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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EA-2025-0238

DIRECT TESTIMONY

OF

MATT R. MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
June, 2025

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DIRECT TESTIMONY

OF

MATT R. MICHELS

FILE NO. EA-2025-0238

I. INTRODUCTION

Q. Please state your name and business address.

A. Matt R. Michels, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am the Director, Corporate Analysis.

Q. Please describe your educational background and employment experience.

A. I joined Ameren Services Company in 2005 as a Consulting Engineer in Corporate Planning. My responsibilities included coordination of the integration of processes and systems following the acquisition by Ameren Corporation of Illinois Power Company ("Illinois Power") in October 2004. I was subsequently involved in the integration of combustion turbine facilities acquired by Ameren Missouri in 2006. In September 2008, I was promoted to Managing Supervisor of Resource Planning with responsibility for long-range resource planning, including Ameren Missouri's Integrated Resource Plan ("IRP") filings and associated analysis. In February 2013, I was promoted to Corporate Analysis Manager, and in June 2017, I was promoted to my current position. In that capacity, I continue to have direct responsibility for Ameren Missouri's resource planning process, including plans that include significant new load additions, such as data centers.

I earned a Bachelor of Science degree in Electrical Engineering from the University of Illinois at Urbana-Champaign in May 1990. I have been employed by Ameren or Illinois Power since June 1990 in various positions related to resource and business planning. During most of that time, my responsibilities have included the development, use and oversight of various planning models used for purposes such as production costing, acquisition evaluation, corporate restructuring, financial forecasting, and resource planning. I have previously testified before this Commission in proceedings involving resource planning, natural gas-fired resources, renewable energy resources, and energy efficiency.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to support the Company's application for a certificate of convenience and necessity ("CCN") for the construction of natural gas simple cycle ("NGSC") generation and a battery energy storage system ("BESS") at the former site of the company's Rush Island coal-fired energy center, to be renamed the Big Hollow Energy Center ("BHEC"). Specifically, I will:

1. Describe the need for the facility to provide dispatchable capacity for the primary purpose of meeting the demand of new large load customers ("LLC") consistent with the Company's preferred resource plan ("PRP");

2. Support the selection of NGSC and BESS to meet these capacity needs;

3. Present analysis of the economic impacts of the planned resources; and

4. Describe the benefits of the planned resources to customers and the Company should LLC demand fall short of current expectations.

Q. Did Ameren Missouri change its PRP from the one included in the Company's 2023 triennial Integrated Resource Plan ("IRP") filing?

A. Yes. Ameren Missouri filed a Notice of Change in PRP with the Missouri Public Service Commission ("Commission") on February 28, 2025.[1] The Company's formal Notice of Change in PRP is attached to my testimony as **Schedule MM-D1**.

Q. What were the main reasons for changing the Company's PRP?

A. There were two primary reasons. First, the Company has seen a surge in interest from LLCs locating in Ameren Missouri's service territory and has signed construction agreements relating to over two gigawatts of new load. Peak demand for individual LLCs can range from 100 megawatts ("MW") to over a gigawatt ("GW"). As discussed in Company witness Ajay Arora's Direct Testimony, the Company expects as much as approximately 2 GW of such loads to begin ramping up on the system as early as 2026 and to be fully ramped-up within three to five years. Given the Company's obligation to serve, a change in the PRP was necessary to accelerate resources needed to reliably provide service. Second, while significantly less impactful from an overall portfolio perspective, the reductions in anticipated demand and energy savings based on the conclusion of the case involving its most recent application for demand-side program approval under the Missouri Energy Efficiency Investment Act ("MEEIA") required that the Company reassess its long-term capacity and energy position.

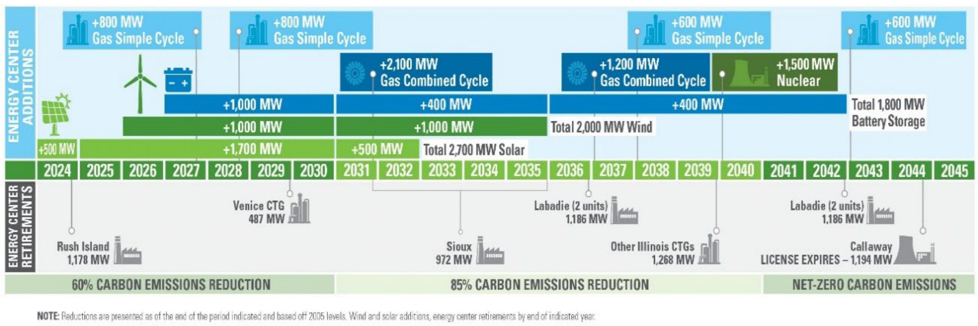
[1] On February 13, 2025, Ameren Missouri filed a brief notice of its intent to file a formal Notice of Change in PRP. The formal notice was filed in accordance with 20 CSR 4240-22.080(12).

III. AMEREN MISSOURI'S PREFERRED RESOURCE PLAN AND NEED FOR CAPACITY

Q. Please describe the Company's current PRP as modified pursuant to its February 28, 2025, Notice of Change in PRP.

A. The Company's current PRP is shown in Figure 1 below, which shows the Company's planned timeline for resource retirements and additions through 2043.

Figure 1. Ameren Missouri 2025 PRP



As Figure 1 shows, the Company's PRP reflects the following:

- Retirement of Sioux Energy Center ("SEC") as early as the end of 2031 and as late as the end of 2035.[2] The retirement date range reflects the need for flexibility to retire the existing coal units at the site only when planned new generation at the site becomes fully operational. That flexibility is important in part because of the long lead time necessary to construct and commission such generation, which can be impacted by supply chains for equipment, materials, and labor.

[2] For modeling purposes, the retirement date for Sioux was assumed to be December 31, 2031, and the in-service date for the replacement generation was assumed to be January 1, 2032.

- Retirement of two units at Labadie Energy Center at the end of 2036 and the remaining two units at the end of 2042. This remains unchanged from the Company's 2023 IRP preferred plan.
- Retirement of Venice Energy Center, a natural gas simple cycle ("NGSC") facility located in Illinois, at the end of 2029. The retirement of Venice is required to comply with the requirements of Illinois' Climate and Equitable Jobs Act ("CEJA"), enacted in 2021, and remains unchanged from the Company's 2023 IRP preferred plan.
- Retirement of the Company's remaining Illinois NGSC facilities at the end of 2039, also to comply with CEJA and unchanged from the Company's 2023 IRP preferred plan.
- Addition of 800 MW of NGSC capacity in late 2027 – the Castle Bluff facility for which the Commission approved a CCN in October 2024, unchanged from the Company's 2023 IRP preferred plan.[3]
- Addition of another 800 MW of NGSC capacity in late 2028 at the former site of the Company's coal-fired Rush Island Energy Center, which was retired in October 2024 – the BHEC NGSC for which the Company is seeking a CCN in this case. This is a new addition not previously explicitly reflected in the Company's 2023 IRP preferred plan but also represents an acceleration of a portion of the "clean dispatchable" resources the Company had planned to add by 2040, as indicated in its 2023 IRP. Adding this generation by 2028 is also driven by the need to make use of the former

[3] File No. EA-2024-0237.

Rush Island coal plant's valuable transmission interconnection rights without the extended time that would be needed for a new generator interconnection request, and the risks associated with such a new request were one to become necessary for failure to implement new generation at Rush Island by September 1, 2028.[4]

- Addition of 1,000 MW of wind generation by 2030 and another 1,000 MW by 2035, unchanged from the Company's 2023 IRP preferred plan.
- Addition of 2,200 MW of solar generation by 2030 (including 500 MW placed in service in late 2024[5] and another 400 MW for which the Commission approved CCNs[6]) and another 500 MW by 2035. This represents an acceleration of solar generation additions from that planned in the Company's 2023 IRP preferred plan. Renewable resource additions are a particularly important consideration in attracting and serving new large customers, such as data centers.
- Addition of 1,000 MW of battery energy storage systems ("BESS") by 2030, 400 MW of which is planned for the BHEC and for which the Company is seeking a CCN in this case, another 400 MW by 2036, and another 400 MW by 2042, for a total of 1,800 MW.[7] This also represents

[4] This facility would also provide a capacity "buffer" under unforeseen circumstances (e.g., a reduction in Ameren Missouri's ability to import capacity from other MISO load zones) in the absence of additional demand from new large load customers, and it also facilitates compliance with the requirements of Section 393.104, RSMo, recently enacted through the passage of Missouri Senate Bill No. 4 ("SB 4"), which was signed into law by Governor Kehoe in April of this year.
[5] Ameren Missouri's Huck Finn, Cass County, and Boomtown solar energy centers.
[6] Ameren Missouri's planned and under construction Split Rail, Bowling Green, and Vandalia solar energy centers.
[7] All BESS included in the PRP is assumed to be 4-hour lithium-ion battery storage for modeling purposes. Additions beyond 2030 may deploy technologies currently under development.

an acceleration as compared to the 2023 PRP, as well as an increase, relative to the 800 MW of BESS additions included in the Company's 2023 PRP. Adding 400 MW of BESS at the former site of the Company's Rush Island Energy Center by September 1, 2028, like the gas generation addition at Rush Island, allows us to take advantage of the valuable transmission interconnection rights that already exist at the Rush Island site.

- Addition of 2,100 MW of natural gas combined cycle ("NGCC") capacity by the end of 2031 and another 1,200 MW of NGCC capacity by the end of 2036. This represents an acceleration of a portion of the "clean dispatchable" resources included in the Company's 2023 IRP preferred plan, shown in 2040 and 2043.
- Addition of a further 600 MW of NGSC capacity at the beginning of 2038 and another 600 MW of NGSC capacity at the beginning of 2043, both representing new additions relative to the Company's 2023 IRP preferred plan.
- Addition of 1,500 MW of nuclear generation at the beginning of 2040. This represents the addition of further clean dispatchable generation, with the selection of specific technology to be made at a later date.[8]

Q. How did Ameren Missouri arrive at its PRP?

A. In short, Ameren Missouri evaluated a range of potential outcomes, or cases, for new large loads, determined for each case the need for acceleration and addition of resources relative to its 2023 PRP to meet load and MISO planning reserve margin

[8] For modeling purposes, the Company's assumptions for modular nuclear generation were used.

("PRM") requirements, and selected the plan that 1) best represents expectations at the time the 2025 PRP was adopted of future large load additions, 2) provides some flexibility in the near term regarding further large load additions, and 3) ensures that the Company maintains both short-term and long-term resource flexibility to address various risks to its portfolio and to facilitate compliance with both the letter and spirit of recently passed statutory provisions included in SB 4 to ensure reliable service to all customers.

Q. Please describe the LLC cases that were evaluated.

A. Ameren Missouri evaluated seven different load cases, as shown in Table 1 below. The seven cases reflect three different levels of large load additions in the near term – 500 MW, 1,500 MW, and 2,000 MW by 2032. Cases 1-3 reflect no further growth in large loads after 2032. Cases 4 and 5 reflect continued growth from 1,500 MW and 2,000 MW loads achieved by 2032, respectively, to 2,500 MW and 3,500 MW, respectively, by 2040. Cases 6 and 7 reflect no further growth in large loads after 2032 (1,500 MW and 2,000 MW in place by 2032, respectively), then a reduction in large loads to 500 MW in 2039. Cases 6 and 7 are used as the basis for evaluating the cost of resource acceleration to meet near-term LLC demand, as I explain later in my Direct Testimony.

Table 1. Large Load Cases – Annual Peak Demand (MW) at Meter[9]

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 500 MW by 2032	300	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2 1,500 MW by 2032	300	500	700	1,000	1,200	1,400	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
3 2,000 MW by 2032	300	700	1,000	1,300	1,600	1,900	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
4 1,500 MW by 2032 and 2,500 MW by 2040	300	500	700	1,000	1,200	1,400	1,500	1,625	1,750	1,875	2,000	2,125	2,250	2,375	2,500
5 2,000 MW by 2032 and 3,500 MW by 2040	300	700	1,000	1,300	1,600	1,900	2,000	2,200	2,400	2,600	2,800	3,000	3,200	3,400	3,500
6 1,500 MW by 2032 dropping to 500 MW	300	500	700	1,000	1,200	1,400	1,500	1,500	1,500	1,500	1,500	1,500	1,500	500	500
7 2,000 MW by 2032 dropping to 500 MW	300	700	1,000	1,300	1,600	1,900	2,000	2,000	2,000	2,000	2,000	2,000	2,000	500	500

[9] Large load demand is assumed to begin at the levels shown on January 1st of each calendar year.

Q. What kind of load factor was assumed for the additional large load demand?

A. A load factor of 85% was used. This results in additional sales of approximately 4 million MWh for each 500 MW of large load demand.

Q. What resources are needed to meet demand in each of the seven load cases you just described?

A. The resource additions for each case are summarized in the attached **Schedule MM-D2**. Note that the planned BHEC resources for which the Company is seeking a CCN in this case are needed even if the Company realizes only a small part of the new LLC demand we are planning for--just 500 MW. Mr. Arora discusses the Company's expectations with respect to LLC demand in his Direct Testimony.

Q. Which case did the Company choose for inclusion in its recently adopted PRP?

A. Ameren Missouri chose Case 4 for inclusion in its PRP and therefore as the basis for determining resource needs. Based on on-going discussions with potential customers, it is also actively planning for Case 5 as an alternative scenario, as I discuss later in my Direct Testimony and as Mr. Arora discusses in his Direct Testimony.

Q. Is it possible that large load demand could exceed the amounts included in the PRP?

A. Yes. Ameren Missouri has included Case 5 as an alternative plan in the Notice of Change in PRP filed with the Commission on February 28, 2025.[10] It should be noted that resource additions through 2032 for Case 5 are identical to those included in

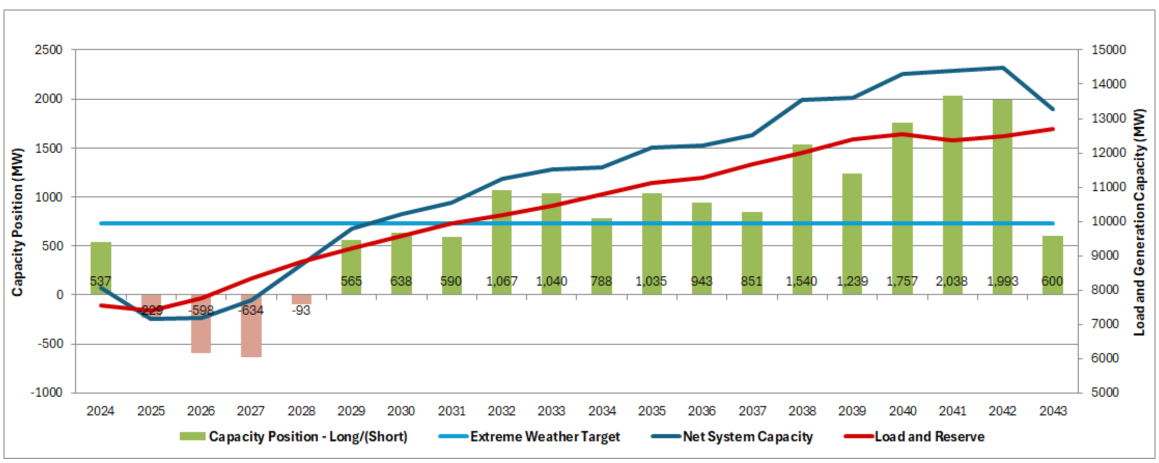
[10] Schedule MM-D1, page 6, Table 1.1.

Case 4, including the BHEC additions that are the subject of this case. This provides flexibility in the near term as the Company continues to evaluate requests for connection and service from prospective customers.

Q. Have you prepared a capacity position for the alternative plan represented in Case 5?

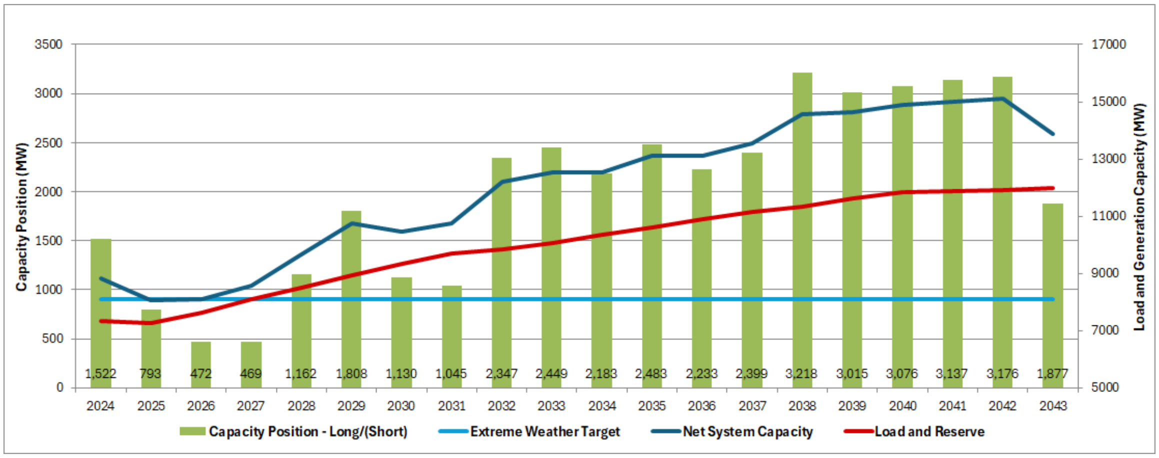
A. Yes. Figure 2 below shows the winter capacity position for Case 5, and Figure 3 shows the summer capacity position, both under normal weather conditions. As the capacity positions in Figures 2 and 3 show, in its alternative plan, Ameren Missouri expects to have sufficient capacity to meet its load and reserve margin obligations starting in winter 2028-2029, with a potential minimal (less than a 100 MW) shortfall in winter 2027-2028, and in summer in all years of the planning horizon. As discussed later in my Direct Testimony, Ameren Missouri is taking steps to address winter capacity shortfalls during the coming three years.

Figure 2. Winter Capacity Position – Load Case 5[11]



[11] All winter capacity position charts shown reflect January and February of the calendar year and December of the prior year.

Figure 3. Summer Capacity Position – Load Case 5



Q. Have you also prepared capacity positions with only existing and approved resources?

A. Yes. Figure 4 below shows the winter capacity position for Case 5 with only existing and approved resources, and Figure 5 shows the summer capacity position with only existing and approved resources, both under normal weather conditions. For purposes of these charts, approved resources include all resources for which the Commission has granted the Company a CCN but which have not yet been placed in service. Figure 4 shows an immediate need for capacity, growing to over 1,200 MW by 2030, and Figure 5 shows a need in 2030 of nearly 1,100 MW.

Figure 4. Winter Capacity Position with Only Existing and Approved Resources – Load Case 5

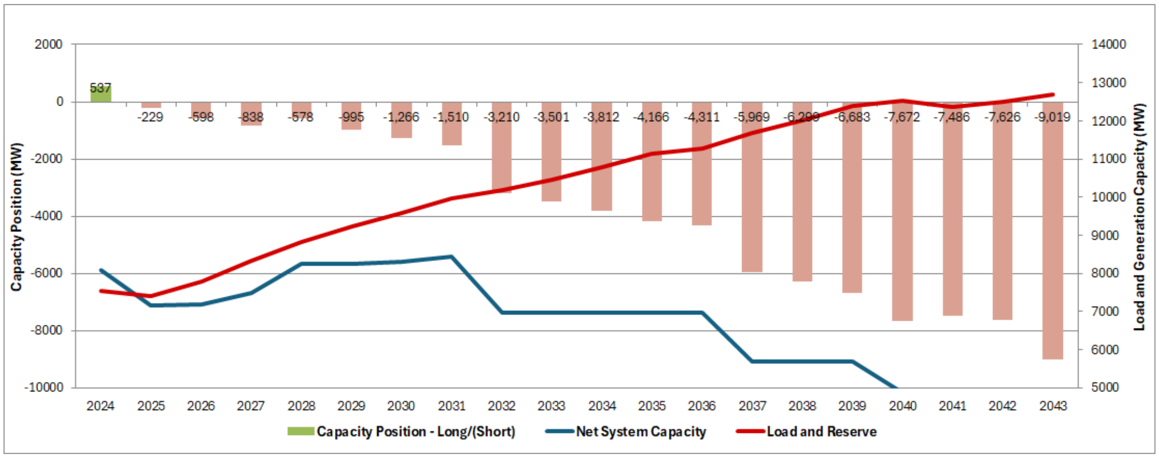
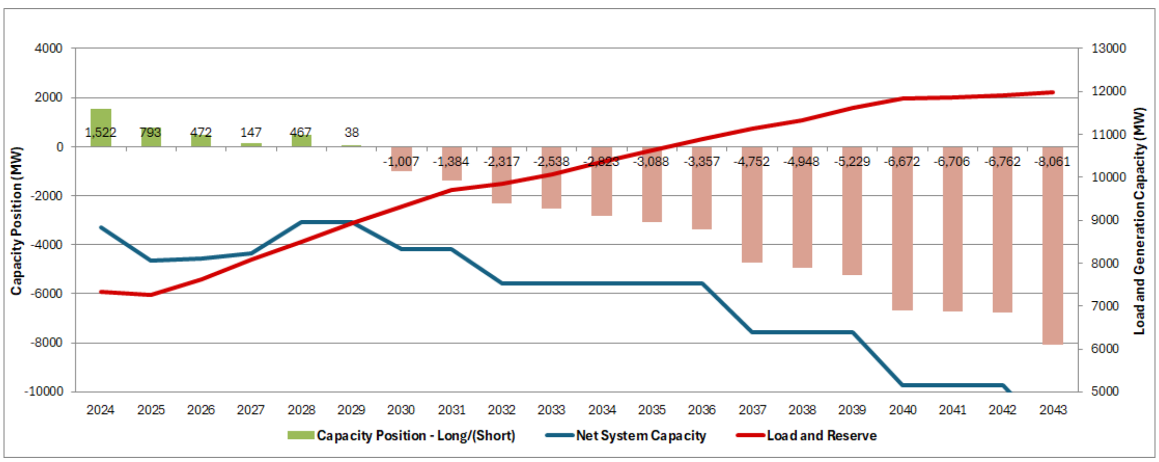


Figure 5. Summer Capacity Position with Only Existing and Approved Resources – Load Case 5



Q. Please explain why the Company chose to accelerate its addition of solar generation when it adopted its new PRP.

A. As the Company has previously described in its 2023 IRP and in several CCN application cases in recent years, it is important to replace the Company's fleet as aging coal-fired energy centers retire, ensuring reliability, maintaining affordability, and addressing risks regarding the use of fossil fuels, including exposure to future environmental regulations. The Company's replacement plans target a balanced portfolio mix of both dispatchable generation and renewable energy resources that have no on-going fuel costs associated with the production of energy. Solar resources, along with efficient natural gas, wind, storage resources, and nuclear generation, play a key role in that transition. The addition of increased demand from LLCs, who also place a high value on the role of lower emitting resources, means more energy generation is needed to serve rising customer energy needs in addition to meeting their needs during times of peak demand, which can be met with peaking resources like NGSC and BESS. While potential wind projects can also be attractive for providing additional energy generation, and indeed the Company continues to include 2,000 MW of wind resource additions in its PRP, solar projects have proven to pose fewer implementation challenges relative to wind projects and provide energy generation during summer peak times. As the Company has explained in its application for a tariff to provide service to LLCs,[12] making sure renewable resources are timely available to address prospective customers' energy needs and their desire to meet their carbon free energy goals is important to attracting the customers in the first place.

Q. What portion of the Company's annual energy production capability is expected to be provided by renewable energy under the plan reflecting Load Case 5?

A. While actual energy production from the Company's fleet depends on a number of factors, including fuel and energy prices and weather conditions, renewables are expected to provide around 30% of the Company's energy production capability. The charts in Figures 6 and 7 below show the Company's expected mix of energy production capability for the years 2030 and 2035, respectively.

[12] File No. ET-2025-0184.

Figure 6. Energy Production Capability Mix – Load Case 5 - 2030

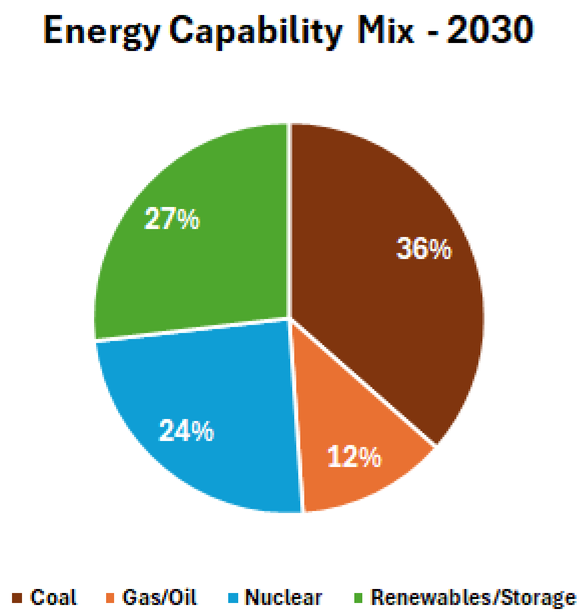
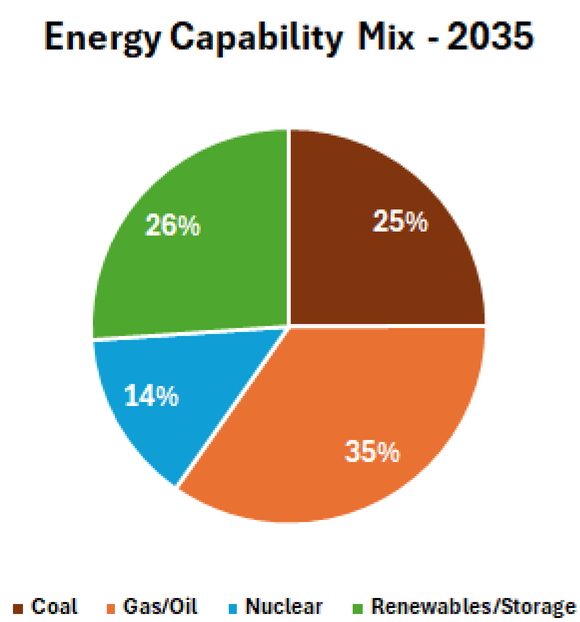


Figure 7. Energy Production Capability Mix – Load Case 5 - 2035

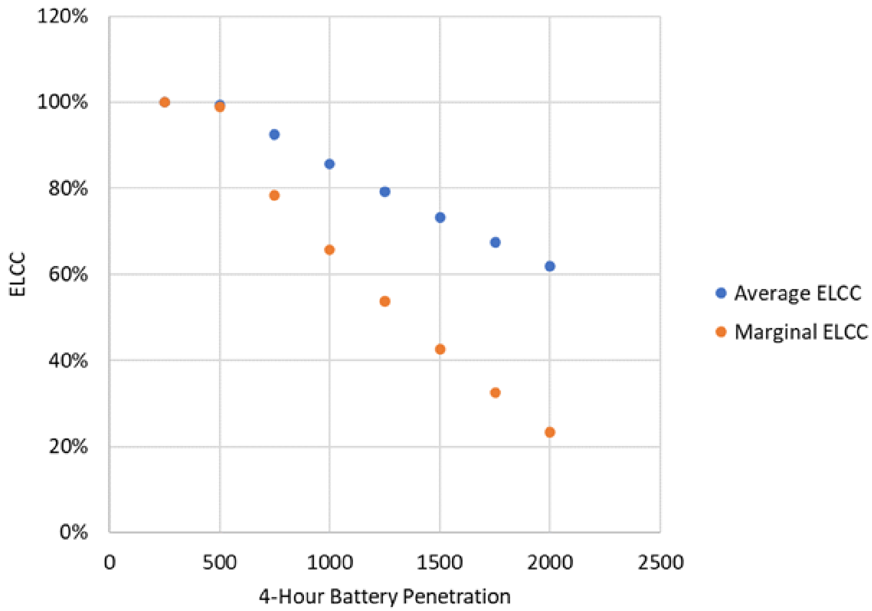


Q. You mentioned NGSC and BESS as resources that can be used to meet peak demand, even though BESS produces no energy itself and NGSC units typically operate at relatively low capacity factors. Please explain the rationale for the Company's inclusion of both in its PRP.

A. Both NGSC and BESS currently provide significant capacity benefits in MISO. Ameren Missouri currently assumes accredited values equal to 95 percent of rated output for BESS and 91 percent of rated output for NGSC, both for the winter season, which is a key driver of resource needs for Ameren Missouri. Over time, and as BESS resources are added to the grid, the capacity value of BESS may decline. Ameren Missouri has relied on analysis by Astrape' Consulting,[13] a reliability modeling consulting firm that provides analytical support to utilities and regional grid operators, including to MISO, to determine the possibility of declining capacity value of battery storage. Figure 8 below shows that BESS provides capacity value at essentially its full rated output up to 500 MW on Ameren Missouri's system. As more BESS resources are added, the incremental capacity benefit, expressed as effective load carrying capability ("ELCC") declines.

[13] Astrape' was acquired by PowerGEM in 2024.

Figure 8. Battery ELCC by Cumulative Capacity Deployed



However, while longer term the marginal ELCC for BESS declines as additional BESS resources are added to the grid, in the near- to-intermediate term, the economics of BESS relative to new NGSC today are advantageous. As a result, there is a cross-over point at which further BESS additions are less economical than additional new NGSC. Ameren Missouri combined its evaluation of BESS and NGSC economics and the insight from Figure 8 above to identify where that cross-over point likely is. Table 2 below shows a comparison of the economics, as measured by the net present value of revenue requirements ("NPVRR"), of increasing amounts of BESS relative to NGSC on a capacity equivalent basis, using the Company's current accreditation value for NGSC and the ELCC curve shown in Figure 8. As Table 2 shows, BESS is more economic than additional NGSC (i.e., beyond that already included in the PRP) on a capacity equivalent basis up to 1,500 MW of BESS additions for Ameren Missouri (the negative numbers in the last row of Table 2 reflect a reduction in net present value of revenue requirement over the planning horizon).

Table 2. Capacity Equivalent Economics – BESS vs. NGSC (Current Accreditation)

Current Accred. CTG vs. ELCC Battery	Initial BESS Additions	Incremental Storage Equivalent Cost at Marginal ELCC					
Incremental Battery Accredited Capacity (MW)	**500**	**250**	**500**	**750**	**1000**	**1250**	**1500**
Total Battery Accredited Capacity (MW)	500	750	1000	1250	1500	1750	2000
Marginal ELCC	100%	87%	74%	62%	49%	36%	23%
Average ELCC	100%	94%	87%	81%	74%	68%	62%
Battery Equiv. Maximum Capacity (MW)	500	267	574	929	1,345	1,840	2,439
Battery PVRR $MM	875	468	1,004	1,626	2,355	3,222	4,270
CTG Equiv. Maximum Capacity (MW)	540	270	540	810	1,080	1,350	1,619
CTG PVRR $MM	1,155	577	1,155	1,732	2,310	2,887	3,465
Difference (Battery - CTG) $MM	**(279)**	**(110)**	**(151)**	**(106)**	**46**	**335**	**806**

Alternatively, I have also made a capacity equivalent comparison of BESS and NGSC using indicative accreditation values for NGSC with dual fuel (as new NGSC are being designed by Ameren Missouri to include) under MISO's proposed Direct-Loss-of-Load ("DLOL") accreditation framework. Table 3 below shows a comparison of BESS and NGSC on a capacity equivalent basis using MISO's indicative DLOL accreditation value for NGSC. Table 3 shows that BESS is more economic than additional NGSC up to at least 1,750 MW, and likely closer to 2,000 MW. Based on the results shown in Table 2 and Table 3, BESS up to 1,500-2,000 MW is more economic relative to additional NGSC above that included in the 2025 PRP. The Company's planned addition of 1,800 MW of BESS falls in this range.

Table 3. Capacity Equivalent Economics – BESS vs. NGSC (MISO DLOL)

DLOL Accred. CTG vs. ELCC Battery	Initial BESS Additions	Incremental Storage Equivalent Cost at Marginal ELCC					
Incremental Battery Accredited Capacity (MW)	**500**	**250**	**500**	**750**	**1000**	**1250**	**1500**
Total Battery Accredited Capacity (MW)	500	750	1000	1250	1500	1750	2000
Marginal ELCC	100%	87%	74%	62%	49%	36%	23%
Average ELCC	100%	94%	87%	81%	74%	68%	62%
Battery Equiv. Maximum Capacity (MW)	500	267	574	929	1,345	1,840	2,439
Battery PVRR $MM	875	468	1,004	1,626	2,355	3,222	4,270
CTG Equiv. Maximum Capacity (MW)	633	316	633	949	1,266	1,582	1,899
CTG PVRR $MM	1,354	677	1,354	2,031	2,708	3,385	4,062
Difference (Battery - CTG) $MM	**(479)**	**(209)**	**(350)**	**(405)**	**(353)**	**(163)**	**208**

Q. Have you evaluated the comparative economics of NGSC and BESS if federal tax credits are no longer available for BESS?

A. Yes. Table 4 below shows a comparison of the economics of increasing amounts of BESS relative to additional NGSC assuming the currently used accreditation values for NGSC, and Table 5 shows a comparison using MISO's indicative accreditation amount for NGSC, both without the inclusion of investment tax credits ("ITC") for BESS.

Table 4. Capacity Equiv. Economics w/o ITC – BESS vs. NGSC (Current Accreditation)

Current Accred. CTG vs. ELCC Battery	**Initial BESS Additions**	**Incremental Storage Equivalent Cost at Marginal ELCC**					
Incremental Battery Accredited Capacity (MW)	**500**	**250**	**500**	**750**	**1000**	**1250**	**1500**
Total Battery Accredited Capacity (MW)	500	750	1000	1250	1500	1750	2000
Marginal ELCC	100%	87%	74%	62%	49%	36%	23%
Average ELCC	100%	94%	87%	81%	74%	68%	62%
Battery Equiv. Maximum Capacity (MW)	500	267	574	929	1,345	1,840	2,439
Battery PVRR $MM	1,114	595	1,277	2,068	2,996	4,099	5,432
CTG Equiv. Maximum Capacity (MW)	540	270	540	810	1,080	1,350	1,619
CTG PVRR $MM	1,155	577	1,155	1,732	2,310	2,887	3,465
Difference (Battery - CTG) $MM	**(41)**	**17**	**123**	**336**	**686**	**1,212**	**1,967**

Table 5. Capacity Equivalent. Economics w/o ITC – BESS vs. NGSC (DLOL)

DLOL Accred. CTG vs. ELCC Battery	**Initial BESS Additions**	**Incremental Storage Equivalent Cost at Marginal ELCC**					
Incremental Battery Accredited Capacity (MW)	**500**	**250**	**500**	**750**	**1000**	**1250**	**1500**
Total Battery Accredited Capacity (MW)	500	750	1000	1250	1500	1750	2000
Marginal ELCC	100%	87%	74%	62%	49%	36%	23%
Average ELCC	100%	94%	87%	81%	74%	68%	62%
Battery Equiv. Maximum Capacity (MW)	500	267	574	929	1,345	1,840	2,439
Battery PVRR $MM	1,114	595	1,277	2,068	2,996	4,099	5,432
CTG Equiv. Maximum Capacity (MW)	633	316	633	949	1,266	1,582	1,899
CTG PVRR $MM	1,354	677	1,354	2,031	2,708	3,385	4,062
Difference (Battery - CTG) $MM	**(241)**	**(82)**	**(77)**	**37**	**288**	**714**	**1,370**

As Table 4 shows, even without the benefit of ITC, BESS maintains an economic advantage relative to additional NGSC up to 750 MW. Likewise, Table 5 shows an advantage for BESS up to 1,250 MW.

Q. Have you evaluated what kind of cost increases for BESS would be needed for the BHEC BESS to break even with the economics of additional NGSC?

A. Yes. Assuming accreditation of NGSC based on the DLOL approach, as is expected to be the case starting with the 2028-2029 planning year, an increase of approximately **____________** for the BHEC BESS would result in a break-even with additional NGSC absent ITC, and an increase of **_____________** would result in a break-even with ITC for BESS.[14]

Q. What if something else changes the relative economics of BESS and NGSC or other factors that may affect their implementation?

A. In that case, the Company could adjust its plans for any uncommitted resources at that time. Ameren Missouri's 2025 PRP reflects 1,000 MW of BESS by the end of 2030. If the economics of further BESS become disadvantageous, the Company would reassess further resource additions. Reassessing further resource additions would also need to account for any advances in both BESS and NGSC technology, such as the potential for longer duration BESS technologies, which would improve the ELCC for BESS relative to the four-hour BESS technology currently planned and analyzed. It would also need to include consideration of any practical limitations on the Company's ability to implement resources in a timely manner, such as permitting, fuel constraints, or supply chain issues. Such changed conditions are a large reason why utilities prepare IRPs every few years and conduct continuous planning in between.

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[14] The calculated break-even increases for BESS without and with ITC are **__________** and **___ _______**, respectively, if the current accreditation amounts are used for NGSC.

Q. You've explained why the Company has included 1,000 MW of BESS by 2030 and 1,800 MW total in its plan, including the 400 MW planned at BHEC. What is the rationale for NGSC additions in the near term?

A. New NGSC additions with oil backup provide reliable capacity when it is needed most. NGSC is highly flexible, and during times of sustained high demand it can operate continuously if needed. Relative to NGCC, NGSC can be implemented more quickly and easily to keep pace with rising demand, partly because NGSC does not require access to a large and continuous source of water for steam turbine operations that is an integral part of NGCC facilities.

Q. With the addition of solar generation for energy production and BESS and NGSC for meeting peak demand, why is there a need for NGCC resources?

A. While the combination of both renewable and peaking resources is necessary for implementing a balanced energy transition, baseload resources are also needed to ensure that customer needs are met around-the-clock and throughout the year. This is especially true when considering the addition of large load customer demand with essentially around-the-clock operations as well as the replacement of retiring baseload or coal generation, such as Sioux. This is why Ameren Missouri looks at the totality of its customers' needs for both capacity and energy.

Q. How does Ameren Missouri evaluate capacity needs?

A. This is done by evaluating the Company's capacity position, the difference between the total generating capacity of its portfolio of resources and the peak demand and MISO PRM. Ameren Missouri also analyzes all four seasons as part of its IRP planning. However, the winter season currently drives resource needs, in part due to lower winter accreditations for gas-only resources that experience fuel supply constraints during cold weather.

Figures 9 and 10 below show the Company's winter and summer capacity positions, respectively, for Case 4 large load additions and existing and approved resources under normal weather conditions. There still exists (without making more resource additions) a short position in the winter in the near- to intermediate-term absent adding more capacity.

Figure 9. Winter Capacity Position – Large Load Case 4 – Existing and Approved Resources – Normal Weather

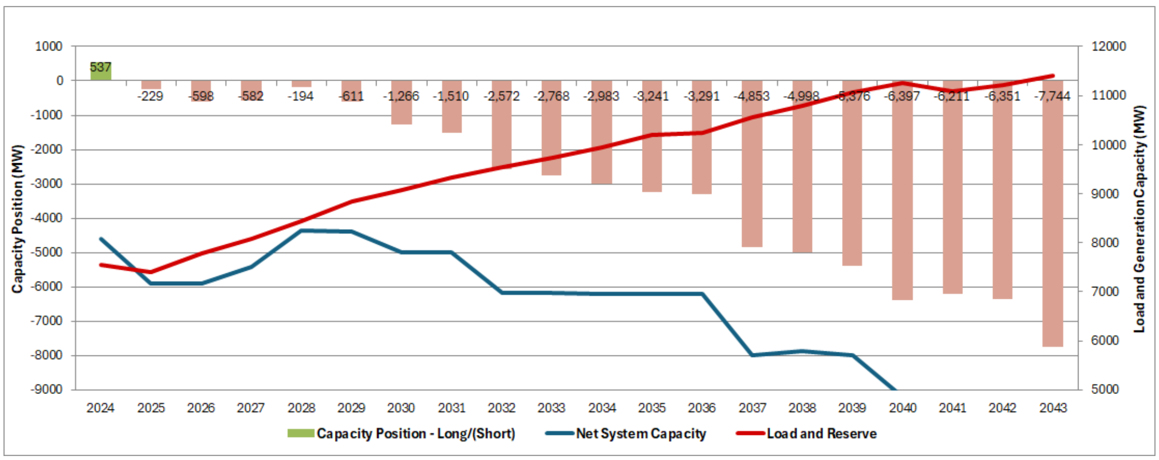
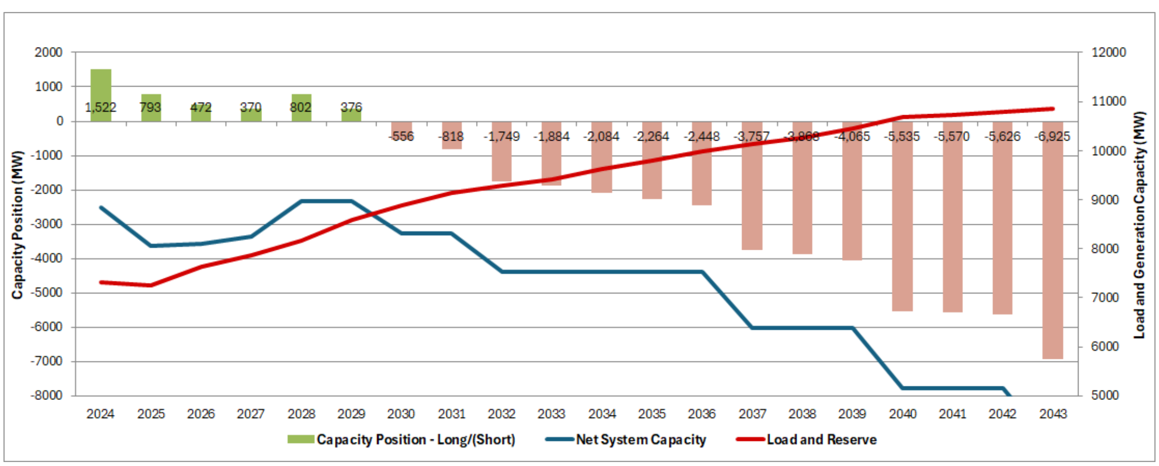


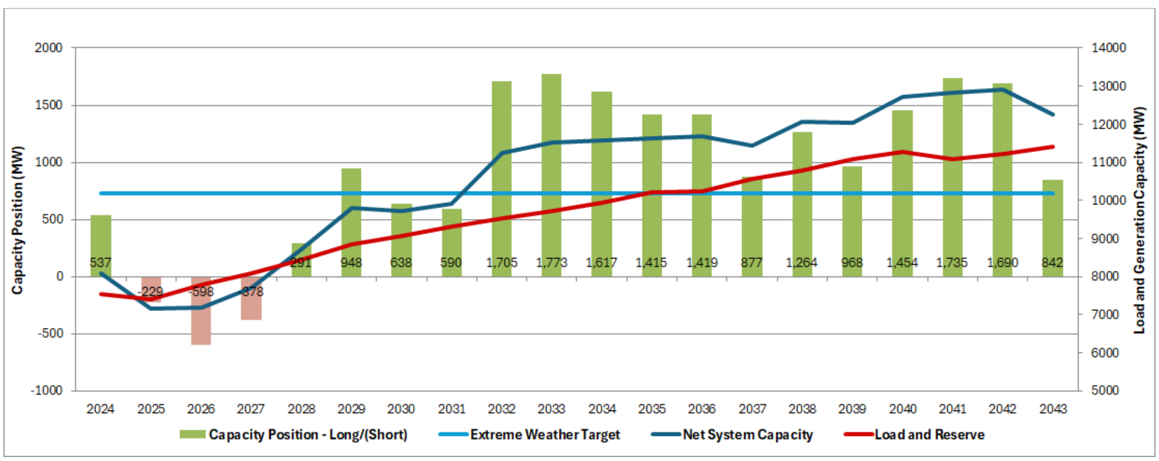
Figure 10. Summer Capacity Position – Large Load Case 4 – Existing and Approved Resources – Normal Weather



Q. Please discuss Ameren Missouri's capacity positions for its PRP (i.e., Case 4 large load demand) with all planned resource additions included, including the acceleration of some resources as discussed earlier.

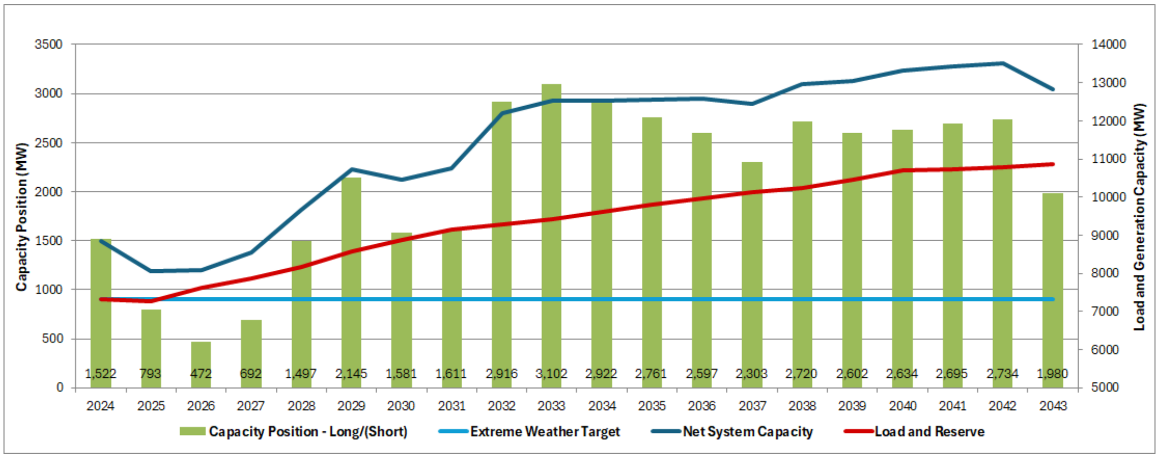
A. Figures 11 and 12 show the Company's winter and summer capacity positions, respectively, for the 2025 PRP under normal weather conditions. Figures 11 and 12 show that implementation of the Company's 2025 PRP will mean that the Company will have sufficient capacity to meet its load and PRM under normal weather conditions with a reasonable buffer starting in 2028.[15]

Figure 11. Winter Capacity Position – Large Load Case 4 – All Planned Resources – Normal Weather



[15] A reasonable capacity buffer is necessary to address risks associated with extreme weather demand, changes in environmental regulation affecting generating resources, and other risks that may significantly affect the need for capacity and the flexibility to consider options for reliably meeting customer energy needs.

Figure 12. Summer Capacity Position – Large Load Case 4 – All Planned Resources – Normal Weather



Q. What is the basis for the load and generating capacity assumptions reflected in the capacity positions included in your direct testimony?

A. The peak demand and unit accreditation values are the same as those used in the Company's 2023 IRP analysis, with the modification to include additional winter capability at Audrain described below.[16]

Q. What was the basis for unit accreditations in the Company's 2023 IRP?

A. The 2023 IRP relied on the unit accreditations provided by MISO for its 2023-2024 Planning Resource Auction ("PRA"), often referred to as MISO's capacity auction. A few modifications were made to normalize accreditations for certain resources, which had experienced significant outages during the prior three years, to better represent going-forward performance expectations for reliability purposes. The primary adjustments that were made were for Callaway and the Taum Sauk pumped hydro storage facility arising from past outage events that are not expected to recur.

[16] An additional correction was made to the capacity for the Venice SCGT units, reducing total generating capacity by 123 MW and resulting in no material differences in plan performance.

Q. Why did you use values from MISO's 2023-2024 PRA instead of more recent values from its 2024-2025 PRA?

A. The primary reason is for continuity and consistency. MISO's approach to unit accreditations changed when it adopted a seasonal resource adequacy ("RA") construct. Company witness Andrew Meyer discusses the evolution of MISO's RA construct in more detail in his Direct Testimony. Part of MISO's current approach includes making an adjustment to unit accreditations based on actual performance during critical hours – roughly 60 hours in each season, or less than 300 hours per year. MISO is phasing this adjustment into its accreditation process over three years, with 40% of the adjustment included for planning year 2023-2024, 60% for planning year 2024-2025, and 80% starting in planning year 2025-2026. It is important to recognize that under this construct, it is not possible to identify when such critical hours will occur in the future or how units will perform during such hours. Another important aspect of the current construct is that changes like the addition of oil backup at Audrain are not fully recognized in winter unit accreditations because MISO phases such changes in over three years, even though the units' improved ability to operate during winter occurs immediately. Because of the uncertain and after-the-fact nature of these adjustments and the forward-looking nature of resource planning, it makes more sense to use the 2023-2024 PRA accreditation values as the basis for the capacity positions presented here. It is also important to note that there have been no significant underlying changes in rated output for Ameren Missouri's existing generating units.

Q. As you noted, Figure 11 shows that the Company expects to be short capacity under normal weather conditions in 2025-2027. Will Ameren Missouri be able to meet its load and PRM obligation during those years?

A. Yes. While Ameren Missouri does not currently own the resources it would need to fully meet its load and PRM obligations during 2025-2027, it expects to secure capacity to meet its obligations during those years. The Company has been consistently projecting a capacity shortfall during that timeframe since its 2023 IRP and has continued to plan to meet its obligations. However, the Company is working to ensure that it has its own resources to meet those needs to eliminate any risks posed by needing to secure other capacity to meet its obligations. Company witness Andrew Meyer discusses the Company's near-term capacity position based on MISO's most recent planning resource auction values for unit accreditation in his Direct Testimony.

IV. ECONOMICS OF RESOURCE ADDITIONS

Q. Did Ameren Missouri revise any of its IRP assumptions in developing its 2025 PRP for its evaluation of different large load plans?

A. Yes. As described in the Company's February 28, 2025, Notice of Change in PRP, Ameren Missouri reviewed its assumptions and made updates to its costs for wind and natural gas-fired resources to reflect current and expected market conditions as well as any necessary transmission infrastructure and environmental mitigation requirements.[17]

[17] Schedule MM-D1 – 2025 Change in Preferred Plan Report, pp. 13-14.

Q. You mentioned earlier that the Company revised its long-term outlook for implementation of MEEIA programs. How did that change affect the Company's need for resources?

A. As also described in the Company's February 28, 2025, Notice of Change in PRP, the change in the Company's long-term outlook for MEEIA programs results in reduced demand savings of approximately 300 MW by 2032 and 700 MW by 2043.[18] Adding the winter PRM of 25 percent results in an increase in resource needs driven by the recent MEEIA decision of approximately 375 MW by 2032 and 875 MW by 2043. The specific annual demand and energy savings and forecasted program budgets for the Company's long-term MEEIA programs is shown in **Schedule MM-D1**, page 16, Table 2.3.

Q. Did the Company update its assumptions for its power price scenarios used in its IRP risk analysis?

A. No. The Company reviewed its price scenario assumptions as part of its 2024 IRP Annual Update process and elected to make no changes at that time. However, Ameren Missouri did use the analytical services of Charles River Associates ("CRA") to evaluate price sensitivity to large additions of large loads across MISO and the broader market, as described in **Schedule MM-D1**, pages 19-22. In general, power prices increased with the inclusion of additional large loads in MISO, with the high-case large load yielding the greatest increase in power prices. These additional power price scenarios were used to test the performance of the various alternative plans, including those with varying large loads (i.e., Cases 1-7).

[18] Schedule MM-D1 – 2025 Change in Preferred Plan Report, p. 15.

Q. What were the results of the analysis of the alternative plans for large load cases 1-7?

A. Unsurprisingly, the results show that the higher the load, the higher the costs. That conclusion is not, in and of itself, useful. However, it does provide a basis for evaluating the balance between costs and the new revenue contributions from the additional demand and energy charges from new large load customers whose demand increases result in the need to accelerate resource additions, as described in the Company's application for a tariff to serve LLCs.[19]

Q. Did the analysis of price sensitivity using the new price scenarios from CRA indicate any concerns with relying on the Company's 2023 IRP price scenario assumptions for purposes of analyzing the cost of the various plans?

A. No. The results of the price sensitivity analysis are shown in **Schedule MM-D1**, pages 26-27 and indicate that using such prices does not alter the conclusions of the Company's plan analysis.

Q. Have you performed additional analysis specific to the BHEC projects for which the Company is seeking a CCN? If so, please describe the analysis.

A. Yes. Specifically, I have evaluated the Company's PRP with updated costs for both the NGSC and BESS projects that are the subject of this case, and I have evaluated alternative plans that exclude each of the two projects – one plan in which the NGSC is removed from the PRP and another plan in which the BESS is removed from the PRP.

[19] File No. ET-2025-0184.

Q. What were the results of the analysis?

A. Table 6 below shows the results of the analysis of the PRP with and without the BHEC projects. As the table shows, NPVRR under probability-weighted average ("PWA") CO_2 prices decreases by $1,606 million when the NGSC is removed and by $723-994 million when the BESS is removed, depending on assumptions for ITC and BESS capital costs. NPVRR results for the different levels of CO_2 price assumption are similar, indicating the results are not significantly sensitive to CO_2 price assumptions.

Table 6. NPVRR Results – PRP With and Without BHEC Resources[20]

	NPVRR Results ($MM)	Low CO2 Price	Base CO2 Price	High CO2 Price	PWA CO2 Price
a	Modified PRP - with Project-Specific Costs and 50% ITC on BESS	109,599	108,348	108,677	108,868
b	Modified PRP - with Project-Specific Costs, 50% ITC, without NGSC	107,973	106,731	107,089	107,261
c	Modified PRP - with Project-Specific Costs, without BESS	108,876	107,614	107,959	108,145
d	Modified PRP - with Project-Specific Costs and No ITC on BESS	109,795	108,544	108,873	109,064
e	Modified PRP - with Project-Specific Costs and 50% ITC on BESS (High Costs)	109,653	108,402	108,731	108,922
f	Modified PRP - with Project-Specific Costs and No ITC on BESS (High Costs)	109,870	108,619	108,948	109,139
	NPVRR Differences				
	Modified PRP without BHEC NGSC (b) - Modified PRP (a)	(1,626)	(1,616)	(1,588)	(1,606)
	Modified PRP without BHEC BESS (c) - Modified PRP (a)	(723)	(733)	(718)	(723)
	Modified PRP without BHEC BESS (c) - Modified PRP with No ITC (d)	(919)	(930)	(914)	(920)
	Modified PRP without BHEC BESS (c) - Modified PRP with High BESS Costs (e)	(777)	(787)	(772)	(777)
	Modified PRP without BHEC BESS (c) - Modified PRP with No ITC and High BESS Costs (f)	(994)	(1,004)	(989)	(994)

Q. What are the implications of the analysis results you just described?

A. Simply that these resources, which are necessary to serve expected customer demand, result in costs that must be recovered through customer rates. It is worth noting that the Company's 2023 PRP already included the implementation of 400 MW of BESS by 2030. The additional NGSC resource is needed primarily to serve new customer demand, as I described earlier in my Direct Testimony. How costs are recovered from new

[20] Plan a in Table 6 reflects a plan with project specific costs for the BHEC Projects, both the NGSC and the BESS, with a base assumption of 50% ITC for batteries. Plans d-f also reflect project specific costs for the BHEC Projects, but with different assumptions for ITC and BESS costs (base or high). Plan b reflects removal of the BHEC NGSC with no replacement (i.e., it assumes the CCN for the NGSC is not approved and the resource is not added). Plan c reflects removal of the BHEC BESS with no replacement (i.e., it assumes the CCN is not approved and the resource is not added).

customers and how the recovery of costs is mitigated by various proposed tariff provisions is the subject of the Company's large load tariff application in File No. ET-2025-0184. The Direct Testimony of Company witness Steve Wills in that case describes in detail the tariff provisions designed to mitigate risks to other customers should one or more LLCs cease service from Ameren Missouri prior to the full term of their agreement(s).

Q. You previously mentioned the need to maintain resource flexibility. Can you elaborate?

A. For most of the last twenty years, the Company and its customers have benefited from Ameren Missouri's capacity length; that is, the Company's resource capacity beyond its load and planning reserve margin requirement. Benefits include revenue from capacity and energy sales in the MISO market, which reduces the revenue requirement recovered from customers through retail rates. Another benefit is the flexibility that capacity length provides in addressing risks to the Company's ability to reliably serve customers, including the preservation of options to address new environmental regulations and capitalize on economic development opportunities that benefit the communities Ameren Missouri serves. When capacity is only marginally sufficient to serve current customer needs, any significant change in customer demand or the Company's resource portfolio can result in the need for immediate action with a potentially limited range of options. Resource flexibility allows the Company to consider other options that may require more time to implement but that better serve the long-term interests of customers.

Q. Did Missouri recently pass legislation that is relevant to the need for resource flexibility?

A. Yes. In March of this year, the Missouri legislature passed Senate Bill 4 ("SB 4") and it was signed by Governor Kehoe on April 9, 2025. SB 4 includes several provisions that encourage Missouri utilities to ensure they have sufficient dispatchable (i.e., available on call) generation to meet customer demand and energy needs. These include requirements to ensure replacement dispatchable generation is in operation prior to retirement of existing generation,[21] requirements for utilities to report on the sufficiency of their resource portfolios to meet expected demand and reserve margin requirements,[22] and streamlining the process for new resource approvals through the IRP and CCN processes.[23] SB 4 also includes provisions for cost recovery mechanisms that address potential limitations or disincentives to the deployment of generation resources. Together, the provisions of SB 4 make clear the state's policy to ensure minimum standards for resource adequacy are always met. To ensure those minimum standards are always met requires consideration of resource flexibility to address risks to resource adequacy.

Q. Had SB 4 been passed at the time the Company updated its PRP?

A. No. As I mentioned previously, the Company filed its Notice of Change in Preferred Resource Plan on February 28, 2025. The Company's consideration of changes to its PRP occurred over the course of several months prior to the filing of its notification, during which time a number of potential legislative actions regarding electric utility

[21] Section 393.401 RSMo.
[22] Section 393.1080 RSMo.
[23] Section 393.1900 RSMo.

regulation were under consideration, including many of the legislative actions that became law when SB 4 did pass.

Q. How do the provisions of SB 4 impact the Company's consideration of resource planning to reliably serve its customers?

A. While the Company normally seeks to address the kinds of risks discussed above, for which these provisions of SB 4 were adopted, as part of its resource planning process, SB 4 confirms that state policy is supportive of the consideration of exactly those kinds of risks and the need for action to address them. For example, the Commission approved the Company's application for a CCN for a new gas-fired generation facility in late 2024 (the Castle Bluff NGSC facility I mentioned previously). As stated in the Company's testimony in that case,[24] the primary rationale for adding this generation to its portfolio was the need to ensure reliability for customers in all hours and under all conditions, including extreme weather. The provisions of SB 4, while not explicitly requiring such considerations, support the consideration of extreme weather risk in resource planning, along with numerous other risks to customer reliability.

Q. Since the passage of SB 4, has the Company evaluated the ability of its current PRP to meet the requirements of Section 393.401, RSMo.?

A. Yes. Section 393.401, RSMo. requires that utilities certify that sufficient new generation is online to replace retiring generation of more than 100 MW within the state. This provision implicates the Company's planned retirement of its Sioux and Labadie Energy Centers, as reflected in its current PRP as shown in Figure 1. The basis for such certification involves the following assessment steps:

[24] File No. EA-2024-0237.

- Determine the average of the winter and summer accredited capacity of the retiring generation based on resource accreditations determined by MISO;
- Identify replacement generation that will be online prior to the retirement of the existing generation and determine the average of its expected winter and summer accredited capacity values (which will likely be based on class average accreditation values from MISO);
- Compare the average accredited value of new dispatchable (i.e., available on demand) generation to 80 percent of the accredited value of the retiring generation;
- Compare the average accredited value of all new generation to the accredited value of the retiring generation; and
- Ensure that both the 80 percent dispatchable requirement and the total replacement generation requirement are met.

Q. What were the results of your evaluation of the ability of the Company's current PRP to meet the requirements you described above?

A. Table 7 below shows the results of the 80 percent dispatchable replacement generation comparison described above for six different cases, which are themselves described in the notes that appear with the table. Because the Company is also adding other generation, including renewable generation and BESS with expected accredited capacity value, the 80 percent dispatchable requirement represents the threshold condition for ensuring overall compliance.

Table 7. Replacement Generation Compliance Cases – 80% Dispatchable

Case	1	2	3	4	5	6
Year	2025 Preferred Resource Plan	NGCC Delay	NGCC Delay w/o Big Hollow	Labadie Early Retirement	Labadie Early Retirement w/ NGCC Delay	Labadie Early Retirement w/ NGCC Delay and w/o Big Hollow
2029	727	727	-	727	727	-
2030	727	727	-	727	727	-
2031	727	727	-	727	727	-
2032	2,023	112	(615)	2,023	112	(615)
2033	2,023	112	(615)	1,056	(855)	(1,582)
2034	2,023	112	(615)	1,056	(855)	(1,582)
2035	2,023	2,023	1,296	1,056	1,056	329
2036	2,023	2,023	1,296	1,056	1,056	329
2037	2,089	2,089	1,362	2,089	2,089	1,362
2038	2,634	2,634	1,907	2,634	2,634	1,907
2039	2,634	2,634	1,907	2,634	2,634	1,907
2040	4,059	4,059	3,332	4,059	4,059	3,332
2041	4,059	4,059	3,332	4,059	4,059	3,332
2042	4,059	4,059	3,332	4,059	4,059	3,332
2043	3,638	3,638	2,911	3,638	3,638	2,911

1 2025 Preferred Resource Plan
2 NGCC delayed three years, from 1/1/2032 to 1/1/2035
3 NGCC delayed three years, from 1/1/2032 to 1/1/2035; Big Hollow NGSC excluded
4 Labadie retirement (2 units) accelerated four years, from 12/31/2036 to 12/31/2032
5 Labadie retirement (2 units) accelerated four years, from 12/31/2036 to 12/31/2032; NGCC delayed three years, from 1/1/2032 to 1/1/2035
6 Labadie retirement (2 units) accelerated four years, from 12/31/2036 to 12/31/2032; NGCC delayed three years, from 1/1/2032 to 1/1/2035; Big Hollow NGSC excluded

As Table 7 shows, the Company's 2025 PRP (Case 1) ensures sufficient dispatchable resources to replace retiring generation throughout the planning horizon. However, some cases indicate an expected shortfall under certain circumstances. Specifically, any combination of 1) a delay in the Company's planned 2032 NGCC addition, 2) the accelerated retirement of Labadie units from the planned retirement at the end of 2036, and 3) the absence of the Company's planned NGSC and BESS additions at the Rush Island site in late 2028 result in a shortfall with respect to the 80% dispatchable replacement generation requirement.

Q. Is the risk of delay in the NGCC implementation a real concern?

A. Yes. Potential constraints in the supply chains for equipment, materials, and labor, for the generation, the necessary transmission infrastructure, or the gas fuel infrastructure, could cause a delay in deployment and commencement of commercial operation.

Q. Is the risk of accelerated retirement of Labadie a real concern?

A. Yes. While an imminent requirement to retire units as a result of new environmental regulations or climate policy is unlikely, we have seen a concerted push for the retirement of coal-fired generation over the last twenty years. In addition, the possibility of catastrophic equipment failure regardless of taking prudent steps to try to avoid such an outcome could also lead to the early retirement of coal-fired units, including those at Labadie.

Q. Section 393.401, RSMo. provides for an allowance of time to place replacement generation in service in the event of unforeseen circumstances that result in early unit retirement or if new generation shares interconnection facilities with existing generation. Does that help to mitigate such concerns?

A. It does to a degree. Section 393.401, RSMo. provides up to 18 months for replacement generation to be placed in service if replacement generation shares interconnection facilities with the existing generation it is meant to replace, and it provides for the development of a plan to replace generation retired due to unforeseen circumstances. While these provisions are important for mitigating the risks to compliance with the replacement generation requirements, they do not alleviate the need for resources to replace retiring generation and ensure reliable service.

Q. Can you walk through some examples of the calculations you did to generate the results shown in Table 7?

A. Yes. Tables 8-10 below show the calculations for steps outlined previously for Cases 1-3, respectively. Starting from the left, the average accredited capacity for retiring generation is calculated using the winter and summer accreditation values used in the Company's latest IRP analysis, with the cumulative retired capacity and 80 percent of that value shown for use in the comparisons required by Section 393.401, RSMo. Next, the average accredited capacity value of dispatchable generation additions is shown, with a cumulative addition included for the comparison. The final two columns show the net of dispatchable capacity additions and retirements and the difference between dispatchable additions and 80 percent of retirements. Table 8 (Case 1) shows that the Company's current PRP includes sufficient capacity additions to cover the entire amount of retired capacity. Table 9 (Case 2) shows that with a delay in the 2032 NGCC in the PRP, capacity additions are still sufficient to cover 80 percent of retiring capacity, but not sufficient to cover the entire retired capacity amount in all years. Table 10 (Case 3) shows that with a delay in the 2032 NGCC and the exclusion of the Big Hollow NGSC, dispatchable capacity additions are not sufficient to cover 80 percent of retiring capacity in all years.

Table 8. Replacement Generation Case 1 Calculations

Case 1 - Ameren Missouri 2025 Preferred Resource Plan

		Accredited Capacity (MW)						Accredited Capacity (MW)					
	Retirements	Winter MW	Summer MW	Ave. W/S	Cumul. Retir.	80% Disp. Need	Replacements	Winter MW	Summer MW	Ave. W/S	Cumul. Repl.	Repl. - Retir.	Repl. - Retir. 80%
2026				-	-	-				-	-	-	-
2027				-	-	-				-	-	-	-
2028				-	-	-				-	-	-	-
2029				-	-	-	Big Hollow	727	727	727	727	727	727
2030				-	-	-				-	727	727	727
2031				-	-	-				-	727	727	727
2032	Sioux	749	788	769	769	615	NGCC	1,911	1,911	1,911	2,638	1,870	2,023
2033				-	769	615				-	2,638	1,870	2,023
2034				-	769	615				-	2,638	1,870	2,023
2035				-	769	615				-	2,638	1,870	2,023
2036				-	769	615				-	2,638	1,870	2,023
2037	Labadie (2 u	1,228	1,189	1,209	1,977	1,582	CC#2	1,033	1,033	1,033	3,671	1,694	2,089
2038				-	1,977	1,582	SC#3	545	545	545	4,216	2,239	2,634
2039				-	1,977	1,582				-	4,216	2,239	2,634
2040				-	1,977	1,582	Nuke	1,425	1,425	1,425	5,641	3,664	4,059
2041				-	1,977	1,582				-	5,641	3,664	4,059
2042				-	1,977	1,582				-	5,641	3,664	4,059
2043	Labadie (2 u	1,228	1,189	1,209	3,186	2,548	SC#4	545	545	545	6,186	3,001	3,638

Table 9. Replacement Generation Case 2 Calculations

Case 2 - 2025 Ameren Missouri Preferred Resource Plan with NGCC Delayed Three Years

		Accredited Capacity						Accredited Capacity					
	Retirements	Winter MW	Summer MW	Ave. W/S	Cumul. Retir.	80% Disp. Need	Replacements	Winter MW	Summer MW	Ave. W/S	Cumul. Repl.	Repl. - Retir.	Repl. - Retir. 80%
2026				-	-	-				-	-	-	-
2027				-	-	-				-	-	-	-
2028				-	-	-				-	-	-	-
2029				-	-	-	Big Hollow	727	727	727	727	727	727
2030				-	-	-				-	727	727	727
2031				-	-	-				-	727	727	727
2032	Sioux	749	788	769	769	615				-	727	(42)	112
2033				-	769	615				-	727	(42)	112
2034				-	769	615				-	727	(42)	112
2035				-	769	615	NGCC	1,911	1,911	1,911	2,638	1,870	2,023
2036				-	769	615				-	2,638	1,870	2,023
2037	Labadie (2 u	1,228	1,189	1,209	1,977	1,582	CC#2	1,033	1,033	1,033	3,671	1,694	2,089
2038				-	1,977	1,582	SC#3	545	545	545	4,216	2,239	2,634
2039				-	1,977	1,582				-	4,216	2,239	2,634
2040				-	1,977	1,582	Nuke	1,425	1,425	1,425	5,641	3,664	4,059
2041				-	1,977	1,582				-	5,641	3,664	4,059
2042				-	1,977	1,582				-	5,641	3,664	4,059
2043	Labadie (2 u	1,228	1,189	1,209	3,186	2,548	SC#4	545	545	545	6,186	3,001	3,638

Table 10. Replacement Generation Case 3 Calculations

Case 3 - 2025 Ameren Missouri Preferred Resource Plan with NGCC Delayed Three Years and Without Big Hollow NGSC

		Accredited Capacity (MW)						Accredited Capacity (MW)					
	Retirements	Winter MW	Summer MW	Ave. W/S	Cumul. Retir.	80% Disp. Need	Replacements	Winter MW	Summer MW	Ave. W/S	Cumul. Repl.	Repl. - Retir.	Repl. - Retir. 80%
2026				-	-	-				-	-	-	-
2027				-	-	-				-	-	-	-
2028				-	-	-				-	-	-	-
2029				-	-	-				-	-	-	-
2030				-	-	-				-	-	-	-
2031				-	-	-				-	-	-	-
2032	Sioux	749	788	769	769	615				-	-	(769)	(615)
2033				-	769	615				-	-	(769)	(615)
2034				-	769	615				-	-	(769)	(615)
2035				-	769	615	NGCC	1,911	1,911	1,911	1,911	1,143	1,296
2036				-	769	615				-	1,911	1,143	1,296
2037	Labadie (2 u	1,228	1,189	1,209	1,977	1,582	CC#2	1,033	1,033	1,033	2,944	967	1,362
2038				-	1,977	1,582	SC#3	545	545	545	3,489	1,512	1,907
2039				-	1,977	1,582				-	3,489	1,512	1,907
2040				-	1,977	1,582	Nuke	1,425	1,425	1,425	4,914	2,937	3,332
2041				-	1,977	1,582				-	4,914	2,937	3,332
2042				-	1,977	1,582				-	4,914	2,937	3,332
2043	Labadie (2 u	1,228	1,189	1,209	3,186	2,548	SC#4	545	545	545	5,459	2,274	2,911

Q. You mentioned the Company's planned Castle Bluff NGSC facility previously. Why is its capacity not included in the additions for the comparisons you have shown for assessing prospective compliance with the requirements of Section 393.401, RSMo.?

A. As I mentioned previously, the primary rationale for the addition of Castle Bluff is to ensure sufficient capacity to meet higher demands during extreme winter weather conditions of the kind we've seen in recent years, such as winter storms Uri (February 2021) and Elliott (December 2022). As I also mentioned previously, it is important to satisfy not only the letter of the new reliability provisions in SB 4, but also the spirit of those provisions, both collectively and individually. Including the capacity for Castle Bluff in the replacement capacity calculations for compliance with Section 393.401, RSMo. would ignore the rationale for the need for *incremental* capacity above and beyond the Company's normal capacity needs and distort the comparison required by Section 393.401, RSMo. by suggesting that Castle Bluff could also replace retiring capacity. By excluding it from the comparison as I have, the existence of incremental capacity in the portfolio to meet demand under extreme conditions is preserved as is the proactive replacement of existing generation that is also still required to meet those needs.

Q. Does that also mean the Company would not or should not include the capacity of Castle Bluff in its capacity position for purposes of satisfying MISO's resource adequacy requirements?

A. Not at all. MISO's resource adequacy requirements are based on expected demand under normal weather conditions, and Castle Bluff should and would be included in the Company's capacity position to demonstrate sufficient capacity in MISO.

Q. Does that then mean that the Company is inappropriately "overcomplying" with MISO's requirements?

A. No, and for several reasons. First, MISO's resource adequacy framework has become more complex and unpredictable, with the inclusion of seasonal requirements and the continued evolution of MISO's process for resource accreditation and planning reserve margin determination. That includes MISO's planned transition to a DLOL approach for resource adequacy, which is planned to take effect for the 2028-2029 planning year and for which MISO has provided only indicative and generic values for accreditation and planning reserve margin requirements. Throughout this evolution of MISO's resource adequacy process, there has been little predictability in the values used to assess forward-looking capacity needs and sufficiency.

Second, the same kinds of risks I've mentioned previously, including the kind portrayed in my discussion of satisfying the requirements of Section 393.401, RSMo., are also relevant to planning for meeting MISO's resource adequacy requirements.

Third, as is evident in this case, prospects for the addition of large loads must be considered in assessing resources needed to ensure reliability in the face of significant uncertainty. In short, it is better to "stay ahead of the game" than it is to "play catchup."

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and Certificate of Public Convenience and Necessity Authorizing it to Construct a New Generation Facility and Battery Energy Storage System	)))))	File No.: EA-2025-0238

AFFIDAVIT OF MATT R. MICHELS

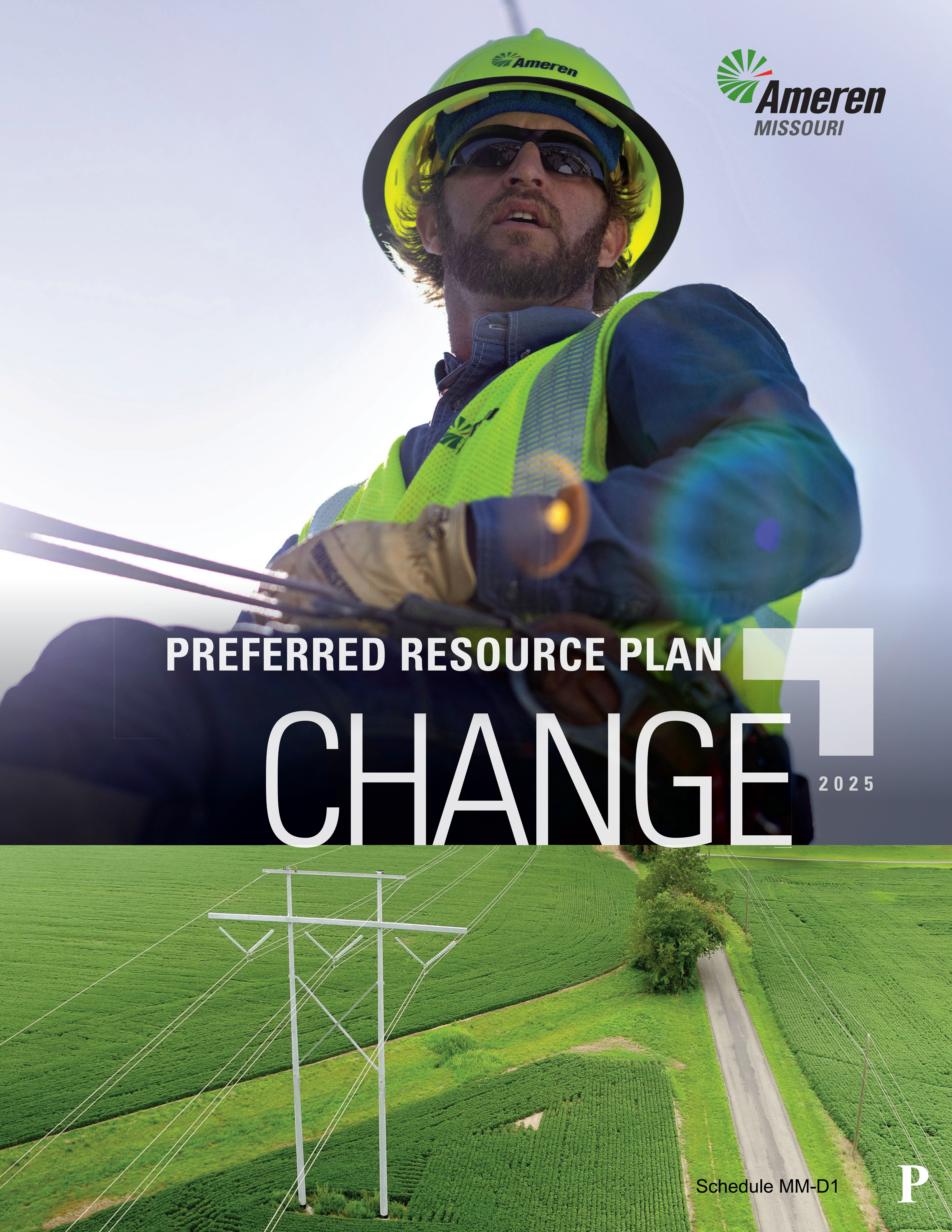
STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Matt R. Michels, being first duly sworn on his oath, states:

My name is Matt R. Michels, and hereby declare on oath that I am of sound mind and lawful age; that I have prepared the foregoing *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Matt R. Michels
Matt R. Michels

Sworn to me this 26th day of June 2025.



Ameren MISSOURI

PREFERRED RESOURCE PLAN

CHANGE

2025

Schedule MM-D1

P

1. Executive Summary

Ameren Missouri's senior management has concluded that the Preferred Resource Plan (PRP) presented in its 2023 Triennial Integrated Resource Plan (IRP) (File No. EO-2024-0020) is no longer appropriate and should be revised. This conclusion was reached as a result of two key changes in the planning environment:

- Data Center and Large Load Potential – Since the Company's 2023 IRP was filed, the Company has seen significant growth in interest of potential data center customers to locate in Ameren Missouri's service territory. Specifically, the Company has fielded interest from customers representing aggregate potential peak demand of approximately 3 GW, with signed construction contracts related to interconnecting to Ameren Missouri's system totaling 1.8 GW. While other steps remain to add these prospective customers to Ameren Missouri's system, including the approval of a new rate tariff under which such customers would be served, these developments evidence both the likelihood and magnitude of these potential load additions.
- Changes in Company-Sponsored Energy Efficiency Programs – The Missouri Public Service Commission (MPSC) approved a non-unanimous stipulation and agreement in File No. EO-2023-0136 in November 2024 regarding the Company's Missouri Energy Efficiency Investment Act (MEEIA) energy efficiency and demand response program budgets and expected energy and demand savings over the next several years. In recognition of concerns raised by the MPSC and some stakeholders, the Company has revised its long-term outlook for these programs. This change results in a reduction in expected winter peak demand savings of approximately 300 MW by 2032 and 700 MW by 2043 relative to the Company's 2023 PRP levels.

In addition to these key changes, Ameren Missouri has also revised its assumptions for the costs of certain resources to reflect current and expected market conditions. Resources with updated costs include wind, simple cycle gas combustion turbine generators (CTG), and natural gas combined cycle (NGCC) generation. The Company also reviewed its assumptions for natural gas prices, carbon prices, power prices and capacity prices and determined they were still appropriate for evaluating the performance of alternative resource plans. Ameren Missouri continues to consider its resource planning decisions in the context of a comprehensive generation strategy, which includes the following objectives:

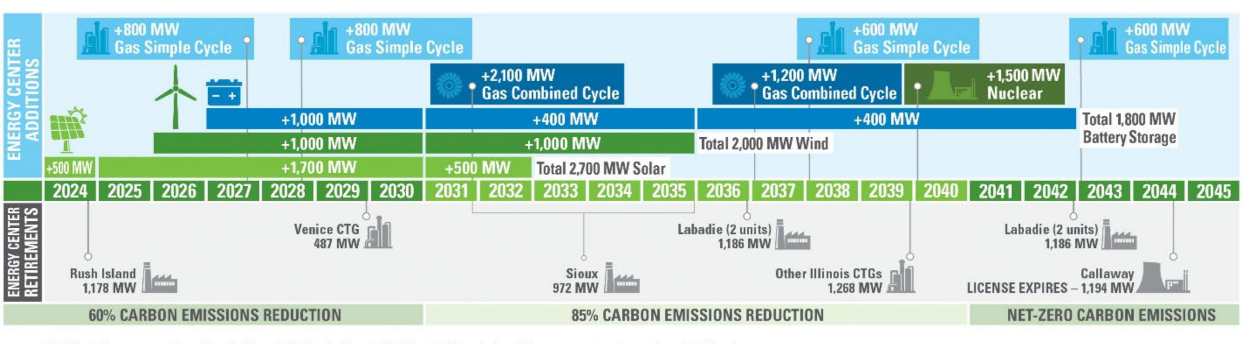
- Operate Energy Centers safely, economically, and in an environmentally responsible fashion while transitioning the generation fleet.
- Ensure overall energy (supply and grid) reliability and affordability.
- Create and capitalize on investment opportunities that are beneficial to customers, shareholders,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

As part of meeting these objectives, the Company seeks greater utilization of renewable energy resources together with appropriate reliance on existing and new dispatchable generation. Ameren Missouri also strives to ensure specific planning 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 while maintaining reliability).
- Mitigate Financial/Regulatory Risk.
- Economic Development.

After considering the prospects for new large load additions and the other changes noted above and with the above stated objectives in mind, Ameren Missouri has selected a PRP that will support 1.5 GW of new additional demand by 2032 and 2.5 GW by 2040. The 2025 PRP resource timeline is shown below in Figure 1.1.

Figure 1.1: Ameren Missouri's 2025 PRP Resource Timeline



The key elements of the Company's new PRP are as follows:

- 2,700 MW of solar generation by 2032 – This includes 500 MW of solar generation placed in service at the end of 2024, another 1,700 MW by the end of 2030 (including 400 MW for which the MPSC has granted the Company's requests for certificates of convenience and necessity (CCN)), and another 500 MW by the end of 2032. Ameren Missouri expects to apply for CCNs for additional solar generation facilities during 2025, with the first CCN application expected in the second quarter of 2025.

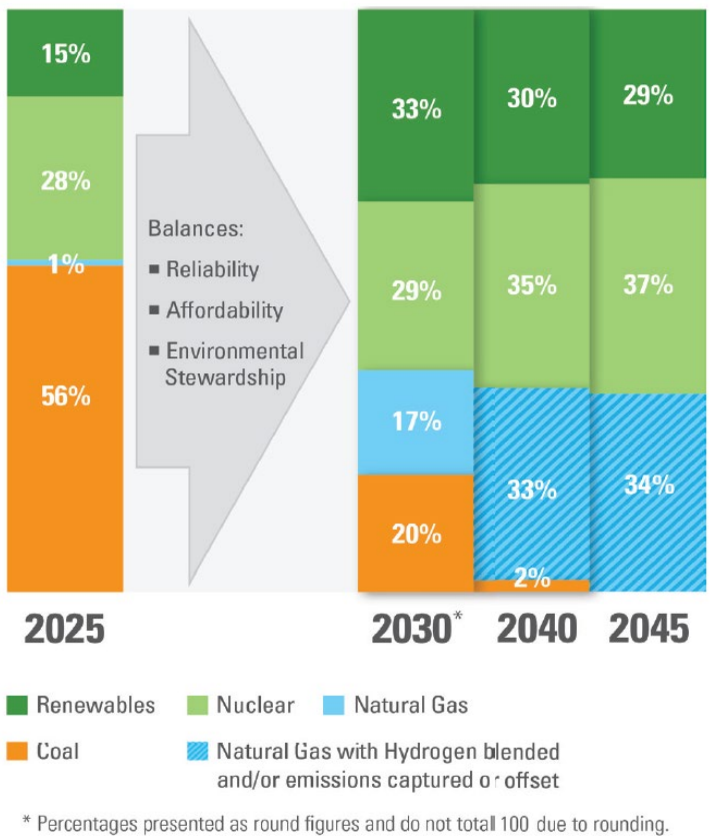
- 2,000 MW of wind generation by 2035 – This remains unchanged from the Company's 2023 PRP and includes 1,000 MW of wind by 2030 and another 1,000 MW by 2035.
- 1,800 MW of battery energy storage systems (BESS) by the end of 2042 – This includes 1,000 MW of BESS additions by 2030, another 400 MW by 2035, and another 400 MW by 2042. The Company expects to submit an application to the MPSC for a CCN for the first tranche of BESS in the second quarter of 2025.
- 1,600 MW of new CTG generation by 2030 – This includes the 800 MW Castle Bluff CTG facility at the site of the Company's former Meramec coal-fired energy center by the end of 2027, for which the MPSC granted the Company a CCN in October 2024.[1] It also includes an additional 800 MW CTG facility to be located at the site of the Company's former Rush Island coal-fired energy center by the end of 2028. The Company expects to seek MPSC approval for a CCN for this facility in the second quarter of 2025.
- An additional 1,200 MW of CTG generation by 2042 – This includes 600 MW of CTG generation by the end of 2037 and another 600 MW by the end of 2042. The Company expects to eliminate or offset emissions from CTG facilities by 2045.
- 3,300 MW of NGCC generation by 2037 – This includes a 2,100 MW NGCC facility at the site of the Company's existing Sioux coal-fired energy center by the end of 2031 and an additional 1,200 MW NGCC facility by the end of 2036. The Company expects to eliminate or offset carbon dioxide emissions from these facilities by 2040 through some combination of hydrogen blending and carbon capture and sequestration (CCS), assuming such technologies are commercially viable.
- Retirement of all of the Company's coal-fired generation by the end of 2042 – This includes retirement of two units at the Labadie Energy Center (LEC) by the end of 2036 and the other two units at LEC by the end of 2042, all unchanged from the Company's 2023 PRP. It also includes retirement of the coal-fired units at Company's Sioux Energy Center (SEC) between the end of 2031 and the end of 2035. The Company is maintaining flexibility with regard to the retirement date for SEC at this time to ensure system reliability during the transition to the new NGCC generation.

[1] File No. EA-2024-0237

- 1,500 MW of new nuclear generation in 2040 – While selection of a specific nuclear technology has not be made, the Company continues to monitor development of new technologies closely, including small modular reactors (SMR). Ameren Missouri expects to see successful implementation of new SMR technology before making a commitment to the technology for deployment in its own fleet. Ameren Missouri also expects to seek an extension to its operating license for its existing Callaway Energy Center nuclear facility, which is currently set to expire in 2044.

Figure 1.2 shows the Company's expected generation energy mix under the 2025 PRP.

Figure 1.2: Ameren Missouri's 2025 PRP Generation Energy Mix



The PRP described above allows the Company to achieve its previously established carbon reduction targets – 60% reduction by 2030 and 85% reduction by 2040, compared to 2005 levels, and net zero emissions by 2045. The carbon reduction targets include both Scope 1 and Scope 2 emissions of greenhouse gases, including carbon dioxide, nitrogen oxides and sulfur hexafluoride.[2] Figure 1.3 below shows the Company's

[2] Note that roughly 99% of the Scope 1 and Scope 2 greenhouse gas emissions are carbon dioxide emissions from Ameren Missouri's fleet of coal and natural gas fired generators.

expected carbon emissions for its new PRP compared to its 2023 PRP. Figure 1.4 shows the Company's expected carbon intensity for its new PRP compared to its 2023 PRP.

Figure 1.3: 2025 PRP Carbon Emissions Compared to 2023 PRP

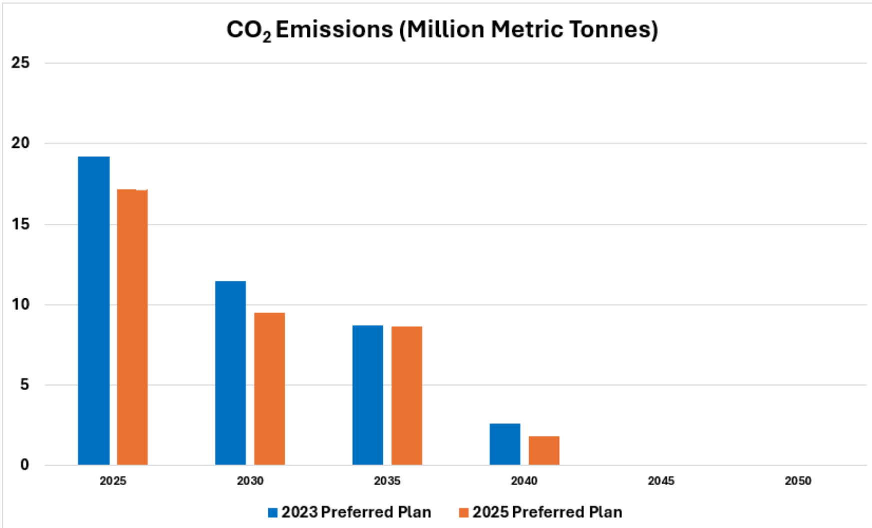
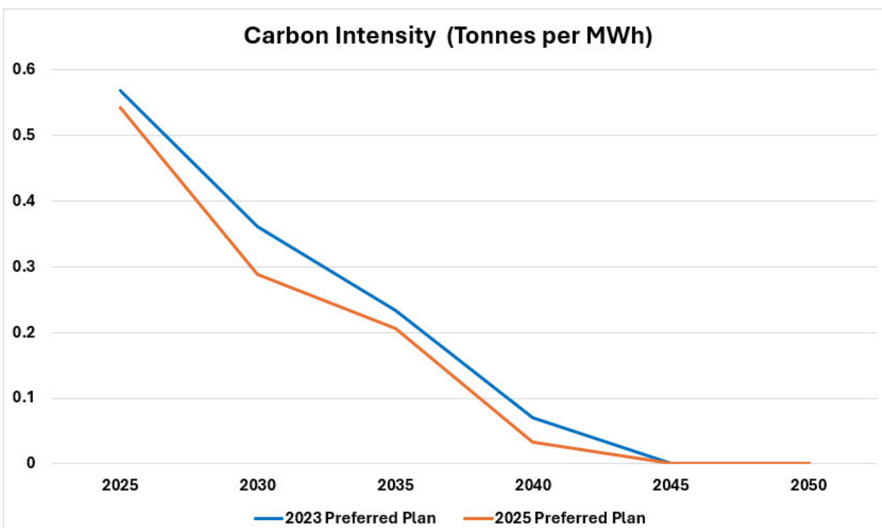


Figure 1.4: 2025 PRP Carbon Intensity Compared to 2023 PRP



In addition to the PRP, Ameren Missouri has also developed and analyzed contingency plans to recognize the uncertainty regarding potential data center load additions. These include an upside contingency plan to support 2 GW of new data center demand by 2032 and 3.5 GW by 2040 and a low contingency plan to support 500 MW of new data center demand by 2032 with no additional data center demand growth thereafter. It is important to note that the resource additions through 2032 for the contingency plan for 2 GW of data center demand by 2032 are the same as the resource additions through 2032 for the

PRP. Also, the addition of 800 MW of CTG generation in 2028 is included in both the upside and low contingency plans as well as the PRP. While the extent and timing of data center load additions remain somewhat uncertain, the combination of the PRP and these contingency plans position Ameren Missouri to serve a range of demand that may materialize while ensuring reliable service at a reasonable cost to all of its customers. Table 1.1 below shows the resource additions for the 2025 PRP as well as the two contingency plans described above. Resource additions for the 2023 IRP are also shown for comparison.

Table 1.1: Resource Additions for the 2025 PRP and Contingencies Compared to the 2023 PRP

	2023 IRP Preferred Plan	500 MW Large Loads	1.5 GW Large Loads	2.0 GW Large Loads
Data Center Load Additions (beginning of year)	N/A	500 MW by 2027 (4 GWh)	1.5 GW by 2032 (12 GWh) 2.5 GW by 2040 (20 GWh)	2 GW by 2032 (16 GWh) 3.5 GW by 2040 (28 GWh)
Energy Efficiency / Demand Response	Aggressive Energy Efficiency and Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs
Total Retail Sales in 2040	36 Million MWh	40 Million MWh	56 Million MWh	64 Million MWh
Coal Retirements (end of year)	Sioux (2032) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)
Gas Retirements (end of year)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)
Wind Additions (end of year)	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035
Solar Additions (end of year)	1,800 MW by 2030 2,700 MW by 2035	1,800 MW by 2030 2,700 MW by 2035	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032
Battery Additions (end of year)	400 MW by 2030 800 MW by 2033	400 MW by 2030 800 MW by 2033	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042
Combined Cycle Gas Additions (beginning of year)	1,200 MW (2033)	1,200 MW (2032)	2,100 MW (2032) 1,200 MW (2037)	2,100 MW (2032) 1,200 MW (2037) 1,200 MW (2038)
Simple Cycle Gas Additions (beginning of year, except 2027 and 2028 additions in Q4)	800 MW (2027)	800 MW (2027) 800 MW (2028)	800 MW (2027) 800 MW (2028) 600 MW (2038) 600 MW (2043)	800 MW (2027) 800 MW (2028) 600 MW (2035) 600 MW (2037)
New Nuclear Additions (beginning of year)	N/A	900 MW (2040)	1,500 MW (2040)	1,500 MW (2040)
Other Clean Dispatchable Additions (beginning of year)	1,200 MW (2040) 1,200 MW (2043)	1,200 MW (2037) 1,200 MW (2043)	N/A	N/A

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

- Submitting an application to establish a new tariff for large load customers, such as data centers, in the second quarter of 2025
- Submitting applications for CCNs to the MPSC for:
    - New solar generation projects (the first in the second quarter of 2025)
    - New BESS facilities to be located at former coal energy center sites (the first in the second quarter of 2025)

  - 800 MW of CTG generation at the former Rush Island coal energy center site (second quarter of 2025)
- Continuing to evaluate proposals for new wind and solar generation projects
- Continuing preparations for the addition of NGCC generation, including an application to the MPSC for a CCN in 2026
- Continuing to manage approved MEEIA programs for customer energy efficiency and demand response
- Continuing to monitor developments regarding environmental regulations, identifying and evaluating options for compliance, and taking steps to maintain available options
- Initiating a new market potential study to identify opportunities for further energy and demand savings from future MEEIA programs

2. Planning Environment

2.1 Environmental Regulations

Ameren Missouri has made significant investments to comply with existing environmental regulations and maintain a sufficient compliance margin. Rules proposed or promulgated since the IRP filing in 2023 include the 2023 update to the Mercury and Air Toxics Standards (MATS), the 2023 Steam Electric Power Generating Effluent Limitations Guidelines (ELG) Update, regulation of greenhouse gas emissions under section 111 of the Clean Air Act (GHG Rule), and the Legacy CCR Rule. Ameren Missouri has reviewed its assumptions on the eventual requirements for pending environmental regulations, as discussed in this section.

Clean Air Act Regulation of Greenhouse Gases (GHG)

On April 25, 2024, EPA issued final actions under Clean Air Act (CAA) section 111 applicable to GHG emissions from power plants: a section 111(b) rule governing new stationary combustion turbines; and a section 111(d) rule, governing existing steam-generating units (Final Rules). Many parties, including State Attorneys General, industry groups and rural electric cooperatives, among others, have sought judicial review of the Final Rules. The GHG rule for existing coal plants base the operational compliance requirements on the planned retirement date of the plant:

- Operation beyond January 1, 2039 - requires emissions reductions equivalent to 90% CCS by 2032.
- Coal fired steam units retiring between 2032 and 2039 - require CO_2 emissions reductions equivalent to 40% natural gas co-firing by 2030.

- Coal plants retiring by 2032 - no additional regulations.

For new natural gas fired combustion turbine units, the rule has different categories for compliance. Specifically, the new gas unit rules establish three categories of units based on unit capacity factor or how much the gas units will operate:

- Low load < 20% of maximum annual capacity; intermediate load-between 20-40% capacity; and base load units > 40% capacity.
- Low and intermediate loads are subject to low emitting fuels and efficient design of the units.
- New base load gas units, however, will require 90% carbon capture and storage (CCS) by 2032.

Litigation pending before the D.C. Circuit Court of Appeals has been stayed following a request by USEPA to hold the GHG rule in abeyance pending administration review. Based upon various Executive Orders, it is likely that USEPA will reconsider both underlying policies and the compliance requirements set forth in the GHG Rule. Nevertheless, for purposes of its current plan analysis, the Company has evaluated plans both with and without compliance with the GHG rule. Compliance with the GHG rule includes scenarios reflecting retirement of SEC by the end of 2031, 40% natural gas cofiring of LEC beginning in 2030, retirement of LEC by the end of 2038, NGCC operation without CCS limited to a 40% capacity factor, and CTG operation limited to a 20% capacity factor.

Cross States Air Pollution Rule (CSAPR) – Ozone Season

In January 2023, EPA disapproved Missouri's Good Neighbor State Implementation Plan (SIP). The disapproval of the state plan is a pre-requisite for EPA to promulgate a federal implementation plan (FIP) implementing the "Good Neighbor" requirements of the Clean Air Act (CAA) for the 2015 Ozone Standard. However, the State of Missouri, Ameren Missouri, and others challenged the EPA's final rule disapproving of the MO Good Neighbor SIP in the 8th Circuit Court of Appeals. The 8th Circuit stayed the EPA's disapproval of the MO Good Neighbor SIP pending the outcome of the ongoing litigation. Recently, The Court of Appeals granted the U.S. Department of Justice request to hold the case in abeyance indefinitely with status reports due every 90 days to allow EPA leadership to review the underlying SIP disapproval. In all, twelve states, including Missouri, have challenged, and obtained stays of, EPA's disapproval of their Good Neighbor SIPs for the 2015 Ozone Standard. Ameren Missouri will continue to follow the judicial process in this case.

On June 5, 2023, EPA promulgated the "Good Neighbor Plan" (FIP) to require upwind states to reduce emissions of the ozone precursor nitrogen oxide (NO_x) from electric generating units (EGUs) and certain stationary industrial sources, in accordance with

EPA's 2015 ozone National Ambient Air Quality Standards (NAAQS). Disapproval of a state SIP is a necessary predicate to the issuance of a FIP. The FIP applied to 23 states including Ameren Missouri EGUs in both Illinois and Missouri and impacted Ameren Missouri's CSAPR allowances and compliance strategy going forward. The FIP was immediately challenged in the DC Circuit Court of Appeals. While the DC Circuit denied a stay request, it intends to conduct an expedited review of the rule and has set a date for oral argument of April 2025 following supplemental briefing. The Supreme Court, however, has stayed the effective date of the FIP following the issuance of stay requests from numerous circuit courts including the 8th Circuit Court of Appeals. If the FIP is eventually implemented in Missouri, additional control technologies and/or reduced dispatch could be necessary as it was modeled and discussed in the 2023 IRP.

It is uncertain as to how USEPA intends to proceed, but USEPA could grant petitions for reconsideration of the FIP or issue an advance notice of proposed rulemaking to rescind the SIP disapprovals. Given such uncertainty, for purposes of the Company's current planning analysis, the Company has analyzed plans that include 40% natural gas cofiring at LEC starting in 2030 and plans that include selective catalytic reduction (SCR) equipment retrofits for compliance with the FIP, if applicable.

Attainment Designations for NAAQS for Ozone

The St. Louis area was designated as marginal with a marginal area attainment date of August 2021. Based on the 2018-2020 design value the St. Louis area failed to attain the 2015 standard and a bump up to moderate non-attainment was expected. However, because the St. Louis area 2019-2021 design value met the 2015 standard, Missouri DNR submitted a redesignation request in January 2022. Illinois EPA was working on a similar request for the Illinois portion of the St Louis non-attainment area. Unfortunately, prior to Illinois EPA's submission, 2022 ozone data indicated that the St. Louis Area ozone design value for 2020-2022 would show non-attainment. As a result, EPA bumped up the St. Louis Ozone non-attainment area to moderate nonattainment in 2022. Because the 2021-2023 design value (and the 2022-2024 design value) also shows non-attainment, the St. Louis Area has failed to attain the 2015 Ozone standard by the August 2024 moderate area attainment date. As a result, it is expected that EPA will "bump up" the St. Louis Area to Serious Non-attainment shortly. Ameren Missouri's coal units are already subject to, and meeting, Reasonably Achievable Control Technology (RACT) for the 2015 Ozone Standard as required by Consent Agreements in the Missouri State Implementation Plan. No additional NO_x control requirements are expected for the coal units if the area is designated serious non-attainment. The bump up to Serious will result in a new attainment date of August 2027 and a reduction in the major source thresholds for PSD and Title V purposes. After the bump up to serious non-attainment, the major source level for NO_x emissions will be 50 tons per year (down from 100 tons per year) for new resources.

On August 6, 2024, EPA published in the Federal Register, at 89 Fed. Reg. 63,860, a proposed rule disapproving Missouri's Supplemental Good Neighbor State Implementation Plan submission with respect to the 2015 8-hour ozone NAAQS. On January 24, 2025, the State of Missouri filed a petition with the U.S. Court of Appeals for the Eighth Circuit petitioning the Court for review of this final ruling.

For purposes of the Company's planning analysis, compliance was evaluated with either SCR retrofit or 40% natural gas cofiring at LEC starting in 2030.

Attainment Designations for NAAQS for SO_2

The EPA lowered the SO_2 ambient standard to 75 ppb on June 2, 2010. Initial attainment designations were finalized on August 5, 2013, and included the designation of two areas in Missouri as nonattainment. The two nonattainment areas included an area in the vicinity of Kansas City (portions of Jackson County) and an area around Herculaneum (portions of Jefferson County). In December 2017, the MDNR submitted a formal request to the EPA to re-designate the Jefferson County SO_2 nonattainment area to attainment. On January 28, 2022, EPA published in the Federal Register a formal redesignation of the Jefferson County, MO SO_2 nonattainment area to attainment. As a part of MDNR's state implementation plan for the Herculaneum area, Ameren Missouri agreed to lower SO_2 emissions limits for the Rush Island, Labadie and Meramec Energy Centers that took effect on January 1, 2017.

On June 30, 2016, the EPA issued a final determination of "unclassifiable" for the area around the Labadie Energy Center. Data collected from the ambient SO_2 monitors indicates that air quality in the vicinity of the Labadie Energy Center complies with the EPA standards. In September 2020, the EPA proposed to re-designate the area around Labadie from unclassifiable to attainment. The EPA is expected to finalize the re-designation by the end of the year. Ameren Missouri continues to operate the monitoring systems and submit the data to both the MDNR and the EPA. Based on monitoring data gathered to date and the EPA proposal to designate the area as attainment, we have assumed the area around Labadie will ultimately be designated as "attainment". Ameren Missouri's assumptions for compliance regarding SO_2 emissions reflect this expectation as well as expected steps necessary to comply with CSAPR.

For purposes of the Company's current planning analysis, compliance at LEC was evaluated with either flue gas desulfurization (FGD) retrofit or 40% natural gas co-firing starting in 2030.

NAAQS for Fine Particulate Matter

Based on current data, St. Louis and Metro East in Illinois are both in attainment with the 2012 PM2.5 standard. The Clean Air Act requires the EPA to review all of the ambient standards on a periodic basis. In December 2020, the EPA finalized a rule to retain the current standard for fine particulate matter. On February 7, 2024, the EPA promulgated a final rule reducing the primary annual PM2.5 NAAQS from 12 μg/m3 to 9 μg/m3. The revised standard is being challenged in court.

Based on recent PM2.5 monitoring in the metro St. Louis Area, the St. Louis area will be designated a non-attainment area for the 2024 PM2.5 standard. As a result of a non-attainment designation, RACT for Particulate Matter (PM 2.5) and precursors (NO_x/SO_2) would be required by the State of Missouri as part of an attainment plan that is required to be submitted to EPA for approval by February 2027.

For purposes of the Company's current planning analysis, compliance at LEC was evaluated with either FGD retrofit or 40% natural gas co-firing starting in 2030.

Clean Air Act Regional Haze Requirements

The goal of the Regional Haze Rule is to set visibility equivalent to natural background levels by 2064 in Class I areas. Class I areas are defined as national parks exceeding 6,000 acres, wilderness and national memorial parks exceeding 5,000 acres and all international parks in existence on August 7, 1977. There are currently 156 Class I areas, two of which are in the State of Missouri (Hercules Glade and Mingo). As part of the first planning period (2008-2018), states have developed implementation plans necessary to meet the glide path for the first 10-year planning period. In addition, the Regional Haze Rule requires compliance with Best Available Retrofit Technology (BART) for SO_2 & NO_x for the first planning period. The EPA has determined that compliance with CSAPR meets the BART requirements. Ameren Missouri is fully compliant with CSAPR, and thus, is compliant with the BART requirements. On August 26, 2022, the Missouri Department of Natural Resources (MDNR) submitted its State Implementation Plan to EPA for approval. As part of this SIP, Ameren Missouri entered into agreements with MDNR to assure continued use of existing control technology. On July 3, 2024, EPA published in the Federal Register, at 89 Fed. Reg. 55,140, a proposal to partially disapprove Missouri's State Implementation Plan for the regional haze second implementation period.

For purposes of the Company's current planning analysis, compliance at LEC was evaluated with either FGD retrofit or 40% natural gas co-firing starting in 2030.

CWA, Steam Electric Effluent Limitation Guidelines Revisions

In May 2024, the EPA finalized regulations generally known as the Steam Electric Effluent Limitations Guidelines (ELG) Rule that govern certain discharge limitations in the Steam Electric Power Generating category. The ELG Rule establishes technical requirements and discharge standards for wastewaters generated at coal fired power plants such as flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate. The ELG rule also establishes a new set of definitions and new effluent limitations for various legacy wastewaters, which may be present in surface impoundments. This new rule is not expected to materially affect Ameren Missouri's generating fleet.

Coal Combustion Residuals

Ameren Missouri is executing its compliance strategy in advance of the regulatory deadlines. On May 8, 2024, EPA finalized changes to the CCR regulations for inactive surface impoundments at inactive electric utilities, referred to as "legacy CCR surface impoundments". Within tailored compliance deadlines, owners and operators of legacy CCR surface impoundments must comply with all existing requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. In addition, through implementation of the 2015 CCR rule, EPA found areas at regulated CCR facilities where CCR was disposed of or managed on land outside of regulated units at CCR facilities, referred to as “CCR Management Units", or CCRMUs. Ameren Missouri is performing the facility reviews required by the Rule. The rule is currently being challenged judicially, and on February 13, 2025, the US Court of Appeals for the DC Circuit issued an order to hold the case in abeyance for 120 days. Ameren Missouri plans to closely watch the current judicial processes and adjust its planning accordingly.

Ash Basin Closure Initiatives

Ash basin impoundments at the Rush Island, Labadie, and Sioux Energy Centers are now complete. Remaining Meramec Energy Center ash basins are expected to be closed by the end of 2026. Closure of the original gypsum pond at Sioux Energy Center is now complete. The closure of the ash ponds will reduce our consumption of approximately 11 billion gallon of water per year.

Capital cost assumptions for mitigation technologies evaluated are shown in Table 2.1.

Table 2.1: Capital Cost Assumptions for Mitigation Technologies ($2024)

$Million (2024$)	Base Capex (Overnight)
ESP	$279
SCR	$637
FGD	$935
Wastewater Treatment for FGD	$65
Cofiring Boiler Modifications	$159

2.2 Supply-Side Resource Review

Ameren Missouri analyzed the cost and performance characteristics of a wide range of supply side resources in its 2023 IRP and has documented its analysis in Chapter 6 of its 2023 IRP filing. New supply side resources that were evaluated in the alternative resource plans in the 2023 IRP include the following:

- Gas Combined Cycle
- Gas Simple Cycle Combustion Turbine
- Wind
- Solar
- Pumped Hydroelectric Energy Storage
- Battery Storage
- Nuclear

Ameren Missouri has reviewed its assumptions for generating resources and determined that changes in cost assumptions are appropriate for wind, natural gas simple cycle, and natural gas combined cycle resources; comparisons to capital costs assumed in the 2023 IRP are shown in Figures 2.1-2.3 below.

Figure 2.1: Wind Capital Cost (Overnight - $/kW)

*** [redacted] ***

Figure 2.2: Simple Cycle Capital Cost (Overnight - $/kW)

*** [redacted] ***

Figure 2.3: Combined Cycle Capital Cost (Overnight - $/kW)

*** [redacted] ***

Transmission Costs

Ameren Missouri has reviewed its assumptions for transmission costs and determined the costs included in the 2023 IRP are appropriate while also including an additional **__________** (2024$) interconnection cost for the combined cycle increased capacity (2,100 MW vs 1,200 MW) in some alternative plans.

2.3 Load Forecast Review

Since the time of its 2023 IRP filing, Ameren Missouri has seen significant growth in the prospects for data centers in its service territory. Ameren Missouri had included incremental economic development load in its 2023 IRP forecast starting at 40 MW in 2025 and reaching 220 MW in 2031. However, the requests Ameren Missouri has received to date far exceed those assumed additions. Ameren Missouri has determined that large load additions, including data centers, are expected to add 500 MW to 2 GW of demand by 2032, and continued growth beyond 2032 could increase total demand to 2.5-3.5 GW by 2040. Table 2.2 below shows the annual peak demand additions assumed for modeling alternative resource plans for three scenarios. Note that the timing of load additions, including in the near term, is still uncertain.

Table 2.2: Data Center Load Addition Scenarios

@Transmission	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
500 MW	300	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2500 MW	300	500	700	1,000	1,200	1,400	1,500	1,625	1,750	1,875	2,000	2,125	2,250	2,375	2,500
3500 MW	300	700	1,000	1,300	1,600	1,900	2,000	2,200	2,400	2,600	2,800	3,000	3,200	3,400	3,500

2.4 Demand-Side Resource Review

Ameren Missouri has reassessed its long-term expectations regarding energy efficiency programs under the Missouri Energy Efficiency Investment Act (MEEIA) following the conclusion of its MEEIA Cycle 4 application proceedings in File No. EO-2023-0136. In that docket, the MPSC approved a stipulation and agreement that substantially reduced program budgets to approximately $50 million annually, with lower energy and demand savings than what the Company had sought in its application. While the potential for greater energy and demand savings is expected to be available in the future, given the concerns that the MPSC and stakeholders expressed in that docket regarding the degree to which such savings can be relied upon for purposes of resource planning, Ameren Missouri has assumed that energy efficiency program budgets would remain relatively constant at MEEIA Cycle 4 levels over the planning horizon.

The Company worked with GDS Associates, Inc., the consulting firm that supported the Company's most recent demand-side resource market potential study, to update its expected energy and demand savings consistent with the aforementioned approved stipulation and agreement. As a result, total annual demand savings for the winter season, which drives overall resource needs, are expected to be reduced by about 300 MW by 2032 and about 700 MW over the 20-year planning horizon through 2043, compared to a portfolio at the realistic achievable potential (RAP) level as was included in the Company's 2023 PRP. Table 2.3 below summarizes the Company's current assumptions for MEEIA program budgets, demand savings, and energy savings through 2043.

Table 2.3: Revised MEEIA Program Budgets and Demand and Energy Savings

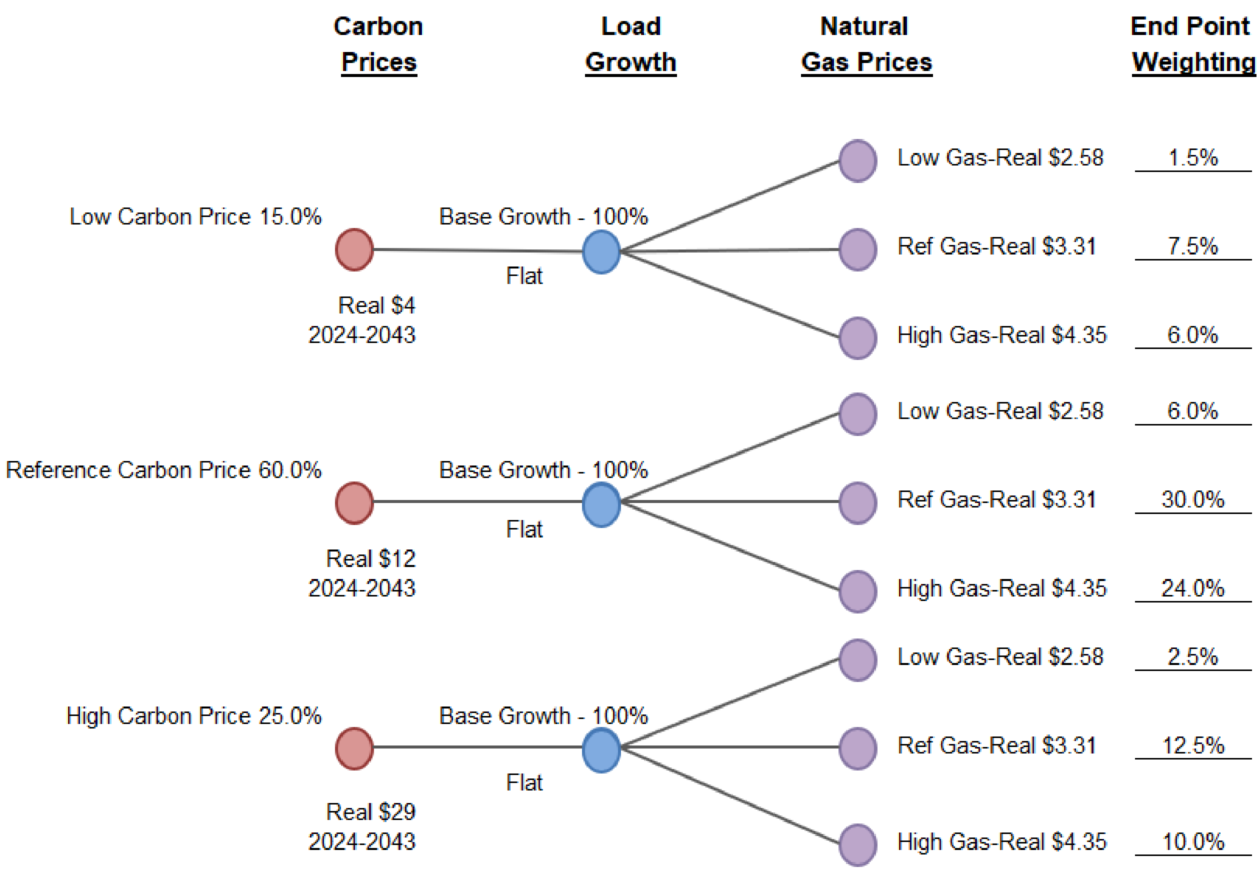
@ Transmission	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
GWh @Meter	180	230	281	332	383	419	465	510	549	573	579	605	632	658	653	659	657	648	651
Summer MW @Gen-EE	75	99	122	146	169	179	198	216	233	245	253	265	276	288	285	289	290	287	289
Summer MW @Gen-DR	264	271	277	277	277	277	277	277	277	277	277	277	277	277	277	277	277	277	277
Winter MW @Gen-EE	33	43	53	63	72	82	91	101	109	113	115	121	126	132	133	135	136	133	134
Winter MW @Gen-DR	86	112	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113
Cost $Million-EE	61	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Cost $Million-DR	15	21	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22

2.5 Uncertain Factors

2.5.1 Price Scenarios

Ameren Missouri has reviewed its assumptions for carbon prices and natural gas prices, which are the major drivers of power prices. As discussed in more detail in this section, Ameren Missouri has determined that its current expectations for the driver variables are within the ranges established in the 2023 triennial IRP. Figure 2.4 shows the scenario tree and the probabilities of each branch from the 2023 IRP.

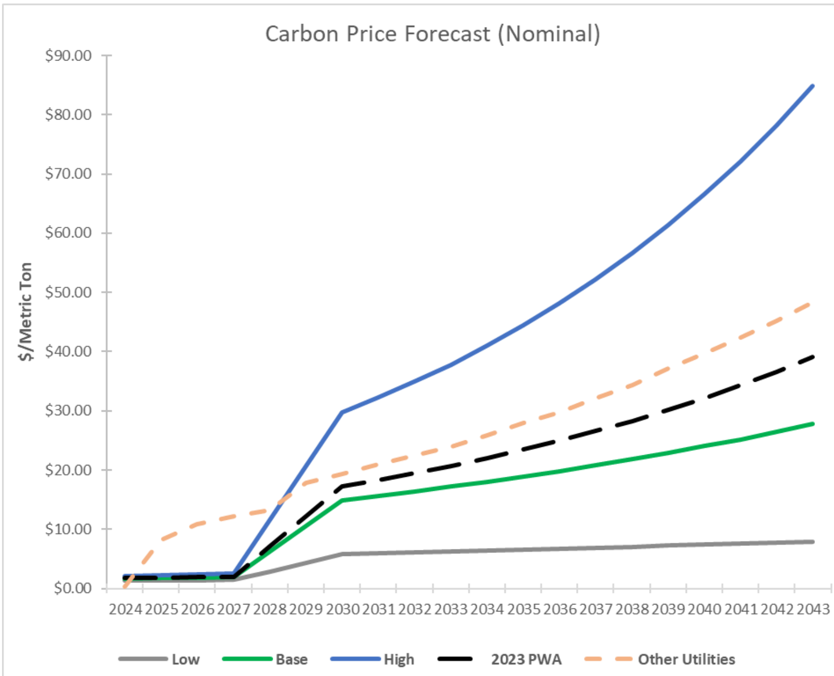
Figure 2.4: Scenario Tree



Carbon Dioxide Emission Prices

The carbon price assumptions from the 2023 IRP were reviewed and remain reflective of expectations for the future price of carbon dioxide emissions. The carbon price scenarios and the probability-weighted average (PWA) are shown in Figure 2.5.

Figure 2.5: CO_2 Price Assumptions



It should be noted that the price assumptions shown 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 its assumptions for natural gas prices. Figure 2.6 shows the three price scenarios and the PWA price. Ameren Missouri continues to monitor factors that may affect assumptions for natural gas prices.

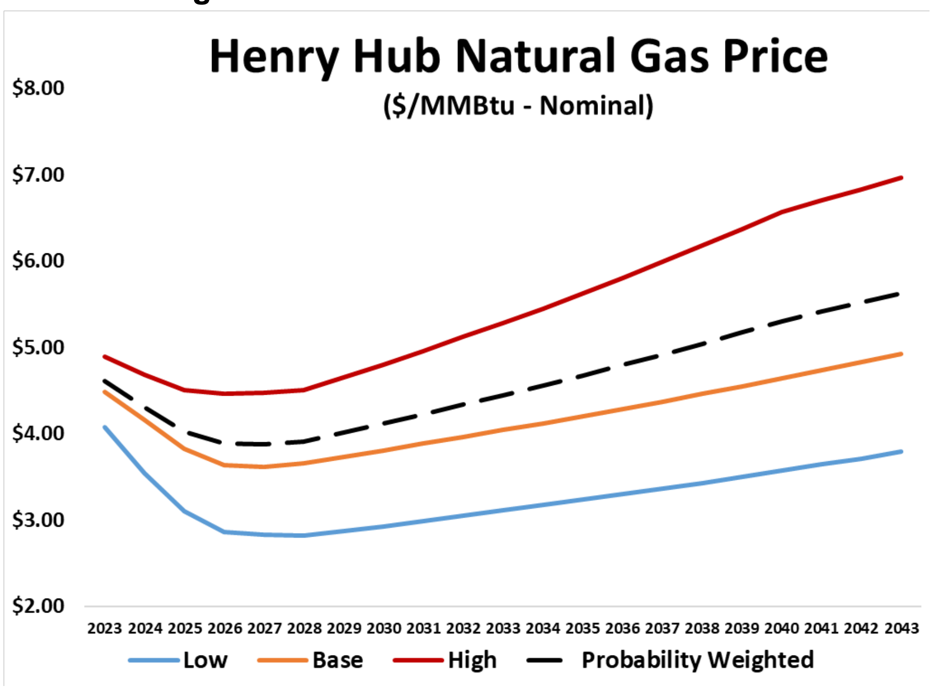
Ameren Missouri considers a number of key natural gas price drivers and risks. For the development of natural gas prices for the Company's 2023 IRP, the following key drivers and risks were examined:[3]

[3] File No. EO-2024-0020 Joint Filing, Resolution for NEE Deficiency 1

- LNG Exports
- Geopolitical Market Drivers
- Domestic Production and Extraction Costs
- Natural Gas Infrastructure Permitting
- Environmental Regulations for Gas Production and Transportation

The Company examined LNG exports based on information from the U.S Department of Energy's 2022 Annual Energy Outlook, which indicated a wide range of potential LNG exports (see Figure 2.6 below). The Company also considered relevant geopolitical events, including the Russian invasion of Ukraine in early 2022.

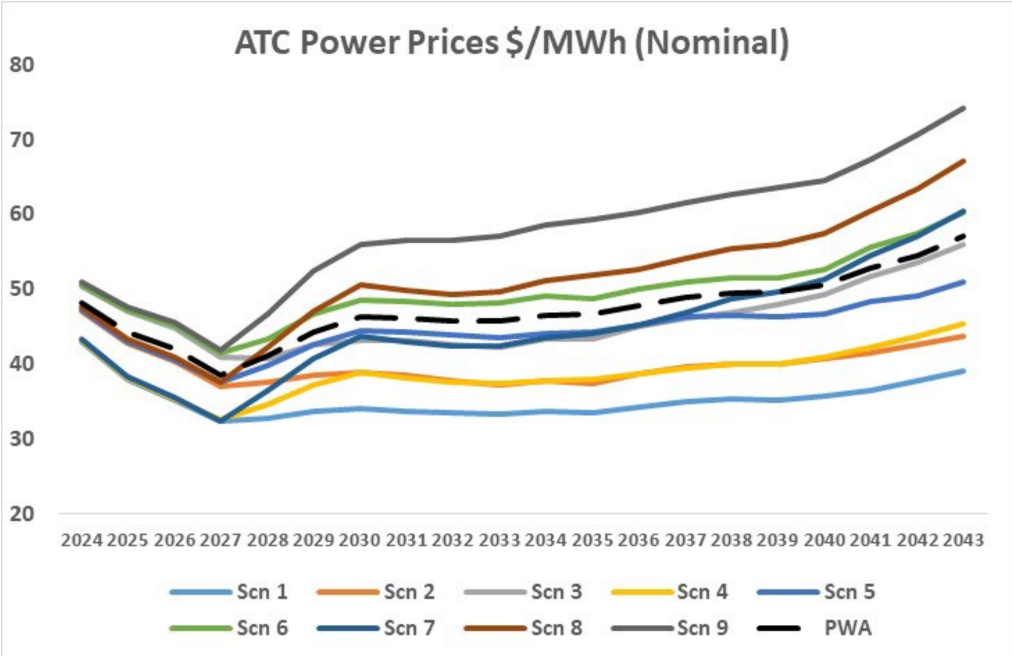
Figure 2.6: Natural Gas Price Forecasts



2.5.2 Scenario Modeling

Since current assumptions for the key driver variables described in section 2.5.1 are within the ranges defined in the 2023 IRP, there is no change to the power price forecasts modeled for the 2023 IRP and the probability-weighted average prices, which are presented in Figure 2.7 below.

Figure 2.7: Market Price Scenarios



Sensitivities for Data Center Load Levels

With the recent surge in data center load potential, not only within Ameren Missouri's service territory but across other regions in the United States, it is important to consider the sensitivity of market prices to the rapid addition of large loads. To evaluate the sensitivity of plan performance to different levels of data center load in the broader Eastern Interconnect and the MISO market, Ameren Missouri contracted with Charles River Associates (CRA) to analyze three scenarios of data center load and provide resultant market prices for energy and capacity. Table 2.4 below shows the data center load for high, middle and low scenarios for both MISO and PJM.

For price scenario modeling, CRA analyzed the following combinations of assumptions using the Company's 2023 IRP scenarios for natural gas prices and carbon prices and load scenarios reflecting the data center load assumptions shown in Table 2.4 as follows:

- High Scenario – 2023 IRP high carbon and gas prices, loads with high assumptions for data center additions
- Middle Scenario – 2023 IRP base carbon and gas prices, loads with middle assumptions for data center additions
- Low Scenario – 2023 IRP low carbon and gas prices, loads with low assumptions for data center load additions

The resultant market prices for energy are shown in Figure 2.8, and the resultant capacity prices are shown in Figures 2.9 to 2.11. The sensitivity to power prices is discussed in Section 3.

Table 2.4: Data Center Load for Sensitivity Scenarios (MW)

PJM	Low Case	Mid Case	High Case	MISO	Low Case	Mid Case	High Case	PJM+MISO	Low Case	Mid Case	High Case
2024	6,665	6,665	6,665	2024	1,829	1,829	1,829	2024	8,494	8,494	8,494
2025	6,825	7,098	7,965	2025	2,100	2,400	2,608	2025	8,925	9,498	10,573
2026	7,250	8,665	11,914	2026	3,000	3,900	4,950	2026	10,250	12,565	16,864
2027	8,163	11,252	18,177	2027	4,350	6,300	9,000	2027	12,513	17,552	27,177
2028	10,226	15,000	24,000	2028	5,700	9,000	13,500	2028	15,926	24,000	37,500
2029	12,110	20,000	30,000	2029	7,050	12,000	18,000	2029	19,160	32,000	48,000
2030	13,843	25,000	37,500	2030	8,306	15,000	22,500	2030	22,148	40,000	60,000
2031	15,444	30,317	45,475	2031	9,266	18,190	27,285	2031	24,710	48,507	72,760
2032	16,929	35,146	52,719	2032	10,158	21,088	31,631	2032	27,087	56,234	84,350
2033	18,311	39,101	58,652	2033	10,987	23,461	35,191	2033	29,298	62,562	93,843
2034	19,600	42,156	63,234	2034	11,760	25,294	37,941	2034	31,360	67,450	101,175
2035	20,804	44,750	66,582	2035	12,482	26,850	39,949	2035	33,286	71,600	106,531
2036	21,931	46,500	68,898	2036	13,158	27,900	41,339	2036	35,089	74,400	110,237
2037	22,986	47,500	70,419	2037	13,792	28,500	42,251	2037	36,778	76,000	112,670
2038	23,750	48,500	72,000	2038	14,250	29,100	43,200	2038	38,000	77,600	115,200
2039	24,500	49,250	73,500	2039	14,700	29,550	44,100	2039	39,200	78,800	117,600
2040	25,000	50,000	75,000	2040	15,000	30,000	45,000	2040	40,000	80,000	120,000

Figure 2.8: Market Energy Prices for Data Center Load Scenarios

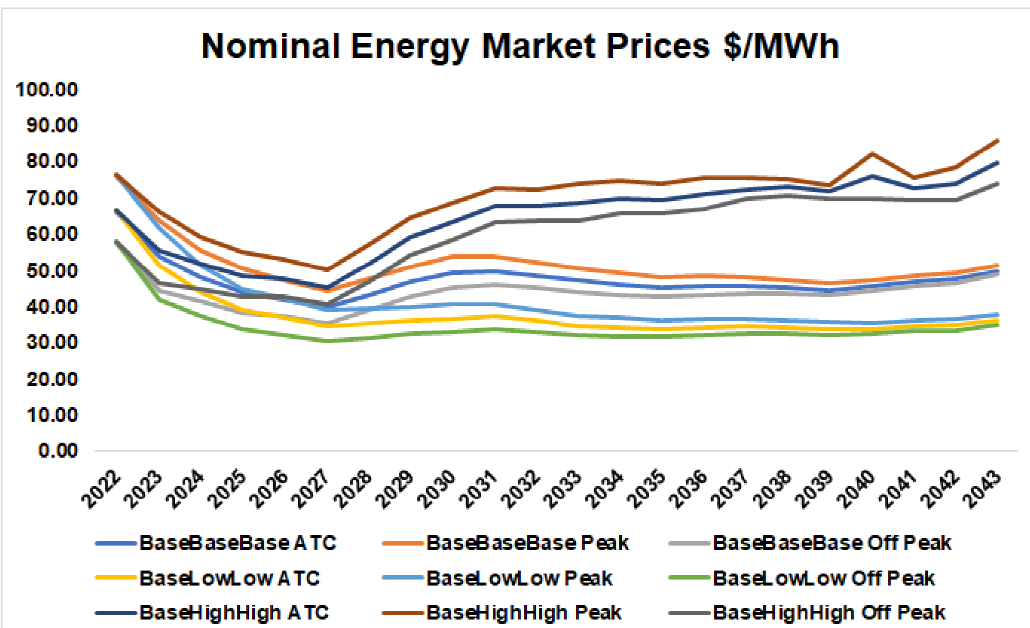


Figure 2.9: Market Capacity Prices for High Data Center Load Scenario

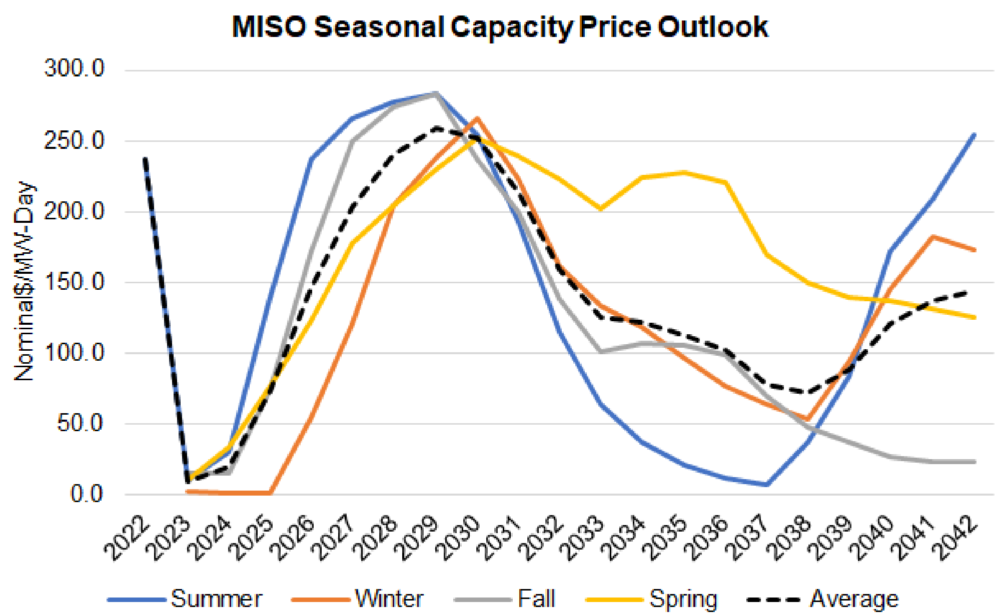


Figure 2.10: Market Capacity Prices for Middle Data Center Load Scenario

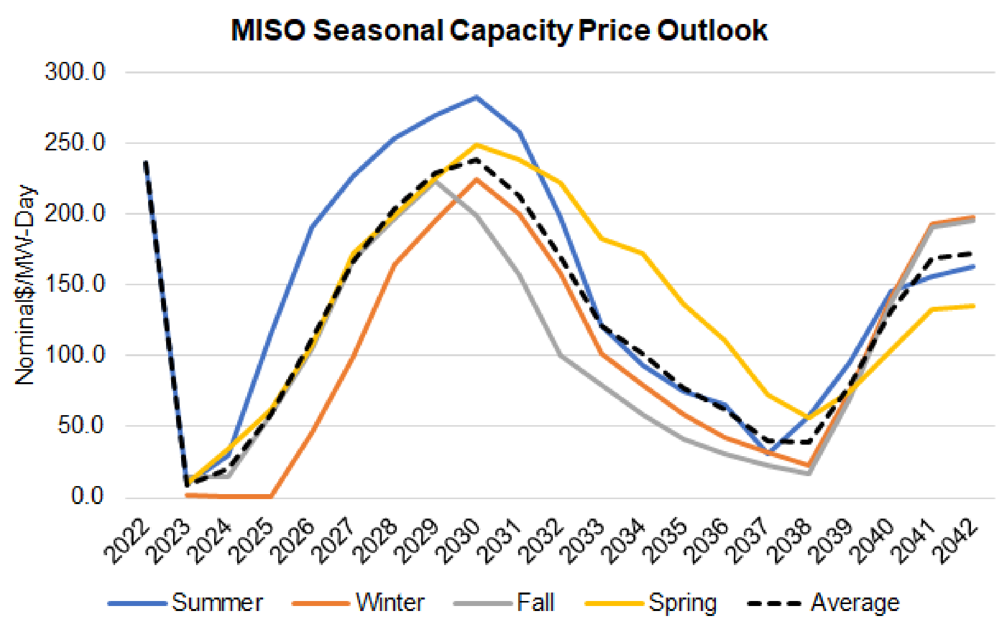
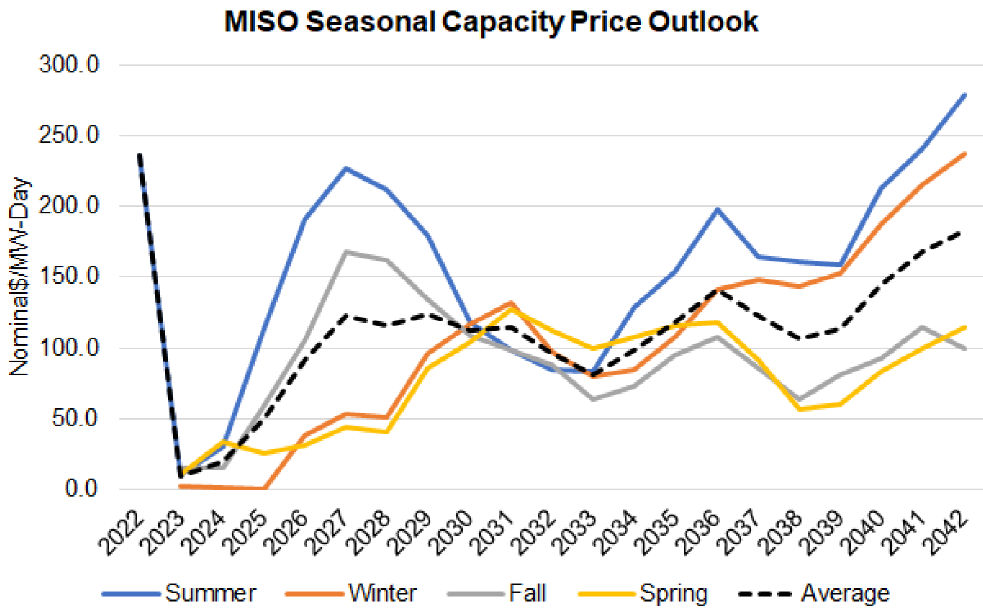


Figure 2.11: Market Capacity Prices for Low Data Center Load Scenario



3. Alternative Plans and Risk Analysis

Ameren Missouri's analysis of alternative plans focused on several objectives:

- Analyze differences in costs for different data center load scenarios, including scenarios in which data center loads are reduced after some period of time
- Analyze the impact of the change in the Company's planned MEEIA programs
- Analyze the relative incremental cost of different compliance alternatives for LEC

To that end, the alternative plans shown in Table 3.1 below were analyzed.

Table 3.1: Alternative Resource Plans Analyzed

	Plan Name	DSM	Renewables	New Supply-Side	Coal Retirements/ Modifications
A	2023 Preferred Plan (RAP)	RAP	Renewable Expansion	SC 2028, CC 2033 CC 2040 and 2043	Base*
B	2023 PRP (RAP)- Sioux'31	RAP	Renewable Expansion	SC 2028, CC 2032 CC 2040 and 2043	Sioux Dec-2031*
C	2023 PRP (RAP) - ESP - Sioux'31	RAP	Renewable Expansion	SC 2028, CC 2032 CC 2040 and 2043	Sioux Dec-2031
D	Lower DSM - CC - ESP	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2037 CC 2040 and CC 2043	Sioux Dec-2031

	Plan Name	DSM	Renewables	New Supply-Side	Coal Retirements/ Modifications
E	Nuke - ESP	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2037 Nuke900 2040, CC 2043	Sioux Dec-2031
F	SCR - FGD	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2037 Nuke900 2040, CC 2043	Sioux Dec-2031 Labadie 2U SCR & FGD
G	Labadie Ret 2031	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2032 CC 2032, Nuke900 2040	Sioux Dec-2031
H	Labadie Ret 2031 GHG	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2032 CC 2032, Nuke900 2040	Sioux Dec-2031 Labadie 4U Dec-2031
I	GHG Cofire	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2039 CC 2039, Nuke900 2040	Sioux Dec-2031 Labadie 4U Cofire Labadie 4U Dec-2038
J	GHG Cofire - FGD	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2039 CC 2039, Nuke900 2040	Sioux Dec-2031 Labadie 4U Cofire Labadie 2U FGD Labadie 4U Dec-2038
K	Cofire - FGD	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2037 Nuke900 2040, CC 2043	Sioux Dec-2031 Labadie 4U Cofire Labadie 2U FGD
L	Cofire	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2037 Nuke900 2040, CC 2043	Sioux Dec-2031 Labadie 4U Cofire
M	Cofire GHG +2500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, CC2100 2032, SC 2029, CC 2039, SC600 2038, SC600 2039 Nuke1500 2040	Sioux Dec-2031 Labadie 4U Cofire Labadie 4U Dec-2038
N	Cofire +500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, SC 2029, CC 2032 CC 2037, Nuke900 2040 CC 2043	Sioux Dec-2031 Labadie 4U Cofire
O	Cofire +1500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, SC 2029 CC2100 2032, SC600 2039 Nuke1500 2040 SC600 2043	Sioux Dec-2031 Labadie 4U Cofire
P	Cofire +2000 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, SC 2029 CC2100 2032, SC600 2037 CC600 2038 Nuke1500 2040 SC600 2043	Sioux Dec-2031 Labadie 4U Cofire

	Plan Name	DSM	Renewables	New Supply-Side	Coal Retirements/ Modifications
Q	Cofire +2500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, SC 2029 CC2100 2032, CC 2037 SC600 2038 Nuke1500 2040 SC600 2043	Sioux Dec-2031 Labadie 4U Cofire
R	Cofire +3500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, SC 2029 CC2100 2032, SC 2029 SC600 2035, CC 2037 SC600 2037 CC 2038, Nuke1500 2040	Sioux Dec-2031 Labadie 4U Cofire
S	Cofire +1500 to 500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +600MW Battery Storage	SC 2028, SC 2029 CC2100 2032, CC600 2043 Nuke900 2043	Sioux Dec-2031 Labadie 4U Cofire
T	Cofire +2000 to 500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +600MW Battery Storage	SC 2028, SC 2029 CC2100 2032, CC600 2037 SC600 2037 Nuke900 2043	Sioux Dec-2031 Labadie 4U Cofire

*All plans except for Plans A and B include new ESPs at two Labadie units.

3.1 Alternative Plans Analysis Results

Table 3.2 shows the present value of revenue requirements (PVRR) results for the alternative plans shown in Table 3.1. These results reflect the 2023 IRP price scenarios described in section 2.5. Several conclusions can be drawn from these results.

First, with respect to data center load additions, the greater the load addition and the longer such load additions are sustained, the higher the total cost in terms of PVRR. It is important to recognize that differences in cost for significantly different levels of customer demand does not imply that higher cost plans are detrimental. In fact, analysis results show that alternative plans with higher data center demand result in lower levelized rates than those with lower data center demand (or none), as shown in Table 3.2. Because the cost effects on Ameren Missouri's existing customers are necessarily dependent on rates for new data center customers, such considerations must be made in the context of establishing a new tariff, for which the Company plans to apply with the MPSC in the second quarter of 2025.

Second, results for environmental compliance options for LEC indicate that 40% natural gas co-firing starting in 2030 is lower cost than either early retirement or retrofitting LEC with FGD and SCR equipment.[4] This is true whether or not EPA's GHG rule for power plants goes into effect. As discussed in section 2.1, significant uncertainty regarding various pending environmental regulations remains. Ameren Missouri will continue to monitor developments with respect to environmental regulations and identify and evaluate compliance options while maintaining flexibility to implement viable options.

Third, the change from the RAP DSM portfolio included in the Company's 2023 PRP to the portfolio based on a continuation of budget levels approved for the Company's MEEIA Cycle 4 programs results in an increase in PVRR of about $2 billion. Ameren Missouri is initiating a new DSM market potential study to inform the preparation of its 2026 triennial IRP and will reassess its long-term plans for MEEIA programs as part of that effort.

Table 3.2: PVRR and Levelized Rates Results for Alternative Plans

Alternative Resource Plan	PVRR ($ Million)	Levelized Rates Cents/kWh
A - 2023 Preferred Plan (RAP)	$85,471	$22.16
B - 2023 PRP (RAP)- Sioux'31	$85,501	$22.17
C - 2023 PRP (RAP) - ESP - Sioux'31	$85,805	$22.25
D - Lower DSM - CC - ESP	$87,927	$22.43
E - Nuke - ESP	$90,725	$23.14
F - SCR - FGD	$92,532	$23.60
G - Labadie Ret 2031	$92,207	$23.52
H - Labadie Ret 2031 GHG	$92,316	$23.55
I - GHG Cofire	$92,000	$23.47
J - GHG Cofire - FGD	$93,126	$23.75
K - Cofire - FGD	$92,696	$23.64
L - Cofire	$91,530	$23.35
M - Cofire GHG +2500 MW Load	$108,898	$20.52
N - Cofire +500 MW Load	$97,386	$22.49
O - Cofire +1500 MW Load	$104,284	$21.02

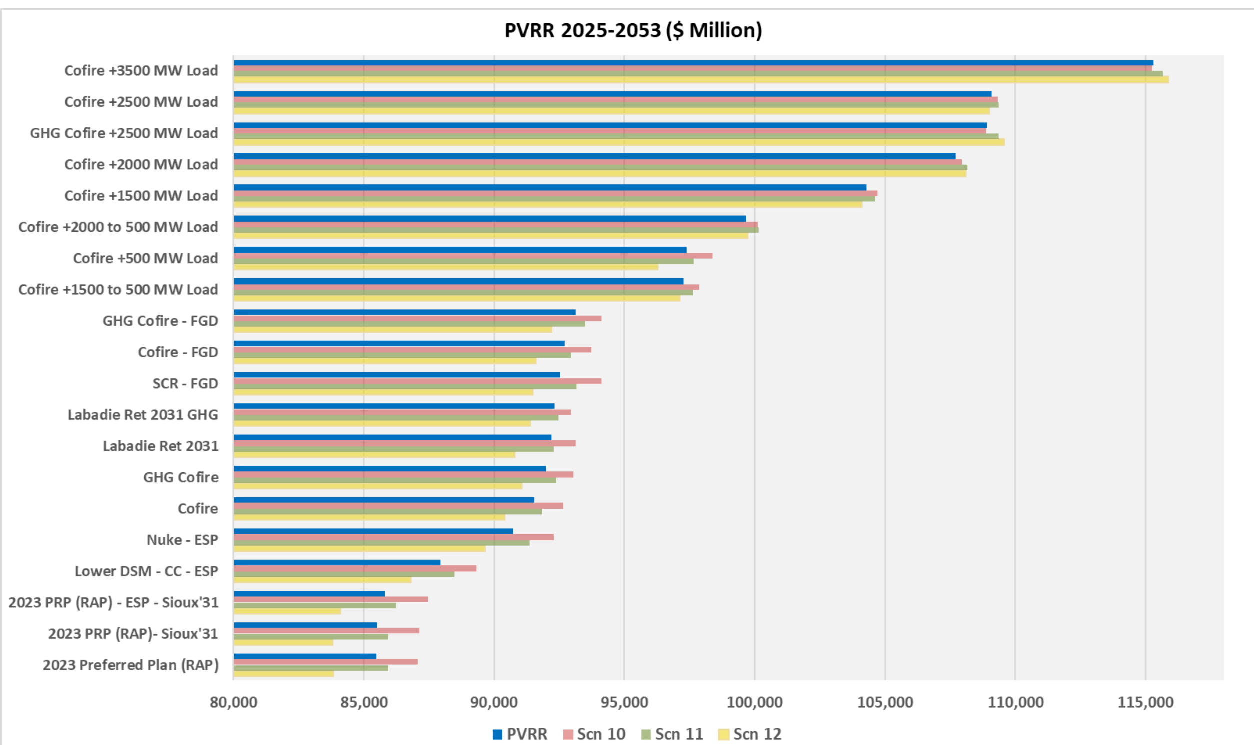
[4] Analysis of environmental compliance is included in this report in part to satisfy the commitment made by Ameren Missouri in its June 2024 Joint Filing in File No. EO-2024-0020.

Alternative Resource Plan	PVRR ($ Million)	Levelized Rates Cents/kWh
P - Cofire +2000 MW Load	$107,708	$20.30
Q - Cofire +2500 MW Load	$109,078	$20.55
R - Cofire +3500 MW Load	$115,307	$19.76
S - Cofire +1500 to 500 MW Load	$97,265	$20.71
T - Cofire +2000 to 500 MW Load	$99,652	$20.30

3.2 Data Center Price Scenario Sensitivity

As mentioned previously, Ameren Missouri has worked with CRA to create additional price scenarios to reflect different levels of data center additions in the Eastern Interconnect to analyze the price sensitivity of alternative plans. Figure 3.1 below shows the PVRR For each alternative plan for the 2023 IRP probability weighted average power prices and separately for each of the additional data center load price scenarios.

Figure 3.1: PVRR Sensitivity to Alternative Data Center Price Scenarios



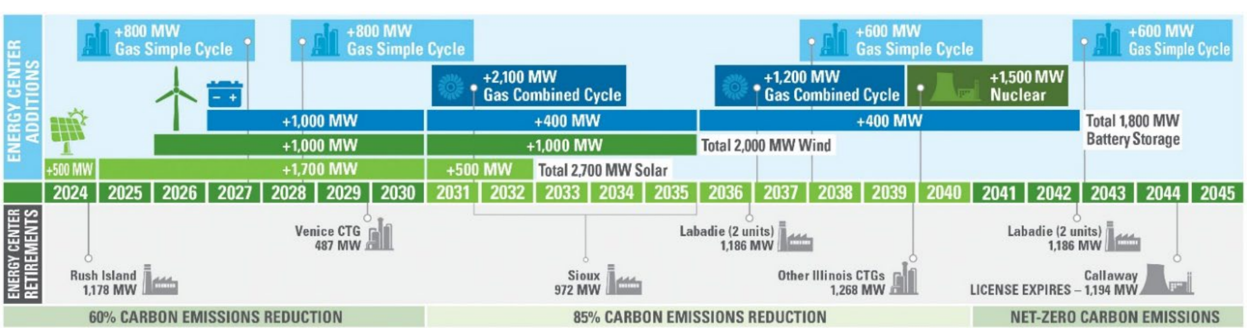
As the chart in Figure 3.1 shows, PVRR changes under some scenarios may slightly alter the order of some plans in the aggregate, but in only one case does the rank of an alternative plan change by more than one position, and this change does not affect the relative cost of relevant decisions regarding environmental compliance or resources needed to serve demand. As a result, final plan analysis results are shown using only the full range of 2023 IRP price scenarios.

3.3 Preferred Resource Plan and Contingencies

Ameren Missouri's management has selected its new PRP in consideration of the prospects for new large load additions and the various costs and risks associated with the resource additions needed to serve them. A diverse portfolio of resources will be needed to ensure reliable service at reasonable rates to both existing and new customers, including resources that primarily provide capacity benefits (CTG, BESS), resources that provide carbon-free energy benefits (solar, wind), and resources that provide both significant capacity and energy (NGCC, nuclear). The potential for a range of large load additions and the potential for future changes in load associated with large load customers, both increases and reductions, has led Ameren Missouri to select a PRP that represents an acceleration of resource additions that were included in its prior PRP but that would be needed in the long-term even if such load additions were not permanent. This includes acceleration of solar resource additions, which provide significant carbon-free energy for large customers like data centers with corporate sustainability and clean energy goals. It includes the acceleration of gas-fired generation and BESS resources to meet peak demand requirements in all seasons.

At the same time, the new PRP reflects more specificity regarding resource additions in the long-term if large load additions are more permanent. The 2023 PRP included 2,400 MW of "clean dispatchable" generation additions. The new PRP includes 1,500 MW of new nuclear generation in 2040. While the specific technology to be used has not yet been determined, the Company will continue to monitor developments in the market and fully evaluate new nuclear potential as part of its future IRP analyses. Ameren Missouri's new PRP is shown in Figure 3.2.

Figure 3.2: Ameren Missouri's Revised PRP



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

Description of Changes and Rationale

Following are the changes represented in the Company's new PRP relative to its prior PRP and the rationale:

- **Addition of data center loads** – The new PRP includes the addition of data center loads with cumulative demand reaching 1.5 GW by 2032 and 2.5 GW by 2040.
- **Reduction in MEEIA programs** – The new PRP includes MEEIA programs through 2043 at levels similar to those recently approved by the MPSC instead of at the RAP level.
- **Acceleration of solar resource additions** – The new PRP includes the same total solar additions as the prior PRP – 2,700 MW – but with accelerated timing for the additions to provide energy for new demand growth and clean energy to support the corporate clean energy goals of new large customers.
- **Acceleration and expansion of battery storage resource additions** – The new PRP includes acceleration and expansion of BESS to provide flexible capacity for new demand and integrate renewable resources, with 1,000 MW in service by the end of 2030, another 400 MW by the end of 2035, and another 400 MW by the end of 2042. This represents an overall increase in BESS of 1,000 MW relative to the prior PRP, driven by significant new load additions and the reduction in expected demand savings from MEEIA programs.
- **Acceleration and expansion of dispatchable generation resources** – The new PRP includes total natural gas and nuclear generation additions of 7,600 MW (3,300 MW NGCC, 2,800 MW CTG, 1,500 MW nuclear) compared to 4,400 MW of natural gas (1,200 MW NGCC, 800 MW CTG) and "clean dispatchable" resources (2,400 MW) in the prior PRP.

Because the changes are driven collectively by the changes in demand, it is helpful to understand how all of the changes affect the Company's capacity position in the final year of the planning horizon. Table 3.3 below shows a reconciliation of the Company's 2043 capacity position under the new PRP relative to the prior PRP.

Because the extent and timing of data center load additions is uncertain, Ameren Missouri has developed contingency plans for different levels of load additions. Table 3.4 below shows the resource additions for the 2025 PRP as well as the two contingency plans described above. Resource additions for the 2023 IRP are also shown for comparison. It is important to note that the resource additions through 2032 for the contingency plan for 2 GW of data center demand by 2032 are the same as the resource additions through 2032 for the PRP. Also, the addition of 800 MW of CTG generation in 2028 is included in both the upside and low contingency plans as well as the PRP.

Table 3.3: Change in Capacity Position – New PRP vs. Prior PRP

Load and Reserve Changes	2023 PRP	2025 PRP	Change
Data Center Load	-	2,555	2,555
Data Center Reserve (25%)	-	634	634
Energy Efficiency & Demand Response	(925)	(247)	678
EE/DR Reserve (25%)	(229)	(61)	168
Load and Reserve Changes	(1,154)	2,880	4,035
Incremental Generation Additions		**Nameplate**	**Accredited**
Battery Storage		1,000	950
Gas Simple Cycle		2,000	1,817
Gas Combined Cycle		2,100	1,852
Nuclear		1,500	1,425
Audrain Oil Backup		-	312
Clean Dispatchable		(2,400)	(2,066)
Total Generation Additions		4,200	4,290
Net Capacity Position Change			**255**

Table 3.4 Resource Additions for the 2025 PRP and Contingencies Compared to the 2023 PRP

	2023 IRP Preferred Plan	500 MW Large Loads	1.5 GW Large Loads	2.0 GW Large Loads
Data Center Load Additions (beginning of year)	N/A	500 MW by 2027 (4 GWh)	1.5 GW by 2032 (12 GWh) 2.5 GW by 2040 (20 GWh)	2 GW by 2032 (16 GWh) 3.5 GW by 2040 (28 GWh)
Energy Efficiency / Demand Response	Aggressive Energy Efficiency and Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs
Total Retail Sales in 2040	36 Million MWh	40 Million MWh	56 Million MWh	64 Million MWh
Coal Retirements (end of year)	Sioux (2032) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)
Gas Retirements (end of year)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)
Wind Additions (end of year)	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035
Solar Additions (end of year)	1,800 MW by 2030 2,700 MW by 2035	1,800 MW by 2030 2,700 MW by 2035	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032
Battery Additions (end of year)	400 MW by 2030 800 MW by 2033	400 MW by 2030 800 MW by 2033	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042
Combined Cycle Gas Additions (beginning of year)	1,200 MW (2033)	1,200 MW (2032)	2,100 MW (2032) 1,200 MW (2037)	2,100 MW (2032) 1,200 MW (2037) 1,200 MW (2038)
Simple Cycle Gas Additions (beginning of year, except 2027 and 2028 additions in Q4)	800 MW (2027)	800 MW (2027) 800 MW (2028)	800 MW (2027) 800 MW (2028) 600 MW (2038) 600 MW (2043)	800 MW (2027) 800 MW (2028) 600 MW (2035) 600 MW (2037)
New Nuclear Additions (beginning of year)	N/A	900 MW (2040)	1,500 MW (2040)	1,500 MW (2040)
Other Clean Dispatchable Additions (beginning of year)	1,200 MW (2040) 1,200 MW (2043)	1,200 MW (2037) 1,200 MW (2043)	N/A	N/A

3.4 Comparison to Prior Preferred Plan

Table 3.5 below shows a comparison of the performance measures used by Ameren Missouri to assess the performance of alternative resource plans and select its preferred plan.

Table 3.5: Comparison of Performance Measures for New and Prior PRP

Performance Measures (2025-2053)	Prior Preferred Plan 2023 IRP	New Preferred Plan 2025 Update	Change	% Change
PVRR, \$MM	\$82,799	\$109,078	\$26,279	31.7%
Levelized Annual Rates, Cents/kWh	\$21.47	\$20.55	-\$1	-4.2%
PV of Free Cash Flow, \$MM	\$3,995	-\$295	-\$4,290	-107.4%
Cumulative CO_2 Emissions, Million Metric Tons	176	176	0	0.2%
PV of Probable Environmental Costs, \$MM	\$1,342	\$1,899	\$557	41.5%
Energy Savings, GWh	92,160	16,178	-75,983	-82.4%
Direct Jobs, FTE-Years	20,920	24,195	3,275	15.7%

As discussed previously in this report, the increase in PVRR is primarily a reflection of the much higher load levels reflected in the new PRP, driven by expected data center customer load additions, relative to the 2023 PRP. Note that the new PRP results in a 4.2% reduction in average rates relative to the 2023 PRP. Free cash flow reflects the need for both accelerated generation investment in the near term and overall greater generation investment in the long term. While the changes to the Company's outlook for MEEIA programs results in changes in both energy savings and jobs, the reduction in jobs is more than offset by construction and operating jobs resulting from new generation additions. Note that jobs are direct jobs and do not reflect job creation resulting from data center construction or economic benefits produced.

3.5 Implementation

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

- Submitting an application to establish a new tariff for large load customers, such as data centers, in the second quarter of 2025
- Submitting applications for CCNs to the MPSC for:
    - New solar generation projects (the first in the second quarter of 2025)
    - New BESS facilities to be located at former coal energy center sites (the first in the second quarter of 2025)

    - 800 MW of CTG generation at the former Rush Island coal energy center site (second quarter of 2025)
- Continuing to evaluate proposals for new wind and solar generation projects
- Continuing preparations for the addition of NGCC generation, including an application to the MPSC for a CCN in 2026
- Continuing to manage approved MEEIA programs for customer energy efficiency and demand response
- Continuing to monitor developments regarding environmental regulations, identifying and evaluating options for compliance, and taking steps to maintain available options
- Initiating a new market potential study to identify opportunities for further energy and demand savings from future MEEIA programs

Appendix A
Supplemental Information

Table A.1 Overnight Capital Cost for Combined Cycle (2024$)

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[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

***

Table A.2 Overnight Capital Cost for Combined Cycle with CCS (2024$)

***

[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

***

Table A.3 Overnight Capital Cost for Simple Cycle (2024$)

***

[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

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Table A.4 PVRR Sensitivity to Alternative Data Center Price Scenarios

Plan - $ Million		PVRR	Scn 10	Scn 11	Scn 12
A	2023 Preferred Plan (RAP)	85,471	87,077	85,917	83,828
B	2023 PRP (RAP)- Sioux'31	85,501	87,138	85,926	83,792
C	2023 PRP (RAP) - ESP - Sioux'31	85,805	87,441	86,230	84,096
D	Lower DSM - CC - ESP	87,927	89,316	88,463	86,808
E	Nuke - ESP	90,725	92,279	91,369	89,644
L	Cofire	91,530	92,639	91,823	90,410
I	GHG Cofire	92,000	93,028	92,381	91,061
G	Labadie Ret 2031	92,207	93,136	92,297	90,777
H	Labadie Ret 2031 GHG	92,316	92,934	92,472	91,380
F	SCR - FGD	92,532	94,103	93,167	91,461
K	Cofire - FGD	92,696	93,721	92,946	91,581
J	GHG Cofire - FGD	93,126	94,108	93,484	92,195
S	Cofire +1500 to 500 MW Load	97,265	97,857	97,629	97,118
N	Cofire +500 MW Load	97,386	98,382	97,667	96,273
T	Cofire +2000 to 500 MW Load	99,652	100,112	100,131	99,739
O	Cofire +1500 MW Load	104,284	104,716	104,626	104,103
P	Cofire +2000 MW Load	107,708	107,933	108,169	108,088
M	GHG Cofire +2500 MW Load	108,898	108,874	109,358	109,580
Q	Cofire +2500 MW Load	109,078	109,337	109,345	109,008
R	Cofire +3500 MW Load	115,307	115,245	115,652	115,860

	2023 IRP Preferred Plan	500 MW Large Loads	1.5 GW and Stop	2 GW and Stop	1.5 GW Large Loads	2.0 GW Large Loads	1.5 GW to 500 MW	2 GW to 500 MW
Case Number		1	2	3	4	5	6	7
Data Center Load Additions (beginning of year)	N/A	500 MW by 2027 (4 GWh)	1.5 GW by 2032 (12 GWh)	2 GW by 2032 (16 GWh)	1.5 GW by 2032 (12 GWh) 2.5 GW by 2040 (20 GWh)	2 GW by 2032 (16 GWh) 3.5 GW by 2040 (28 GWh)	1.5 GW by 2032 (12 GWh) 0.5 GW by 2039 (4 GWh)	1.5 GW by 2032 (12 GWh) 0.5 GW by 2039 (4 GWh)
Energy Efficiency / Demand Response	Aggressive energy efficiency and demand response programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs
Total Retail Sales in 2040	36 Million MWh	40 Million MWh	56 Million MWh	64 Million MWh	56 Million MWh	64 Million MWh	40 Million MWh	40 Million MWh
Coal Retirements (end of year)	Sioux (2032) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)
Gas Retirements (end of year)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)
Wind Additions (end of year)	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2036	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035
Solar Additions (end of year)	1,800 MW by 2030 2,700 MW by 2035	1,800 MW by 2030 2,700 MW by 2035	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032
Battery Additions (end of year)	400 MW by 2030 800 MW by 2033	400 MW by 2030 800 MW by 2033	950 MW by 2030 1,550 by 2037 2,150 by 2042	950 MW by 2030 1,550 by 2037 2,150 by 2043	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042	950 MW by 2030 1,550 by 2037	950 MW by 2030 1,550 by 2037
Combined Cycle Gas Additions (beginning of year)	1,200 MW (2033)	1,200 MW (2032)	1,800 MW (2032)	1,800 MW (2032) 600 MW (2037)	2,100 MW (2032) 1,200 MW (2037)	2,100 MW (2032) 1,200 MW (2037) 1,200 MW (2038)	1,800 MW (2032) 600 MW (2037)	1,800 MW (2032) 600 MW (2037)
Simple Cycle Gas Additions (beginning of year, except 2027 and 2028 additions in Q4)	800 MW (2027)	800 MW (2027) 800 MW (2028)	800 MW (2027) 800 MW (2029) 600 MW (2037)	800 MW (2027) 800 MW (2029) 600 MW (2037) 600 MW (2043)	800 MW (2027) 800 MW (2028) 600 MW (2038) 600 MW (2043)	800 MW (2027) 800 MW (2028) 600 MW (2035) 600 MW (2037)	800 MW (2027) 800 MW (2029)	800 MW (2027) 800 MW (2029) 600 MW (2037)
New Nuclear Additions (beginning of year)	N/A	900 MW (2040)	1,500 MW (2040)	1,500 MW (2040)	1,500 MW (2040)	1,500 MW (2040)	900 MW (2043)	900 MW (2043)
Other Clean Dispatchable Additions (beginning of year)	1,200 MW (2040) 1,200 MW (2043)	1,200 MW (2037) 1,200 MW (2043)	N/A	N/A	N/A	N/A	N/A	N/A

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