BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri 2023 Utility Resource Filing Pursuant to 20 CSR 4240-Chapter 22	))))	File No. EO-2024-0020

NATURAL RESOURCES DEFENSE COUNCIL'S COMMENTS ON AMEREN'S 2023 INTEGRATED RESOURCE PLAN

****PUBLIC VERSION****

Pursuant to 20 CSR 4240-22.080, Natural Resources Defense Council ("NRDC") respectfully submits these comments on the 2023 Integrated Resource Plan ("IRP") filed by Ameren Missouri ("Ameren" or the "Company"). NRDC respectfully requests that the Company agree to fix, or the Commission order the Company to fix in its 2024 IRP Annual Update, the deficiencies identified herein.

PUBLIC VERSION

Comments of Natural Resources Defense Council Ameren Missouri's 2023 Integrated Resource Plan Filing

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1 Summary

The Natural Resources Defense Council ("NRDC") engaged Energy Futures Group ("EFG") to review Ameren Missouri's 2023 Integrated Resource Plan ("IRP") filing. EFG is a clean energy consulting company focused on integrated resource planning as well as design, implementation, and evaluation of programs and policies to promote investments in efficiency, renewable energy, other distributed resources, and strategic electrification. EFG has performed IRP modeling and critically reviewed IRPs in over a dozen states, provinces, and territories. Our work in these jurisdictions involves either conducting our own simulations and/or reviewing modeling conducted using a wide variety of electric system modeling platforms including EnCompass, SERVM, Aurora, PLEXOS, PowerSIMM, PROSYM, System Optimizer, and Strategist.

The following sections discuss EFG's review of Ameren's 2023 IRP filing and how Ameren's IRP complies with Missouri's Chapter 22 requirements. Table 1 below provides a summary of our areas of concern and deficiency and the proposed remedy.

Table 1. Chapter 22 Deficiencies and Concerns for Ameren's IRP

Title	Deficiency or Concern	Chapter 22 Citation	Proposed Remedy
Policy Objective	Deficiency	20 CSR 4240-22.010 (2)(B)	1. Engage stakeholders in a collaborative process to select a model 2. Utilize capacity expansion and production cost modeling to ensure minimization of costs
Supply Side Resource Analysis (Costs)	Deficiency	20 CSR 4240-22.040 (1)	1. Increase base cost for combined cycle resources by at least 10% 2. Align probabilities for the high and low project costs with appropriate AACE cost estimates
Supply Side Resource Analysis (Evaluation of all resources)	Deficiency	20 CSR 4240-22.040 (1) and 20 CSR 4240-22.040 (4)	1. Evaluate the Grain Belt Express project alongside supply side resources 2. Ameren should work with project developers in a collaborative manner to ensure that all benefits from the Grain Belt

			Express project are reflected in the modeling.
Integrated Resource Plan and Risk Analysis	Deficiency	20 CSR 240-22.060 (1) and 20 CSR 240-22.060 (1)	1. Remove the color coding and arbitrary score weighting from the portfolio scorecard 2. Provide a qualitative discussion along with reporting measured metrics for each resource plan.

2 Ameren's 2023 Triennial IRP

2.1 Ameren's Preferred Plan

Table 2 below shows the differences between the Preferred Plan proposed by Ameren in this 2023 Triennial IRP filing and Ameren's Preferred Plan in its 2022 IRP Annual Update. The major differences between the two plans include a delay in coal retirements achieved by 2030, a shift in the addition of a 1,200 MW natural gas combined cycle ("NGCC") unit from 2031 to 2033, the addition of 800 MW of dispatchable peaking generation by the end of 2027, a shift in battery storage and renewable resource additions, and the addition of 1,200 MW of clean dispatchable[1] resources in 2040.

Table 2. Differences Between the 2022 Preferred Plan and the 2023 Preferred Plan[2]

Categories	2023 Preferred Plan	2022 Preferred Plan
Coal Retirements	*2,000 MW by 2030* 3,000 MW by 2035 5,400 MW by 2042	*3,000 MW by 2030* 3,000 MW by 2035 5,400 MW by 2042
Natural Gas Retirements	500 MW by 2030 1,800 MW by 2040	500 MW by 2030 1,800 MW by 2040
Natural Gas Additions	*1,200 MW 2033*	1,200 MW 2031
Dispatchable Peaking (Gas/Oil) Generation Additions	*800 MW 2027*	None
Renewable Additions	2,800 MW by 2030 *4,700 MW by 2036*	2,800 MW by 2030 4,300 MW by 2035 4,700 MW by 2040

[1] The clean dispatchable resources were modeled as an unspecified technology type.
[2] Ameren 2023 IRP Chapter 1 Executive Summary at page 6.

Battery Storage Additions	400 MW by 2030 800 MW by 2035	400 MW by 2035 800 MW by 2040
Other Clean Dispatchable Additions	*1,200 MW 2040* 2,400 MW by 2043	1,200 MW 2043

2.2 Ameren's Modeling Process

2.2.1 Capacity Expansion Modeling

Ameren's modeling approach was not typical of utilities of a similar size. Ameren developed fixed portfolios of new resource alternatives rather than allowing its model to economically select the resources in its portfolio. Its model only simulated the dispatch of those new resources in combination with existing units. The results of its production cost model, PowerSIMM,[3] are then combined with an internally developed financial model to incorporate the PowerSIMM outputs to develop the revenue requirements for each alternative resource plan.[4]

The drawback of this approach is that Ameren is creating portfolios without the benefit of a resource optimization modeling tool and therefore cannot as easily develop insights into the tradeoffs in changing the size, time, and type of resource builds or retirements. Using an optimization tool for capacity expansion planning allows the utility to leverage a model that can economically select resources to create an optimal mix of new resource additions (and retirements). Most of the models used by utilities can perform both capacity expansion modeling and 8760 hourly production cost runs on the portfolio. This is typically the approach we see utilities use for IRP modeling.

In addition, it is time consuming to construct portfolios by hand. It is challenging if not impossible to manually create a portfolio that is truly optimal. A significant amount of iteration would be needed to develop portfolios that can fairly evaluate the available resources. Third, developing portfolios in this manner can result in the loss of the ability to evaluate how certain inputs, such as a CO_2 or fuel price, may impact the selection of new resources or optimized retirement dates.

Moving to a capacity expansion model does not mean there is no value in including portfolios that are not the result of pure economic optimization since, for example, it is typically useful to compare significantly different portfolios under the same scenario conditions. But generally such portfolios are informed by first determining the economically optimized portfolio and then are developed from there. It would be extremely difficult to develop a similar set of portfolios based merely on the modeler's judgement.

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[3] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis at page 31.
[4] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis at page 31.

With regard to the modeling process used to develop the IRP, Ameren said:

> *We expect to continue our efforts to improve the efficiency, effectiveness, and transparency of our modeling tools into 2024. The nature and timing of any changes we make will largely be a function of our assessment of the currently available options. As we consider these options, we plan to share thoughts with other Missouri utilities and with our stakeholder group. This may or may not provide opportunities to move to a common modeling platform. Ameren Missouri will remain open to such an outcome while ensuring that its own tools and processes are able to support the Company's business needs and objectives*.[5]

Based on this statement, it appears that Ameren may be open to the idea of moving to a different modeling platform for future IRPs. However, in other parts of the IRP, Ameren also stated:

> *Ameren Missouri has used a modular approach to modeling for this IRP as it did in the 2017 and 2020 IRPs. Instead of using MIDAS or other off-the-shelf alternatives for integration and risk analyses, Ameren Missouri continues to use a combination of standalone models for 1) production costing, 2) market settlements, 3) revenue requirements, and 4) financial statements. Items 2-4 on this list are collectively referred to as the "Financial Model". This approach permitted analysts maximum flexibility, customization and trouble-shooting capabilities. It also lends itself to greater transparency for stakeholders by limiting the use of proprietary third-party software*."[6]

We agree with Ameren that transparency for stakeholders is important, but there is also value in moving to a single modeling platform that can consolidate Ameren's different modeling steps into one process will not sacrifice increased transparency for stakeholders. The key distinction is in the details of the model selected by Ameren. We have experience with many different modeling platforms and some provide more transparency than others. In order to ensure that transparency is a top priority item, it ought to be explicitly evaluated when Ameren considers a new model.

Due to the drawbacks of its current modeling approach, we recommend that Ameren emulate other jurisdictions that have used a collaborative process to determine which capacity expansion and production cost model to adopt. EFG has been a part of two collaborative processes – one in Minnesota and one with DTE Energy in Michigan. We discuss each in more detail in the following subsection.

[5] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis at pages 32-33.
[6] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis at page 31.

2.2.2 IRP Model Selection in Other Jurisdictions

When the Minnesota[7] utilities sought a model to replace Strategist and System Optimizer, which were being phased out, they decided to issue a Request for Information ("RFI") to solicit information from model vendors. Many stakeholders were also involved in this process, including the utilities, Commission Staff, the consumer advocate, and environmental intervenors. Stakeholders were not only able to provide input on the questions to ask and the models to evaluate, but also participated in the presentations by each model vendor and gave feedback on those presentations. Ultimately, the final model selected was up to each utility, but all four utilities decided to choose Anchor Power Solutions' EnCompass software.

Following its last IRP, DTE Electric conducted a modeling software collaborative that involved DTE Electric, Michigan Staff, stakeholders involved in DTE's IRP case, employees of Michigan utilities including Consumers Energy and Upper Peninsular Power Company, Xcel Energy, and a representative from Electric Power Research Institute ("EPRI"). DTE also sought to identify a new IRP model to replace Strategist. DTE hosted this collaborative as a technical stakeholder workshop over two days where all participants were able to learn about the potential models and ask questions. DTE started with nine software programs and narrowed them down to four and asked the vendors for those four programs to give presentations so that stakeholders could learn more about each software. DTE developed 33 ideal model attributes grouped into five categories including model capabilities, model transparency, functionality, value and IRP process efficiency, and "nice to have". These criteria are outlined in Table 3, below.

Table 3. DTE Evaluation Criteria for Software Consideration[8]

Model Capabilities
1. Ability to optimize to emission limits
2. Capable of optimizing a broad range of retirement dates
3. Captures accurate long-term costs of different lived alternatives
4. Accepts a non-linear escalation rate and negative escalation rates
5. Chronological model instead of using a load duration curve simplification for better renewable and storage modeling
6. Storage logic can handle more than once a day charging and discharging as well as long term storage modeling over weeks, seasons
7. Ability to tie storage charging to a specific technology
8. Ability to model ancillary service markets and assign benefits to specific technologies
9. Ability to accurately model economic reserve shutdowns (start-up cost, min down time, run time)
Model Transparency

[7] Minnesota utilities including Xcel Energy, Minnesota Power, Otter Tail Power, and Great River Energy.
[8] MPSC Case No. U-20471. DTE Electric Company's Integrated Resource Plan Modeling Software Collaborative Summary Report, page 28 – 29.

10 .Availability of manual to stakeholders (without a license preferred)
11. Provide transparency into modeling; access to software inputs, outputs (without a license preferred)
12. Licenses available at reasonable cost
Functionality
13. Ability to change the granularity (down to sub-hourly resolutions) and type of commitment logic depending on purpose of run (build plan generation or detailed dispatch)
14. Ability to run stochastics or other risk analysis on different types of runs including retirement analysis
15. Ability to coordinate the IRP modeling with the Distribution Operations long-term plan
16. Ability to optimize fuel blending
17. Specific storage technology properties such as degradation, storage level
18. Ability to design a simpler, more transparent, yet still robust approach to IRP modeling by reducing the number of software programs
19. Market Price forecasting
Value and IRP Process Efficiency
20. Best value of the cost over entire lifecycle, for DTE and stakeholders
21. Intuitive interface making it easy to transition from current model
22. Dedicated software support
23. Reasonable model run time
24. Additional server not preferred
25. Large user base
Nice to Have
26. Data visualization within the software
27. Straightforward error checking (messaging or other notification)
28. Program that may also work for other DTE modeling groups (e.g. Gen Ops)
29. Uncomplicated data import capabilities
30. Automatic reporting
31. Ability to track who makes the change to a database
32. Batch Running, ability to use macros and scripts
33. Easy exporting of input and outputs with no use of text files

Based on a recommendation from EFG, the South Carolina Public Service Commission directed Dominion Energy South Carolina to emphasize criteria 1 – 7 and 9 – 12 in choosing a new IRP model. We think this is an appropriate prioritization of criteria, particularly with respect to transparency, given that the purpose of IRP (and related) modeling is to demonstrate that the utility's plan is in ratepayers' best interest. We strongly recommend all these criteria because they address not just important factors such as transparency, but also factors critical to the functionality of the model such as usability, granularity, error checking, and other critical functions of an IRP model.

In addition, a number of jurisdictions including South Carolina, Arizona, New Mexico, and others have adopted requirements that allow stakeholders to be given access to an executable modeling license and be able to request all modeling files including model settings, access the model manual, and even execute modeling runs using the same platform as the utility. This access bolsters the case record and brings greater scrutiny to the analytical work that underpins IRPs.

We recommend that Ameren utilize a collaborative approach such as the one employed by the Minnesota utilities and DTE to evaluate potential IRP model candidates. In the report that DTE issued on its collaborative, DTE stated that "DTE Electric, Software suppliers, and Michigan stakeholders had an open robust dialogue that will inform our final selection of a new IRP modeling software."[9] We believe that the kind of open and robust dialogue that was able to take place in the DTE software collaborative would also benefit Ameren's evaluation of a new IRP model that would be able to perform both capacity expansion and production cost modeling.

2.3 Determining the Optimal Combination of Renewable and Battery Storage Resource Additions

One of the main benefits of utilizing a capacity expansion model is the ability to generate optimal resource portfolios. With Ameren's current process for developing new resource additions for portfolios, fixed builds are assumed across several different scenarios for the renewable resources and two fixed build pathways for battery storage resources. [10] Table 4 and Table 5 below show the annual additions for renewables and battery storage resources, respectively. With this approach, one cannot be sure that the synergistic benefit between renewables and battery storage resources is captured through the process of hand developing fixed portfolios. Utilizing a capacity expansion model provides more opportunities to evaluate and capture the interplay between renewable and battery storage resources.

[9] MPSC Case No. U-20471. DTE Electric Company's Integrated Resource Plan Modeling Software Collaborative Summary Report, page 4.
[10] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis at page 8.

Table 4. Annual Solar and Wind Additions (Nameplate Capacity)[11]

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

Table 5. Annual Battery Storage Additions (Nameplate Capacity)[12]

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

2.4 Important Considerations Capacity Expansion Modeling

With a movement to a capacity expansion model, there also comes the need for consideration of some of the key inputs to the model which may not be captured when portfolios are developed by hand. For instance, one of the most important inputs into a capacity expansion model are resource build limits. Capacity expansion modeling can be performed without any build limits in the model to develop a true optimized portfolio. However, build limits can be used to specify when a resource is first available for selection, the number of megawatts that can be added for a specific resource each year, or a total cumulative build limit across the entire planning period. These assumptions become critical for capacity expansion modeling and will be important for Ameren to discuss with stakeholders, especially if Ameren moves to a capacity expansion modeling approach.

[11] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis, Table 9.2 at page 8.
[12] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis, Table 9.3 at page 8.

3 New Thermal Resources

3.1 New Thermal Resource Capital Costs

Ameren used the average of four data sources, EIA, NREL, EPRI, and Lazard to produce its gas thermal capital cost estimates. These four sources appear to represent a mix of F-class and advanced class (H/J) turbines so may not accurately reflect the price separation that appears to exist between these turbine types. But more importantly, one of the primary challenges of estimating thermal capital costs is, as has occurred for other supply-side technologies, the magnitude of the impact in cost due to worldwide demand for gas turbines, competition for the specialized engineering and labor needed to build these facilities, and increasing costs for balance of plant materials such as transformers. The approach that Ameren uses misses the dynamic nature of the current market for turbines and related infrastructure because it relies on historical information rather than anticipating price increases. Indeed, Ameren anticipates that combined cycle costs will continue to fall in real terms as shown in Figure 1.

CONFIDENTIAL INFORMATION REMOVED

Confidential Figure 1. **CONFIDENTIAL INFORMATION REMOVED**

Since the start of the pandemic, there have been very few new combined cycle projects that have come far enough along in development to have produced more than a screening level cost estimate. One exception that is of a similar size as was assumed by Ameren – Entergy's 1,215 MW Orange County Advanced Power Station (OCAPS). As of October 2022, the estimated cost of that facility (excluding hydrogen co-firing capability) was $1,419,160,000 or about $1,168 per kW in 2026 nominal dollars. This is almost identical to Ameren's assumption of $1,161 per kW in 2026 nominal dollars.

In its most recent filing on cost escalation to the Public Utilities Commission of Texas on the cost of OCAPS, Entergy stated:[13]

> *…[Entergy Texas, Inc. ("ETI")] reports price increases of 91% for steel; 54% for aluminum; 35% for copper; and 69% for nickel over the period June 2020 to September 2022. In addition, prices for major components to be included in the OCAPS project, including the combustion turbines, steam turbine, and HRSGs, have experienced escalation of approximately 31%...*
> *Given the current market conditions, federal fiscal policy, and geopolitical climate, ETI and the EPC Consortium expect that the currently elevated materials and major component prices will continue to increase and adversely affect the total cost of OCAPS…*

While balance of plant related costs have tempered somewhat, EFG still sees significant competition for turbines, engineering services, and labor which have led to project delays and cost increases. This dynamic particularly affects turbines with in-service dates before 2030, but there is no reason that turbines with in-service dates after 2030 should be assumed to be immune to these dynamics.

Finally, Ameren's combustion turbine costs also appear to be understated. While the capital cost appears to be benchmarked to an over 1,000 MW plant, in most plans, only 800 MW of SC capacity is added in any one year.

We would recommend increasing the base starting CC cost by at least 10% and aligning the probabilities with the appropriate Association for the Advancement of Cost Engineering (AACE) class estimate, likely at a Class 5, with a low-end range of -20% to -50% and a high-end range of +30 - +100%.

3.2 Carbon Capture and Sequestration ("CCS")

Ameren reported that CCS with a 98.5% capture rate was assumed for any CC assumed to come online in 2035 or after and that any CC put in service prior to 2035 is retrofitted for CCS by 2040. [14] However, this was not the assumption applied to the CC that comes online in 2032 after the retirement of Sioux, which is the first CC added in Ameren's Preferred Plan. Ameren stated:

> *Any CC added on or after 2035 include CCS, and CCs that go into service prior to 2035 with the exception of CC added right after Sioux retirement do get retrofitted with a CCS*

[13] Entergy Texas, Inc. Fourth Periodic Report on Mkt. Escalation at 2-3, Pub. Util. Comm'n of Tex. Docket No. 52487 (October 7, 20022), https://interchange.puc.texas.gov/Documents/52487_487_1244409.PDF
[14] Ameren response to Sierra Club 1.7(c)(i).

in 2040. The CC that is placed into service upon Sioux retirement is assumed to have its CO2 emissions eliminated beginning in 2040. This may be achieved through some combination of alternative fuels (e.g., hydrogen, renewable natural gas), carbon capture and sequestration, purchased offsets, or reduced operation. Because of the uncertainty regarding the eventual method used to mitigate carbon emissions, the higher variable and fixed operating and maintenance (O&M) costs for CC with CCS are included with no major capital expenditures for CCS. Plan V adds the capital cost of CCS as well to indicate the change in cost for including this capital expenditure. Ameren Missouri assumed that the incentives in the IRA will help green hydrogen and CCS projects become commercially available by 2040.[15]

This is an important distinction that Ameren has made for the CC in the Preferred Plan as Ameren reported that the capital cost to retrofit a CC with CCS will be around $1.63 billion.[16] When comparing the PVRR of the Preferred Plan (Plan 4 or "RAP – Renewable Expansion") of $**_____** to the PVRR[17] of the Preferred Plan with the CC assuming CCS (Plan 23 or "CCS on 1st CC") the PVRR is $**_____**, which is an increase of approximately $**___** million dollars. Omitting this cost indubitably makes the portfolio that includes this early CC look more cost-effective and overlooks a very significant risk. This additional cost should be included in Ameren's Preferred Plan for the new 1,200 MW CC that comes online after Sioux is retired.

3.3 Simple Cycle ("SC") Additions in 2028

Each alternative resource plan modeled by Ameren assumed the addition of 800 MW of SC at the end of 2027. Ameren stated that the 800 MW of SCs is needed for reliability. [18] However, it is not clear what specific reliability need the SCs are being added to address. In addition, it is also not clear if the potential addition of oil backup at Audrain would be able to offset some of the new SC capacity. In the IRP Ameren reported that oil backup was being considered at Audrain and that it could add over 300 MW of winter capacity.[19] Ameren did assume in its modeling that oil backup was restored at Peno Creek and Kinmundy Energy Centers[20], but oil backup was not assumed for Audrain in the 2023 IRP. [21]

Ameren should perform an economic analysis to evaluate the costs of pursuing oil backup at Audrain and the potential to offset some of the 800 MW of SC that Ameren is stating are needed at the end of 2027 across each resource plan.

[15] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis at page 15.
[16] Ameren response to Sierra Club 1.7(d)(i). The cost assumption is based on a 100 mile pipeline being needed to transport the captured CO_2 to be stored at a storage facility.
[17] Reported PVRR of the Integrated Analysis. Ameren workpaper "PVRR 08-21-23Confidential".
[18] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis at page 15.
[19] Ameren 2023 IRP Chapter 4 Existing Supply Side Resources at page 15.
[20] Ameren 2023 IRP Chapter 4 Existing Supply Side Resources at page 15.
[21] Ameren response to NRDC 1.6.

4 Grain Belt Express

As part of Ameren's 2020 Triennial IRP filing, the Grain Belt Express ("GBE") project was included as a candidate resource option (included in Plan Y).[22] As part of the 2020 Triennial IRP process, Clean Grid Alliance issued an alleged deficiency related to the evaluation of GBE. It appears that the resolution reached between Ameren and Clean Grid Alliance for this deficiency was:

> *Parties agree that Ameren Missouri makes generic assumptions in its IRP and rarely does it model specific projects, such as what it did for Plan Y. Moreover, the determination that Plan Y is neither the Preferred nor Contingent Resource Plan in this IRP does not prevent Ameren Missouri from considering it as a potential supply-side resource in future IRPs or in future transaction structures*.[23]

In response to discovery questions on the exclusion of GBE, Ameren indicated that generic resources were studied in the IRP per the IRP rules.[24] However, Ameren is clearing considering other site specific resources such as gas replacement at its Sioux and Labadie sites. And based on the resolution reached in the 2020 IRP Triennial filing, it is not clear why GBE has not continued to be evaluated as part of the IRP process. One of the items that Ameren highlighted with regard to reliability and resiliency is a portfolio of geographically diverse renewable resources. As Ameren stated in the IRP:

> *Another important factor to ensure long-term system reliability and resiliency is to pursue a geographically diverse portfolio of renewable energy resources to ensure energy is always available to meet our customers' needs, even during peak energy time periods. Since solar and wind generation are dependent on weather conditions which vary by geographical location, a regionally diverse renewable resource portfolio will be more reliable under varying weather conditions.*[25]

The GBE project should be evaluated by Ameren to determine if there are benefits related to the project that cannot be captured through the modeling of generic candidate resources such as the diversity benefits offered from renewable resources located in geographic regions with higher capacity factors.

5 Transmission

Ameren conducted several transmission planning scenarios evaluating different combinations of retirements at Sioux, Venice, and Labadie and replacement with a 600 MW NGCC and/or

[22] Ameren response to MECG 1.3.
[23] Ameren Missouri 2020 IRP. File No. EO-2021-0021. Joint Filing Attachment A at page 4.
[24] Ameren response to Grain Belt 1.2.
[25] Ameren 2023 IRP Chapter 10 Strategy Selection at page 18.

battery additions. Battery installations at any one site did not exceed 200 MW despite the fact that Ameren has completed a review of the amount of battery storage that could be sited at the Meramec and Rush Island sites and found that a maximum of about 1,000 MW of storage could be located at each site.[26]

Furthermore, in no scenario, did Ameren examine whether other combinations of resource at sizes similar to the existing capacity could avoid transmission improvement costs. This despite the fact that its own transmission study concluded that adding batteries to the sites of retiring coal plants has the ability to reduce transmission costs as shown in Confidential Table 6.

Confidential Table 6. **CONFIDENTIAL INFORMATION REMOVED[27]**

CONFIDENTIAL INFORMATION REMOVED

6 Modeling Coal Retirements and Securitization

In the 2022 Change in the Preferred Plan, Ameren said, "The Company expects to file an application with the MPSC to securitize the remaining balance for the Rush Island Energy Center and other appropriate energy transaction costs in the second half of 2023."[28] Since Ameren intends to use securitization to facilitate the retirement of the Rush Island Energy Center, Ameren should also be evaluating securitization benefits when evaluating alternative resource plans that include different early retirement for the Sioux[29] and Labadie[30] coal plants. Evaluating the impact of securitization will be especially important around the retirement of Labadie given the potential environmental costs of $697 million to install selective non-catalytic reduction ("SCR") systems at Labadie in 2027 to meet the Cross States Air Pollution Rule ("CSAPR") regulation.[31]

[26] Ameren 2023 IRP Chapter 10 Appendix, Table 10D.1 at page 5.
[27] Taken from Ameren's workpaper, "Transmission cash flows 2023IRP-rev1".
[28] Ameren 2022 Change in the Preferred Plan, page 7.
[29] In this IRP filing, Ameren modeled retirement dates of 2028, 2030, and 2032 as alternative resource plans for Sioux.
[30] In this IRP filing, Ameren modeled retirement dates of 2031, 2036, and 2039 as alternative resource plans for Labadie.
[31] Ameren 2023 IRP Chapter 5 Environmental Compliance, Table 5.2 at page 21.

7 Selection of Preferred Plan

7.1 Ameren Scorecard and Top Tier Comparison

Table 7 shows the planning objectives that Ameren uses to evaluate the alternative resource plans and the associated weight assigned to each planning objective and measure.

Table 7. Ameren's Planning Objectives and Measures[32]

Planning Objective Categories	Measures	Weighting
Cost	Present Value of Revenue Requirements	30%
Customer Satisfaction	Customer Preferences, Levelized Rates	20%
Portfolio Transition	Resource Diversity, CO_2 Emissions, Probable Environmental Costs	20%
Financial/Regulatory	Free Cash Flow, Financial Ratios, Stranded Cost Risk, Transaction Risk, Cost Recovery Risk	20%
Economic Development	Direct Job Growth (FTE-years)	10%

Based on the information presented in the IRP, the cost objective is based on the scoring of the PVRRs from a scale of 1 to 5, with the highest group of costs receiving a score of 1 and the lowest group of costs receiving a score of 5. The customer satisfaction objective is scored with a similar approach, but additional points will be added to plans that include DSM, early retirement of coal generation, and include the addition of significant renewable resources. The portfolio transition objective is based on the number of points awarded for increased resource diversity and/or environmental impact of reduction in emissions. Points are based on the inclusion of DSM, addition of nuclear generation, early retirement of coal generation (1 point per 2 large units), the addition of significant renewables, displacement of fossil resources with additional storage and/or renewables, and the addition of low-emission efficient gas generation. The financial/regulatory objective measures are scored with a default score of 5 and then points are deducted for risks and financial impacts. Point reductions include lack of DSM programs above what has already been approved, nuclear construction, financing, and operating risks, risks associated with a heavy concentration of gas-fired generation, and risks associated with recovery of coal-fired generation investment. The economic development objective is measured based on a score for direct job creation where jobs were translated into full-time ("FTE") equivalent years and then ranked based on the FTE years.

[32] Ameren 2023 IRP Chapter 10 Strategy Selection, Table 10.1 at page 4.

Once the scores have been determined for each resource plan, all the plans are compared from highest to lowest scores. Table 8 below shows Ameren's Scorecard with the overall assessment for each resource plan across the planning objectives.

Planning Objectives, Weights and Measures							
	Category	Environmental/ Renewable/ Resource Diversity	Financial/ Regulatory	Customer Satisfaction	Economic Development	Cost	Overall Assessment
	Category Weight	20%	20%	20%	10%	30%	100%
Plan	Description	Resource Diversity	PV Free Cash Flow	Rate Increases	Net Job Growth (FTE-years)	PVRR	
O	Labadie 2039	4	5	5	4	4	4.40
L	Pumped Hydro w/ MAP LF	4	4	4	4	5	4.30
B	Sioux Retired 2028	4	4	5	4	4	4.20
M	SC	3	4	4	3	5	4.00
P	Labadie 2036	4	5	4	4	3	3.90
A	Sioux Retired 2030	3	4	4	4	4	3.80
C	RAP - Renewable Expansion	3	4	4	4	4	3.80
R	RAP LF	3	4	4	4	4	3.80
H	MAP LF-RES Compliance	3	4	3	5	4	3.70
T	All Renewables	3	2	4	4	5	3.70
Q	Labadie 2031	5	5	4	3	2	3.70
D	Labadie SCR	3	4	4	4	3	3.50
U	SC instead of First CC	2	4	4	3	4	3.50
K	Renewables for Capacity Need	3	4	3	4	3	3.30
V	CCS on 1st CC	3	4	3	4	3	3.30
E	MAP	3	4	2	5	3	3.20
S	MAP LF	3	4	2	5	3	3.20
W	RAP 80%	3	2	4	4	2	2.80
N	SMR w/ RAP LF	4	2	2	4	2	2.60
F	RAP-RES Compliance	2	3	2	3	2	2.30
G	MAP-RES Compliance	2	3	1	5	2	2.30
I	No Additional DSM	2	1	3	2	1	1.70
J	No Additional DSM-RES Compliance	1	2	2	1	1	1.40

Table 8. Ameren 2023 IRP Scorecard[33]

Based on the overall assessment score, Ameren then passes the plans with the highest score into the comparison of the "Top Tier Plans" where the plans are compared based on whether one has a relative advantage or disadvantage. From this process, Ameren selected Plan C as the Preferred Plan. Table 9 below shows Ameren's comparison of the Top Tier Plans.

Table 9. Comparison of Top Tier Plans[34]

[33] Ameren 2023 IRP Chapter 10 Appendix A Alternative Plans Preliminary Scorecard at page 1.

[34] Ameren 2023 IRP Chapter 10 Strategy Selection, Figure 10.20 at page 42.

7.2 Recommendations on the Scorecard and Top Tier Comparison

While we recognize the potential utility of using a scorecard to evaluate and compare resource plans against one another, we have concerns about the process used by Ameren. As Northern Indiana Public Service Company ("NIPSCO") stated in its 2021 IRP, "The scorecard is a means of reporting key metrics for different portfolio options to transparently review tradeoffs and relative performance. It does not produce a single score or ranking of portfolios, but serves as a tool to facilitate decision-making."[35] This is in contrast to Ameren's approach which includes subjective color coding and weighting in addition to a lack of transparency around assigning or taking away points based on the metric being evaluated. We discuss our concerns in more detail below.

First, the color coding that Ameren uses is arbitrary. For example, the color shading of green, yellow, and red shown in the table in Figure 3 would lead the reader to come to the conclusion that green is significantly better than yellow which is significantly better than red. However, the "green" plans have a composite score that ranges from 3.80 – 4.40 while the "yellow" plans have a composite score range that is much narrower of 3.30 – 3.70 and the "red" plans have the largest range of 1.40 – 3.20. Those ranges are completely arbitrary even if one accepts that each plan is appropriately measured on a 1 – 5 scale. One could easily create a different set of ranges that are evenly spread out that would move more plans to the top, green tier including the "All Renewables" plan. Because color coding is so highly subjective, we recommend that Ameren remove all color coding in its scorecard analysis. Instead, Ameren should present the

[35] NIPSCO 2021 IRP at page 16.

results of each metric to allow for each resource plan to be compared to one another across each metric evaluated.

Second, it is not clear how Ameren determined the weights assigned to each planning objective/metric. This is important because these weights are inputs into the development of the overall assessment score that Ameren then uses to determine which resource plans are then passed onto the Top Tier Comparison. Ameren's weights mean that Cost is only as important as the combination of Economic Development and Customer Satisfaction – despite Ameren's obligation to provide least cost/least risk service, no rationale for this assumption is given. We recommend that Ameren not use a weighting approach. Instead, Ameren should report the absolute value of each metric for each resource plan and use a qualitative discussion in conjunction with the data from the metrics to compare and contrast resource plans to one another.

Third, Ameren's assignment or deduction of points for the different planning objectives is not transparent and is arbitrary. For instance, in Ameren's workpapers for the scorecard analysis, the "All Renewables" plan received a point deduction for a category called "Reliability Recovery Risk" in the Financial/Regulatory objective. The "All Renewables" Plan was the only plan to have a point deducted for this category and it is not clear what the definition for this category was or how Ameren determined that the plan should have a point deducted. The Financial/Regulatory objective also had a metric called "High Gas Generation Concentration" which seemed to deduct a point for plans that had more than one CC addition. Again, it is not clear how Ameren determined the distinction between having one or more CC in a plan. It would be more transparent for Ameren to have a specific metric, such as the percentage of generation from a CC compared to the generation from the total fleet of resources as a way to compare plans and to report that absolute value so that the reader can also determine if it's material. Ranking 1 through 5 or color coding do not convey whether gas generation is 15 or 50% of your portfolio. The diversity measure for the Environmental/Renewable/Diversity objective is also unclear. This measure is based on adding points if the resource plan includes any level of DSM, new nuclear generation, accelerated coal retirements, renewables above the RES Compliance levels, and what Ameren calls "efficient gas generation". This measure is very broad and seemingly applies to any action that changes the status quo portfolio, which makes it is hard to discern the meaning of assigning it to the portfolios. It would be more transparent for Ameren to have metrics broken out to account for the different aspects of the Environmental/Renewable/Diversity objective. For example, metrics like cumulative carbon emissions for each resource plan, the percent of renewable generation compared to the total fleet generation, and the number of unique generators would provide better data points for how the resource plans compare on the different items contained in this objective.

In order to provide more transparency around the metrics and comparison of plans, we recommend that Ameren report the absolute values of the metrics that support each performance objective. We recognize that IRP Rule 2.40-22.060(2)(A) identifies metrics to calculate, however, we recommend that Ameren include the following metrics for future IRP filings as shown in Table 10.

Table 10. Recommended Metrics for Comparing Resource Plans

Objective	Description and Metrics	Metrics
Cost/Customer Satisfaction	Impact to Customer Bills	1. NPV of PVRR 2. Levelized rates
Cost/Customer Satisfaction	Measure the risk of different resource plan options to customers associated with fuel price volatility	1. Total energy generation from coal and gas divided by total fleet generation
Portfolio Transition/ Environmental/Renewable/Diversity	Carbon intensity of resource plan	1. Cumulative carbon emissions[36]
Portfolio Transition/ Environmental/Renewable/Diversity	Percent generation from renewable resources	1. Renewable energy generation divided by total generation
Portfolio Transition/ Environmental/Renewable/Diversity	Resource diversity	1. Number of unique generators 2. Number of unique fuel types 3. Number of unique renewable resources in different regions
Economic Development	Total amount of property taxes paid from generation assets and the number of jobs created by investment in supply side and DSM resources	1. NPV of property taxes from the entire resource plan 2. Direct job growth from supply side and DSM resources

Our recommendation to Ameren is to remove metrics from scorecard if they cannot be summarized in a single point value and to discuss each metric qualitatively, with supplemented information about the quantitative data that captures the objective of the metric. It is more informative for Ameren to discuss how it balances the tradeoffs of portfolios than to simply color code plans.

[36] Can also include other missions such as SO_2 or NOx or other important environmental impacts to measure such as water usage.

7.3 Comparison to the "All Renewables" Portfolio

Based on the resource plans included in the Top Tier, the "All Renewables" plan had an overall score of 3.7, which falls slightly short of the 3.8 cutoff of where Ameren drew the line for the plans to be included to move to the Top Tier comparison. Table 11 below shows the Present Value of Revenue Requirements ("PVRR") comparison for the seven plans with the lowest PVRR from the Integrated Analysis step, which shows the PVRR from the most likely scenario of the uncertainty factor probability tree. The column labeled as Risk Analysis, shows the resulting PVRR from the Risk Analysis step where the consideration of all the uncertain critical factors (Load, Carbon Price, Natural Gas Price, Project Cost) is included in the PVRR.

Confidential Table 11. **CONFIDENTIAL INFORMATION REMOVED[37]**

Resource Plan	Integrated Analysis PVRR[38]	Risk Analysis PVRR[39]
SC	$**_____**	$**_____**
All Renewables	$**_____**	$**_____**
Pumped Hydro with MAP LF	$**_____**	$**_____**
MAP LF-RES Compliance	$**_____**	$**_____**
SC Instead of First CC	$**_____**	$**_____**
Sioux Retired 2028	$**_____**	$**_____**
RAP – Renewable Expansion[40]	$**_____**	$**_____**

As Table 11 indicates, the All Renewables plan is the second lowest PVRR in the Integrated Analysis step and is the lowest cost plan in the Risk Analysis step. In both the Integrated and Risk Analysis, the All Renewables plan is lower in cost compared to Ameren's Preferred Plan, which is the "RAP – Renewable Expansion" plan. It would be even more cost effective in comparison to Ameren's Preferred Plan if the costs to retrofit the CC in 2032 to CCS, as discussed in Section 3.3.

In the IRP Ameren reported that the All Renewables plan did not meet reliability requirements. Ameren said, "Coupling even more renewable resources with batteries results in even lower cost and levelized rates, however, it does not meet reliability requirements."[41] It is not clear what basis Ameren is using for this claim, but we will talk about the reliability modeling performed in SERVM in the next section.

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[37] Ameren workpaper named "PVRR 08-21-23Confidential".
[38] Ameren workpaper named "PVRR 08-21-23Confidential".
[39] Ameren workpaper named "PVRR 08-30-23Confidential".
[40] Ameren's Preferred Plan.
[41] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis at page 30.

8 SERVM Modeling

Ameren used the Strategic Energy Risk Valuation Model ("SERVM") to evaluate the Loss of Load Expectation ("LOLE") for different portfolios at points of time across the 20-year planning horizon. SERVM is a modeling tool that assesses the ability of a system to meet load across hundreds and thousands of iterations of varying unit forced outage rates, renewable profiles, and load. Table 12 below provides an overview of the cases modeled in SERVM.

Table 12. SERVM Modeling Cases

Case	Study Year	Description
Case 1	2043	No further renewables or battery resources added beyond existing and approved wind and solar resources
Case 2	2043	Includes renewable resources in Ameren's Preferred Plan
Case 3	2043	No new gas added and a combination of wind, solar, and battery storage resources are added to try to achieve the same LOLE as Case 2
Case 4	2026	Preferred Plan renewable additions
Case 5	2026	No renewable additions
Case 6	2031	Preferred Plan renewable additions
Case 7	2031	No renewable additions

Table 13 below shows the LOLE result for each of the cases modeled in SERVM. The LOLE standard of one day in ten years is translated into an annual basis of 0.1 days/year.

Table 13. Astrapé Reliability Analysis Results[42]

Year	2043	2043	2043	2026	2026	2031	2031
Case	*1*	*2*	*3*	*4*	*5*	*6*	*7*
Rush Island	-	-	-	-	-	-	-
Sioux	-	-	-	974	974	-	-
Battery Storage	-	800	4000	-	-	-	-
CCGT	4200	2400	-	-	-	1200	1200
Labadie	-	-	-	2372	2372	2372	2372
CT Gas	788	788	-	2711	2711	2058	2058
DR	704	704	704	704	704	704	704
Hydro	370	370	370	370	370	370	370
Nuclear	1236	1236	1236	1236	1236	1236	1236
PSH	440	440	440	440	440	440	440
Purchases	2200	2200	2200	2200	2200	2200	2200
Solar	350	2700	6500	900	350	1800	350
Wind	400	2400	7400	400	400	1400	400
LOLE	0.04	0.04	0.14	0.09	0.13	0.01	0.08

The information presented for Cases 4-7 provides important information about the benefit that additional renewable resources can have on lowering the LOLE of the system. When comparing Case 4 and 5 for the 2026 study year, including the renewables from Ameren's Preferred Plan lowers the LOLE from 0.13 down to 0.09, or results in the system moving from not meeting the LOLE expectation to being under it. Similarly for Cases 6 and 7, the inclusion of the renewables from the Preferred Plan results in the system moving from a LOLE of .08 down to .01.

It appears that Ameren might be relying on the analysis performed for the 2043 study where the addition of renewables and battery storage resources are included without any new fossil resources in an attempt to try to approximate the LOLE of Cases 1 and 2, which is 0.04. As Ameren stated in the IRP:

> *Case 3 shows an alternative portfolio in which no new gas resources are added. Case 3 includes a combination of wind (7,400 MW), solar (6,500 MW), and battery storage (4,000 MW) to attempt to achieve the same LOLE as Case 2. As the table shows, this still falls short from a reliability perspective, with an LOLE of 0.14. Further increments of wind, solar, and storage could be added to achieve the 0.04 LOLE achieved by Cases 1 and 2 but would simply result in even higher (and more unrealistic) levels of such resources.*[43]

[42] Ameren 2023 IRP Chapter 10 Strategy Selection, Table 10.3 at page 33.
[43] Ameren 2023 IRP Chapter 10 Strategy Selection at page 32.

If Ameren is using the results from Case 3 to conclude that the "All Renewables" plan is not reliable that is problematic for several reasons. First, Case 3 cannot be directly compared to Case 1 and 2 since those cases included significant CT capacity while Case 3 does not have any CT capacity. Second, the 2043 study year assumed generation technologies are limited to commercial technology options available today. Ameren also does not contemplate battery storage resources in any duration except for four-hour storage.[44] This is a very conservative view of battery storage resources. It was just five years ago that utility scale battery storage began to be developed and there are a number of new battery technologies that are in early commercial stages such as the Form Energy multi-day battery. This analysis also does not seem to contemplate the potential for additional DSM (either demand response or energy efficiency) or pumped storage hydro, which Ameren did include in some of the alternative resource plans. All of this is to say that value of the 2043 study year is in indicating the characteristics of resources that will be important for resource adequacy but it is an extremely narrow view of the industry to conclude that it is demonstrative of the technology types Ameren will *need* in 2043. Again, if this analysis was what Ameren used to determine that the All Renewables plan is not reliable, then that is a flawed approach.

9 Demand Side Management ("DSM")

9.1 Cost Savings from DSM

Ameren evaluated several different levels of DSM potential as part of the IRP as shown in Table 14 below.

Table 14. DSM Portfolio Savings[45]

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

In addition to including alternative resource plans with varying levels of DSM, Ameren also modeled a resource plan where no additional DSM is included. On a PVRR basis, the "No

[44] Ameren response to NRDC 1.19(c).

[45] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis, Table 9.1 at page 5.

Additional DSM" plan is the costliest plan out of the alternative plans considered by Ameren. [46] This is also consistent with the levelized cost of energy (Cents/kWh) comparison that Ameren performed which indicated that the RAP level of DSM was the lowest cost, and the MAP level of DSM was in the top five of the lowest cost resources. Both the RAP and MAP level of DSM were lower on a LCOE basis than new CC or CT resources.[47]

Ameren's Preferred Plan contains the Realistic Achievable Potential ("RAP") of DSM and if you compare that plan to the "No Additional DSM" plan, the RAP DSM included in the Preferred Plan shows that the RAP DSM helps to avoid two additional 1,200 MW of CC resources in 2028 and 2043. [48]

As Ameren stated in the IRP:

> *Ameren Missouri believes the cleanest and cheapest form of energy is the energy you do not have to produce in the first place. This is why the plan continues to include robust and cost-effective customer energy efficiency and demand response programs to help customers better control consumption and reduce their electric bills. By 2043, these programs are expected to result in nearly 1,700 MW of peak demand savings in addition to peak demand savings achieved by programs implemented to date*.[49]

Ameren's statement highlights the importance of including DSM as part of the alternative resource portfolios. We recommend that Ameren continue to model different achievable levels of potential as part of the IRP analysis.

10 Summary of Recommendations

Based on our review of Ameren's 2023 IRP filing, we offer the following recommendations:

1. Ameren should engage stakeholders in a collaborative to evaluate capacity expansion and production cost models.
2. Ameren should increase the base cost for combined cycle resources by at least 10% and align probabilities for the high and low project costs with appropriate AACE cost estimates.
3. Ameren should evaluate the Grain Belt Express project alongside supply side resources included in this IRP filing and should work with project developers in a collaborative manner to ensure that all benefits from the project are reflected in the modeling.

[46] Ameren 2023 IRP Chapter 9 Integrated Resource Plan and Risk Analysis at page 30.
[47] Ameren 2023 IRP Chapter 1 Executive Summary at page 16.
[48] Ameren response to MPSC 1.2.
[49] Ameren 2023 IRP Chapter 1 Executive Summary at page 5.

4. Ameren should remove the color coding and arbitrary score weighting from the portfolio scorecard and provide a qualitative discussion along with reporting quantitative metrics for each resource plan.

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was filed on EFIS and sent by email on this 28th day of February, 2024, to all parties on the Commission's service list in this case.

/s/ Sarah W. Rubenstein