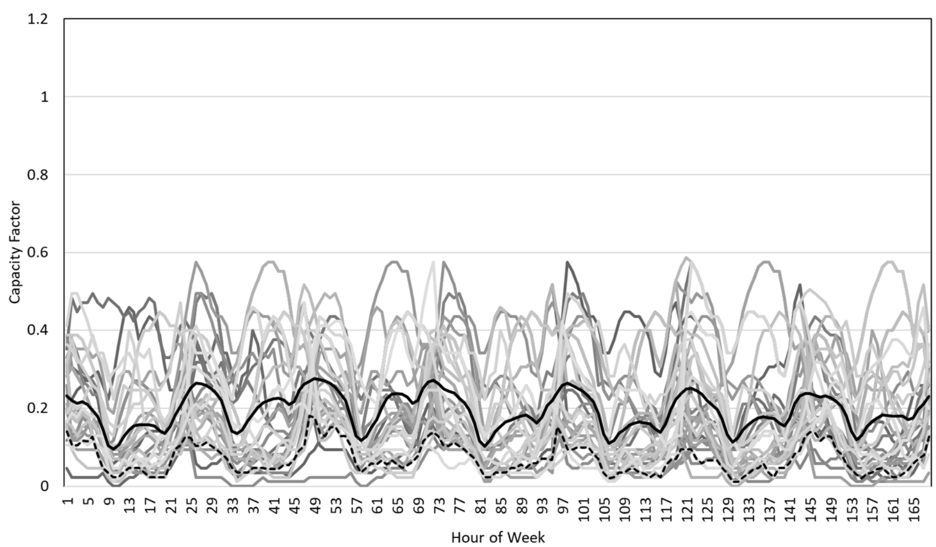


Figure 13: Wind Generation – First Week of August



Turning to the last set of cases, Cases 8-10, the Company examines the relative reliability benefits of gas-fired resources and battery storage in the context of the full deployment of renewable resources and the retirement of all coal-fired generation in Ameren Missouri's fleet. Case 9 starts with the portfolio modeled in Case 8 and adds 600 MW of NGCC generation, resulting in an improvement in LOLE from 1.0 to 0.2 and a reduction in the need for perfect resources by 513 MW. In contrast, Case 10 limits NGCC capacity to 1,200 MW and includes a total of 1,540 MW of battery storage, increasing LOLE to 2.1 and increasing the amount of perfect resources needed to 817 MW. Notably, the SERVM model could not solve for sufficient additional battery storage to achieve 0.1 LOLE, further demonstrating the limits of benefits resulting from greater levels of short-duration (i.e., 4-hour) battery storage and the benefits of dispatchable resources such as NGCC generation. It is clear that given this storage penetration on the Ameren Missouri system, firm resources or longer duration battery storage will be necessary to achieve resource adequacy targets.

The reliability analysis described here provides useful insights and guidance as the Company thinks about the continued transition of Ameren Missouri's resource portfolio. Ameren Missouri will continue to employ this kind of rigorous reliability analysis to inform Ameren Missouri's resource planning efforts, including the evaluation of reliability benefits of demand-side resources. Ameren Missouri will also continue to engage with MISO's resource adequacy efforts to ensure that the framework continues to provide necessary reliability for customers and useful guidance for long-term resource planning.

<u>Renewable Transition Risk Analysis</u>

Renewable resources will play a critical role in the transition of Ameren Missouri's generation portfolio. Renewable resources are an abundant source of clean energy and can be deployed in manageable increments. The 2020 IRP indicated a need for 5,400 MW of new wind and solar generation, and the new Preferred Resource Plan retains that key element of portfolio transition. The 2020 IRP described a host of risks inherent in waiting until Ameren Missouri is nearing a capacity shortfall and then attempting to rapidly deploy thousands of megawatts of renewable energy resources. In December 2021, Ameren Missouri filed additional analysis of the relative risks to customers and shareholder of such a large and rapid deployment. To support further investigation and quantification of the risks faced by customers, Ameren Missouri engaged Roland Berger, a consulting firm with extensive experience in electric utility planning and analysis. Ameren Missouri has integrated the results of Roland Berger's work into its resource plan analysis, as described later in this report. In this section, the Company describes its updated assessment of transition risks and the work performed by Roland Berger to characterize and quantify certain of these risks. Roland Berger's report is attached to this report as Appendix A.

The key question at hand in performing the transition risk assessment is whether customers, investors, communities, and the environment are best served by a continuous and incremental deployment of renewable resources over time or by an approach in which renewable resources are only added at the time of a need for capacity to meet load and planning reserve margin requirements. As was the case with the 2020 IRP, Ameren Missouri has evaluated two different alternative resource plans – one representing each of these two different approaches to renewable transition. These plans formed the basis for the Company's updated risk analysis and the basis for the risk assessment performed by Roland Berger. The resource timelines in Figures 14 and 15 illustrate, respectively, the key elements of the two plans – the "Renewable Transition Plan" and the "Capacity Need Plan" – with the key difference between the two plans being the timing of renewable additions.

Figure 14: Renewable Transition (Preferred) Plan Resource Timeline

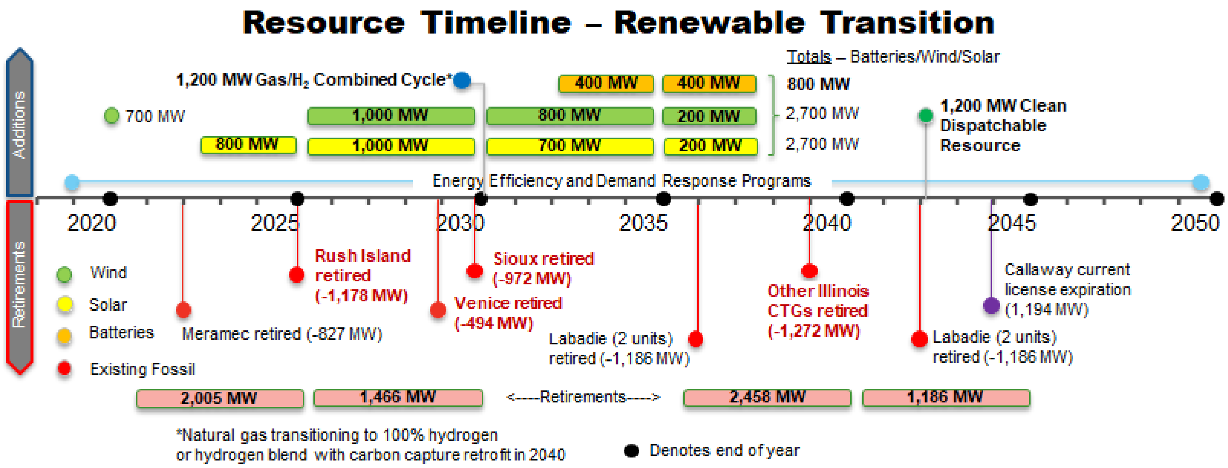
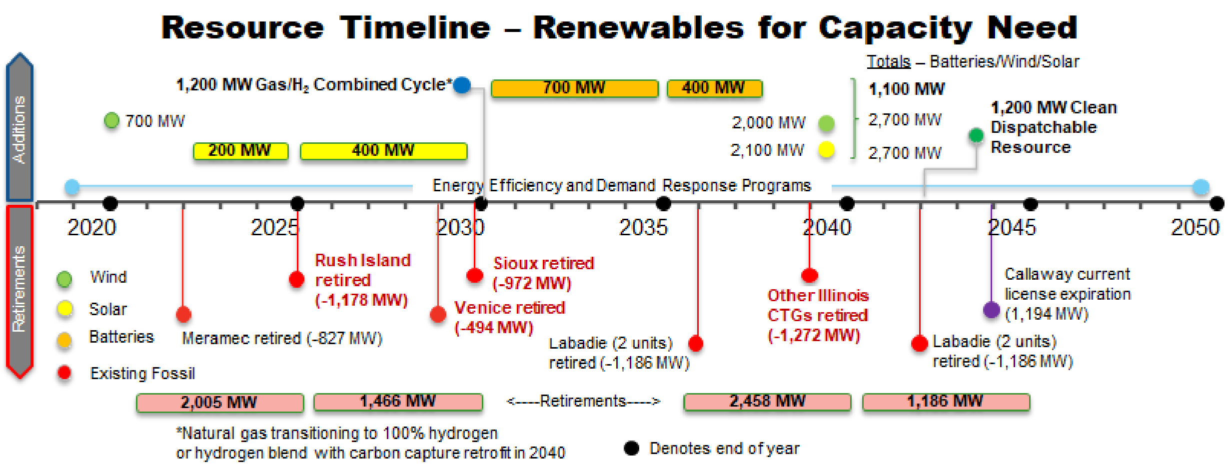


Figure 15: Capacity Need Plan Resource Timeline



The Renewable Transition Plan includes a sustained series of investments in wind and solar generation resources over the next 20 years. This sustained approach provides substantial mitigation of risks associated with the inevitable transition of Ameren Missouri's generation portfolio to cleaner sources of electricity. Such risks include risks associated with expectations of a price on carbon emissions and the resulting impact on the market price for power. They also include risks of implementation, including project development and construction, and siting and construction of enabling transmission investments, all of which are complex and challenging, as experience in the industry has shown. A sustained transition also provides opportunities to capitalize on more attractive projects that may not be available in the future, and guards against rapid changes to other portions of the generation portfolio that may result from changes in energy policy or market conditions, such as a federal clean energy standard, increased requirements under Missouri's Renewable Energy Standard, or changes in regulations targeting coal generation emissions. Another benefit of a sustained transition is the potential for financing cost advantages available to utilities that demonstrate a commitment to portfolio transition, including the potential for green bonds. Finally, a sustained transition supports ongoing operational learnings to ensure continued system reliability as Ameren Missouri and the entire U.S. power industry significantly increase their reliance on intermittent renewable resources and reduce overall carbon emissions. The risk mitigation provided by the planned sustained transition could not be provided by a plan that reflects deployment of new renewable resources only when new capacity is expected to be needed, which the new Preferred Resource Plan estimates would not occur until more than 15 years from now.

To provide important context regarding the Company's risk assessment, it is important to think about the rationale for the planned transition represented in the Renewable Transition Plan and the risks of delaying that transition. While certain risks may prove over time to be more significant than others, the approach represented in the Renewable Transition Plan addresses them collectively and in a manner that ensures flexibility to adjust to changing conditions so the Company can continue to ensure reliable and affordable electric service for its customers. The key risks are:

- Changes in Energy Policy – The Biden administration has maintained a focus on transitioning the U.S. power system to net zero carbon emissions by 2035 through a combination of legislative and regulatory action. The enactment of federal or state policies, such as Clean Energy Standards ("CES"), changes to state Renewable Energy Standards ("RES"), or the imposition of an explicit price or tax on carbon emissions continues to receive serious attention. Such policies, which could be enacted in any number of combinations, would likely further accelerate the need for renewable resources and challenge the supply chains for labor, equipment and other goods and services that are needed for the deployment of renewable resources. They could also necessitate further acceleration of the retirement of coal-fired resources, resulting in a need for new energy resources much sooner than otherwise expected. While the outcome of potential legislative efforts at the federal level remains uncertain, the appetite for policies, both legislative and regulatory, encouraging a more rapid transition continues to remain strong. Policy changes could also be implemented through regulation under existing law. One example is the proposed revision to the CSAPR ozone season NOx regulations, which is expected to be finalized later this year. Ameren Missouri will be evaluating compliance options once a final rule is published. Finally, renewable tax credit extension and/or expansion has been considered in legislative proposals and could provide additional economic benefits for a more distributed transition to renewable resources.

- Carbon Pricing – As demonstrated in the Company's 2020 IRP filing, the economics of various resources are sensitive to assumptions for carbon emission prices and may drive consideration of changes to the timing of resource retirements and additions. This is particularly true for coal-fired resources but is also significant for renewable resources which benefit from the inclusion of such charges in the market price of power. In light of this reality, while the Renewable Transition Plan represents a purposeful balance of risks and benefits based on reasonable assumptions today, that may change. The carbon price assumptions used for the Company's resource plan analysis are shown in the Planning Environment section of this report.

- Implementation Risks – The potential challenges of deploying over 5,000 MW of wind and solar resources should not be underestimated, and such challenges have been evident in the Company's implementation of new resources already. Potential challenges are present in every stage of implementation, including project planning, siting, permitting, contract negotiation, construction, commissioning, testing and transmission interconnection. Waiting to begin the deployment of renewable resources allows these potential challenges to compound, particularly in the context of any nationwide clean energy policies that may be enacted. As previously mentioned, the Biden administration has maintained a focus on transitioning the U.S. power system to net zero carbon emissions by 2035 through a combination of legislative and regulatory action. Should those efforts or subsequent such efforts be successful, the challenges of implementation will be further magnified. Waiting to begin deployment of renewable resources also risks lost opportunities with respect to higher quality projects that may not be available later.

- Reliability Risks – Deployment of over 5,000 MW of new wind and solar resources also requires a particularly deep focus on integration and reliable operation of these new renewable generation resources to ensure the Company can continue to provide the reliable energy supply upon which all its customers depend. The experience of Texas and other regions during the winter of 2020-2021 highlights the need to ensure that resources, systems, regulatory processes, and market mechanisms are in place and properly coordinated to ensure reliability of critical energy services to customers. Other lower probability, high impact events must be considered to ensure reliability at the most critical times. It is therefore vitally important to deploy new renewable generation in a continuous and balanced manner to allow for operational learnings over an extended period, while existing coal-fired generation is available to provide reliability services. Through that methodical deployment of new renewable resources, the Company can fully understand how best to optimally and reliably operate the renewable generation portfolio that will replace much of its current generation portfolio, and system operators and regulators can implement necessary measures to ensure reliability with confidence.

- Financing Risks – Investors and financial analysts continue to be focused on utility company plans and progress on portfolio transition and sustainability. Access to lower cost debt may become increasingly tied to a utility's ability to demonstrate concrete plans and progress on transition and establishing and meeting sustainability goals. At the same time, we see indications that financing costs are likely to rise in the future, so taking advantage of lower cost financing in the near term can provide economic benefits to customers over the long term. Ameren Missouri has included consideration of financing cost risks in its transition risk analysis and economic analysis of alternative plans, as described later in this report.

As mentioned previously, Ameren Missouri engaged Roland Berger to analyze, and where possible quantify, key risks associated with a delayed transition. Table 5 lists the risks evaluated by Roland Berger and the extent to which quantification of each could impact PVRR. Note that some risks could have a more significant impact on revenue requirements and rates than has been quantified, but the ability to quantify them to a greater degree is limited. For example, as more and more renewable projects are executed in

MISO, the challenges of ever greater needs for transmission infrastructure could limit the ability to connect new projects. Transmission congestion issues can also fluctuate over time as new generation and transmission infrastructure are added to the grid.

Table 5: Key Risks of Delayed Transition

	Variable	Assessment	Estimated Impact on PVRR
Renewables costs	Land availability	• We expect lower capacity factors for wind and solar in the "Capacity when needed" plan given expectation that more attractive areas are limited and will continue to be built out	●
	Financing costs	• Ameren will likely face higher financing costs under its "Capacity when needed" plan due to limited investor willingness to finance CO2 heavy generation portfolios	●
	Tax credits	• The proposal in the Build Back Better plan to extend the PTC and ITC may still pass separately	●
	Equipment costs	• Solar and wind equipment cost declines likely to be less pronounced than what NREL ATB predicts • Assumed step-change in wind technology performance not be applicable to high-capacity factor areas such as the U.S. Midwest	◕
	Interconnection costs	• Available MISO and SPP interconnection data indicate a range of $50 / kW to $200 per kW • We expect longer interconnection distances as more attractive land near transmission is developed over time	◑
	MISO congestion	• The relationship between congestion and transmission capacity appears to be inconclusive • SMEs suggest that there are multiple drivers for congestion beyond transmission capacity and project development • Our analysis of congestion pricing indicates a low potential impact to PVRR	◔
	Labor costs and availability	• The relationship between labor shortfalls and construction and O&M costs is not significant enough to change CapEx or O&M assumptions	○
	Operational learnings	• The relationship between operational efficiency and O&M costs is not significant enough to change operating cost assumptions	○

○ Low Impact ● High Impact

Table 6: Incremental Cost of Delayed Transition

Risk Variable	Description	Change in PVRR[10]
Financing Costs	Fossil-heavy generation portfolios likely to have higher financing costs than cleaner and less carbon-intensive portfolios	$ 292 million
Land availability	Continued renewable build out will make “good land” scarcer over time, limiting capacity factors for wind	$ 247 million
Wind equipment Cost	Wind equipment cost declines and performance improvements may be less pronounced than NREL ATB assumes	$ 122 million
Solar equipment cost	Onshoring of solar PV equipment manufacturing as consequence of trade relations with China may result in higher costs	$ 59 million
Tax Credits	Extension of ITC and PTC per the proposal in the Build Back Better plan done through separate congressional action	$ 339 million

Table 6 shows the estimated impact on relative PVRR of the Capacity Need Plan (i.e., wait until there is expected to be a capacity shortfall and then rapidly build-out large quantities of renewables) compared to the Renewable Transition Plan (as reflected in the new Preferred Resource Plan). The risks and PVRR

[10] Positive PVRR change indicates that the Capacity Need Plan gets relatively more expensive than the Renewable Transition Plan over study period.

impacts shown in Table 6 are described in detail in Roland Berger's report in Appendix A. The first four risks listed – all but "Tax Credits" – are included in the Company's economic analysis of alternative plans. The PVRR impact of "Tax Credits" was excluded since it is contingent on action by Congress. Should Congress pass tax credit extensions, the value of extended tax credits will mean there are additional benefits from following the Renewable Transition Plan.

A key element of Ameren Missouri's resource planning process is the assessment of risks that could affect the costs of resource decisions for customers. Ameren Missouri analyzes such risks in accordance with the Commission's IRP rules, specifically the risk analysis provisions set forth in 20 CSR 4240-22.060, and describes the assumptions, analytical approach and results of this analysis in Chapters 9 and 10 of the 2020 IRP filing. The 2020 IRP risk analysis considered a number of variables, or uncertain factors, which might have a significant impact on the performance of the various alternative resource plans the Company evaluated. The Company considers both dependent and independent uncertain factors. Dependent uncertain factors are those that exhibit a strong interdependent relationship with other uncertain factors. These generally include variables that have a direct bearing on the market price of power – natural gas prices, prices on carbon emissions, and the growth of demand across the market. Independent uncertain factors are those that do not exhibit a strong interdependence with other uncertain factors. These generally include financing costs (interest and equity returns), capital costs for new resources, resource operating characteristics (e.g., forced outage rates, variable O&M expense), DSM costs and energy savings, and prices for non-carbon emissions (e.g., SO_2, NOx). Of the uncertain factors evaluated, several were found to be critical to the comparative evaluation of alternative resource plans. They include dependent uncertain factors – natural gas prices and carbon emission prices – that together define nine scenarios for power market prices. They also include two independent uncertain factors – load growth and DSM program costs. Ameren Missouri continues to include these uncertain factors as part of the analysis of plans in support of this Preferred Resource Plan change notification. For more on the testing and selection of critical uncertain factors, see Chapter 9 of the 2020 IRP.

<u>Shareholder Risks</u>[11]

IRP risk analysis is focused on risks from a customer perspective. Investor risks are considered in the assessment of plans through the financial and regulatory risk objective included in the Company's scorecard evaluation of alternative resource plans using both quantitative and qualitative factors. These factors include quantification and comparison of free cash flows and qualitative assessments of risks associated with financing and recovery of potential stranded costs. To provide more direct quantification of shareholder risks associated with the planned portfolio transition, the Company can consider categories of risks to return of and return on the investment by shareholders. Key categories of such risks are:

- Project Management Risk – the risk of mismanagement of project execution resulting in disallowances from rate recovery.

[11] The Company also addressed these risks in its December 15, 2021*, Response Regarding Detailed Analysis Required by the Commission's Order Regarding 2020 Integrated Resource Plan*, File No. EO-2021-0021.

- Retail Sales Risk – the risk that retail sales through which investment returns are realized do not materialize as expected.
- Regulatory Risk – the risk that inefficiencies in the regulatory and ratemaking processes will prevent full realization of expected and/or allowed rates of return.

Shareholder risk can be quantified in general by considering the capital revenue requirements associated with the investments. The PVRR for the investment component of the planned renewable transition is approximately $4.5 billion. A recovery loss of 2-5% of this revenue requirement would be $90-225 million.

For additional context, the first-year revenue requirement for the capital costs of a wind project with a 30-year economic life is approximately 13% of the initial investment, and the average annual capital revenue requirement over the life of the wind project is approximately 8% of the initial investment. This indicates that even small delays in the recovery of new wind resource investments could have significant impacts on investor returns even absent the other risks described above. The same would be true for solar resource investments. While shareholder risks cannot be more specifically defined or estimated with any degree of confidence, the analysis presented here provides an indication of the potential magnitude of the collective range of risks to shareholders that can be compared to the customer risks described earlier in this document.

Alternative Plans and Risk Analysis

To assess key alternatives in light of the planning environment changes described earlier in this report, Ameren Missouri has evaluated several alternative resource plans. In addition, the 2020 IRP preferred plan was also analyzed under the updated assumptions described in this report for comparison to the new Preferred Resource Plan across the various performance measures. The plans analyzed are:

A. 2020 IRP Preferred Plan
B. Renewable Transition with Sioux retired at the end of 2028 and 1,200 MW NGCC generation in service at the beginning of 2029
C. Renewable Transition with Sioux retired at the end of 2030 and 1,200 MW NGCC generation in service at the beginning of 2031
D. Renewable Transition with Sioux retired at the end of 2033 and 1,200 MW NGCC generation in service at the beginning of 2034
E. Renewables for Capacity Need with Sioux retired at the end of 2030 and 1,200 MW NGCC generation in service at the beginning of 2031
F. Renewable Transition with Maximum Achievable Potential ("MAP") demand side management ("DSM"), Sioux retired at the end of 2030 and 1,200 MW NGCC generation in service at the beginning of 2031

Each of Plan B, C, D and F include the renewable additions shown in Figure 12. Plan E includes the renewable additions shown in Figure 13. Retirement of Rush Island Energy Center was assumed at the end of 2025 for analysis purposes, pending final action by the U.S. District Court. Variation from that retirement date is not expected to affect other resource decisions. Plans A, B, C, D and E each include Realistic Achievable Potential ("RAP") DSM. Plans B, C, and D were used to inform decisions around the concurrent retirement of the existing Sioux coal units and the addition of NGCC generation in light of the results of the reliability analysis performed by Astrapé and described earlier in this report. The decisions regarding that concurrent timing include consideration of the time needed to implement new NGCC generation and the risks of operating the Sioux coal units beyond the prior expected retirement date of 2028.

It should be noted that Plan F included NGCC generation in 2031 just as Plans C and E do because the additional load reduction from MAP DSM is not sufficient to avoid the NGCC addition. Ameren Missouri has initiated a new DSM market potential study, which is expected to be completed in the first quarter of 2023 and will be a key input for the Company's 2023 IRP, which is due by October 1st of that year. As part of the 2023 IRP analysis, Ameren Missouri will assess the need for new capacity under a range of options for demand-side resources, including MAP energy efficiency and demand response. Whether or not higher levels of DSM than that reflected in the Company's most recent estimates of RAP DSM are both achievable and sufficient to defer, reduce, or eliminate the need for dispatchable generation resources, Ameren Missouri expects the need for significant new renewable energy resources to remain.[12]

Table 7: PVRR Results ($ Million)

	PVRR and PVRR Differences ($MM)	0%	50%	50%	<<<Probabilities
		No CO_2 Price	Low CO_2 Price	High CO_2 Price	Prob. Wtd.
A	2020 IRP Preferred Plan	75,361	76,594	78,946	77,770
B	Renewable Transition - Sioux 2028	77,277	78,172	79,934	79,053
C	Renewable Transition - Sioux 2030	77,181	78,116	79,933	79,024
D	Renewable Transition - Sioux 2033	77,092	78,085	79,973	79,029
E	Renewables for Capacity Need	77,307	78,502	80,811	79,656
F	Renewable Transition - Sioux 2028 - MAP	78,302	79,157	80,804	79,981
	Difference (Plan C vs. Plan E)	(126)	(386)	(878)	(632)

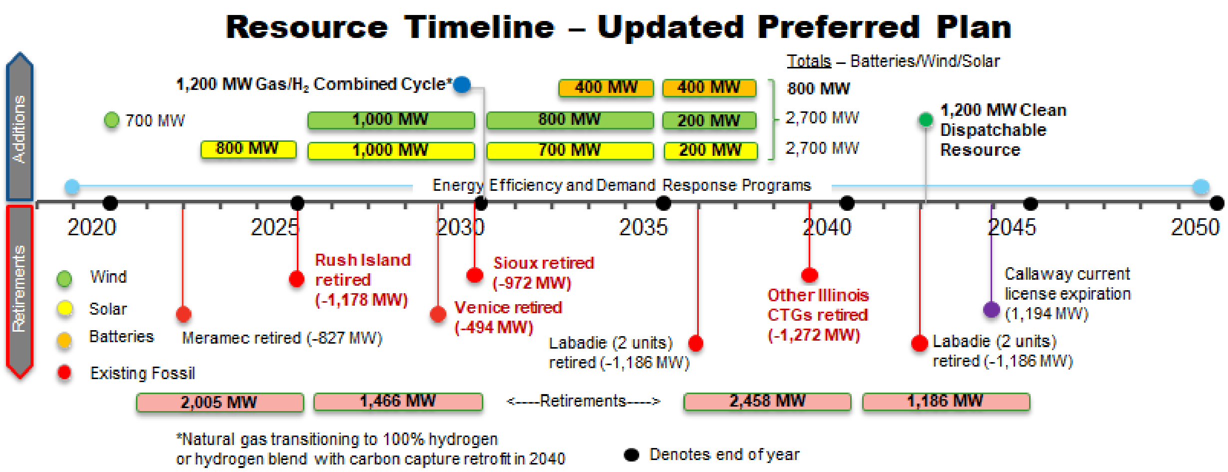
PVRR results for the six plans are shown in Table 7. Also shown is the difference in the PVRR results for Plans C and E, which differ by the timing of renewable additions, with all other resource retirements and additions being the same. Note that results are shown with no carbon price for reference only. As discussed previously in this report, management has updated the carbon price assumptions to reflect a 50% probability for each of the High and Low Carbon Price scenarios. As the PVRR differences show, the Renewable Transition Plan (Plan C) results in lower costs than the Capacity Need Plan (Plan E).

Preferred Resource Plan and Implementation

Based on the analysis of alternative plans and consideration of Ameren Missouri's planning objectives, management has selected Plan C as its new Preferred Resource Plan as shown in Figure 16.

[12] Assessing sufficiency must also include the need for resource flexibility, which Ameren Missouri will continue to evaluate through its current DSM market potential study and its ongoing reliability analysis.

Figure 16



Notifications of changes in a utility's Preferred Resource Plan are governed by 20 CSR 4240-22.080(12). This section requires that an electric utility notify the PSC in writing when its Preferred Resource Plan and/or Acquisition Strategy is no longer appropriate and that the notification must include the following:

- A description of all the changes to the Preferred Resource Plan and/or Acquisition Strategy.
- The impact of each change on the present value of revenue requirement and all other performance measures specified the last filing pursuant to 20 CSR 4240-22.080.
- The rationale for each change.

The Company is also required to file for review a revised Resource Acquisition Strategy, including specification of the ranges or combinations of outcomes of critical uncertain factors that define the limits within which the new Preferred Resource Plan remains appropriate.

Following is the specific information required for inclusion with the notification of a change in Preferred Resource Plan and/or Acquisition Strategy.

Description of (and Rationale for) Changes in Preferred Resource Plan and/or Acquisition Strategy

- **Early retirement of Rush Island Energy Center** – Ameren Missouri announced in December 2021 that it would seek a revised order from the District Court to change the required remedy resulting from the NSR litigation to retirement of the units rather than adding FGD equipment. Because the outcome of this process was not known at the time analysis for this Preferred Resource Plan change was performed, the retirement date was assumed to be the end of 2025. Any variance from this assumption is not expected to affect the other resource decisions reflected in the new Preferred Resource Plan.

- **Accelerated retirement of Venice Energy Center** – Pursuant to the requirements of Illinois law under CEJA, including the fact that Venice is located near an Environmental Justice Community as defined in the law, the units at Venice will be retired by the end of 2029.
- **Accelerated retirement of other Illinois CTGs** – Also pursuant to the requirements of CEJA, Ameren Missouri plans to retire the remaining Illinois CTGs by the end of 2039. This includes the units at the Goose Creek, Raccoon Creek, Pinckneyville and Kindmundy Energy Centers.
- **Delayed retirement of Sioux Energy Center** – In conjunction with the addition of NGCC generation and in light of the reliability risks identified and described herein, Ameren Missouri has chosen to delay in the retirement of Sioux Energy Center by two years from 2028 to 2030.
- **Addition of 1,200 MW of new NGCC generation** – To meet capacity planning needs and ensure reliability and flexibility of Ameren Missouri's portfolio to integrate the included wind and solar additions, the new Preferred Resource Plan includes the addition of 1,200 MW of NGCC generation in 2031, with plans to switch to hydrogen fuel and/or blend hydrogen fuel with natural gas and install carbon capture technology by 2040.
- **Changes in the timing of wind and solar additions** – To reflect current market conditions, available projects, and a more sustained plan for project implementation, the timing of wind and solar additions has been updated. The planned additions still result in total renewable generation of 5,400 MW, including the 700 MW of wind placed in service in 2020 and 2021.
- **Addition of 800 MW of battery storage resources** – To ensure sufficient capacity while limiting risks associated with additional gas-fired generation and recognizing the unique contributions of storage resources, Ameren Missouri has included 800 MW of battery storage resources in its new Preferred Resource Plan. Future IRP analyses will include comparisons of load-shifting resources, including energy storage, demand response, and demand-side rates to ensure a reasonable mix and aggregate deployment of such resources.
- **Increase from 800 MW to 1,200 MW of clean dispatchable resources in 2043** – While outside the 20-year planning horizon, Ameren Missouri is mindful of the need for new resources in the longer term as the last remaining coal-fired units are retired. With the Company's goal of achieving net zero carbon emissions by 2045, Ameren Missouri has assumed new resources added in this timeframe will be zero-emitting resources. The need for dispatchable capacity to ensure reliability and flexibility necessitate the increase from 800 MW in the prior preferred plan to 1,200 MW in the new Preferred Resource Plan.

Impact of Changes on Present Value of Revenue Requirements (PVRR) and Other Performance Measures

Ameren Missouri modeled its updated Preferred Resource Plan using the same model setup used for its 2020 IRP with updated assumptions as described in this report. A summary of the results for key performance measures for the new vs. prior Preferred Resource Plan is shown in Table 8. As the table shows, PVRR for the 2023-2050 period is increased by approximately $1.2 billion, or about 1.6%.

Table 8: Performance Measures Comparison

Performance Measures (2023-2050)	Prior Preferred Plan 2020 IRP	New Preferred Plan 2022 Update	Change	% Change
PVRR, $MM	$77,770	$79,024	$1,254	1.6%
Levelized Annual Rates, $/kWh	$18.66	$18.96	$0	1.6%
PV of Free Cash Flow, $MM	$6,638	$6,356	-$281	-4.2%
Cumulative CO_2 Emissions, Million Metric Tons	342	285	-57	-16.8%
PV of Probable Environmental Costs, $MM	$2,594	$2,524	-$70	-2.7%
Energy Savings, GWh	95,296	95,296	0	0.0%
Direct Jobs, FTE-Years	34,356	40,284	5,928	17.3%

(Note: "Net Jobs" reflects the total FTE-Years across the planning horizon for all direct jobs associated with implementation of new resources, including construction and operation {1 job over 10 years = 10 FTE years}; this measure does not reflect the number of new jobs produced at any particular point in time, which would be much lower)

Detailed Description of Revised Preferred Resource Plan and Acquisition Strategy

As discussed in the Company's 2020 IRP filing, the Resource Acquisition Strategy includes three main elements – the preferred resource plan, contingency planning, and an implementation plan for the years 2022-2024. The Preferred Resource Plan is described above.

Contingency Planning and Critical Uncertain Factors

Contingency plans may be triggered by either a change in critical uncertain factors or a change in other considerations that are critical to meeting the fundamental objective of the resource planning process. Based on prior analysis completed for the Company's 2020 IRP, critical uncertain factors include carbon prices, natural gas prices, load growth and DSM costs/performance. The new Preferred Resource Plan includes several near-term actions that will be pursued as part of the Company's implementation plan prior to the filing of the next triennial IRP filing (due by October 1, 2023). In light of this, contingencies are limited pending that new triennial filing.

Because implementation of renewable projects is subject to unique uncertainties and risks, Ameren Missouri seeks to maintain a steady pipeline of potential projects for implementation to mitigate these risks. This is consistent with the evaluation of transition risk described earlier in this report and for which Roland Berger has provided quantitative analysis. Regarding demand-side resources, Ameren Missouri has initiated a new DSM market potential study that will be a key input for the Company's 2023 IRP and is currently seeking new estimates of near-term demand-side resource potential through a direct market solicitation. These actions will continue to ensure that Ameren Missouri is identifying demand-side resource potential on a timely basis and is able to evaluate any impacts on other aspects of its resource acquisition strategy. Finally, the addition of NGCC generation is closely tied to the retirement of the existing coal units at Sioux Energy center. As implementation proceeds, it may be necessary to modify the final timing of unit retirements and additions to ensure system reliability during the transition. As shown in the PVRR analysis of alternative plans, changing the timing of Sioux retirement and NGCC additions has a relatively small impact on PVRR.

Because Ameren Missouri will be making its next triennial IRP filing in 2023, and because significant changes have been made to the preferred plan, a full revised Expected Value of Better Information ("EVBI") analysis including comparisons to the full range of alternative resource plans identified in the Company's 2020 IRP was not performed. Instead, comparisons have been made between the new Preferred Resource Plan and the prior Preferred Resource Plan across the ranges of values of the critical uncertain factors along with a small but meaningful set of other alternative plans. A table summarizing the Company's analysis of EVBI is presented in Table 9. Based on the analysis, the new Preferred Resource Plan is appropriate across most values for critical uncertain factors, with two exceptions. Under either low carbon prices or high gas prices, the PVRR is slightly lower ($30-35 million) for Plan D, which delays the retirement of Sioux and addition of NGCC generation by three years. Ameren Missouri will continue to monitor critical uncertain factors and provide updates through its regular IRP filings, including its next IRP annual update due by October 1st of this year.

Table 9: EVBI Analysis

Alternative Resource Plans		PVRR Without Better Info	Carbon Price		Natural Gas Price			Load Growth			DSM		
			Base	High	Low	Base	High	Low	Base	High	Low	Base	High
A	2020 IRP Plan	77,770	76,594	78,946	77,682	77,755	77,887	76,532	77,908	78,595	77,473	77,750	78,227
B	Renewable Transition-Sioux 2028	79,053	78,172	79,934	78,784	79,013	79,402	77,815	79,191	79,878	78,756	79,033	79,510
C	Renewable Transition-Sioux 2030	79,024	78,116	79,933	78,779	78,988	79,343	77,786	79,162	79,849	78,728	79,004	79,481
D	Renewable Transition-Sioux 2033	79,029	78,085	79,973	78,814	78,996	79,309	77,791	79,167	79,854	78,732	79,009	79,485
E	Renewables for Capacity Need	79,656	78,502	80,811	79,234	79,604	80,183	78,418	79,794	80,481	79,359	79,636	80,113
F	Renewable Transition-MAP	79,981	79,157	80,804	79,803	79,952	80,216	78,743	80,119	80,806	79,368	79,905	81,201
Minimum PVRR among plans			78,085	79,933	78,779	78,988	79,309	77,786	79,162	79,849	78,728	79,004	79,481
Plan with Minimum PVRR			D	C	C	C	D	C	C	C	C	C	C
Subjective Probability			50%	50%	25%	50%	25%	20%	60%	20%	10%	80%	10%
Expected Value of Better Info			31	0	0	0	34	0	0	0	0	0	0

Implementation Plan

Ameren Missouri's revised implementation plan for years 2022-2024 includes the following:

- Submitting applications for CCNs to the MPSC for solar generation projects.
- Applying for the creation of a Renewable Solutions program to help communities and large customers meet their sustainable energy goals.
- Issuing a new RFP to identify additional wind and solar project opportunities to support planned additions.
- Finalizing plans for the retirement of Rush Island Energy Center:
    - Completing the Attachment Y process with MISO.
    - Receiving a revised decision from the U.S. District Court reflecting early retirement as the means of compliance.
    - Finalizing plans for operation of the units until retirement.

  - Completing transmission system upgrades necessary to ensure reliability after retirement of the units.
- Adjusting depreciation expense for Sioux Energy Center to reflect retirement by the end of 2030 as part of Ameren Missouri's next rate review.
- Filing an application with the MPSC to securitize the remaining balance in rate base and other energy transition costs for Rush Island Energy Center.
- Conducting preliminary work for the development of new NGCC generation, including site studies, permitting, and engineering.
- Continuing to provide energy efficiency and demand response programs to customers to help them manage their energy costs and reduce the need for new generation resources, including any approved modifications to the Company's programs and budgets through 2024.

MARKET STUDY

The Risk of Ameren Missouri Delaying Renewable Development

Mike Granowski, Director; Ben Lowe, Principal

May 2022

Roland Berger

Table of Contents

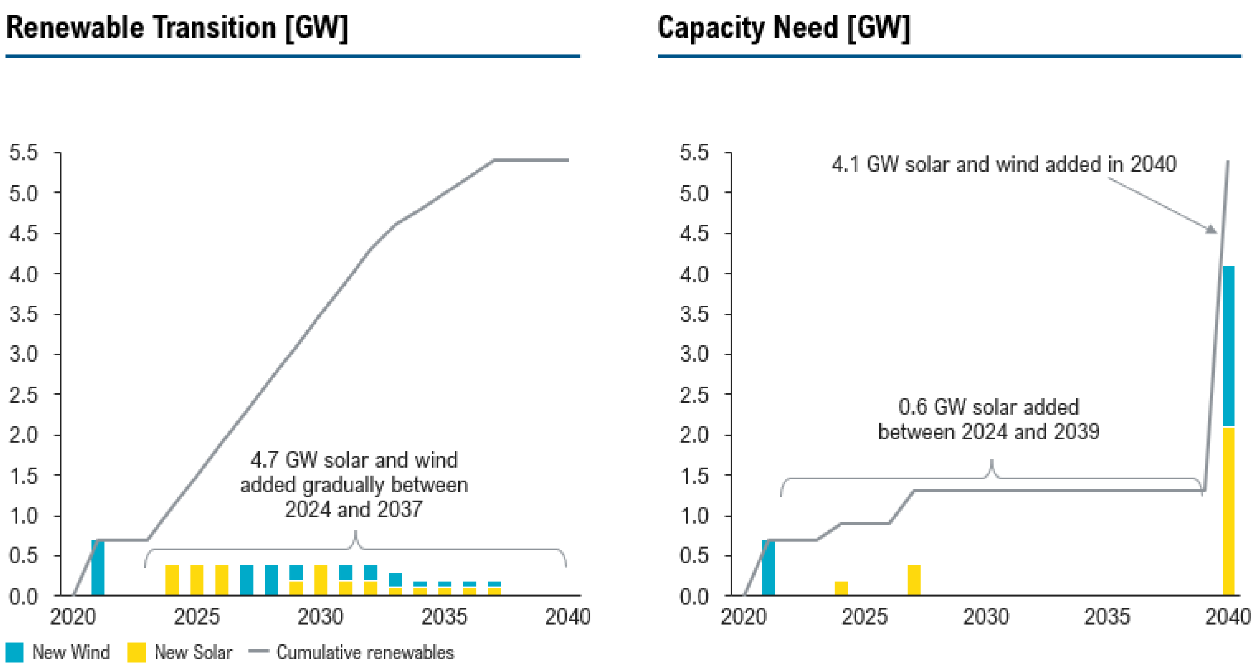
Table of Figures

1. Executive Summary

Ameren Missouri retained Roland Berger to analyze, and where possible quantify, the potential risks associated with delaying renewable energy deployment in Ameren Missouri's generation portfolio. The central analysis quantified the incremental difference in revenue requirement between Ameren Missouri's two proposed build plans from its new Preferred Resource Plan: Renewable Transition and Capacity Need.[1] Our analysis assessed the present value of the incremental change in revenue requirement for each of these cases broken out by individual risk variable.

Both plans include 4.7 GW of solar and wind additions, but they differ in timing and pace of deployment. The Renewable Transition plan builds solar and wind generation gradually from the early 2020s to the late 2030s, while the Capacity Need plan adds almost all new renewable capacity (4.1 GW) in 2040, when there is a capacity shortfall. Both build plans assume that solar and wind plants would be built in or near Ameren Missouri's service territory; Missouri, Illinois, Kansas, and Iowa are all potential locations and would be considered based on the best available project economics. Figure 1 details the capacity installed over time of the two build plans.

Figure 1: Ameren Missouri 2022 Change in Preferred Resource Plan Alternative Renewable Build Plans

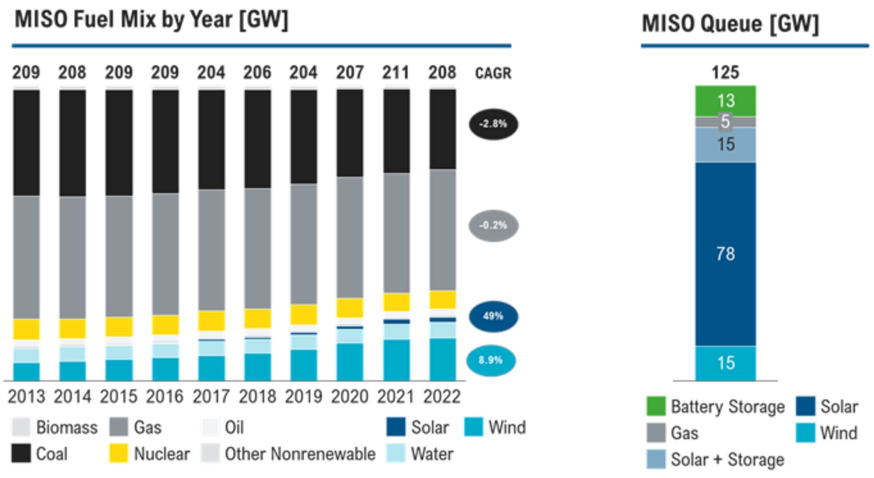


Source: Ameren Missouri

Across the United States and in MISO in particular, the transition to cleaner renewable energy sources has been underway for many years. Initially, the transition was largely driven by renewable portfolio standards and generous subsidies both at the federal and local levels. More recently, as the cost of renewable resources has declined, the transition has been driven more by economic considerations and demand from commercial and industrial customers. The last 10 years has seen 17.4 GW of wind and 3.7 GW of solar constructed in MISO representing compound annual growth rates of 8.9% and 49%, respectively. Although it is likely that less than half will see operation, the current MISO interconnection queue is dominated by renewable resources, with 15 GW of wind and 78 GW of solar (92.7 GW including solar + storage hybrid assets). Figure 2 details the growth of renewables over the last 10 years and the resources that currently comprise the MISO interconnection queue.

[1] Ameren Missouri 2022 Change in Preferred Resource Plan

Figure 2: MISO Historical Fuel Mix and Interconnection Queue



Source: S&P Global MI, MISO, Roland Berger

The fuel mix and generation queue in MISO indicate that the transition is accelerating. For this reason, we assessed potential risk factors that could impact project development costs and plant operational performance over time. We analyzed multiple risk variables and were able to quantify four key risks: financing costs, land availability, tax credits, and equipment costs. We were unable to quantify several other risk variables but addressed them qualitatively in the body of this report. Figure 3 below summarizes risk variables we were able to quantify and their potential impact on Ameren Missouri's renewable build alternatives (PVRR change between the Capacity Need and Renewable Transition plans). The Capacity Need plan is much more exposed to these risks than the Renewable Transition plan.

Figure 3: Risk Variables Impacting Ameren Missouri's Alternative Renewable Build Plans

Risk Variable	Description	Change in PVRR[2]
Financing Costs	Fossil-heavy generation portfolios likely to have higher financing costs than cleaner and less carbon-intensive portfolios	$ 292 million
Land availability	Continued renewable build out will make "good land" scarcer over time, limiting capacity factors for wind	$ 247 million
Wind equipment Cost	Wind equipment cost declines and performance improvements may be less pronounced than NREL ATB assumes	$ 122 million
Solar equipment cost	Onshoring of solar PV equipment manufacturing as consequence of trade relations with China may result in higher costs	$ 59 million
Tax Credits	Extension of ITC and PTC per the proposal in the Build Back Better plan done through separate congressional action	$ 339 million

Source: Roland Berger

[2] Positive PVRR change indicates that the Capacity Need plan gets relatively more expensive than the Renewable Transition plan over study period.

Further analysis breaking out the individual impacts of each risk variable on the incremental revenue requirements of each renewable plan, the underlying assumptions, and the third-party information on which we relied are discussed in Section 3 of the report.

2. Analytical Approach

2.1.1 Overview

Our analysis evaluated the central risks and uncertainties in Ameren Missouri’s build plans and assumptions underlying its 2020 Integrated Resource Plan ("IRP") filing, and build plans and assumptions reflected in the 2022 Change in Preferred Resource Plan. We assessed market data and trends in MISO and the four states of primary interest (Kansas, Missouri, Iowa and Illinois). We articulated key risk variables that could impact Ameren Missouri’s alternative renewable build plans from its recent IRP and assessed each using quantitative and qualitative methods. We aligned with Ameren Missouri on its base assumptions related to cost and operational performance for the "Renewable Transition” and "Capacity Need" plans. Through our independent financial and market modeling, we were able to quantify the incremental difference in revenue requirement for each case broken out by individual risk variable. After quantifying the impact of the risk variables, each variable was applied to both renewable build plans equally.

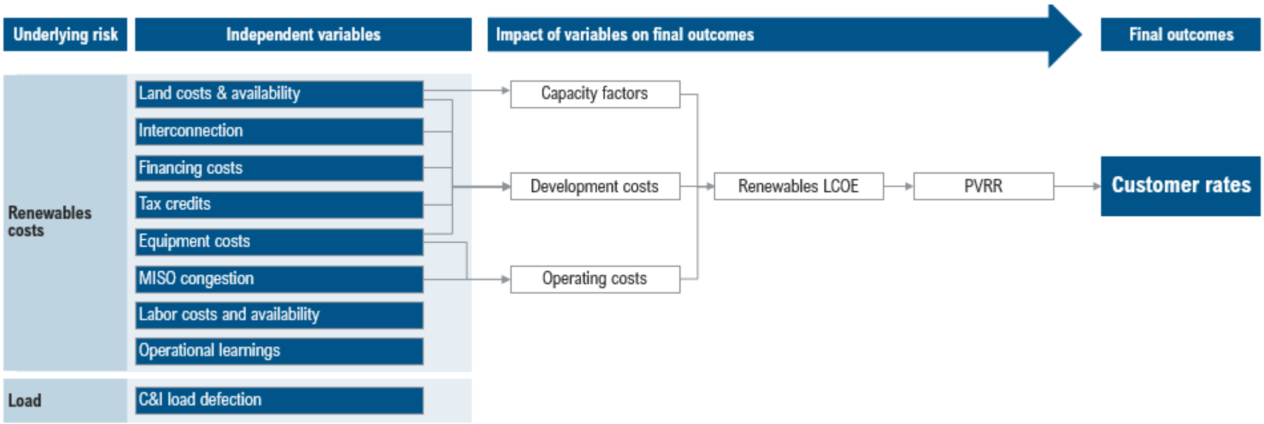
In developing our results, we utilized a range of public resources and databases, Ameren Missouri-specific data and subject matter expertise to inform our analysis. We interviewed experts in renewable project development, MISO power market operations, and renewable technology. We layered in data from energy organizations like the Energy Information Administration (EIA), the National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), and the U.S. Department of Energy (DOE). Using this information and our own expertise and analysis, we developed an objective view of the potential outcomes related to the key risk variables.

2.1.2 Methodology

In framing the analysis, Roland Berger reviewed and summarized existing Ameren Missouri materials, including its 2020 IRP filing and related documents. We accounted for updates since its last IRP, including commodity price forecasts, avoided costs, and options for fossil-fueled power plant retirements (e.g., Rush Island). Using Ameren Missouri’s input, we aligned on the planning horizon for the study and identified key assumptions like load growth and generation capacity supply and demand balance.

Having aligned on the base assumptions, Roland Berger identified key risk variables over the planning horizon that could impact the economics of Ameren Missouri's planned renewable deployment. During this phase of the study, we leveraged Ameren Missouri inputs on operational and financial data, internal and external subject matter expertise and primary source inputs to begin quantifying variables with direct and indirect impacts on Ameren Missouri’s alternative renewable plans. As shown below in Figure 4, we connected risk variables to specific inputs (e.g., renewable output, operational cost assumptions, capacity factors) and developed preliminary scenarios and assumptions for the Renewable Transition and Capacity Need plans.

Figure 4: Renewable risk variable and revenue requirement impact flow chart



Source: Roland Berger

As we researched each of the potential risk variables to delayed renewable deployment, we prioritized the most important, quantifiable variables and de-prioritized variables that did not have material impacts on the revenue requirement analysis. Our internal research, corroborated by external subject matter experts, concluded that land availability, equipment costs, tax credits and financing costs materially affected the cost to build renewables over the planning horizon. Factors like interconnection costs, congestion and potential load defection could still have economic impacts, however, they are much harder to quantify objectively. During this part of the analysis, we tested and refined our hypotheses regarding the prioritization of risk variables with Ameren Missouri. Figure 5 summarizes the risk variables that we assessed and qualitatively illustrates the weighted impact on PVRR results.

Figure 5: Renewable risk variable prioritization framework

	Variable	Assessment	Estimated Impact on PVRR
Renewables costs	Land availability	• We expect lower capacity factors for wind and solar in the "Capacity when needed" plan given expectation that more attractive areas are limited and will continue to be built out	●
	Financing costs	• Ameren will likely face higher financing costs under its "Capacity when needed" plan due to limited investor willingness to finance CO2 heavy generation portfolios	●
	Tax credits	• The proposal in the Build Back Better plan to extend the PTC and ITC may still pass separately	●
	Equipment costs	• Solar and wind equipment cost declines likely to be less pronounced than what NREL ATB predicts • Assumed step-change in wind technology performance not be applicable to high-capacity factor areas such as the U.S. Midwest	◕
	Interconnection costs	• Available MISO and SPP interconnection data indicate a range of $50 / kW to $200 per kW • We expect longer interconnection distances as more attractive land near transmission is developed over time	◑
	MISO congestion	• The relationship between congestion and transmission capacity appears to be inconclusive • SMEs suggest that there are multiple drivers for congestion beyond transmission capacity and project development • Our analysis of congestion pricing indicates a low potential impact to PVRR	◔
	Labor costs and availability	• The relationship between labor shortfalls and construction and O&M costs is not significant enough to change CapEx or O&M assumptions	○
	Operational learnings	• The relationship between operational efficiency and O&M costs is not significant enough to change operating cost assumptions	○

○ Low Impact ● High Impact

Source: Roland Berger

After incorporating land availability, equipment costs, renewable tax credits and financing costs into the PVRR model, we calculated the change in revenue requirement for each of the plans for each variable individually and then compared the change between the two plans to see which was more impacted. Although the PVRR impacts are additive, we presented the impacts individually to show the relative impact of each variable.

2.1.3 Data Sources

Databases

- Energy Information Administration 923 dataset for 2021 generation
- S&P Global for historical and pipeline solar and wind build; nuclear retirements; transmission lines and pipeline; mapping
- National Renewable Energy Laboratory (NREL) Geospatial Data Science Wind and Solar supply curve datasets
- 2021 NREL Annual Technology Baseline
- MISO Definitive Planning Phase (DPP) Phase 1 – 3 Reports

Reports

- U.S. Department of Energy, *Solar Photovoltaics – Supply Chain Deep Dive Assessment*, February, 2022
- National Renewable Energy Laboratory, *Land use and turbine technology influences on wind potential in the United States*, Lopez, A. et al., January, 2021
- National Renewable Energy Laboratory, *2021 Standard Scenarios Report: A U.S. Electricity Sector Outlook*, Cole, W. and Carag, J., November 2021
- U.S. Department of Energy, *Land-Based Wind Market Report – 2021 Edition*, August 2021
- International Energy Agency *World Energy Outlook 2021* for U.S. electricity generation growth projection and wind/solar breakdown
- Management Science, *Environmental Externalities and Cost of Capital*, Chava, S., September 2014
- MISO Transmission Expansion Planning Reports: 2019 – 2020
- Oxford University, *The Energy Transition and Changing Financing Costs;* Zhou, X., Wilson, C., Caldecott, B., April 2021

Expert interviews

- Former VP, Development – Central Region, IPP
- Manager, Product High Efficiency Modules, Solar manufacturer
- Chief Commercial Officer – Renewable Developer
- Renewables Director – Renewable Developer
- Software Developer – National Renewable Energy Lab
- Senior Vice President and Chief Customer Officer – MISO
- Product Manager – Solar Developer

Management Interviews

- Renewables Director – Ameren Missouri
- General Executive, Renewables – Ameren Missouri
- Renewable Development Manager – Ameren Missouri
- Market Intelligence Manager – Ameren Missouri
- Senior Director, Transmission Policy – Ameren Missouri
- Senior Director, Asset Management and Trading – Ameren Missouri

2.1.4 Models Used

Ameren Missouri Levelized Cost of Energy (LCOE) Model

We used Ameren Missouri's LCOE model for solar and wind to calculate the annual revenue requirements for the lifespan of the renewable generation assets. The solar and wind models assume 30-year lifespans. Capital cost inputs for wind and solar were based on the 2021 NREL ATB overnight capital cost forecast and vary annually through 2040. Revenue requirement was calculated using the appropriate fixed charge rate and was extracted from the "Total Cost" output, normalized on a USD/MW basis for later use in the PVRR model.

Ameren Missouri Fixed Charge Rate (FCR) Model

Roland Berger incorporated Ameren Missouri's FCR model outputs for wind and solar as levelized fixed charge rates to calculate levelized capital costs in the LCOE model. The FCR model calculates separately for wind and solar and is based on factors such as capital cost, depreciation schedule, financing assumptions, availability of tax credits, etc.

Ameren Missouri Revenue Requirement (PVRR) Model

We assessed the impact of each sensitivity on the revenue requirement for each plan. We did this by calculating the difference in revenue requirement between baseline assumptions and sensitivities developed for each variable. We adapted Ameren Missouri's PVRR model to assess the quantitative impact of variables in the alternative renewable development scenarios. We assumed a present worth discount rate of 6.04% for all cases.[3]

We used the base assumptions for both the Renewable Transition and Capacity Need plan and turned on each of the risk variables. After testing each risk variable, we calculated the forecasted revenue requirements for the Renewable Transition and Capacity Need plans. Next, we compared each scenario to the results with the base assumptions and calculated the difference. For each risk variable, the incremental change in PVRR between the Capacity Need plan and the Renewable Transition plan represents how much more (or less) expensive each build plan is relative to the other.

---

[3] Revenue requirements are in nominal USD.

3. Risk Variable Analysis

This section details the risk variables that impact Ameren Missouri’s alternative renewable build plans. Wind land availability, equipment costs, tax credits and financing (Sections 3.1 – 3.4) were assessed quantitatively and flowed through the LCOE, FCR, and PVRR models as described in Section 2. Interconnection costs, congestion costs, potential for load defection and solar land availability (Sections 3.5 – 3.8) were looked at qualitatively and did not impact the revenue requirement analysis.

3.1 Financing Costs

3.1.1 Overview

As mentioned in the Summary of this report, the transition to renewable energy has been accelerating across the U.S. An element of the economic reasons underlying the acceleration is the increasing preference by energy equity and debt investors for exposure to lower carbon portfolios over higher carbon portfolios. This preference is beginning to take the form of higher return requirements for the more carbon intensive portfolios.

3.1.2 Methodology

We based our analysis on secondary research sources along with an analysis of the market sources of Ameren Missouri's capital to estimate the prospect of higher financing costs for Ameren Missouri under the Capacity Need plan relative to the Renewable Transition. The Sustainable Finance Programme at the University Oxford in April 2021 published a study that found that borrowing costs for coal power plants increased from 2017 to 2020 compared to the same period 10 years earlier. In reviewing available loan transaction data, the Sustainable Finance Programme found that the bank spread for coal power plants increased 38% to up to 365 basis points based on the data they analyzed. We used a separate study to confirm the above findings. In “Environmental Externalities and Cost of Capital”, author Sudheer Chava found a positive relationship between a higher cost of capital and known firm environmental characteristics. His conclusions supported our assessment that Ameren Missouri would incur higher borrowing costs by delaying the decarbonization of its generation portfolio.

3.1.3 Impact on Revenue Requirement

We expect that Ameren Missouri will lose the opportunity for borrowing cost savings by delaying its generation portfolio transition. We assume the premium associated with higher carbon portfolios will expand to 200 basis points by 2030 over lower carbon portfolios. This impact applies only to the Capacity Need plan. In the Renewable Transition plan, where Ameren Missouri has a clear and consistent pathway to decarbonization of its generation portfolio, the cost of debt remains stable. Assuming this financing cost impact develops, the Capacity Need plan becomes USD ~292 million relatively more expensive on a PVRR basis than the Renewable Transition plan.

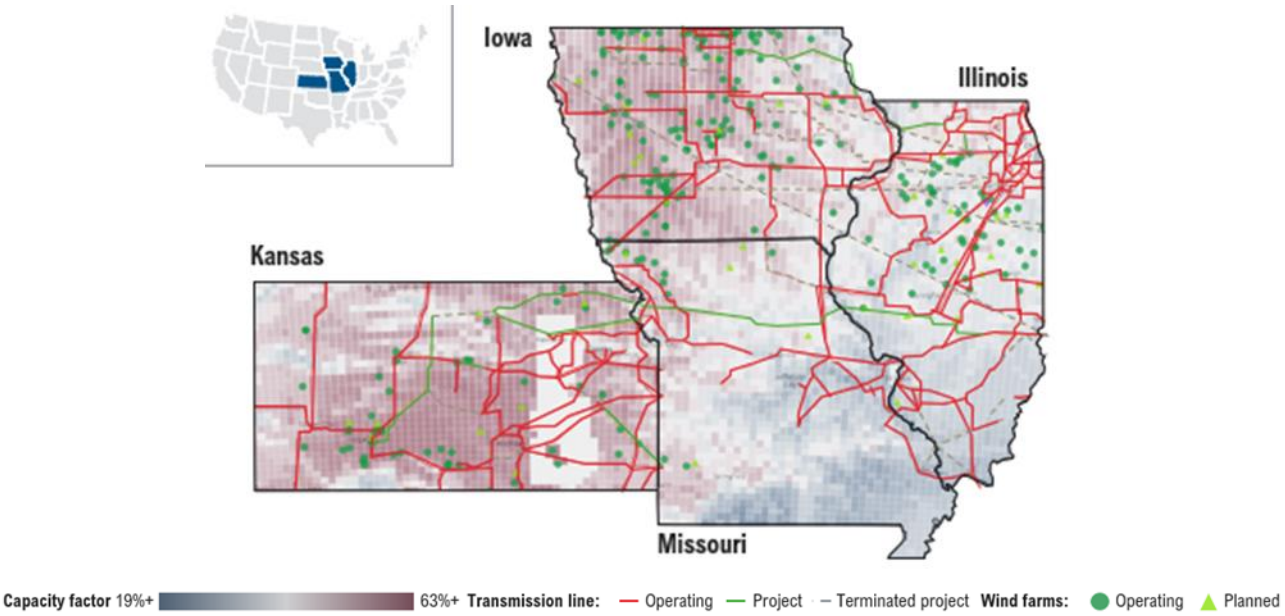
3.2 Land Availability for Wind

3.2.1 Geospatial Analysis

Roland Berger assessed land availability for wind as a potential risk variable associated with delaying renewable deployment. Foundationally, "good" land requires attractive wind resources, transmission access and capacity for interconnection, and available space. Transmission access and interconnection capacity are important considerations for developers but can be addressed through new transmission build over time. Generally, wind projects are sited near existing or planned transmission.

Our analysis showed that wind resources vary over the region, with capacity factors ranging from 19% to over 63%. Overall, the most attractive regions are Kansas, Iowa and Northwest Missouri, highlighted in the wind capacity factor map in Figure 6. We concluded that as land becomes scarce, wind developers will need to build in areas with lower wind resources and pay for longer spur lines, putting upward pressure on levelized wind costs.

Figure 6: Map of wind capacity factors, development and transmission lines



Source: Roland Berger; NREL; S&P Global

According to NREL's 'Limited Access' wind energy supply curve scenario[4], there is potential for 116 GW wind across Missouri, Illinois, Iowa and Kansas – of that total, 50% of the wind potential is in Kansas alone. We summed NREL's estimated potential wind capacity for parcels of land across the four states. Importantly, available land excludes the following: competing land use and associated infrastructure (e.g., roads, buildings), siting topography (e.g., terrain slope, elevation), known protected wilderness, local ordinances related to setbacks, and it does not consider transmission constraints. A summary of exclusions used in NREL's Limited Access scenario is shown below in Figure 7. The primary difference between the Limited Access scenario and the others is the setback provisions. Setbacks for wind have become an increasingly contentious issue across the country as wind farms have encroached on more populated areas. Wind resource availability is based on seven years of generation data and represents a 2030 turbine at 120-meter hub-height as in Annual Technology Baseline Moderate Case; wind capacity potential is based on the available land, assuming 3 MW/km^2.

[4] National Renewable Energy Laboratory wind supply curve datasets, for details see National Renewable Energy Laboratory, Land use and turbine technology influences on wind potential in the United States, Lopez, A. et al., January, 2021

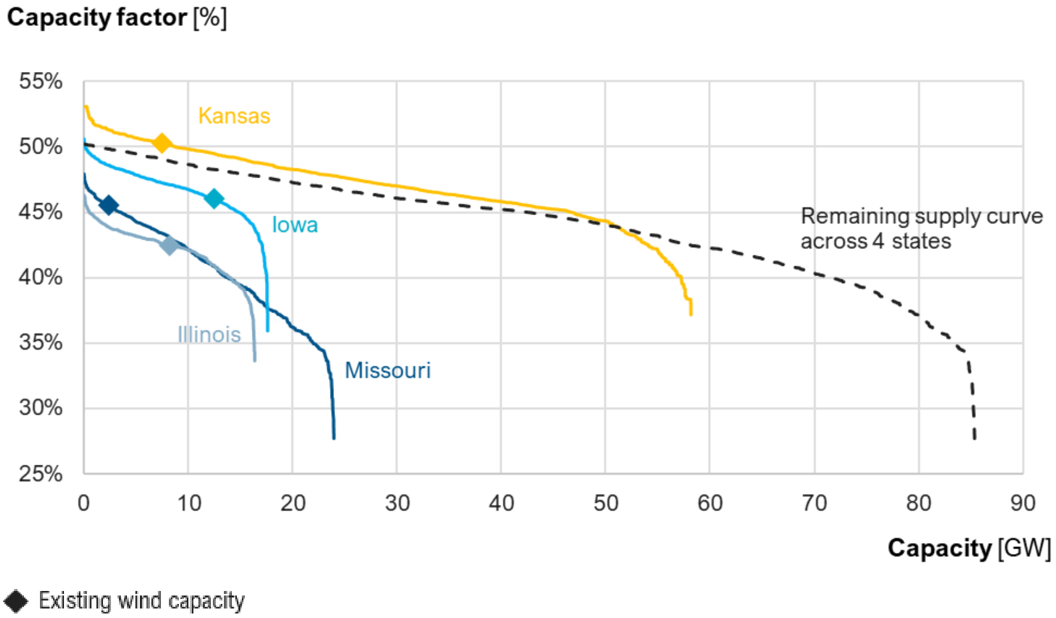
Figure 7: Overview of exclusions used in NREL's siting regimes

Siting exclusion category	Open access scenario	Reference access scenario	Limited access scenario
Infrastructure			
Setbacks to transmission rights-of-way, railroads, roads, building structures	Structure only, no setbacks	Setback = 1.1x wind turbine tip height	Setback = 3x wind turbine tip height
Urban areas and airports	Excluded	Excluded	Excluded
Radar	–	4 km NEXRAD, 9 km SRR/LRR	NEXRAD and SRR/LRR line-of-sight
Regulatory			
Documented state and country setback and height ordinances	–	Applied	Applied
Protected public lands and conservation easements	Excluded	Excluded	Excluded
Other federal lands	–	–	Excluded
Physical			
Slope >25%	–	Excluded	Excluded
Mountainous landforms and high (>9000 ft) elevation	Excluded	Excluded	Excluded
Water and wetlands (with 305-m buffer)	Excluded	Excluded	Excluded

Source: S&P, NREL, Roland Berger

NREL's dataset provides the average capacity factor associated with the potential wind capacity for each parcel of land. We developed a supply curve for each of Missouri, Illinois, Iowa and Kansas by ordering the land from highest to lowest capacity factor and calculating the cumulative potential wind capacity. We then removed the land that has already been used for wind development, assuming the best-resource land has been developed first (this is an imprecise, but conservative assumption). We subtracted the existing, under-construction and advanced development wind capacity from the top of the curve. We then combined the remaining state curves to develop a total *remaining* supply curve for the region and assumed future development will target the best land. The total wind supply curves by state and remaining supply curve across the four-state region are shown below in Figure 8.[5]

Figure 8: Total wind supply curve and existing[6] wind capacity by state and remaining supply curve across Missouri; Illinois; Iowa; Kansas

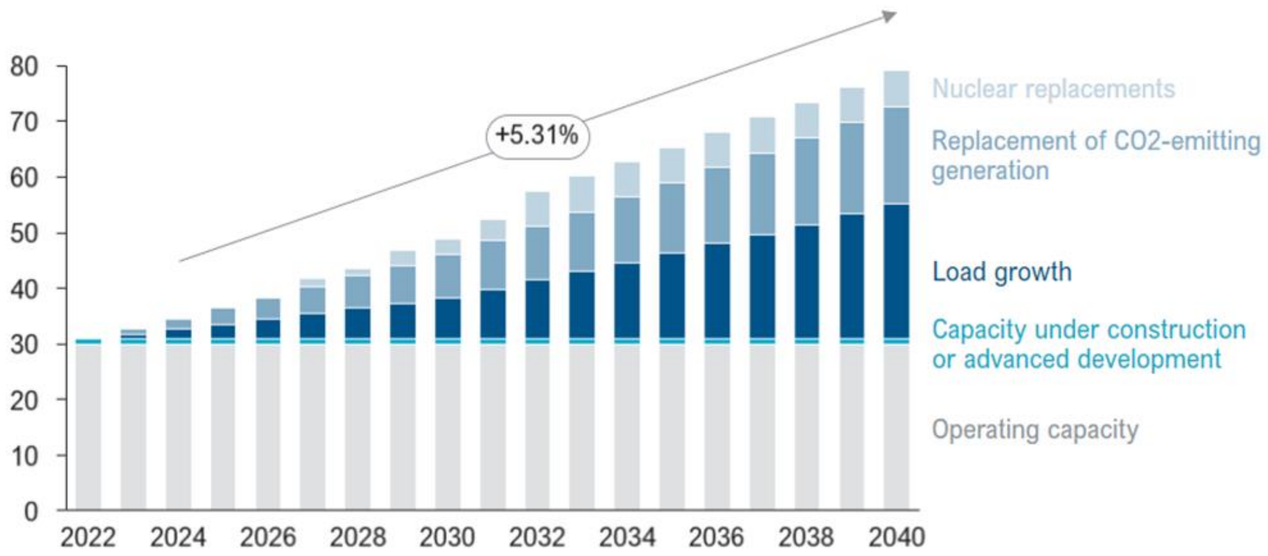


Source: Roland Berger; NREL; S&P Global. Note: 'Existing' wind capacity includes projects currently under construction or under advanced development. State curves show all potential wind capacity, with existing wind marked by a diamond. Dashed black line shows remaining potential capacity across all four states, after existing capacity has been removed.

3.2.2 Projected Wind Build

There is 30 GW of wind capacity already operating across Missouri, Illinois, Kansas and Iowa, and an additional 0.9 GW is under construction or advanced development and expected to be commissioned in 2022. We used the IEA's most recent World Energy Outlook to assess how much wind could be developed in our 4-state region of interest. According to the Announced Pledges Case (Paris Accord zero-carbon by 2050 for the US), 48 GW of new wind capacity would be needed by 2040 to achieve net zero by 2050 across Missouri, Illinois, Kansas and Iowa. The projected wind build represents the capacity needed to meet load growth, replace retiring nuclear plants and replace carbon-emitting generation, shown in Figure 9. Figure 10 summarizes the key inputs to the analysis of how much wind will penetrate the four-state region of interest.

Figure 9: Projected cumulative wind capacity – Missouri, Illinois, Kansas and Iowa [GW]



Source: Roland Berger; S&P Capital IQ; Energy Information Administration-923; International Energy Agency World Energy Outlook; NREL

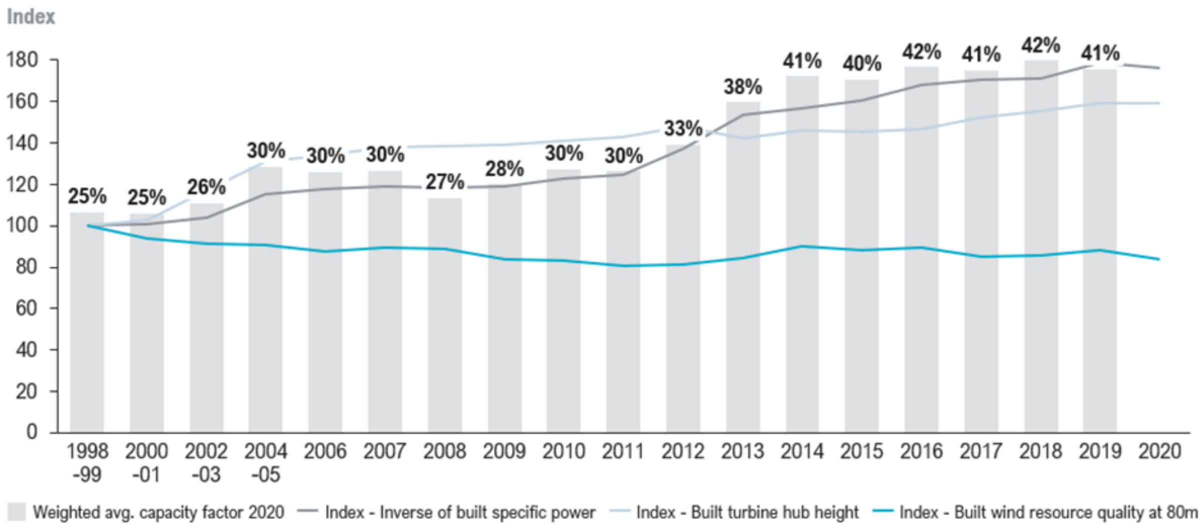
[5] State-specific supply curves are the total before removing already-developed land. The dotted-black line representing remaining supply across the four states nets out land already developed for wind builds.

[6] Existing wind capacity includes operating as well as capacity under construction or advanced development

3.2.3 Projected Wind Capacity Factors

Historically, wind resource quality has declined 16% between 1998 and 2020.[7] Through expert interviews and analysis, we learned that wind resource quality is continuing to deteriorate for built wind because many of the best sites are being taken. At the same time, constructed wind capacity factors have improved from 1998 to 2014[8] and have now flattened, as shown below in Figure 10. Technology improvements have contributed to increasing capacity factors, including specific power and turbine height. However, deteriorating wind resources for constructed wind capacity is expected to put downward pressure on capacity factors.

Figure 10: U.S. built wind: Capacity factors [%], indexed specific power, hub height and wind resource, 1998-2020



Source: EIA; FERC; Berkeley Lab

Mapping wind deployment against the regional supply curve (see Figure 8 on page 13) suggests wind capacity factors could decline approximately 6 percentage points between 2023 and 2040, putting upward pressure on wind LCOEs over time. By taking advantage of higher capacity factors earlier in the study period, less capacity would need to be built to generate the same amount of energy, decreasing build plan costs. Referenced on page 13, Figure 8 details the expected penetration of the supply curve with the expected build and the resulting decline in capacity factors for the four-state region of interest.

3.2.4 Impact on Revenue Requirement

From 2023 to 2040, it is possible that wind capacity factors worsen over time due to reduced availability of good land. In the Capacity Need plan, more of the capacity build will fall in lower capacity factor years (e.g., 2040). This case is therefore expected to be relatively more expensive than the Renewable Transition plan (which builds wind in earlier years presumably on land with better capacity factors). Meanwhile, because of the decline in capacity factors, more wind capacity will be needed in the Capacity Need plan to produce the equivalent output of the capacity deployed in the Renewable Transition plan. It is realistic that the Capacity Need plan will need additional capacity to produce the same output as the Renewable Transition plan, but we did not add additional capacity in the PVRR model. The Renewable Transition plan has an advantage of approximately USD 247 million on a PVRR basis relative to the Capacity Need plan given the land availability risk variable and corresponding declining capacity factors.

---

[7] U.S. Department of Energy, "Land-Based Wind Market Report – 2021 Edition," August 2021.

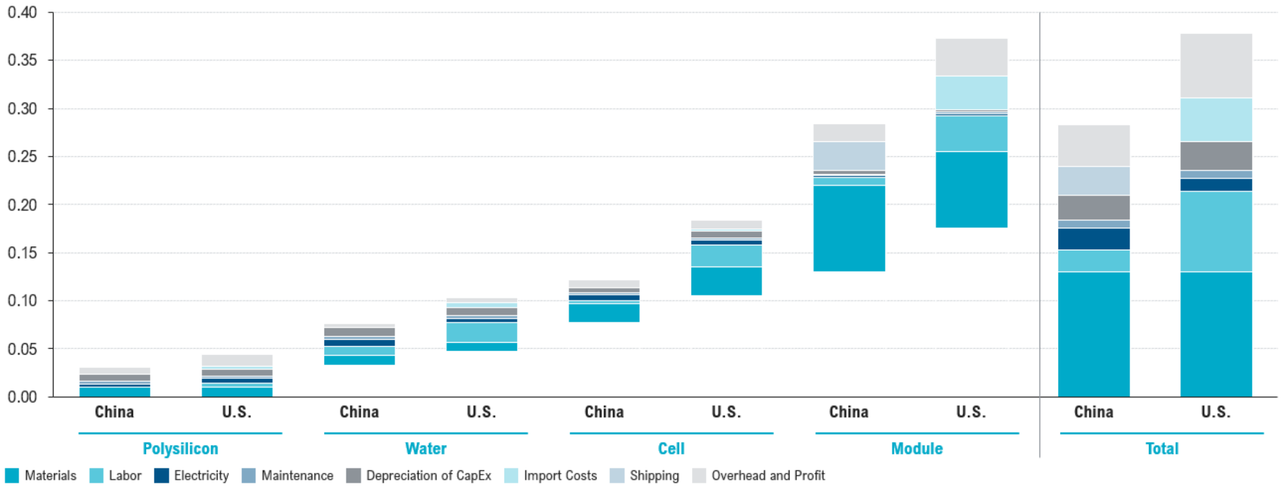
[8] Ibid.

3.3 Equipment Costs

3.3.1 Overview

Solar and wind equipment costs have significant impacts on Ameren Missouri's two alternative renewable build plans. We analyzed the risks for both cases, concluding that the economics are better for the Renewable Transition plan than the Capacity Need plan. Regarding solar, we learned from subject matter expert interviews that there is a considerable likelihood of solar equipment onshoring. Currently, China produces panels ~25% cheaper than the U.S., as illustrated in Figure 11 below.

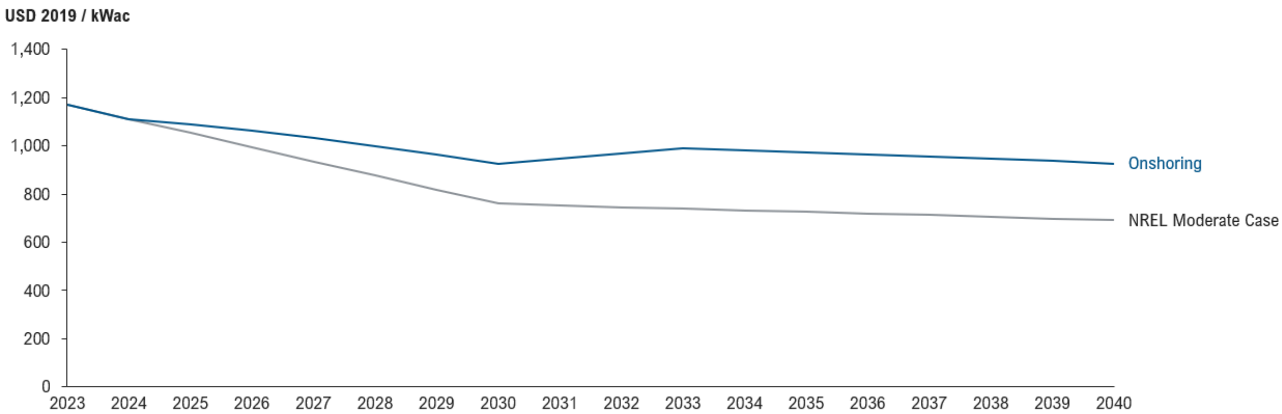
Figure 11: Solar PV production cost in China and U.S. across supply chain [$/Wdc]



Source: Roland Berger; Department of Energy; NREL

Domestic manufacturing would take at minimum 5-7 years to ramp up and mining of input materials for polysilicon would take an additional 5+ years. Overall, it would likely take 10+ years for the value chain to fully onshore. We forecasted solar equipment costs in an Onshoring Case, compared to the NREL ATB Base case assumption for capital costs, shown below in Figure 12. The cost delta could also be applied to Ameren's capital cost base case, which updates NREL's Moderate Case to reflect current market conditions.

Figure 12: Solar overnight capital cost curve comparison: Onshoring Case vs NREL ATB Moderate Case

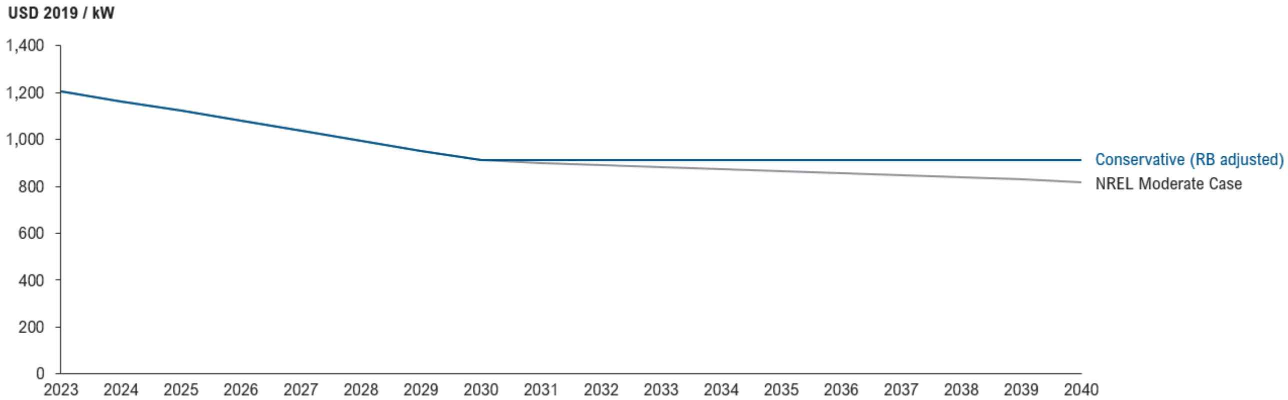


Source: Roland Berger

Solar onshoring is directly related to worsening trade relations with China and lessons learned about overreliance on one region for the solar supply chain. As of this writing, trade relations have intensified under the Biden Administration, which is investigating whether solar manufacturers used factories in Southeast Asia to circumvent U.S. tariffs on solar equipment imports from China. Crystalline silicon solar cells and modules assembled in Cambodia, Malaysia, Thailand and Vietnam could be subject to the same U.S. tariffs imposed on Chinese-made solar components to enforce antidumping and countervailing duties. If onshoring materializes as expected by industry experts, the Renewable Transition plan would benefit more than the Capacity Need plan. Because the Renewable Transition would build solar in the years where solar onshoring is still ramping up, early solar deployments would likely be able to take advantage of relatively cheaper imported equipment while the Capacity Need plan would face higher solar equipment costs by 2040.

Regarding wind equipment costs, we interviewed NREL analysts to better understand their projections.[9] According to NREL, there is risk in their cost decline curves as they rely on certain technological advancements (such as higher module heights) which have the potential to be less impactful in regions such as the Midwest (i.e., in or near Ameren Missouri's territory), which already has good wind potential and output. The national average cost decline curves may, therefore, be less relevant for Ameren Missouri and the ATB's Conservative case may be a better proxy for forecasted wind equipment costs and performance. An equipment cost comparison of the NREL ATB Moderate case and Conservative case is shown below in Figure 13.[10] The ATB's Conservative case benefits the Renewable Transition plan more than the Capacity Need plan due to the reduced cost decline of wind capital costs over the study period. If wind costs develop according to these assumptions, it would be relatively cheaper to build renewables early, as wind plants built later in the forecast would not be advantaged by greater equipment cost declines. The cost delta could also be applied to Ameren's capital cost base case, which updates NREL's Moderate Case to reflect current market conditions.

Figure 13: Wind overnight capital cost curve comparison: Conservative vs NREL ATB Moderate Case



Source: Roland Berger

3.3.2 Impact on Revenue Requirement

From our analysis, we see a strong risk that solar may get more expensive over time due to onshoring. If this plays out as expected, the Renewable Transition plan would be less impacted than the Capacity Need plan by USD ~59 million on a PVRR basis. In addition, when applying the conservative NREL ATB wind assumptions to both alternative renewable build plans, the Capacity Need plan gets relatively more expensive than the Renewable Transition plan by USD ~122 million on a PVRR basis.

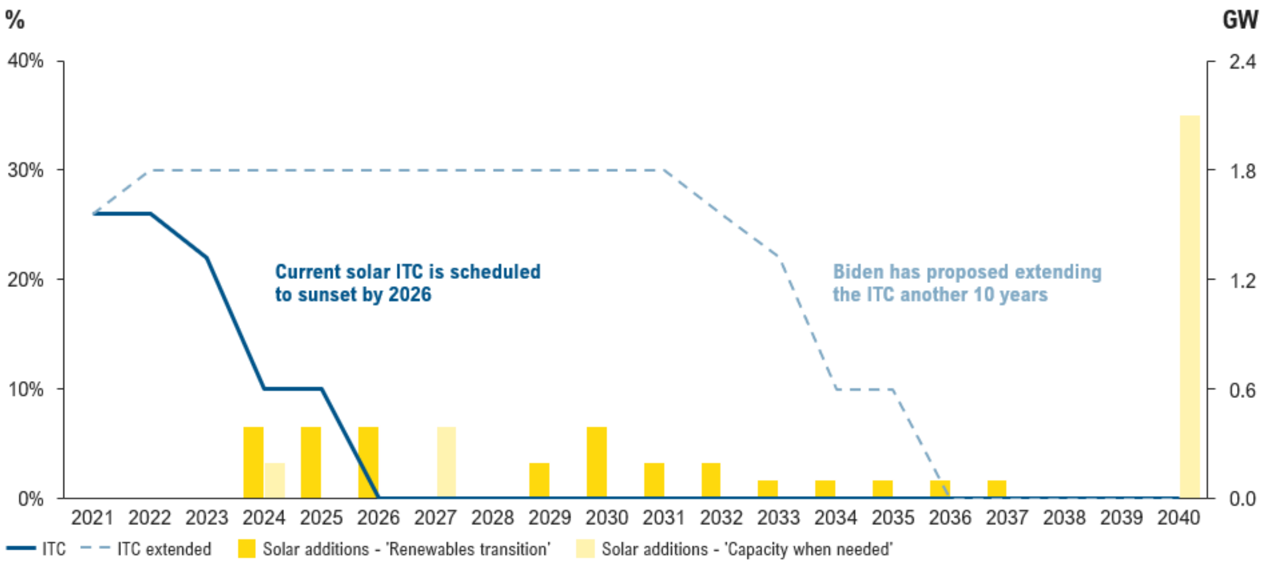
3.4 Tax Credits

3.4.1 Overview

Renewable tax credits are an important risk variable in the revenue requirement analysis. While the production tax credit (PTC) expired in 2021 and the investment tax credit (ITC) is scheduled to step down to 10% by 2024, President Biden has proposed extending the PTC for another 5 years (and including solar in addition to wind) and the ITC for another 10 years.[11] Through the Reconciliation Bill, President Biden has also proposed to expand the ITC at 30% and include an option for "direct-pay" for projects that comply with national content provisions. In addition, President Biden has proposed expanding the PTC rate to USD 0.025/kWh plus a USD .005/kWh bonus, extended through 2026. If both the PTC and ITC are expanded and extended, it will be considerably cheaper to deploy solar and wind while they are available instead of waiting until 2040.

The proposed ITC and PTC extensions would impact a significant portion of the renewable projects deployed in the Renewable Transition plan, while the delayed renewable build plan would only take limited advantage of the cost savings. The current and extended ITC and PTC overlaid against Ameren Missouri's solar and wind build plans are illustrated in Figure 14 and Figure 15 below. As we accounted for the extension of the ITC and PTC in the PVRR model, we used the proposed ITC extension through 2031, sunsetting by 2036. While we assume the PTC would be extended until 2026, we applied the credit to wind projects through 2028, due to the potential grandfathering of new wind additions that begin construction two years prior to the PTC expiration year.[12] The current and extended ITC and PTC overlaid against Ameren Missouri's solar and wind build plans are illustrated in Figure 14 and Figure 15 below. This assumption impacts an additional 800 MW of wind capacity in the Renewable Transition build plan; full PTC and ITC assumptions used in the PVRR model are shown in Figure 16.

Figure 14: Current and extended ITC versus Ameren Missouri solar addition plans



Source: Roland Berger, Ameren Missouri

---

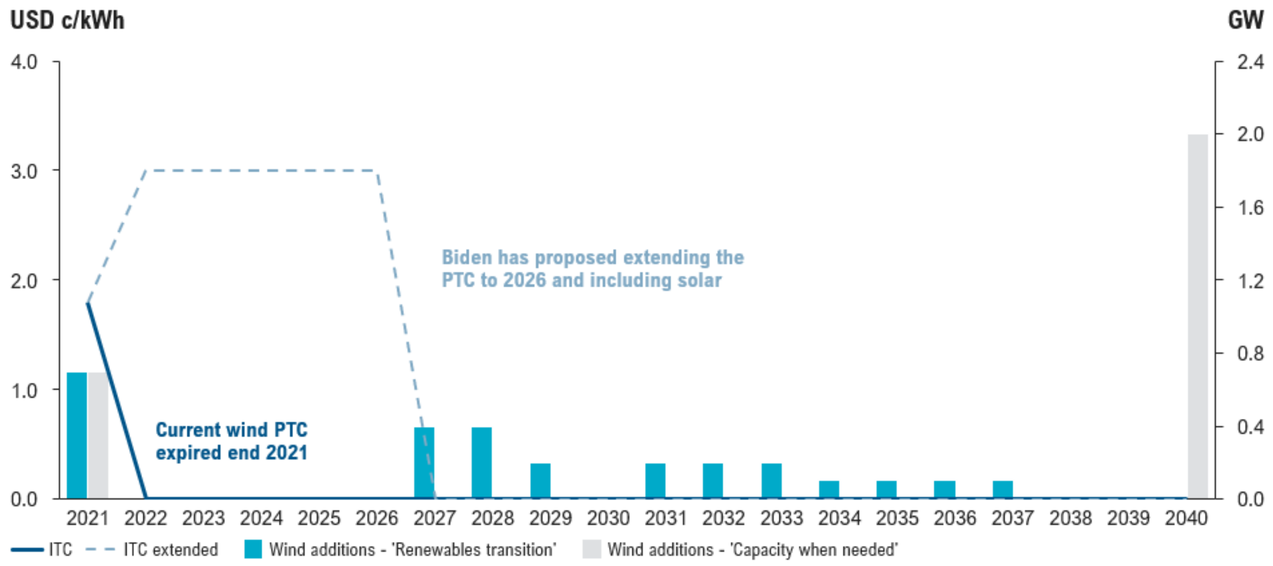
[9] NREL's Annual Technology Baseline (ATB) is widely used in the energy industry to forecast wind and other generation resource costs.

[10] Roland Berger adjusted NREL ATB Conservative Case to reflect NREL's insight on flattening wind equipment costs in the Midwest.

[11] The ITC largely impacts new solar builds while the PTC impacts new wind plants.

[12] Renewable projects can be grandfathered by proving that they have "begun construction" by paying 5% or more of the total cost of the project within two years of the qualifying tax credit year.

Figure 15: Current and extended PTC versus Ameren Missouri wind addition plans



Source: Roland Berger, Ameren Missouri

Figure 16: Ameren Missouri FCR model renewable tax credit assumptions

	ITC	PTC
2023	30%	100%
2024	30%	100%
2025	30%	100%
2026	30%	100%
2027	30%	100%
2028	30%	100%
2029	30%	0%
2030	30%	0%
2031	30%	0%
2032	30%	0%
2033	26%	0%
2034	22%	0%
2035	10%	0%
2036	0%	0%
2037	0%	0%
2038	0%	0%
2039	0%	0%
2040	0%	0%

Source: Roland Berger

3.4.2 Impact on Revenue Requirement

The Renewable Transition plan would take better advantage of the potential extension of the tax credits. This would result in a significantly lower revenue requirement for the Renewable Transition plan and only a slightly lower revenue requirement for the Capacity Need plan, based on the reduced solar build in the 2020's. When extended tax credits are considered as a risk variable, both plans get cheaper, but the Renewable Transition plan becomes an additional USD ~339 million cheaper on a PVRR basis than the Capacity Need plan. If the proposed renewable tax credit extensions are signed into law, a significant amount of solar and wind additions planned in the Renewable Transition plan will cost much less to build than if they were delayed until 2040.

3.5 Interconnection Costs

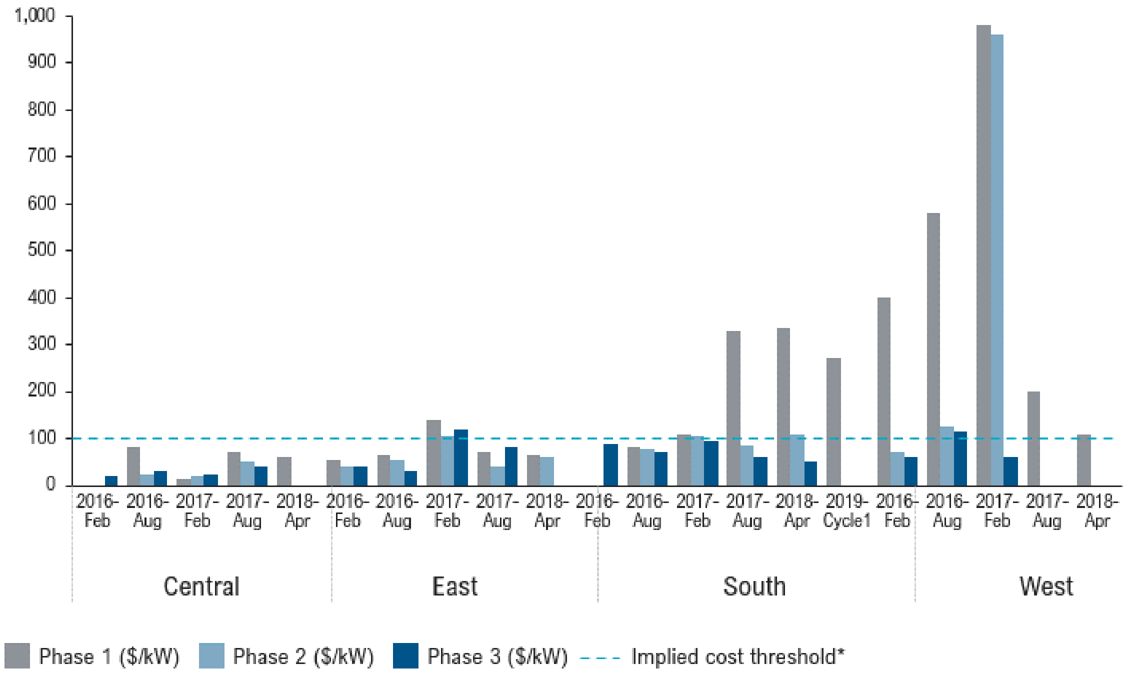
3.5.1 Overview

During the study, we analyzed the relationship between interconnection costs and available transmission capacity in MISO. Interconnection costs include generator tie lines, network upgrades, and make up a relatively small but typically material percentage of project development costs. Transmission capacity correlates strongly with interconnection costs: when there is sufficient transmission capacity, fewer network upgrades are needed, putting downward pressure on costs to generators. However, due to the lumpy, cyclical nature of transmission investment, it is difficult to predict when new capacity will be available and what costs will be passed on to new generators trying to interconnect to the grid. For this reason, we assessed interconnection costs qualitatively and did not quantify the risk factor in our PVRR modeling.

3.5.2 Methodology

We used recent MISO Transmission Expansion Planning (MTEP) reports, MISO Definitive Planning Phase (DPP) report data and MISO Interconnection Queue data to better understand the relationship between interconnection costs and transmission constraints. In addition, we relied on subject matter expert interviews with Midwest renewable developers and MISO operators and managers to corroborate our internal research and interconnection cost hypotheses. Figure 17 shows historical interconnection costs by planning region in MISO.

Figure 17: Historical MISO Interconnection Costs ($/kW)



Source: 2020 MISO MTEP Report, Roland Berger

3.5.3 Key Takeaways

Fundamentally, generator interconnection costs are largely driven by expensive transmission network upgrades, especially for remotely sited renewables in MISO and SPP. Interconnection costs ebb and flow over time depending on the availability of transmission capacity and the number of generators requesting to be interconnected at desirable points of interconnection (POI). For example, while MISO transmission capacity increased significantly through the MISO MVP projects in the 2010's, it was quickly exhausted by new generation from 2015 – 2019, mostly in MISO Central and West.[13] It is common for generators to try to game interconnection strategy, based on our expert interviews. Generators will frequently drop out of the interconnection queue if costs are too high, lowering total cost of new network upgrades and lowering costs for remaining generators, only to return when prospects are better.

Due to the backlog in the MISO interconnection queue, projects may stay in the DPP process for years, incurring study costs until they are forced to drop out. Desirable POIs quickly get saturated as multiple renewable projects attempt to take advantage of available transmission capacity, ensuring their output can reach load, eventually driving the need for new network upgrades. While there is a clear correlation between transmission constraints and higher interconnection costs, the ongoing cycle of GI requests, POI saturation and interconnection queue strategy makes long-term renewable interconnection costs difficult to predict.

3.6 Congestion Costs

Congestion pricing in MISO is unpredictable and not easily manageable. After internal research and analysis, we concluded that it was not a material factor in determining timing of renewables deployment. Congestion pricing depends on the balance of supply and demand for transmission, which varies as plants are added/ retired and transmission lines are added or taken offline temporarily. In addition, fluctuation in congestion prices can be seen in the historical data, which varies greatly over time. It is difficult to forecast congestion prices long-term due to the many uncertain factors that affect prices beyond interconnect requests and transmission availability. Congestion prices are not easily managed due to the difficulty and cost involved in hedging; financial transmission rights (FTRs) or other hedging options can be expensive. During the study, we learned from MISO operations experts that congestion costs do not materially impact developers' decision-making in building renewable resources, which confirmed our preliminary analysis.

3.7 Potential for Load Defection

In analyzing the potential for load defection, we looked at Ameren Missouri's largest commercial and industrial (C&I) customers and assessed risk of lost load if Ameren Missouri delayed renewable deployment. Almost all of Ameren Missouri's top ten largest C&I customers have committed to significant emissions reductions targets, as shown in Figure 18. AT&T, Walmart, AB InBev, General Motors, Bayer AG (Monsanto) and Boeing have all committed to Scope 1 and 2 GHG emissions reductions targets ranging from 25% - 72% relative to base year.[14] Of note, AB InBev has committed to sourcing 100% renewable electricity by 2025 and achieved their 100% renewable goals four years early, in June 2021.[15] Aggressive renewable targets from C&I customers in their footprint pose a potential risk to Ameren Missouri if it pursues the Capacity Need plan. There is additional risk that new business and associated load will not come to Missouri if Ameren Missouri is not greening its generation fleet. While there is some risk that load from these large customers could be lost if they defect and procure energy from other LSEs or move operations to greener regions of the country, it is difficult to predict and quantify.

[13] 2020 MISO MTEP Report

[14] According to the Greenhouse Gas Protocol, Scope 1 emissions are direct emissions from owned or controlled sources. Scope 2 emissions are all indirect emissions from the generation of purchased energy.

[15] https://www.edie.net/anheuser-busch-meets-100-renewable-energy-goal-four-years-early/

Figure 18: Largest Ameren Missouri C&I Customers' Emissions Reductions Targets

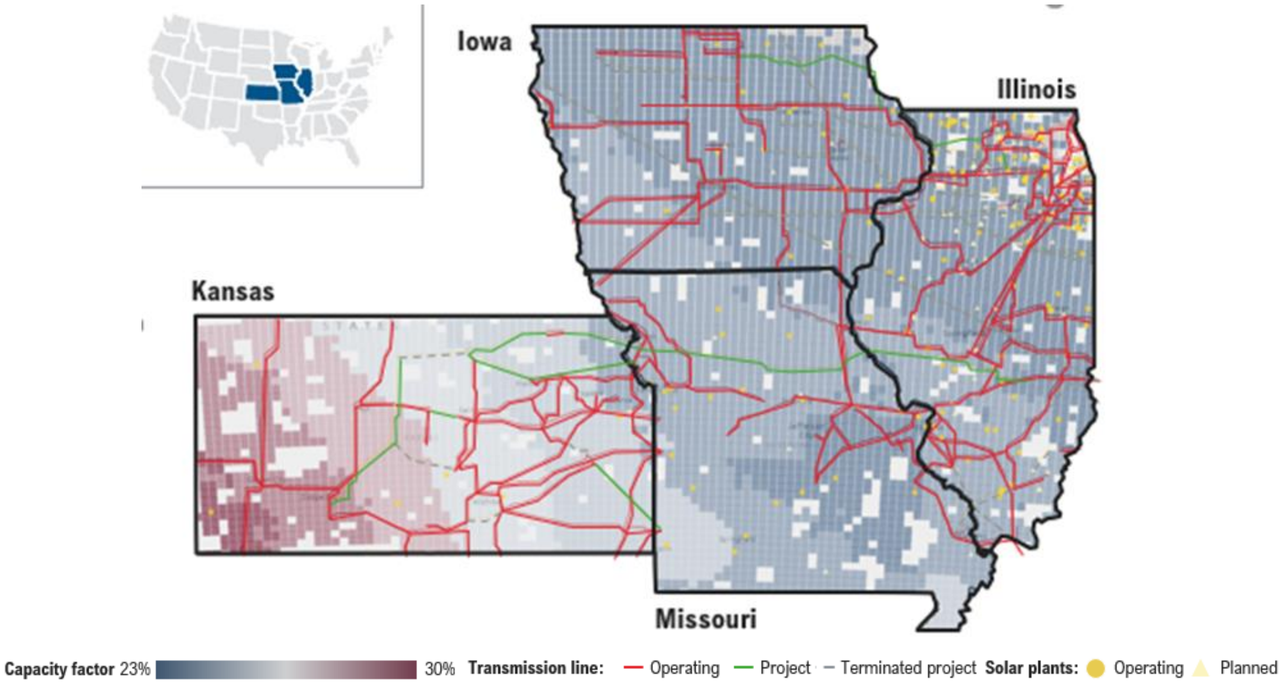
Company	Net-Zero Committed?	Emissions Reduction Target	Additional Green Policies
AT&T	No	Reduce Scope 1 and 2 emissions by 35% by 2025 and 65% by 2030 from 2015 base year	
Walmart	Yes	Reduce Scope 1 and 2 emissions by 35% by 2025 and 65% by 2030 from 2015 base year	
AB InBev	No	Reduce Scope 1 and 2 emissions by 35% by 2025 from 2017 base year	Commits to source 100% renewable electricity by 2025
General Motors	Yes	Reduce Scope 1 and 2 emissions by 72% by 2035 from 2018 base year	
Bayer AG (Monsanto)	Yes	Reduce Scope 1 and 2 emissions by 42% by 2019 from 2019 base year	
Boeing	Yes	Reduce emissions by 25% by 2027, reduce CO_2 by 50% by 2050	Commits to reduce energy consumption by 10% by 2025

Source: Roland Berger

3.8 Land Availability for Solar

In assessing solar land availability, we concluded that solar is less challenging to site than wind and does not have to contend with setbacks, geospatial resource differences and space requirements. Solar projects have a higher power density and can be developed at smaller sized sites than wind; they are more easily connected to distribution grids (e.g., southern Missouri) and can be sited closer to load (e.g., Chicago). Solar capacity factors are less variable across states than wind, as shown below in Figure 19. AC solar capacity factors are less varied locally, instead ranging from 23% in the east to 30% in the west, compared to 19-63% for wind.

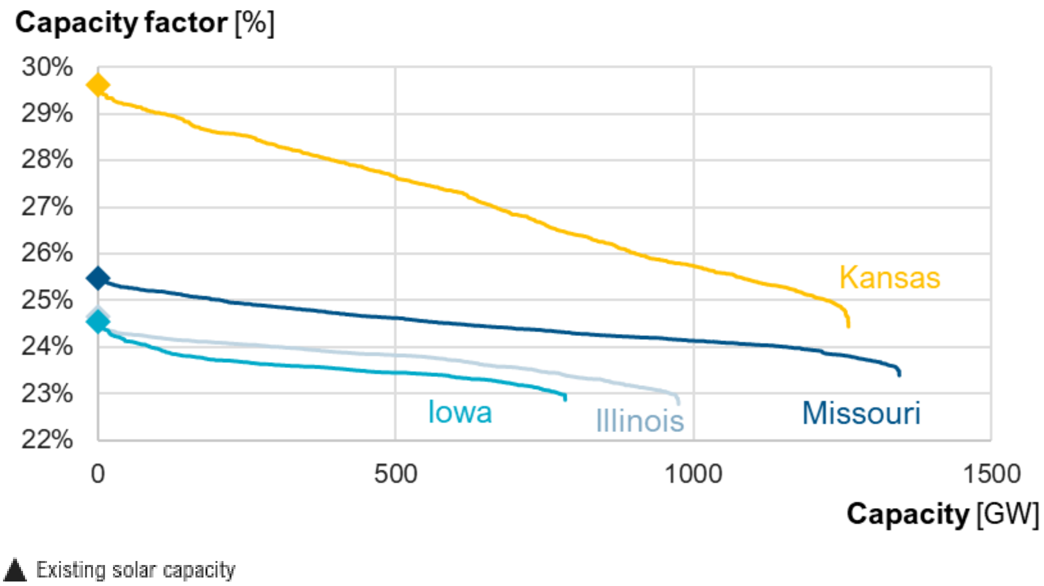
Figure 19: Map of solar capacity factors, development and transmission lines



Source: Roland Berger; NREL; S&P Global. Note: AC capacity factor.

We performed a similar analysis for solar land availability as we did for wind. Because solar additions are not as constrained by land and resource potential as wind, we found that the capacity factor degradation over time as solar is developed on land in the region is minimal. Figure 20 details the solar supply curves under the NREL Limited Availability scenario. NREL's dataset provides the average capacity factor associated with the potential solar capacity for each parcel of land. Solar potential reflects land constraints and resource quality. We developed a supply curve for each of Missouri, Illinois, Iowa and Kansas by ordering the land from highest to lowest capacity factor and calculating the cumulative potential solar capacity.

Figure 20: Solar supply curve and existing solar capacity by state



Source: NREL, S&P Global MI, EIA, Roland Berger

3.9 Conclusion

Figure 21 below summarizes the risk variables we were able to quantify and their potential impact on Ameren Missouri's renewable build alternatives (PVRR change between the Capacity Need and Renewable Transition plans). The Capacity Need plan is much more exposed to these risks than the Renewable Transition plan.

Figure 21: Risk Variables Impacting Ameren Missouri's Alternative Renewable Build Plans

Risk Variable	Description	Change in PVRR[16]
Financing Costs	Fossil-heavy generation portfolios likely to have higher financing costs than cleaner and less carbon-intensive portfolios	$ 292 million
Land availability	Continued renewable build out will make "good land" scarcer over time, limiting capacity factors for wind	$ 247 million
Wind equipment Cost	Wind equipment cost declines and performance improvements may be less pronounced than NREL ATB assumes	$ 122 million
Solar equipment cost	Onshoring of solar PV equipment manufacturing as consequence of trade relations with China may result in higher costs	$ 59 million
Tax Credits	Extension of ITC and PTC per the proposal in the Build Back Better plan done through separate congressional action	$ 339 million

Source: Roland Berger

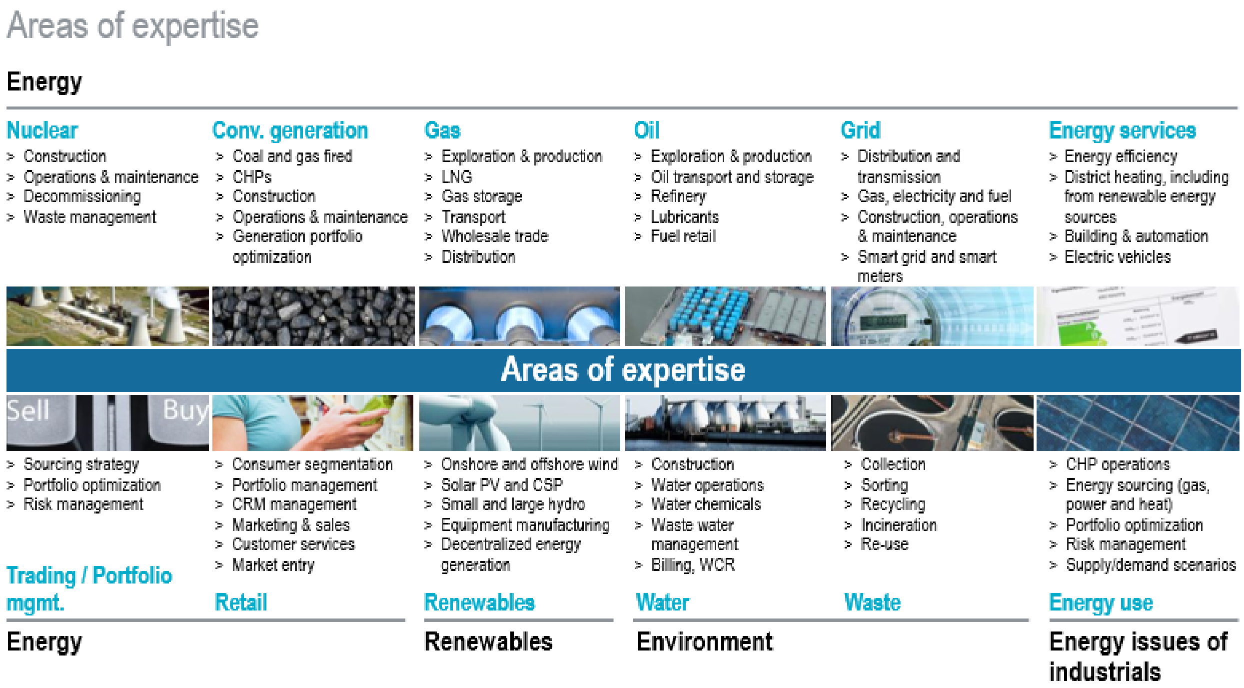
[16] Positive PVRR change indicates that the Capacity Need plan gets relatively more expensive than the Renewable Transition plan over study period.

4. Appendix

4.1 Roland Berger Overview

Founded in 1967, Roland Berger LP is a global management consulting firm that is independently owned by its 250 partners. Roland Berger has 50 offices in 35 countries with 2,400 employees and more than 1,000 international clients. Roland Berger is headquartered in Munich, Germany, and has three offices in the United States: Chicago, Illinois; Detroit, Michigan and Boston, Massachusetts.

Roland Berger's Energy & Utilities practice area has completed more than 1,000 projects for more than 100 clients since 2012. Typical clients include multinational players, energy service specialists, industrial players and investor-owned utilities. In addition to the energy transition, the U.S. Energy and Utilities practice focuses on issues such as market integration and globalization; efficient use of resources; regulation and deregulation; and new technologies / digitization.



4.2 Report Authors

Mike Granowski has over two decades of energy consulting experience. He is a former nuclear engineer and is an expert on utility integrated resource planning, wholesale power markets, power plant valuation, and decarbonization pathways for electric generation fleets. His recent work includes supporting a Midwest transmission utility on energy storage options, a California utility on a multi-decade effort to reimagine the grid to support 100% clean generation, and multiple renewable developer and asset transactions. At Roland Berger, Mike leads the U.S. Digital Analytics practice and is a leader of the U.S. Energy & Utilities practice. Mike earned his MBA from the University of Iowa and earned bachelor's degrees in Nuclear Engineering and in Physics from the University of Wisconsin.

Benjamin Lowe has more than two decades of experience in the electricity sector. He is a former manager at Charlotte-based Duke Energy Corp., where he worked in a number of operational and strategic roles. Ben has worked as a policy director for an energy storage original equipment manufacturer and as the electric utilities reporter for the *Philadelphia Inquirer*. At Roland Berger, Ben advises clients the implications of the renewable transition, focusing on energy market transition with respect to renewables and energy storage technologies. From 2019 to 2021, Ben was on the board of directors of the Energy Storage Association. Ben earned his MBA from Northwestern University's Kellogg School of Management and his B.A. in Economics-Political Science from Columbia University in New York City.