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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EA-2026-0226

DIRECT TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
July 2026

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DIRECT TESTIMONY

OF

MATT MICHELS

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I. INTRODUCTION

Q. Please state your name and business address.

A. Matt 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 of 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.

Q. Have you testified in proceedings before the Missouri Public Service Commission (the "Commission") or any other utility regulatory agency?

A. Yes. 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 AND KEY CONCLUSIONS

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 a 2,100 megawatt ("MW") natural gas combined cycle ("NGCC") facility adjacent to the site of the Company's Sioux coal-fired energy center and to be known as the West Alton Energy Center, which I will also refer to as the "Project" throughout my Direct Testimony.

Q. What are the key conclusions reflected in your Direct Testimony?

A. The key conclusions of my Direct Testimony are:

- The Project is needed, along with other new resources, to meet both capacity and energy requirements for Ameren Missouri customers; and
- The Project is a cost-effective means of meeting customer capacity and energy requirements compared to reasonable alternatives.

III. AMEREN MISSOURI'S PREFERRED RESOURCE PLAN

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

A. Yes. Ameren Missouri filed a Notice of Change in PRP with the 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, at that time, the Company had experienced a surge in interest from large load customers ("LLCs") locating in Ameren Missouri's service territory and had signed construction agreements relating to over two gigawatts ("GW") of new load. Peak demand for individual LLCs can range from 75 MW to over a GW. As I discuss later in my Direct Testimony, the Company indicated in its Notice of Change in PRP filing that it expected 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 generation resources that had been slated for construction later in the planning horizon because the resources would be needed sooner to reliably provide service to all customers when the new LLC load materializes. Second, while significantly

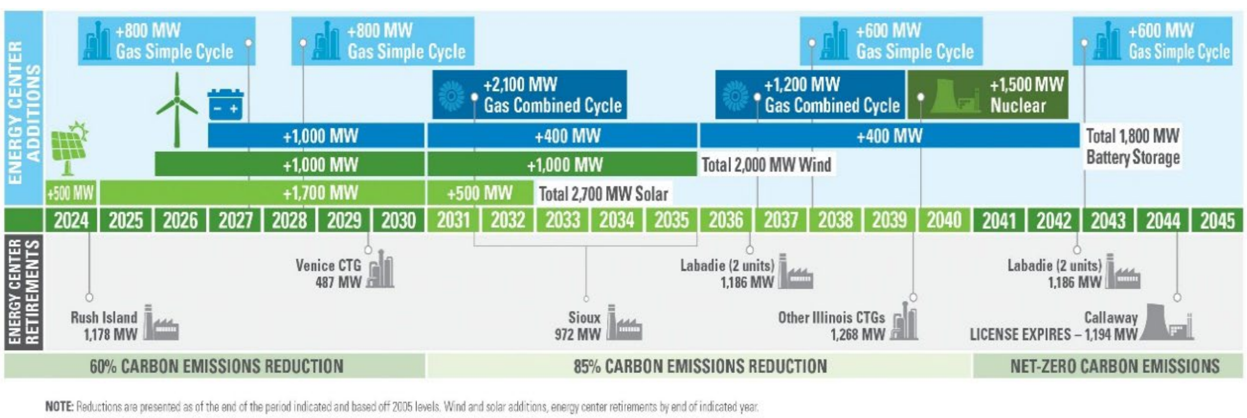
[1] On February 13, 2025, Ameren Missouri filed a brief notice of its intent to file a formal Notice of Change in PRP. The formal notice was filed in accordance with 20 CSR 4240-22.080(12).

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 positions.

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 the Company's oldest coal-fired plant,[2] the Sioux Energy Center ("SEC"), as early as the end of 2031 and as late as the end of 2035.[3] The retirement date range reflects the need for flexibility to retire the existing coal units at the site when planned new generation at the site

[2] The plant will be 60 years old next year.
[3] For modeling purposes, the retirement date for SEC was assumed to be December 31, 2031, and the in-service date for the replacement generation was assumed to be January 1, 2032. As discussed further below, that replacement generation is the Project.

becomes fully operational so that it is providing capacity to serve customer needs and meet resource adequacy requirements. 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.

- 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 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 – remains unchanged from the Company's 2023 IRP preferred plan.[4]
- 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

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

retired in October 2024 – the Big Hollow Energy Center ("BHEC"), for which the Commission approved a CCN in February 2026.[5]

- 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 900 MW now in service,[6] another 250 MW for the Reform Solar project, for which the Company was granted a CCN in May 2026,[7] and another 1,050 MW, including the 175 MW Tom Sawyer Project and the 225 MW Ringer Project (for which the Company is seeking CCNs in File No. EA-2026-0183) and another 500 MW by 2035. This represents an acceleration of solar generation additions from those included in the Company's 2023 IRP preferred plan, which included 1,800 MW of solar resources by 2030.[8] Renewable resource additions are a particularly important consideration in attracting new LLCs, such as data centers.
- Addition of 1,000 MW of battery energy storage system ("BESS") capacity by 2030 (including 400 MW which has been approved for construction at the Company's BHEC[9] and another 545 MW for which the Company is seeking CCNs in File No. EA-2026-0183), another 400 MW by 2036, and

[5] File No. EA-2025-0238.
[6] Ameren Missouri's Huck Finn, Cass County, Boomtown, Spit Rail, Vandalia, and Bowling Green solar energy centers.
[7] See File No. EA-2025-0239.
[8] The addition of Tom Sawyer and Ringer would bring the Company's total in-service and approved solar generation to approximately 1,550 MW, including 900 MW currently in service or expected to be in service in 2026, 250 MW for the Reform project, 175 MW for the Tom Sawywer project, and 225 MW for the Ringer project.
[9] File No. EA-2025-0238.

another 400 MW by 2042, for a total of 1,800 MW.[10] This also represents 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.

- Addition of 2,100 MW of NGCC capacity by the end of 2031 (the Project for which the Company is seeking a CCN in this case) and another 1,200 MW of NGCC capacity by the end of 2036, representing 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.[11]

Q. How did Ameren Missouri arrive at its PRP?

A. In short, Ameren Missouri evaluated a range of potential outcomes, or cases, for what its system load would be if new large loads were added, determined for each case the need for acceleration and, longer term, for addition of resources relative to its 2023 PRP to meet load and Midcontinent Independent System Operator ("MISO") planning reserve margin ("PRM") requirements, and selected the plan that 1) best

[10] 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.
[11] For modeling purposes, the Company's assumptions for modular nuclear generation were used.

represented expectations of future large load additions at the time the 2025 PRP was adopted, 2) provides some flexibility in the near term regarding further large load additions, and 3) ensures the Company maintains both short-term and long-term resource flexibility to address various risks to its generation portfolio.

Q. Please describe the LLC cases that the Company evaluated.

A. Ameren Missouri evaluated seven different LLC load cases, as shown in Table 1 below. The seven cases reflected three different levels of large load additions in the near term: 500 MW, 1,500 MW, and 2,000 MW by 2032. Cases 1 through 3 reflected no further growth in large loads after 2032. Cases 4 and 5 reflected continued growth from 1,500 MW and 2,000 MW loads, respectively, achieved by 2032, to 2,500 MW and 3,500 MW, respectively, by 2040. Cases 6 and 7 reflected 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 were used as the basis for evaluating the cost of resource acceleration to meet near-term LLC demand.

Table 1. Large Load Cases – Annual Peak Demand (MW) at Meter[12]

	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

[12] 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 percent was used. This results in additional annual energy sales of approximately four million megawatt-hours ("MWh") for each 500 MW of large load demand.

Q. What resources did the 2025 PRP show were needed to meet customer demand and energy needs in each of the seven load cases you just described?

A. The resource additions called for by the 2025 PRP for each case are summarized in the attached **Schedule MM-D2**.

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

A. Ameren Missouri chose Case 4 for inclusion in its PRP and therefore as the basis for determining resource needs. Based on discussions with potential customers at that time, the Company was also actively planning for Case 5 as an alternative scenario, as I discuss later in my Direct Testimony, with the potential for even further additional demand.

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

A. Yes. Ameren Missouri included Case 5 as an alternative plan in the Notice of Change in PRP filed with the Commission on February 28, 2025.[13] It should be noted that resource additions through 2032 for Case 5 are identical to those included for Case 4. This provided flexibility in the near term as the Company continued to evaluate requests for connection and service from prospective LLCs. Because discussions with potential customers were ongoing, we recognized that demand could exceed even the high case.

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

Q. Has the Company signed service agreements with LLCs under the Company's Large Load Tariff approved in File No. ET-2025-0184?

A. Yes. In February and May of this year, Ameren Missouri signed Electric Service Agreements ("ESAs") reflecting 2.8 GW of LLC customer load. *** ____________________ ***.

Q. What steps has Ameren Missouri taken to ensure that it has the generation needed to ensure reliability and to meet its obligation to serve existing and new customers, including those that elect to take service under its approved tariffs?

A. In addition to increasing the Company's own system capacity through recently completed projects and projects expected to be completed in the next year or two that the Commission has already approved – i.e., the Castle Bluff and BHEC NGSC units, the BHEC BESS, and the Huck Finn, Boomtown, Vandalia, Split Rail, Cass County, Bowling Green and Reform solar facilities – we will utilize the interim capacity provisions of the large load tariff to secure capacity from the capacity market or bilaterally in the short term. We have also completed adding oil backup capabilities to the Peno Creek Combustion Turbine Generator ("CTG") facility to provide additional winter capacity and are in the process of doing the same at the Audrain CTG facility. With respect to longer-term resource planning, given the expected large load additions and the reduction in our demand-side programs (and the lower level of MW savings from those programs) approved in our last MEEIA docket, our February 2025 PRP contemplates acceleration of other resources in the intermediate term, like the Project, as well as other generation through the 20-year planning horizon. As the charts in Figures 2 and 3 below show, based on the generation projects for which Ameren Missouri has received CCNs and which it is actively constructing, Ameren Missouri is short of system capacity required to serve expected demand, including expected new LLCs, starting in 2027 and continuing into the future unless the Project and other generation additions in the Company's 2025 PRP are constructed. The Company therefore has a need to build new generation resources to meet its capacity needs and fulfill its obligations to provide reliable electric service to all customers.

Q. What are the Company's goals to ensure reliability for all its customers – existing and new?

A. The Company has two main goals to ensure reliability for all its customers. First, continue conducting robust integrated resource planning analysis to ensure the Company has sufficient dispatchable system capacity over the planning horizon, with enough reserve margin to meet its peak retail load demand needs even in extreme weather and adverse system reliability conditions. And second, to ensure a balanced mix of dispatchable and renewable generation resources to provide cost-effective energy during all hours of every day for all customers in a reliable manner.

Q. How is the Company ensuring it has adequate reserve margin to serve all customers even under extreme weather conditions?

A. The Company is implementing its current PRP while also preparing a new PRP, to be filed as part of its 2026 IRP by October 1st of this year, to ensure the construction and acquisition of resources consistent with the Company's updated load expectations and to ensure reliability for all customers. The Project, along with other resources, is required to ensure that the Company has sufficient system capacity and the capability to generate enough energy to meet its expected customer needs.

IV. AMEREN MISSOURI'S NEED FOR CAPACITY AND ENERGY

Q. How does Ameren Missouri evaluate capacity needs?

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

Q. Is the Company's 2025 PRP the basis for the load and generating capacity assumptions used for the capacity positions presented in your Direct Testimony?

A. No. While the 2026 triennial IRP is not yet complete, we are at a point in its preparation where we have updated capacity (and energy capability) information and so I have based the positions presented in my Direct Testimony on assumptions currently being used in the preparation of the Company's 2026 IRP.[14]

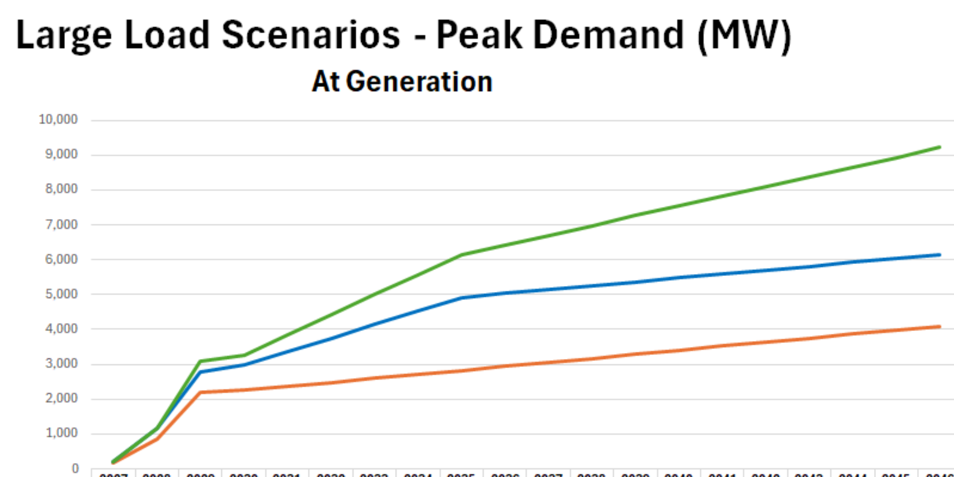
Q. How do the Company's assumptions for load differ from those used in the Company's 2025 PRP?

A. The main difference between the assumptions used for the 2025 PRP and those used in the 2026 IRP is an increase in expected demand for the latter. That increase is due to the Company's updated expectations for LLC demand compared to what was

[14] I expect no material change in these assumptions between now and when the Company files the 2026 IRP just over two months from now.

included in the Company's 2025 PRP. As I mentioned previously, the Company has signed ESAs with peak demand totaling 2.8 GW. This exceeds the Company's previous LLC demand expectations of 1.5 to 2 GW by 2032, as shown in the Company's 2025 Notice of Change in Preferred Plan and summarized in Table 1 above. Figure 2 below shows the Company's current base, low, and high expectations for LLC demand being used in the development of its 2026 IRP.[15] As Figure 2 shows, the Company's base LLC demand expectation is approximately 3 GW in 2030, rising to approximately 4.9 GW in 2035, and 6.1 GW in 2046.[16] The high case shows LLC demand of approximately 3.3 GW in 2030, rising to approximately 6.1 GW in 2035, and 9.2 GW in 2046. The low case shows LLC demand of approximately 2.3 GW in 2030, rising to 2.8 GW in 2035, and 4.1 GW in 2046.

Figure 2. Ameren Missouri 2026 IRP LLC Demand Assumptions



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Summer Peak - Large Load - Low	184	870	2,202	2,253	2,369	2,483	2,599	2,714	2,829	2,944	3,060	3,174	3,290	3,405	3,521	3,635	3,751	3,866	3,981	4,096
Summer Peak - Large Load - Base	190	1,164	2,787	2,970	3,360	3,750	4,141	4,531	4,922	5,033	5,144	5,255	5,366	5,477	5,588	5,699	5,811	5,922	6,033	6,144
Summer Peak - Large Load - High	190	1,164	3,095	3,277	3,850	4,424	4,997	5,571	6,144	6,423	6,703	6,982	7,261	7,540	7,820	8,099	8,378	8,657	8,937	9,216

[15] Figure 3 shows summer LLC demand. LLC demand in other seasons differs slightly due to timing of load additions.
[16] Grossed up for transmission losses. 2030 LLC demand in the base case is expected to be approximately 2.9 GW in the base case.

Q. Has the Company also updated its assumptions for the MISO PRM for each season and for unit accreditations?

A. Yes. The Company's 2026 IRP assumptions for MISO seasonal PRM values and for new generating capacity accreditations are based on MISO's 2025-2026 Planning Year data for new resources.[17] Capacity accreditations for existing resources are based on expected unforced capacity ("UCAP") using assumptions for future changes in forced outages rates.

Q. Why did you use calculated UCAP values for existing resources instead of MISO's current accreditations for existing resources?

A. UCAP values were used for several reasons, primarily for consistency and stability. First, 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 has been 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. Second, 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 in such changes over three years, even though the units' improved ability to operate during winter occurs immediately. Third, by using future assumptions for forced outages to calculate UCAP values, we can reflect expected unit reliability in the

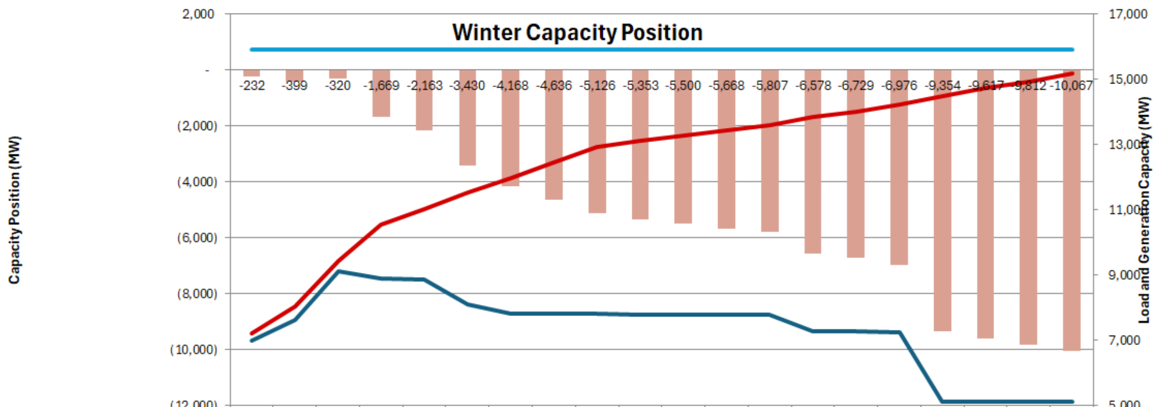
[17] MISO data from the 2025-2026 Planning Year were used due to the absence of indicative accreditation data for certain resources for the 2026-2027 Planning Year.

capacity accreditations. Because of the uncertain and after-the-fact nature of MISO's accreditation adjustments and the forward-looking nature of resource planning, it makes more sense to use the UCAP values as the basis for existing unit accreditations reflected in 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. Have you prepared capacity positions to show the resource capacity needed to meet the Company's current expectations for customer demand?

A. Yes. Figure 3 below shows the Company's winter capacity position using the winter base LLC demand assumptions consistent with the summer base LLC demand assumptions shown in Figure 2 above. The capacity position in Figure 2 reflects the inclusion of the Company's existing resources as well as planned resources for which the Company has secured, or is currently seeking, CCNs, but excluding the Project. The horizontal blue line shows the capacity length the Company needs, approximately 750 MW beyond the MISO PRM requirement, to ensure reliability during extreme weather events. As the figure shows, the resources included fall well short of the capacity needed to ensure reliability during extreme weather, and well short of the capacity needed to meet the MISO PRM requirement starting in 2030, which shows a capacity deficit to the MISO PRM of 1,669 MW. The capacity deficit continues to increase after 2030.

Figure 3. Ameren Missouri Winter Capacity – Base LLC Demand, Existing and Approved Resources, and Other Resources with Active CCN Applications



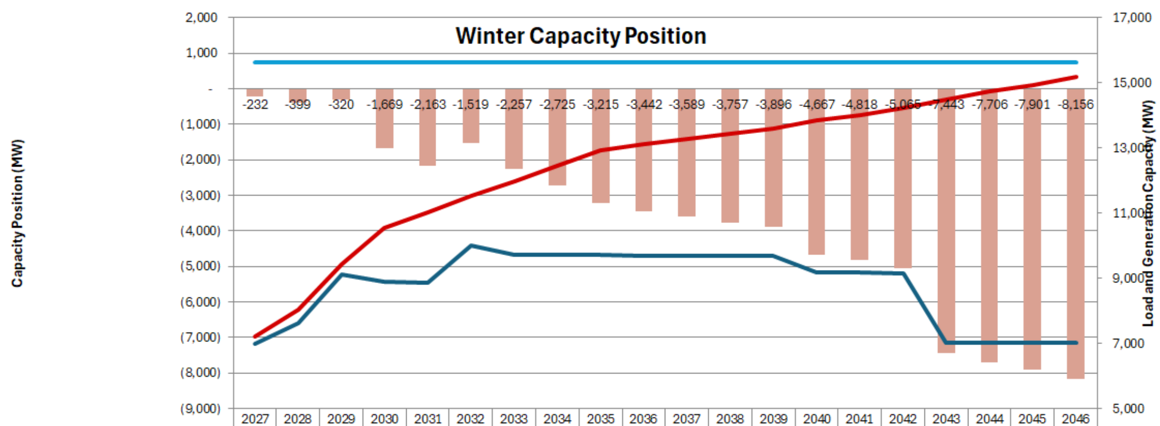
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Position - Long/(Short)	(232)	(399)	(320)	(1,669	(2,163	(3,430	(4,168	(4,636	(5,126	(5,353
Extreme Weather Target	750	750	750	750	750	750	750	750	750	750
Net System Capacity	6,991	7,639	9,128	8,881	8,846	8,099	7,800	7,804	7,802	7,776
Load and Reserve	7,223	8,038	9,448	10,550	11,009	11,530	11,968	12,440	12,928	13,128

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Capacity Position - Long/(Short)	(5,500	(5,668	(5,807	(6,578	(6,729	(6,976	(9,354	(9,617	(9,812	(10,06
Extreme Weather Target	750	750	750	750	750	750	750	750	750	750
Net System Capacity	7,771	7,768	7,779	7,263	7,274	7,247	5,116	5,116	5,116	5,116
Load and Reserve	13,271	13,436	13,586	13,841	14,003	14,223	14,470	14,732	14,928	15,182

Q. Does the addition of the Project satisfy the Company's need for capacity?

A. Only in part. Figure 4 below shows the Company's winter capacity position with the same assumptions reflected in Figure 3, but including the addition of the Project starting in 2032. As the figure shows, the Company's resource capacity still falls well short of the total demand and PRM. The Company needs the Project and will also clearly need resources in addition to the Project to meet customer needs.

Figure 4. Ameren Missouri Winter Capacity – Base LLC Demand, Existing and Approved Resources, the Project, and Other Resources with Active CCN Applications

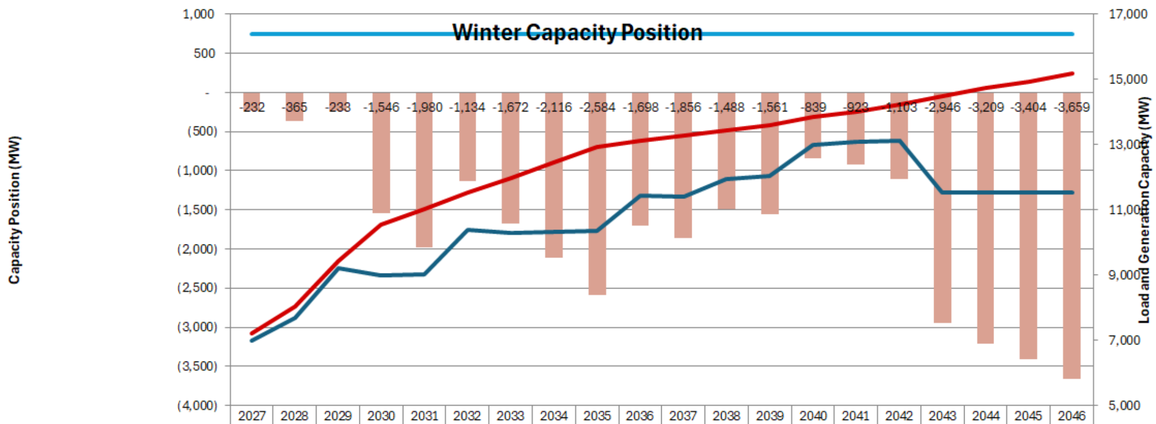


	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Capacity Position - Long/(Short)	(232)	(399)	(320)	(1,669	(2,163	(1,519	(2,257	(2,725	(3,215	(3,442	(3,589	(3,757	(3,896	(4,667	(4,818	(5,065	(7,443	(7,706	(7,901	(8,156
Extreme Weather Target	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Net System Capacity	6,991	7,639	9,128	8,881	8,846	10,010	9,711	9,715	9,713	9,687	9,682	9,679	9,690	9,174	9,185	9,158	7,027	7,027	7,027	7,027
Load and Reserve	7,223	8,038	9,448	10,550	11,009	11,530	11,968	12,440	12,928	13,128	13,271	13,436	13,586	13,841	14,003	14,223	14,470	14,732	14,928	15,182

Q. You discussed the Company's 2025 PRP at length earlier in your Direct Testimony. Do the resources included in the PRP satisfy the capacity need?

A. Not completely. Figure 5 below shows the Company's winter capacity position with the same assumptions reflected in Figure 4, but including all other resources included in the Company's 2025 PRP. The Company's total capacity resources under its 2025 PRP still fall well short of meeting the expected capacity needs, with or without consideration of extreme weather.

Figure 5. Ameren Missouri Winter Capacity – Base LLC Demand and All 2025 PRP Resources



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Capacity Position - Long/(Short)	(232)	(365)	(233)	(1,546	(1,980	(1,134	(1,672	(2,116	(2,584	(1,698	(1,856	(1,488	(1,561	(839)	(923)	(1,103	(2,946	(3,209	(3,404	(3,659
Extreme Weather Target	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Net System Capacity	6,991	7,673	9,215	9,004	9,029	10,395	10,296	10,324	10,345	11,430	11,415	11,948	12,025	13,002	13,079	13,120	11,524	11,524	11,524	11,524
Load and Reserve	7,223	8,038	9,448	10,550	11,009	11,530	11,968	12,440	12,928	13,128	13,271	13,436	13,586	13,841	14,003	14,223	14,470	14,732	14,928	15,182

Q. The capacity position in Figure 5 suggests the Company will need a significantly different portfolio of resources to meet expected customer needs. Does the Company plan to file a new notice of change in preferred resource plan?

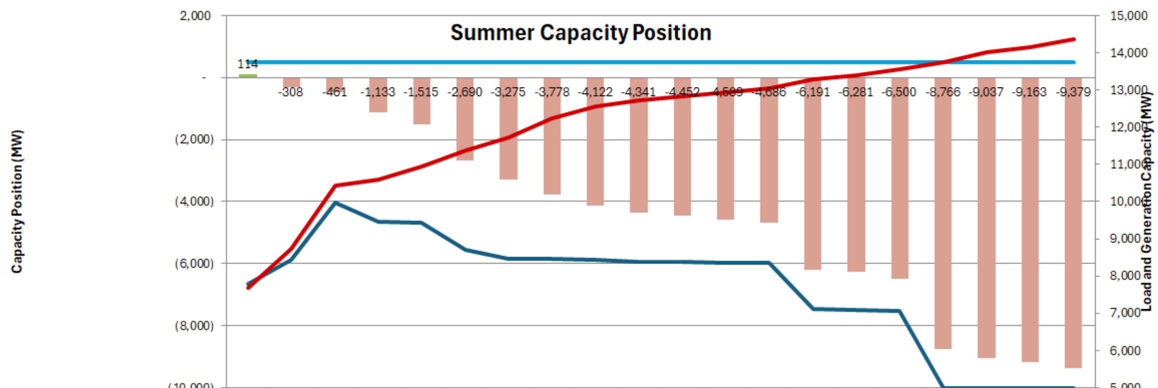
A. No. As I mentioned previously, the Company is due to file a new IRP by October 1st of this year, which is less than 70 days from the filing of the Company's application in this case. The Company expects to formally adopt a new preferred resource plan and document its adoption of that preferred resource plan in its upcoming IRP filing. Because the Company has not yet formally adopted a new preferred resource plan, and because the Company will file its IRP within the next few months, filing a notice of change in preferred resource plan is not necessary or useful.

Q. You've shown winter capacity positions for several different portfolios. Have you also created summer capacity positions for these portfolios?

A. Yes. Figures 6 through 8 below show the Company's summer capacity position for the same portfolios used as the basis for Figures 3 through 5, respectively.

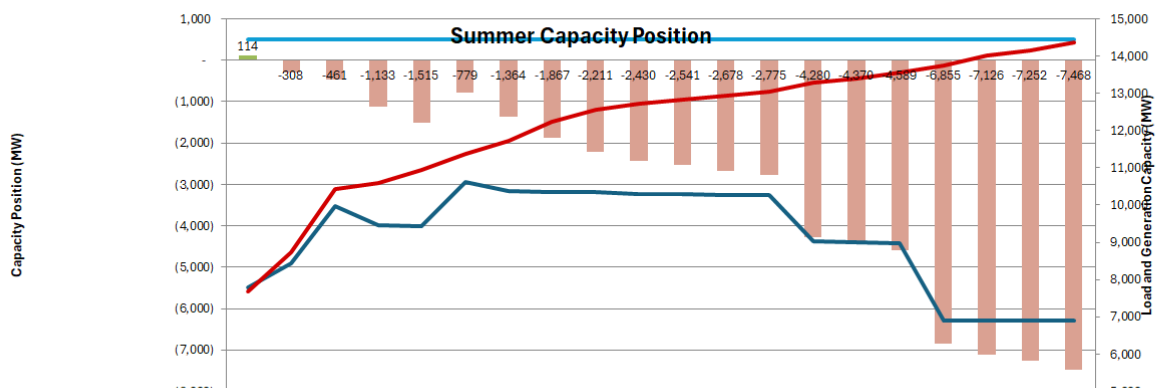
They show that the Company's need for summer capacity is somewhat less than its need for winter capacity but is still quite significant.

Figure 6. Ameren Missouri Summer Capacity – Base LLC Demand, Existing and Approved Resources, and Other Resources with Active CCN Applications



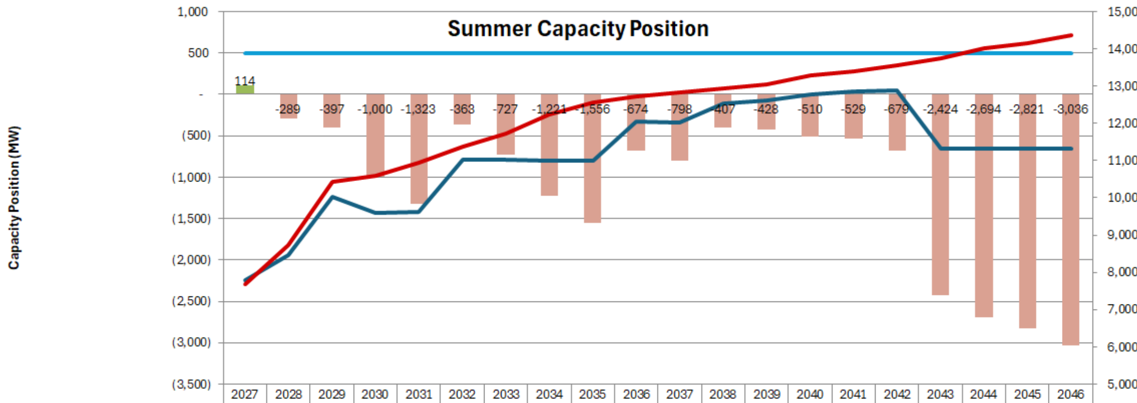
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Capacity Position - Long/(Short)	114	(308)	(461)	(1,133	(1,515	(2,690	(3,275	(3,778	(4,122	(4,341	(4,452	(4,589	(4,686	(6,191	(6,281	(6,500	(8,766	(9,037	(9,163	(9,379
Extreme Weather Target	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Net System Capacity	7,802	8,432	9,971	9,451	9,429	8,695	8,462	8,451	8,433	8,392	8,372	8,354	8,349	7,107	7,101	7,060	4,985	4,985	4,985	4,985
Load and Reserve	7,688	8,740	10,432	10,584	10,944	11,384	11,737	12,229	12,555	12,733	12,824	12,943	13,035	13,298	13,382	13,559	13,751	14,021	14,148	14,363

Figure 7. Ameren Missouri Summer Capacity – Base LLC Demand, Existing and Approved Resources, the Project, and Other Resources with Active CCN Applications



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Capacity Position - Long/(Short)	114	(308)	(461)	(1,133	(1,515	(779)	(1,364	(1,867	(2,211	(2,430	(2,541	(2,678	(2,775	(4,280	(4,370	(4,589	(6,855	(7,126	(7,252	(7,468
Extreme Weather Target	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Net System Capacity	7,802	8,432	9,971	9,451	9,429	10,606	10,373	10,362	10,344	10,303	10,283	10,265	10,260	9,018	9,012	8,971	6,896	6,896	6,896	6,896
Load and Reserve	7,688	8,740	10,432	10,584	10,944	11,384	11,737	12,229	12,555	12,733	12,824	12,943	13,035	13,298	13,382	13,559	13,751	14,021	14,148	14,363

Figure 8. Ameren Missouri Summer Capacity – Base LLC Demand and All 2025 PRP Resources

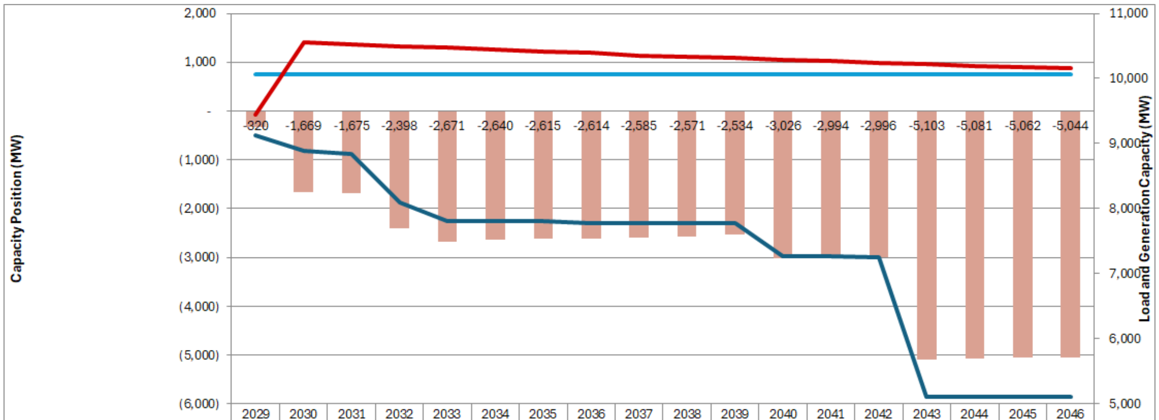


	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Capacity Position - Long/(Short)	114	(289)	(397)	(1,000	(1,323	(363)	(727)	(1,221	(1,556	(674)	(798)	(407)	(428)	(510)	(529)	(679)	(2,424	(2,694	(2,821	(3,036
Extreme Weather Target	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Net System Capacity	7,802	8,452	10,035	9,584	9,621	11,021	11,010	11,008	10,999	12,058	12,026	12,536	12,607	12,788	12,853	12,880	11,327	11,327	11,327	11,327
Load and Reserve	7,688	8,740	10,432	10,584	10,944	11,384	11,737	12,229	12,555	12,733	12,824	12,943	13,035	13,298	13,382	13,559	13,751	14,021	14,148	14,363

Q. You've shown capacity positions for several different portfolios based on the Company's current base case expectations for LLCs. You've also shown it with the base case assumption from the 2025 PRP for LLC load, which is lower than the LLC load under contract today. What if LLC demand is limited to the 2.8 GW of demand from currently signed ESAs?

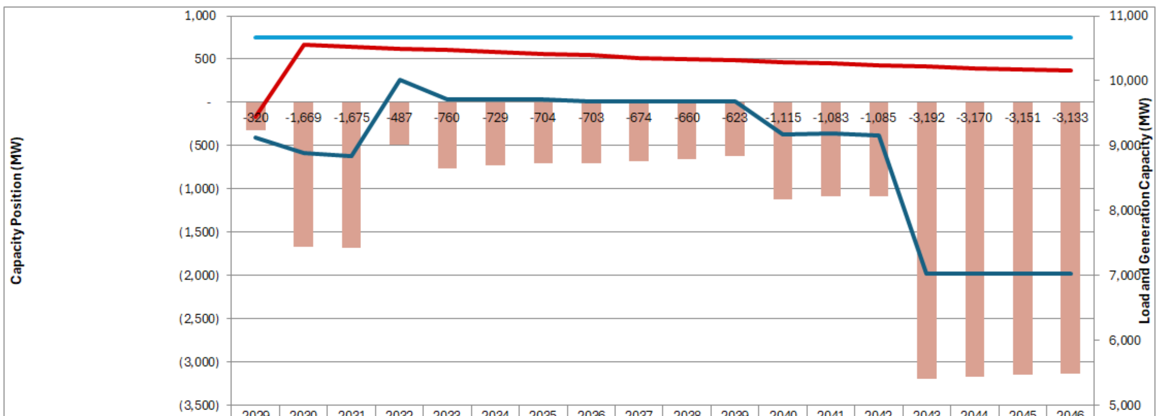
A. Figures 9 and 10 below show the Company's winter capacity position without the Project (Figure 9) and with the Project (Figure 10) if demand remains completely flat after 2030, which approximates the total demand including the signed ESAs. Figures 9 and 10 show that the Project is needed to meet capacity needs, and that the Project alone is not sufficient to meet total capacity needs, even if demand remains flat after 2030.

Figure 9. Ameren Missouri Winter Capacity – ~2.8 GW LLC Demand, Existing and Approved Resources, and Other Resources with Active CCN Applications



	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Capacity Position - Long/(Short)	(320)	(1,669)	(1,675)	(2,398)	(2,671)	(2,640)	(2,615)	(2,614)	(2,585)	(2,571)	(2,534)	(3,026)	(2,994)	(2,996)	(5,103)	(5,081)	(5,062)	(5,044)
Extreme Weather Target	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Net System Capacity	9,128	8,881	8,846	8,099	7,800	7,804	7,802	7,776	7,771	7,768	7,779	7,263	7,274	7,247	5,116	5,116	5,116	5,116
Load and Reserve	9,448	10,550	10,521	10,497	10,471	10,444	10,417	10,390	10,356	10,339	10,313	10,289	10,268	10,243	10,218	10,197	10,178	10,160

Figure 10. Ameren Missouri Winter Capacity – ~2.8 GW LLC Demand, Existing and Approved Resources, the Project, and Other Resources with Active CCN



	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Capacity Position - Long/(Short)	(320)	(1,669)	(1,675)	(487)	(760)	(729)	(704)	(703)	(674)	(660)	(623)	(1,115)	(1,083)	(1,085)	(3,192)	(3,170)	(3,151)	(3,133)
Extreme Weather Target	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Net System Capacity	9,128	8,881	8,846	10,010	9,711	9,715	9,713	9,687	9,682	9,679	9,690	9,174	9,185	9,158	7,027	7,027	7,027	7,027
Load and Reserve	9,448	10,550	10,521	10,497	10,471	10,444	10,417	10,390	10,356	10,339	10,313	10,289	10,268	10,243	10,218	10,197	10,178	10,160

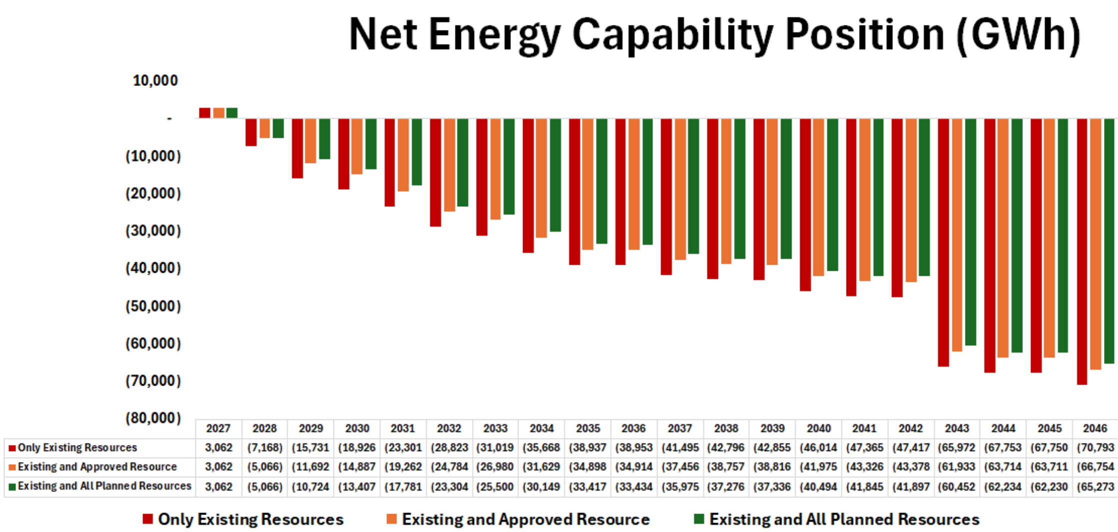
Q. Does the Company expect demand to remain flat?

A. No, as discussed in detail in Company witness Ajay Arora's Direct Testimony.

Q. Have you also evaluated the Company's annual energy capability position for the three portfolios for which you've shown winter and summer capacity positions?

A. Yes. Figures 11 through 13 below show the Company's annual energy capability position. The energy capability position represents the maximum reasonable energy production of the portfolio relative to customer energy needs, considering unit planned and forced outages and permit limits. As with the winter and summer capacity deficits, the Project only partially addresses the Company's energy capability deficit. The same is true for the portfolio of resources included in the Company's 2025 PRP.

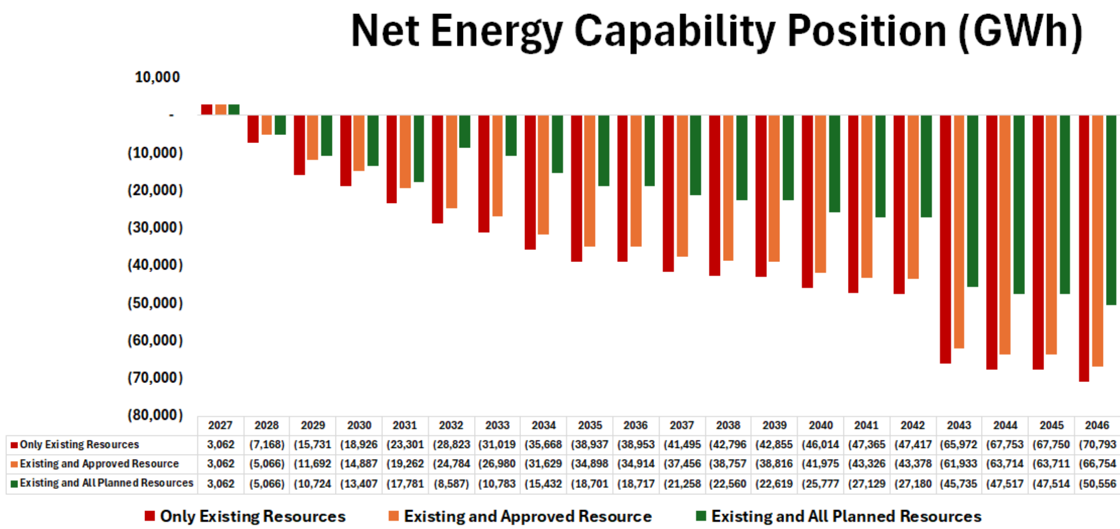
Figure 11. Ameren Missouri Energy Capability – Base LLC Demand, Existing and Approved Resources, and Other Resources with Active CCN Applications



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Only Existing Resources	3,062	(7,168)	(15,731	(18,926	(23,301	(28,823	(31,019	(35,668	(38,937	(38,953
Existing and Approved Resource	3,062	(5,066)	(11,692	(14,887	(19,262	(24,784	(26,980	(31,629	(34,898	(34,914
Existing and All Planned Resources	3,062	(5,066)	(10,724	(13,407	(17,781	(23,304	(25,500	(30,149	(33,417	(33,434

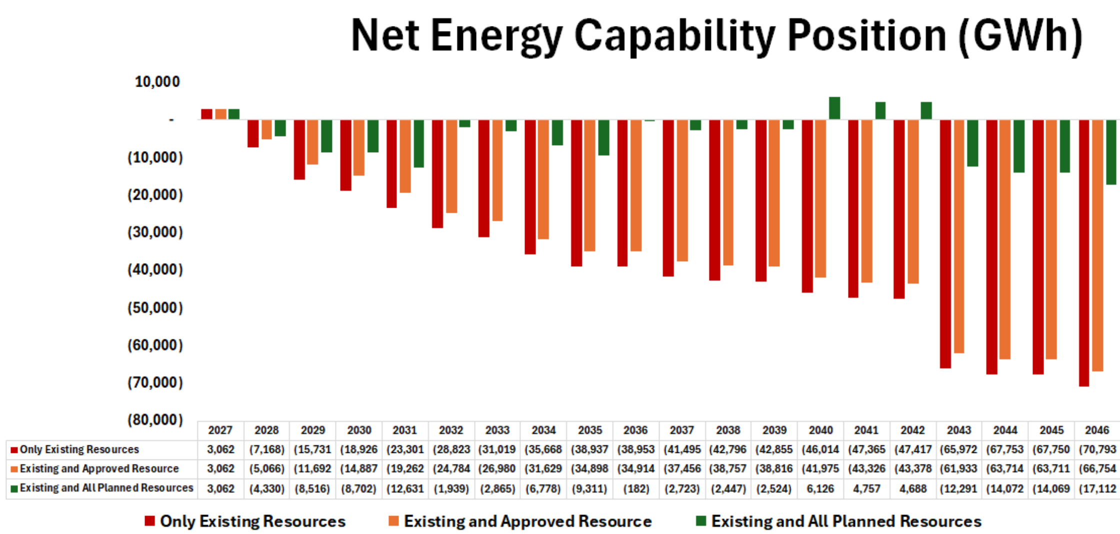
	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Only Existing Resources	(41,495	(42,796	(42,855	(46,014	(47,365	(47,417	(65,972	(67,753	(67,750	(70,793
Existing and Approved Resource	(37,456	(38,757	(38,816	(41,975	(43,326	(43,378	(61,933	(63,714	(63,711	(66,754
Existing and All Planned Resources	(35,975	(37,276	(37,336	(40,494	(41,845	(41,897	(60,452	(62,234	(62,230	(65,273

Figure 12. Ameren Missouri Energy Capability – Base LLC Demand, Existing and Approved Resources, the Project, and Other Resources with Active CCN Applications



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Only Existing Resources	3,062	(7,168)	(15,731	(18,926	(23,301	(28,823	(31,019	(35,668	(38,937	(38,953	(41,495	(42,796	(42,855	(46,014	(47,365	(47,417	(65,972	(67,753	(67,750	(70,793
Existing and Approved Resource	3,062	(5,066)	(11,692	(14,887	(19,262	(24,784	(26,980	(31,629	(34,898	(34,914	(37,456	(38,757	(38,816	(41,975	(43,326	(43,378	(61,933	(63,714	(63,711	(66,754
Existing and All Planned Resources	3,062	(5,066)	(10,724	(13,407	(17,781	(8,587)	(10,783	(15,432	(18,701	(18,717	(21,258	(22,560	(22,619	(25,777	(27,129	(27,180	(45,735	(47,517	(47,514	(50,556

Figure 13. Ameren Missouri Energy Capability – Base LLC Demand and All 2025 PRP Resources



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Only Existing Resources	3,062	(7,168)	(15,731	(18,926	(23,301	(28,823	(31,019	(35,668	(38,937	(38,953	(41,495	(42,796	(42,855	(46,014	(47,365	(47,417	(65,972	(67,753	(67,750	(70,793
Existing and Approved Resource	3,062	(5,066)	(11,692	(14,887	(19,262	(24,784	(26,980	(31,629	(34,898	(34,914	(37,456	(38,757	(38,816	(41,975	(43,326	(43,378	(61,933	(63,714	(63,711	(66,754
Existing and All Planned Resources	3,062	(4,330)	(8,516)	(8,702)	(12,631	(1,939)	(2,865)	(6,778)	(9,311)	(182)	(2,723)	(2,447)	(2,524)	6,126	4,757	4,688	(12,291	(14,072	(14,069	(17,112

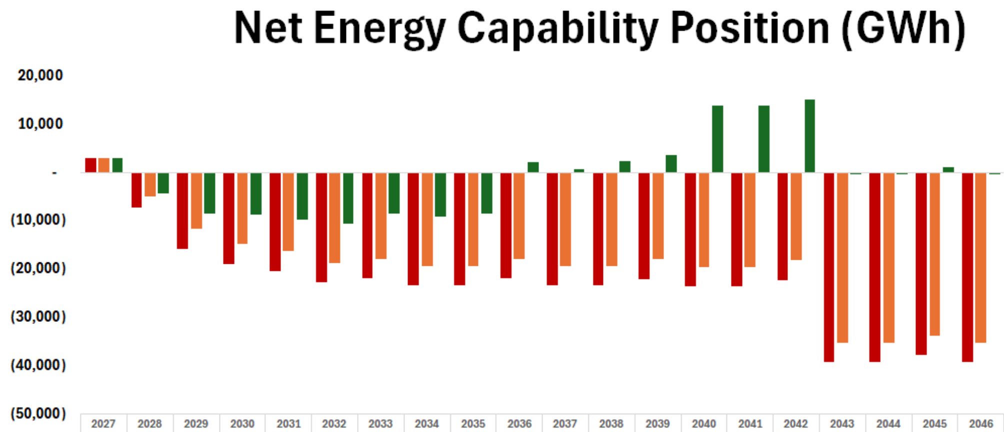
Q. Figure 13 appears to show that the Company's 2025 PRP comes close to satisfying customer energy needs in the years 2036-2042. Would additional resources still be necessary?

A. Yes. The energy capability positions show the reasonable maximum energy generation of a portfolio relative to customer energy needs on an annual basis, but they do not account for energy needs in each hour of the year. Additional resources are needed to meet capacity needs and ensure sufficient energy in all hours. The Company's upcoming IRP will address the entirety of the Company's expected customer needs over the entire planning horizon.

Q. While the Company does not expect demand to remain flat, what would the Company's energy capability position look like if the Company signed no additional ESAs beyond the signed ESAs for 2.8 GW of LLC load?

A. Figure 14 shows that the Company will remain in an energy capability deficit position for many years even if we add all the resources the 2025 PRP calls for (excluding the Project), and even if load remains flat after 2030. While we would not be in a deficit position in most years starting in 2036, we would still have energy capability that is far less than the historical length we had in the first couple of decades of the 2000s and far less than what would be needed on an annual basis to ensure sufficient generation to meet demand in all hours of the year. Note that this reflects the addition of baseload NGCC generation in 2036 and new nuclear in 2040, as reflected in the 2025 PRP. The Company clearly needs significant baseload energy generation in the long term, even if load remains flat after 2030.

Figure 14. Ameren Missouri Energy Capability Position – 2.8 GW LLC Demand and All 2025 PRP Resources Except the Project



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Only Existing Resources	3,062	(7,168)	(15,731	(18,926	(20,354	(22,723	(21,916	(23,367	(23,364	(21,944	(23,393	(23,359	(22,047	(23,580	(23,653	(22,249	(39,262	(39,274	(37,843	(39,262
Existing and Approved Resource	3,062	(5,066)	(11,692	(14,887	(16,315	(18,684	(17,877	(19,328	(19,325	(17,905	(19,354	(19,320	(18,008	(19,540	(19,614	(18,210	(35,223	(35,235	(33,804	(35,223
Existing and All Planned Resources	3,062	(4,330)	(8,516)	(8,702)	(9,684)	(10,555	(8,478)	(9,193)	(8,455)	2,111	662	2,273	3,567	13,843	13,752	15,139	(298)	(310)	1,121	(298)

Q. Does the Project provide any benefits with respect to flexibility for the Company's generation portfolio?

A. Yes. Adding the Project to the Company's generation portfolio provides flexibility to meet its customers' ongoing needs in the event that it becomes necessary to retire other generation resources, such as the Company's Labadie Energy Center, sooner than is currently planned. This could result from changes in regulation or other energy policy or some unforeseen catastrophic event.

V. ECONOMICS OF THE PROJECT

Q. Have you performed any analysis of the Project's economics?

A. Yes. I have analyzed the cost of implementing the project compared to the cost of doing nothing (and therefore relying on the market)[18] and compared to the cost of alternative resources.

[18] As contemplated by the Stipulation and Agreement in File No. EA-2023-0286.

Q. What have you used as the basis for your economic analysis?

A. I have used the modeling framework and assumptions, with some targeted updates, which was used for the Company's 2025 Notice of Change in Preferred Resource Plan filing.[19]

Q. You mentioned previously that the Company is preparing to file its 2026 IRP by October 1st of this year. Why have you used the 2025 PRP analysis framework and assumptions?

A. Primarily because the 2026 IRP analysis is not yet complete, nor has the Company adopted a new PRP which could be used as a basis for analysis comparison. The economic analysis I have performed is in large part necessary to meet the requirements of specific provisions in settlement agreements that the Company has signed with parties to prior cases, and which the Commission has approved, which require analysis based on the Company's PRP. Until the Company adopts a new PRP, its current PRP remains in effect.

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.[20]

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[19] File No. EO-2025-0235.
[20] Schedule MM-D1 – 2025 Change in Preferred Plan Report, pp. 13-14.

Q. Have you made any additional changes in assumptions beyond what was used in the Company's 2025 Notice of Change in PRP filing?

A. Yes. I have updated the cost of NGSC generation to reflect the assumptions currently being used in the development of the Company's 2026 IRP, as well as the cost of the Project (an NGCC) to ensure a fair and current comparison of those two options.

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 through 7).

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

A. Unsurprisingly, the results show that the higher the load, the higher the revenue requirement. 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 LLCs whose demand increases result in the need to accelerate resource additions, as described in the Company's application for a tariff to serve LLCs.[21]

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. Please describe the economic analysis you have performed to support the Company's request for a CCN for the Project.

A. I have evaluated the Company's PRP with updated costs for the Project, and I have evaluated alternative plans that exclude the Project,[22] with both 1) no replacement resources, and 2) replacement with an equivalent amount of NGSC capacity. I have evaluated plans with both the base project costs and the risk adjusted project costs for the Project described in the Direct Testimony of Company witness Chris Stumpf. A summary of the key assumptions used for the economic analysis of the Project is shown in **Schedule MM-D3**.

Q. What were the results of the analysis?

A. Table 2 below shows the results of the analysis of the PRP with and without the Project, for both base project costs and risk adjusted project costs, and including a plan with a capacity-equivalent amount of NGSC capacity in lieu of the Project. As the table shows, the Net Present Value of Revenue Requirement ("NPVRR") (under probability-

[21] File No. ET-2025-0184.
[22] As contemplated by the Stipulation and Agreement in File No. EA-2023-0286.

weighted average CO_2 prices) decreases when the Project is removed, regardless of assumptions for project capital costs. These cost differentials represent 3 to 5 percent of total costs to customers as measured by total NPVRR, depending on capital cost assumptions for the Project. Relative NPVRR results for the various levels of CO_2 price assumption are similar for each plan comparison.

Table 2. NPVRR Results ($Millions) – PRP With and Without the Project and with Reasonable Substitution Resources[23]

		Low CO_2 Price	Base CO_2 Price	High CO_2 Price	PWA CO_2 Price
a	PRP with Base Project Costs for West Alton	110,522	109,280	109,600	109,794
b	PRP with Risk-adjusted Project Costs for West Alton	111,911	110,669	110,989	111,183
c	PRP without West Alton	107,080	105,465	105,903	106,142
d	PRP without West Alton and With 2,100 MW NGSC in 2032	110,350	108,709	109,084	109,366
c-a	PRP without West Alton vs. PRP with Base Costs	(3,442)	(3,816)	(3,697)	(3,652)
c-b	PRP without West Alton vs. PRP with Risk-adjusted Costs	(4,831)	(5,204)	(5,086)	(5,040)
d-a	NGSC Substitute vs. PRP with Base Costs	(173)	(571)	(516)	(427)
d-b	NGSC Substitute vs. PRP with Risk-adjusted Costs	(1,561)	(1,960)	(1,905)	(1,816)

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

A. The analysis shows that: 1) the Project, which is necessary to serve expected customer capacity and energy needs, results in costs that must be recovered through customer rates; and 2) the Project cost approximately $427 million more under base project cost assumptions than a capacity-equivalent quantity of NGSC resources, which would not provide nearly the same amount of energy as the Project. This differential represents a difference of approximately 0.4 percent of total costs to customers as measured by total NPVRR.

[23] Plan a in Table 2 reflects a plan with base project specific costs for the Project. Plan b reflects a plan with risk-adjusted project specific costs for the Project. Plan c reflects removal of the Project. Plan d reflects removal of the Project and replacement with a capacity-equivalent amount of NGSC resources.

Q. You've compared the costs of deploying NGSC resources instead of the NGCC resources that the Project will deploy. Are there other considerations that should be taken into account when comparing these two types of resources?

A. Yes, primarily the differences in the way these resources are operated. The Project will use a highly efficient combination of natural gas turbines, heat recovery steam generators, and steam turbines. This combination will result in a high level of utilization, or capacity factor, of the generators in the market, resulting in baseload operation (*i.e.*, the units will run in most hours during which they are available). In contrast, NGSC technology is designed for operation during times of greatest need, including peak demand hours. NGSC resources are also typically limited in their hours of operation due to permitting constraints, as is the case with the Castle Bluff and BHEC NGSC facilities for which the Company received CCN approval from the Commission.

Q. Could the Company deploy additional energy resources in addition to NGSC resources to ensure the capability to produce a similar amount of energy to the Project?

A. Theoretically, yes, although this would come at significant additional cost and would introduce other issues. To make the comparison simple, we can assume a capacity factor of 20 percent for 2,100 MW of NGSC capacity, which would yield annual energy production of 3.7 million MWh. In comparison, the Project would yield annual energy production of approximately 14.7 million MWh at an 80 percent capacity factor, about 11 million MWh more than the comparable NGSC capacity.[24] To generate an

[24] Please note that my use of an 80% capacity factor is slightly less than the 85% referenced by Messrs. Stumpf and Meyer. They are referring to the more near- to intermediate term expectation that the facility would operate at an 85% (or better) capacity factor while my longer-term analysis over a 30-year time horizon somewhat more conservatively assumes 80%.

additional 11 million MWh per year would require over 4,600 MW of additional solar capacity at a 27 percent capacity factor or about 3,000 MW of additional wind capacity at a capacity factor of 42 percent. The additional capital cost alone would be approximately $9.6 billion if 4,600 MW of additional solar were deployed, or approximately $7 billion if 3,000 MW of wind were deployed.[25] Beyond the additional capital cost, project availability and interconnection within the next five years would be important considerations. The Company's 2025 PRP already calls for a cumulative total of approximately 5,400 MW of wind and solar resources, and the Company has indicated it is targeting up to 30 percent of its generation to come from renewable resources. Adding a further 11 million MWh of renewable generation would introduce unnecessary challenges, including challenges resulting from the fact that renewable energy resources are not available in all hours in the same way the Project is, if doing so in a timely manner were even feasible.

Q. Are there other new baseload resources that the Company could deploy instead of the planned NGCC technology?

A. Not in the planned timeframe for the Project, which is necessary to meet the needs that exist in that timeframe (in fact, those needs are earlier, but a project of this magnitude takes a few years to develop and implement). New nuclear is a longer-term option for baseload generation, but its long lead times and strict site requirements are not conducive to deployment anywhere near the early 2030s. While fuel cells are becoming a viable option for a portion of our gas-fired energy portfolio, the industry has little experience with deployments at scales needed to meet a majority of the Company's and its customers' incremental needs.

[25] Cost estimates based on the Company's current IRP assumptions.

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 Certificates of Public Convenience and Necessity for A Natural Gas Electrical Generation Facility.	))))	File No.: EA-2026-0226

AFFIDAVIT OF MATT MICHELS

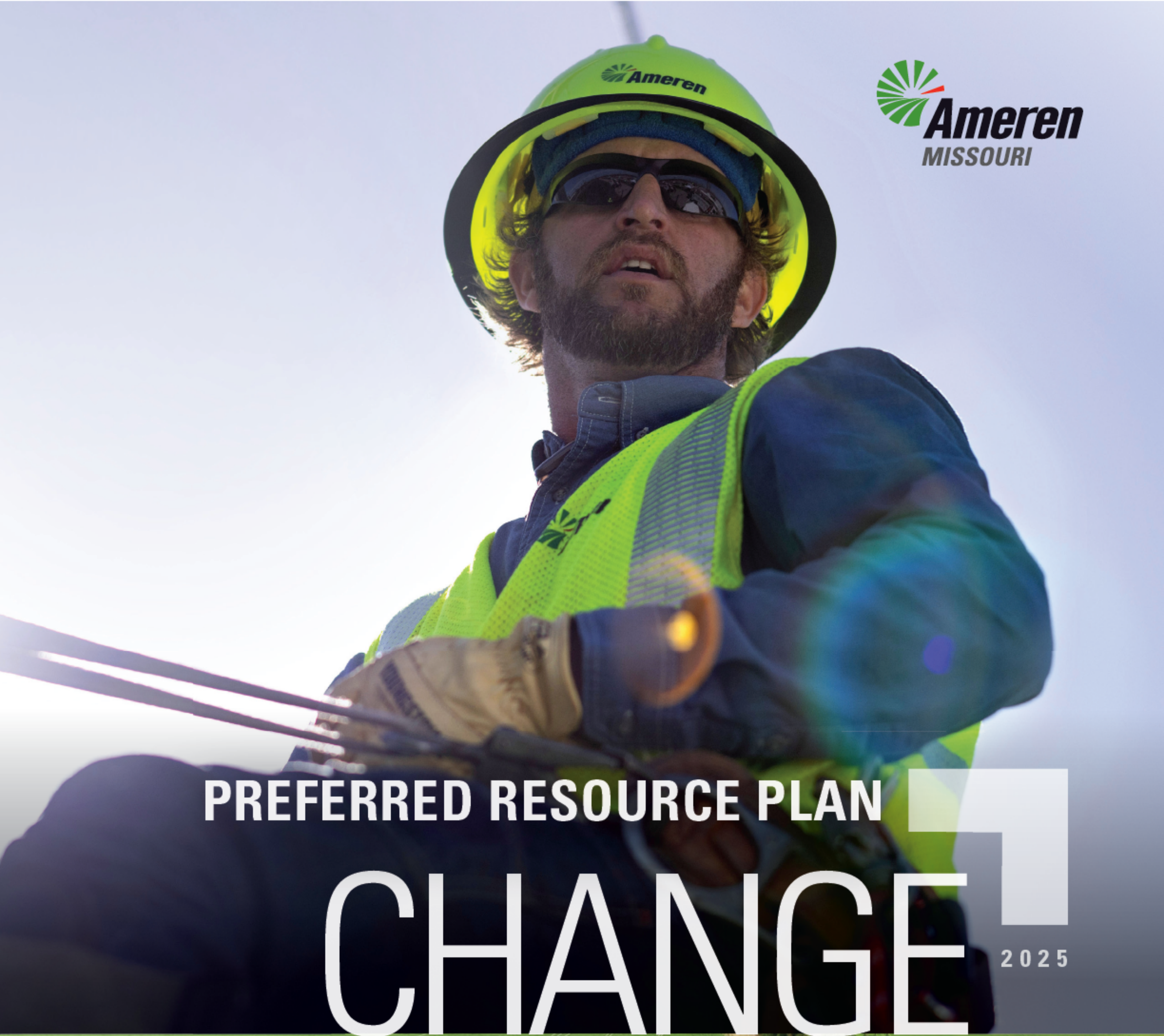
STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

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

My name is Matt 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 Michels
Matt Michels

Sworn to me this 24th day of July, 2026.



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:

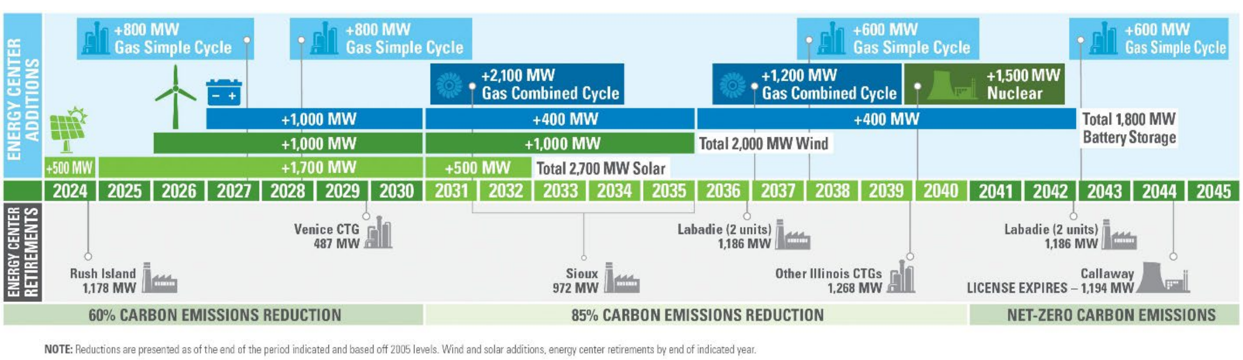
- Operate Energy Centers safely, economically, and in an environmentally responsible fashion while transitioning the generation fleet.
- Ensure overall energy (supply and grid) reliability and affordability.
- Create and capitalize on investment opportunities that are beneficial to customers, shareholders,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

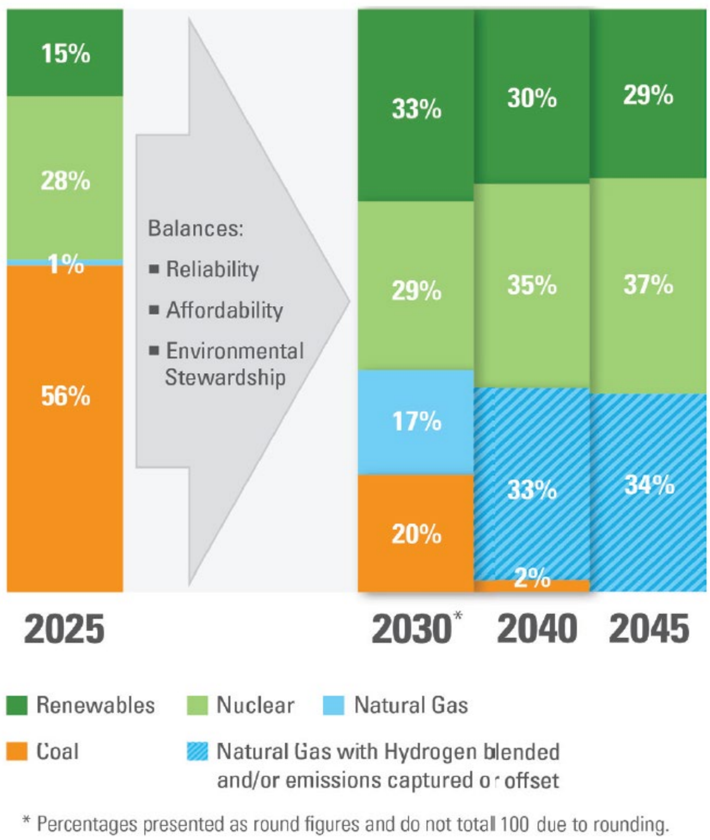
- 2,000 MW of wind generation by 2035 – This remains unchanged from the Company's 2023 PRP and includes 1,000 MW of wind by 2030 and another 1,000 MW by 2035.
- 1,800 MW of battery energy storage systems (BESS) by the end of 2042 – This includes 1,000 MW of BESS additions by 2030, another 400 MW by 2035, 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

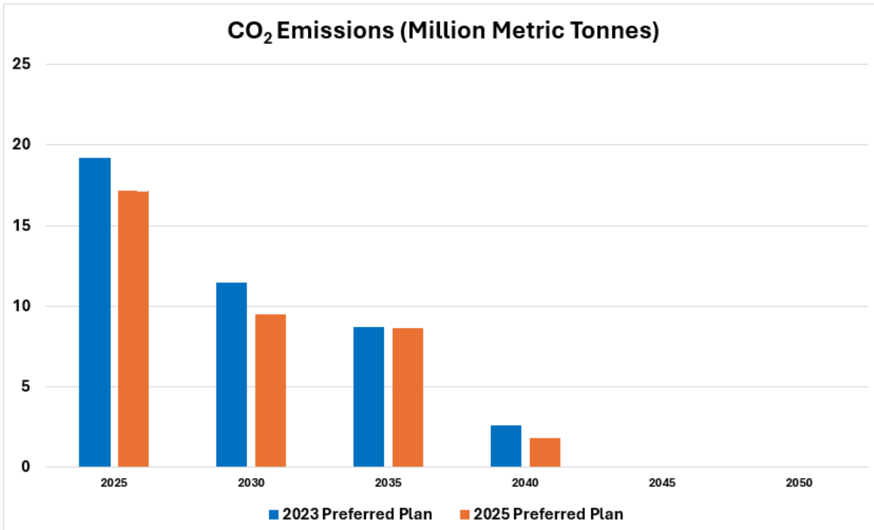
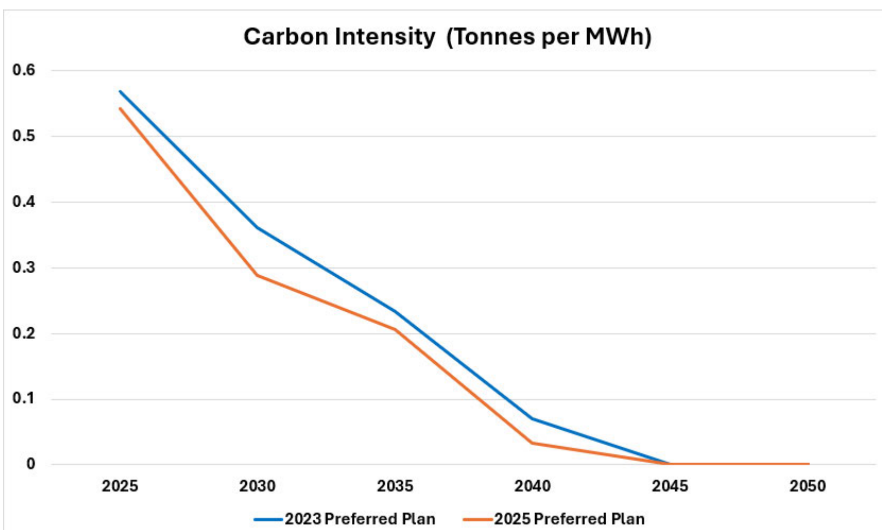


Figure 1.4: 2025 PRP Carbon Intensity Compared to 2023 PRP



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

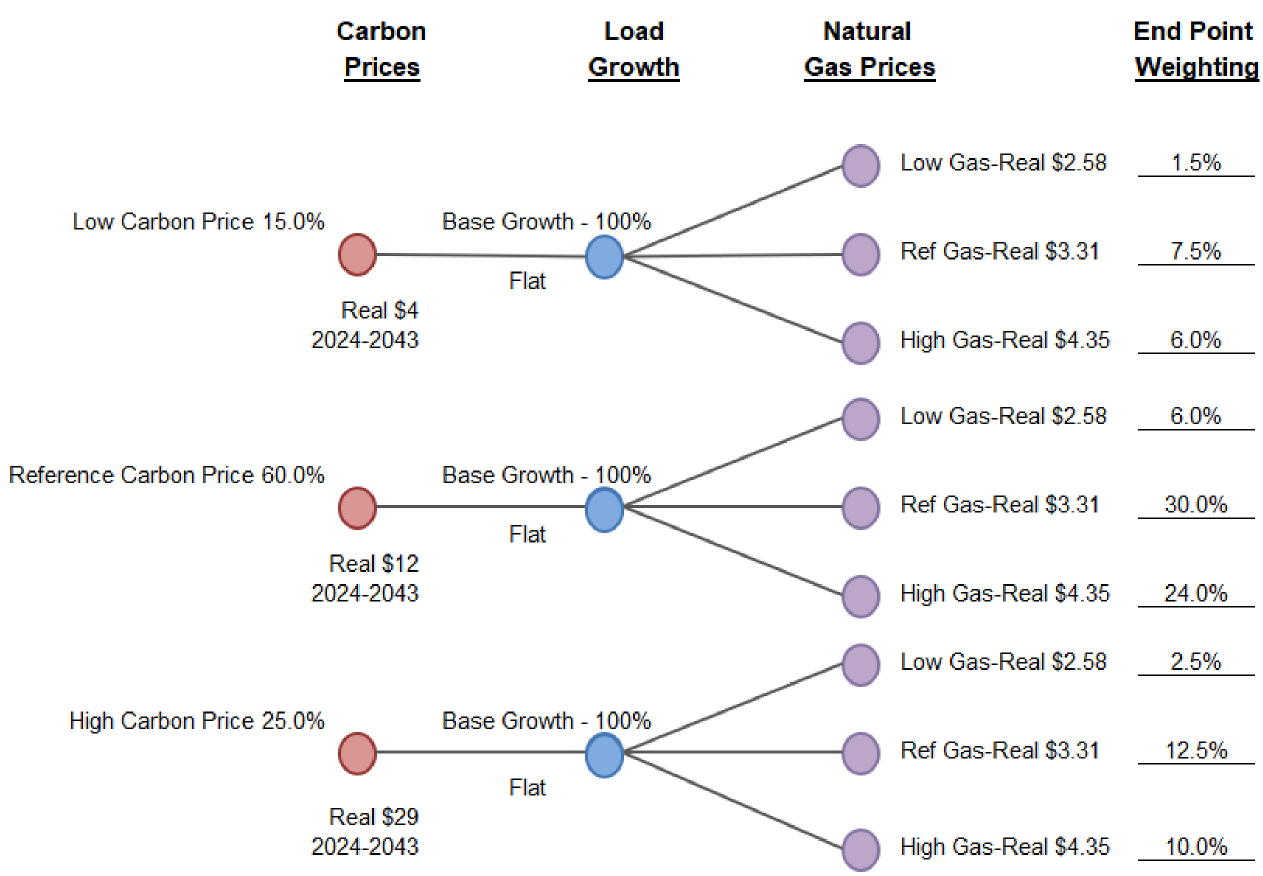
@ Transmission	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
GWh @Meter	180	230	281	332	383	419	465	510	549	573	579	605	632	658	653	659	657	648	651
Summer MW @Gen-EE	75	99	122	146	169	179	198	216	233	245	253	265	276	288	285	289	290	287	289
Summer MW @Gen-DR	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.

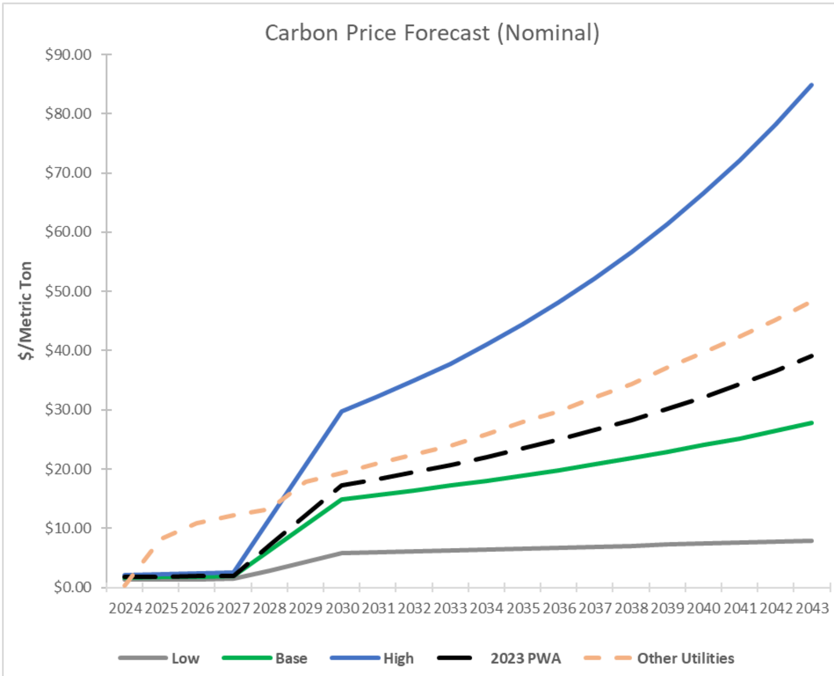
Figure 2.4: Scenario Tree



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]

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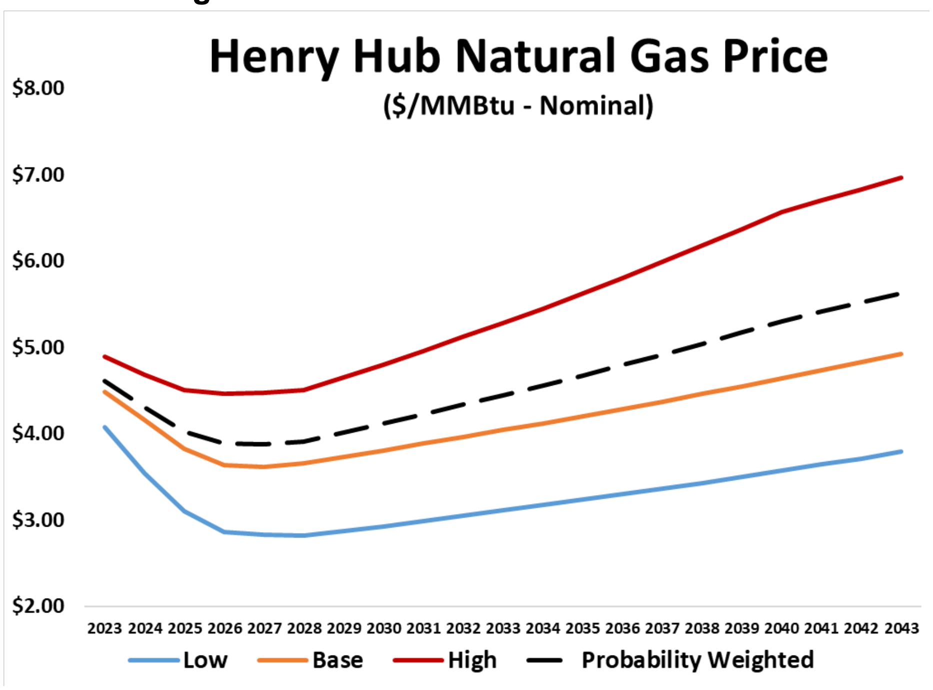
[3] File No. EO-2024-0020 Joint Filing, Resolution for NEE Deficiency 1

- 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.

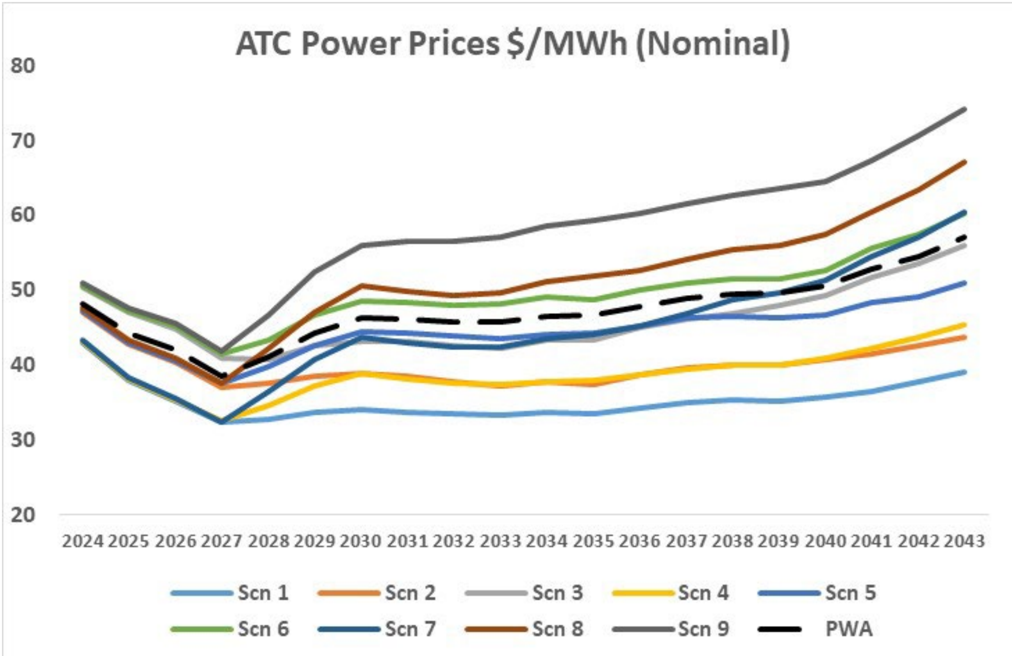
Figure 2.6: Natural Gas Price Forecasts



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

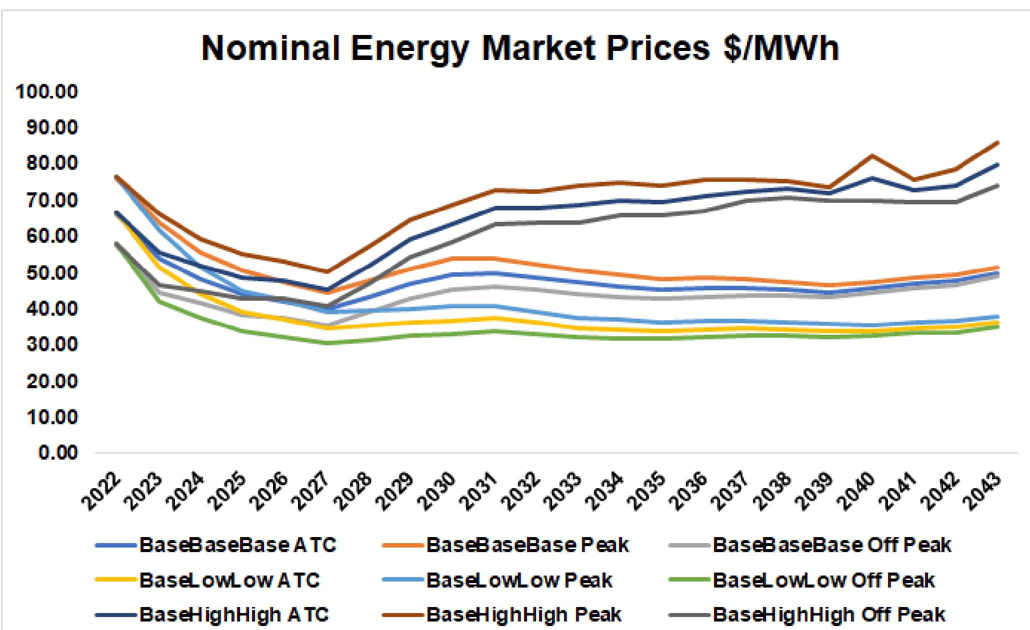


Figure 2.9: Market Capacity Prices for High Data Center Load Scenario

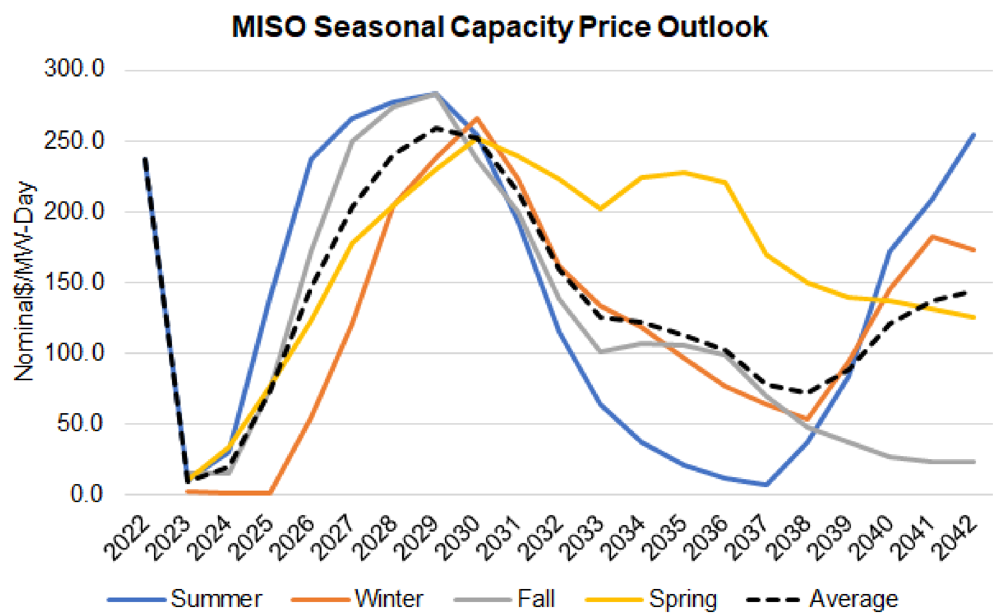


Figure 2.10: Market Capacity Prices for Middle Data Center Load Scenario

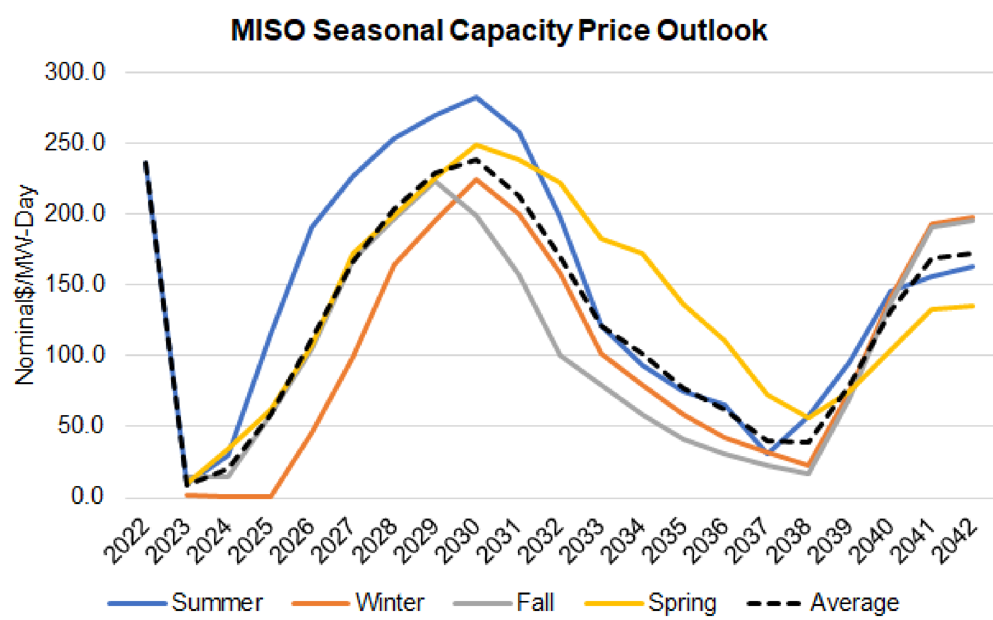
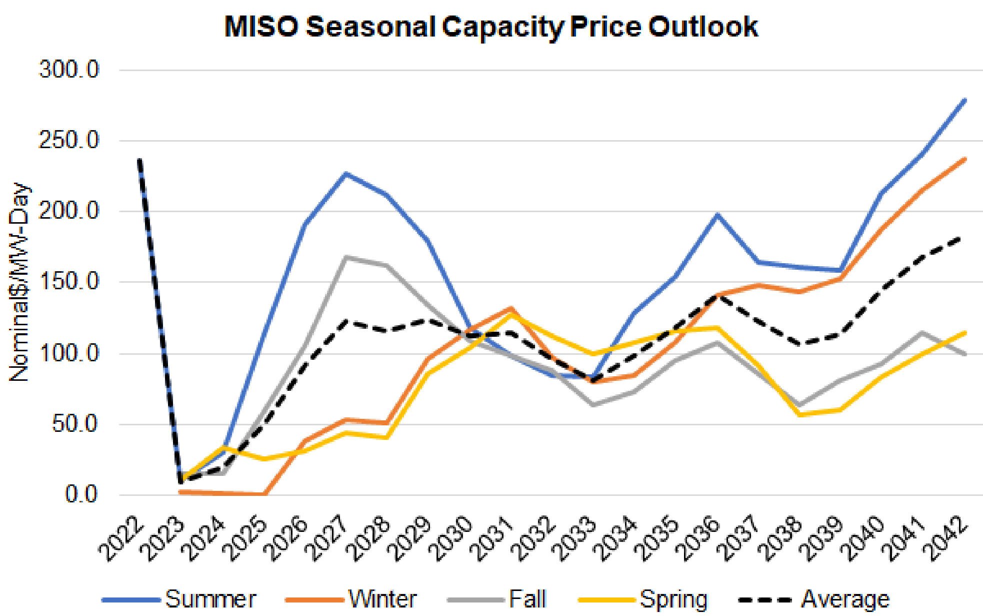


Figure 2.11: Market Capacity Prices for Low Data Center Load Scenario



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

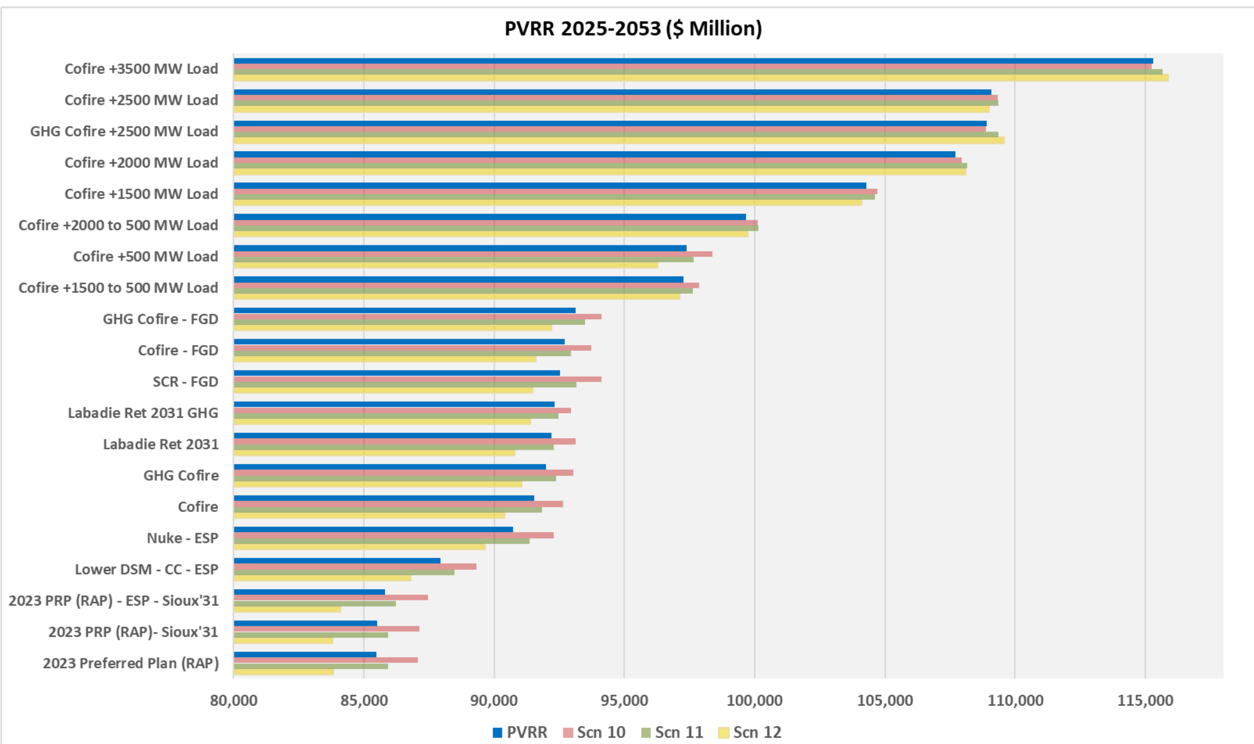
[4] Analysis of environmental compliance is included in this report in part to satisfy the commitment made by Ameren Missouri in its June 2024 Joint Filing in File No. EO-2024-0020.

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



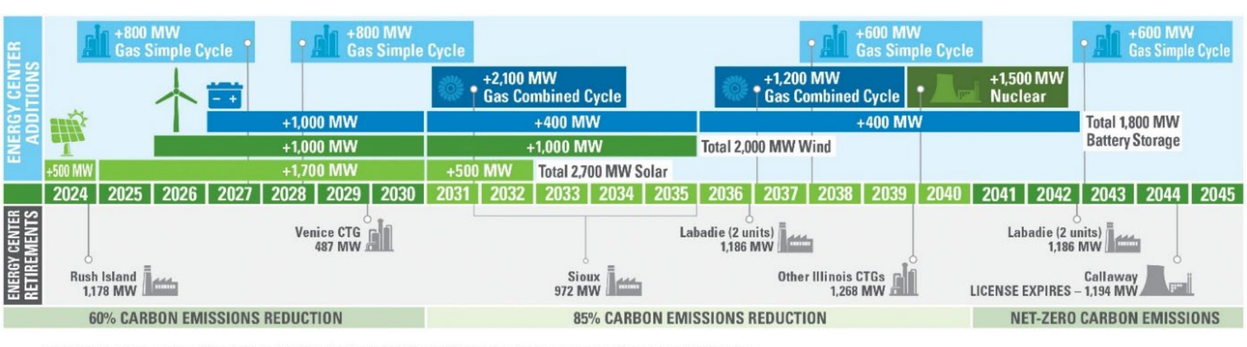
As the chart in Figure 3.1 shows, PVRR changes under some scenarios may slightly alter the order of some plans in the aggregate, but in only one case does the rank of an alternative plan change by more than one position, and this change does not affect the relative cost of relevant decisions regarding 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



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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