A Review of Evergy Missouri Metro and Evergy Missouri West's 2025 Integrated Resource Plan Annual Update

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1. INTRODUCTION

Energy Futures Group ("EFG") was engaged by the Council for the New Energy Economics ("NEE") to review and provide comments on Evergy's 2025 IRP Annual Update. EFG is a clean energy consulting company that performs IRP modeling and critically reviews IRPs in over a dozen states, provinces, and territories. Our work in these jurisdictions involves conducting our own simulations and/or reviewing modeling conducted using a wide variety of electric system modeling platforms including the PLEXOS and SERVM software used by Evergy.

These comments were also drafted by Ivan Urlaub and Nick Jones of NEE.

The following sections briefly discuss our review of Evergy's 2025 IRP filing and how Evergy's IRP complies with the Missouri Public Service Commission's ("PSC") IRP process. Our recommendations throughout this report are intended to provide feedback on improvements Evergy could make in preparation for future IRP filings. The deficiencies we have identified, the relevant portions of the Missouri IRP Rules, and our proposed remedies are as follows:

Deficiency	Chapter 22 Citation	Proposed Remedy
Capital Cost Assumptions – Cost Scenario Approach	20 CSR 4240-22.040(5) Supply-Side Resource Analysis	Evergy should update the approach to capital cost scenario weighting to reflect the higher likelihood of base and high scenarios.
New Wind Resource Costs	20 CSR 4240-22.040(5) Supply-Side Resource Analysis	Evergy should provide clarity around its approach to new wind build assumptions, and consider a broader use of submitted bids to include lower capacity factor and all COD submissions.
Natural Gas Price Forecast	20 CSR 4240-22.040(5) Supply-Side Resource Analysis	Evergy should update natural gas price forecasts and raise the risk weighting of high-case gas price scenarios.
New Thermal Resource Ownership Options	20 CSR 4240-22.040(3) Supply-Side Resource Analysis	Evergy should model a wider variety of ownership structures when considering new thermal plants.

Fuel Cost Causation and Fair Cost Allocation in Rate Setting	20 CSR 4240-22.030(4)(A) Load Analysis and Load Forecasting 20 CSR 4240-22.060(5) Integrated Resource Plan and Risk Analysis	Evergy's IRP should address fair adjustment clause cost allocation that considers which customers' new loads may be causing increased fuel costs.
Large Load Forecasting and Planning Reserve Margin	20 CSR 4240-22.030(5), (6), (7) & (8) Load Analysis and Load Forecasting 20 CSR 4240-22.060(5) Integrated Resource Plan and Risk Analysis	Evergy should include updated SERVM analysis to ensure portfolios meet reliability criteria as large loads are added.
Large Load Pipeline Reporting	20 CSR 4240-22.030(5), (6), (7) & (8) Load Analysis and Load Forecasting 20 CSR 4240-22.060(5) Integrated Resource Plan and Risk Analysis	The Commission should establish a quarterly large load reporting requirement within the IRP to provide valuable and current information to the Commission and the Company.
Interconnection Study Process Improvements	20 CSR 4240-22.040(3) Supply-Side Resource Analysis 20 CSR 4240-22.045 Transmission and Distribution Analysis	The Commission and Evergy should clarify in facility interconnection requirements whether the outlined Transmission Protection Requirements apply to large loads and which other specific studies are required for large loads, such as whether harmonic distortion, voltage flicker, power factor, voltage fluctuation, and ferroresonance risk assessment are formally required for large load interconnection requests, and make modeling requirements explicit including specifying required types of modeling data.

2. CAPITAL COST ASSUMPTIONS

2.1 COST SCENARIO APPROACH

The low-end of Evergy's capital cost assumptions in this update are not representative of expected ranges for new construction and are disconnected with the current inflationary environment in the United States. Evergy applies a blanket uncertainty factor across all capital costs: a 25 percent increase or decrease for high and low cost scenarios respectively and a 25 percent weighting applied to those scenarios. While we agree that it's important to model cost uncertainty, it's also important to reevaluate whether Evergy's approach still captures the risk. This is demonstrated in Confidential Table 1, below, which shows the nominal installed cost for each of the low, medium, and high cost cases. The low cost scenario uses costs that are well below expected ranges. In EFG's work across multiple jurisdictions, we have seen rising demand for turbines and renewable resources alike and rising costs, especially for gas turbines. While we don't disagree that additional supply or an easing of demand, among other factors, could reduce costs in the future, the current risk is much more heavily weighted to the high side. The even weighting of high and low does not reflect the current environment for new generation supply.

Table 1. New Resource Capital Costs, Low, Medium & High Scenarios

Resource Type	Technology	Low Nominal Installed Cost ($/kW)	Nominal Installed Cost ($/kW)	High Nominal Cost ($/kW)
Solar	Single Axis Tracking PV	[redacted]		
Wind	Wind Turbine			
Battery	Li-ion 4 Hour			
Combustion Turbine	Single Cycle H-Class			
Combined Cycle*	H-Class 1x1			

* All resources have a COD of 2028 except for thermal resources which have a COD of 2030.

For example, as Evergy noted in its testimony in Kansas Corporation Commission Docket No. 25-EKCE-207-PRE, it's 2024 IRP assumption for a CCGT coming online in 2029 was $1,271 per kW.[1] Part of the difference between that assumption and the mid case assumption provided

[1] *See* Kansas Corporation Commission ("KCC") Docket No. 25-EKCE-207-PRE, *Direct Testimony of Cody VandeVelde, p. 23* (Nov. 6, 2025).

in Confidential Table 1 is simply that Evergy was not modeling a cost aligned with the market at the time, but there was also additional escalation in price between the 2024 IRP Update and the filing of Evergy's pre-determination case for the Viola and McNew units related to the continued supply crunch for new turbines. This at least warrants weighting the high case more than the low case.

2.2 WIND CAPITAL COSTS

The cost assumption Evergy uses for new wind resources is substantially higher than costs we typically see for new wind. It appears that Evergy may continue to use an approach that relies on average project pricing received in past RFPs. We have several concerns about this approach as it relates to wind capital costs. First, it is not apparent whether the construction costs are inclusive of fixed operating costs or not, which may mean that Evergy is averaging apples and oranges costs. Second, Evergy appears to have excluded [redacted] Since Evergy is more likely to acquire the lowest cost project, the average of the bottom 50% of projects by cost or, conservatively, the median of project costs makes a more suitable midpoint. Finally, Evergy utilizes just [redacted] bids to base all forward cost assumption off of, which fails to represent the full scope of projects that may be available based on the RFP.

3. FUEL COST FORECASTS

Evergy confirmed in the 2025 IRP Annual Update stakeholders' workshop that no changes were made to natural gas forecasts since the 2024 Triennial IRP. The stated rationale was that, although revisions had been considered, no significant market developments had emerged to prompt major revisions. NEE contests that the intervening period has yielded dramatic market developments. As a result, long-term forecasts and early indicators are beginning to reflect a higher natural gas price and more upside risk in the natural gas market.

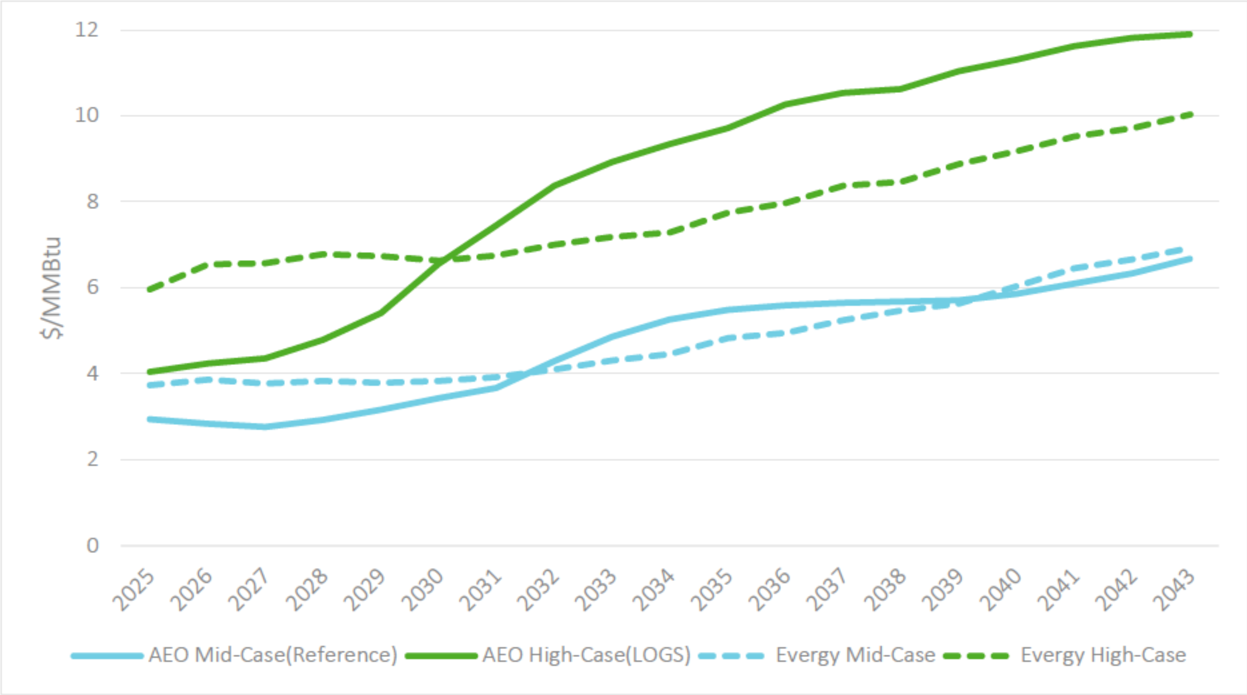
The 2024 Triennial IRP was prepared before Evergy or the larger marketplace had begun fully appreciating the potential scale of load growth from AI and related data centers. The need to accommodate new large loads has since become an issue for utilities nationwide. The anticipation of this new load has led to a national surge of interest in new natural gas plants. More natural gas plants will result in more demand for natural gas, which means fuel prices will rise.

Also potentially contributing to increased demand, recent national regulatory and policy changes have encouraged greater development of natural gas power plants and Liquified Natural Gas (LNG) export facilities while slowing the development of other energy resources like wind power. These changes are expected to increase national demand for natural gas. While there is uncertainty concerning the extent to which these factors will drive higher prices, the price outlook has certainly shifted upward, and upside risk has increased since the 2024 Triennial IRP was prepared.

Two recent publications support this view. The Energy Information Administration (EIA) published the Annual Energy Outlook (AEO) 2025, with natural gas prices significantly revised upward in the 2030s.[2] The AEO is a trusted resource and one of the forecasts that Evergy has previously used in building its IRP price forecasts. As can be seen in Figure 1 below, a sharp increase in prices is now expected in the early 2030s. Under a revised forecast, therefore, natural gas plants operating in the 2030s will be more expensive for ratepayers than previously thought. This would apply to the 3,010 MW of new natural gas capacity that Evergy Missouri Metro and West are together planning to add by 2039.[3] The new AEO forecast also reflects increased risk for natural gas prices. A 'Low Oil & Gas Supply' scenario, which has previously been used by Evergy to set a high-case natural gas price scenario,[4] now forecasts prices to surpass $10 per MMBtu by 2036.

[2] Energy Information Administration, Annual Energy Outlook 2025, Accessible at: https://www.eia.gov/outlooks/aeo/.
[3] *Evergy Missouri West 2025 Integrated Resource Plan,* Table 3, p. 5; *Evergy Metro 2025 Integrated Resource Plan,* Table 3, p. 4.
[4] *Evergy Missouri West 2025 Integrated Resource Plan,* p.17; *Evergy Metro 2025 Integrated Resource Plan,* p. 16.

Figure 1: AEO 2025 vs. Evergy IRP Forecasts



Further, the Kansas City Federal Reserve recently published its quarterly survey of oil & gas executives in the Midcontinent region. In that survey, executives were asked what natural gas price they anticipated five years from today. The average response was $4.78 per MMBtu,[5] roughly $1 per MMBtu higher than Evergy's mid-case forecast for 2030. At least one respondent answered that natural gas would be $10 per MMBtu in 2030. When asked what price would allow their companies to expand production – with a substantial increase in production likely necessary to meet the demand growth described above – responses averaged $5.10 per MMBtu. Like the 2025 AEO, the survey provides compelling support for our view that Evergy's mid-case forecast is too low relative to market developments.

4. THERMAL OWNERSHIP OPTIONS

Evergy has not considered diverse ownership structures for new power plants. This has limited the Company's ability to "right-size" its planned thermal additions under its current preferred portfolio. By limiting their potential ownership in natural gas plants to 50% or 100% shares, Evergy has squeezed out other potential resources which may otherwise meet a portion of capacity or energy needs at a lower cost.

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[5] Kansas City Federal Reserve, *Tenth District Energy Survey* (Apr. 11, 2025), Accessible at: https://www.kansascityfed.org/documents/10801/Q125.pdf.

Capacity expansion models, such as PLEXOS, select from discrete resource options input by the user. In other words, the model can only build resources which Evergy allows. The Company offered the model three new thermal resource options: a 100% ownership share in a 440 MW natural gas combustion turbine (CT) plant, a 100% ownership share in a 710 MW combined cycle gas turbine plant (CCGT), or a 50% ownership share in a 710 MW CCGT (also expressed as 355 MW net-owned capacity in a CCGT).

The Company's inclusion of this last option acknowledges that partial ownership is often preferable to full ownership for utilities the size of Evergy's subsidiaries. There are at least three reasons why this might be the case. First, joint ownership allows each utility to more closely match its owned capacity to its needs. As a corollary, this allows for incremental resource additions which are well-suited to match gradual load additions and offset unit-level retirements. Second, whereas owning a single large thermal plant might concentrate risk as that plant is built and operated, owning a fraction of multiple plants spreads out risks. Third, joint ownership allows all the above goals to be accomplished without down-scaling the physical plant to a level which would sacrifice capital and operational efficiencies. Some of these advantages likely contributed to Evergy Missouri West's 2025 preferred portfolio including three half-shares of CCGT plants and Evergy Missouri Metro's 2025 preferred portfolio including seven half-shares of CCGT plants.[6]

Power plants and other large energy infrastructure assets are frequently held as joint ventures by multiple owners outside of full ownership or 50/50 split ownership. As illustration, Evergy itself acquired a 22.2% share of the Dogwood Energy Center CCGT in 2024.[7] The Crystal River CCGT in Florida is co-owned by Duke Energy Florida with three other smaller regional utilities at ownership stakes ranging as low as 1.6%.[8] The West Riverside CCGT in Wisconsin is shared by a total of six utilities with ownership percentages ranging from 0.8% to 73.8%.[9] CT plants also can be and often are held by multiple owners at widely varying ownership percentages. Given current load growth, limited gas turbine and transformer supply, and other market conditions at this moment, NEE anticipates that Evergy could readily find joint venture partners for new thermal capacity.

NEE, testifying on behalf of Renew Missouri, recently presented analysis showing that by divesting a portion of its net-ownership in the CCGT plants or a portion of its full ownership in

[6] *Evergy Missouri West 2025 Integrated Resource Plan,* Table 3, p. 5; *Evergy Metro 2025 Integrated Resource Plan,* Table 3, p. 4.
[7] Missouri Public Service Commission ("PSC") Docket No. EA-2023-0291, *Order Approving Stipulation and Agreement and Granting Certificate of Convenience and Necessity* (Mar. 3, 2024).
[8] Energy Information Administration, Form EIA-860 M Detailed Data Schedule 4 'Generator Ownership.' Accessible at: https://www.eia.gov/electricity/data/eia860/.
[9] *Id*.

the CT plant, Evergy could better diversify the utility's future capacity stack and more effectively mitigate against fuel market risks and wholesale power market risks while lowering capital and operational costs.[10] While that testimony only focused on the plants included in that CCN proceeding, similar results could be possible for the other thermal additions in Evergy's current preferred portfolios.

NEE recommends that Evergy diversify the resource options available to include more potential ownership structures. We acknowledge that it may not be possible within the model framework to test for every possible percentage of ownership – nor would such a practice lead to implementable portfolios as the final terms of a joint ownership agreement will depend on negotiation with other parties. We recommend a sensible approach of breaking out thermal resource ownership by 25% increments, *i.e.*, capacity expansion models would have the choice of adding CCGT or CT resources at 25%, 50%, 75% or 100% ownership (see Table 2 below). Such a change would merely require that five additional resource types be input into the capacity expansion model and represent a drastic increase in the amount of flexibility the model would have to optimize resource size.

Table 2: Recommended Resource Changes in Capacity Expansion Model

	Combined Cycle Gas Turbine (CCGT)	Combustion Turbine (CT)
Ownership Options in Current Model	50%, 100%	100%
NEE Recommendation	25%, 50%, 75%, 100%	25%, 50%, 75%, 100%

As mentioned, when a specific plant is built under a joint venture, the actual percentage of ownership is subject to negotiation with partners and will likely vary from the exact percentage selected by the model. This is analogous to the physical capacity of an addition varying from the IRP due to plant designs once a specific project is developed. If the model selects a 25% ownership in a new capacity build, for instance, that demonstrates an approximate guideline of what percentage would be justified under Evergy's IRP process. Actual ownership would ultimately fall in a band near the model-selected percentage, for instance between 20-30%. However, even if the IRP process is not able to definitively

[10] Missouri PSC Docket No. EA-2025-0075, *Direct Testimony of William "Nick" Jones* (Apr. 25, 2025).

determine an optimal percentage of ownership, allowing for the model to have more flexibility will lead to resource additions which are closer to being optimal.

We believe this recommended revision to the Company's modeling practice would yield lower-cost portfolio options. Lower costs would be achieved first through "right-sizing" thermal additions and second through allowing better-optimized investment in other resources for meeting energy and capacity needs.

5. INCORPORATING LARGE LOAD

The emergence of large loads presents a unique challenge requiring careful attention to where resource planning, ratemaking, transmission planning, and prudence intersect. Of particular interest for Evergy's planning purposes are several key issues related to large load: operational and resource adequacy risks associated with electricity supply, the dynamic nature of large loads, stranded asset risk associated with transmission, generation and other system upgrades, and appropriate allocation of system costs. Given the substantial change in Evergy's forecast of large load between the 2024 and 2025 IRP updates, we highlight three focus areas below.

5.1 RATE SETTING

Large load additions have material impacts on both grid operations and service costs that influence rates. We understand that Evergy has filed a Large Load Power Service Rate Plan application ("LLPS Rate Plan") intended to create a new rate class for large loads.[11]

As load increases, market power prices increase, and the average fuel costs may rise as well. Typically, such costs are recovered through a fuel adjustment clause that averages those costs across all rate classes. Important risks that influence large load requests and have the potential for unfair cost causation to the detriment of ratepayers are not addressed in Evergy's Triennial IRP compliance filing nor here in the Company's 2025 IRP Update.

5.2 LOAD FORECASTING & RESERVE MARGIN ISSUES

The IRP provides an opportunity for Evergy to furnish critical detail about the nature of its large load pipeline. We've seen utilities across the country struggle to forecast large load additions accurately. There are a wide variety of approaches used, but a commonality among these approaches is that relatively little information about these loads is being requested. Utilities may ask for as little information as the peak demand of potential customers, which can leave the door open to numerous inquiries that have little probability of becoming

[11] *See* Missouri PSC Docket No. EO-2025-0154.

realized customers. In its 2025 IRP update, Evergy increased its large load forecast substantially. This additional large load forecast, which is added to the base load forecast in 2026, represents customers who have submitted an Attachment AQ study, with the expectation of fully executed agreements in the second quarter of 2025.[12]

However, we were not able to identify Evergy's approach to determining this load. We were able to identify the peak load forecasts for customers who submitted studies [redacted] but when those forecasts are added to the base load, they do not represent the full amount of new large load shown in Figures 6 and 7.[13] It is not clear what assumptions were made in regard to that additional large load. Without clear insight into the amount of forecasted large load, it is difficult to assess whether the selected portfolio is appropriate. As presented, this load requires substantially increased supply, which Evergy proposed in its preferred scenario (see Table 3), requiring increased wind, combined cycle, and combustion turbine buildout, in addition to the conversion of the existing Jeffrey 2 coal unit to natural gas.

Expanding on the information provided in Figures 6 and 7, we recommend that future IRP filings provide and incorporate the following LLPS Rate Plan information, if that Plan is approved in some form by the Commission, into IRP stakeholder presentations and each stage of the resource planning process. The implementation of the LLPS Rate Plan will have meaningful impacts that should be considered during each IRP. For instance, certain proposed riders under that plan offer opportunities for large customers to offset some of their own energy and capacity needs. The IRP process must consider the effect of these offsets to determine the amount of energy supply and capacity additions which Evergy should prudently plan to execute. Specifically, if the LLPS rate plan is approved, we recommend that future IRPs include the following items for each rider and tariff in the approved LLPS Rate Plan:

- Information on current subscriptions to each new LLPS tariff, including number of subscribers, total MWs and MWhs by year for each tariff and rider in the LLPS Rate Plan;
- A breakdown of the large load forecast, in charts, indicating how much of the forecasted large load is committed or likely to participate in each of the proposed large load tariffs and riders; and

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[12] *Evergy Missouri Metro 2025 Annual Update Integrated Resource Plan,* p. 13.
[13] *Evergy Missouri 2025 Annual Update Integrated Resource Plans,* Metro Plan Workbook 'MET AAAA' and West Plan Workbook 'MET ACAA.'

- A narrative describing the quantified impact on each step of the planning process of the committed or likely participation in MWs and MWhs of new large loads in each large load tariff and rider.

In its 2025 Update, Evergy transitions to the use of Accredited Capacity (ACAP) rather than Installed Capacity (ICAP) for its Planning Reserve Margin (PRM) calculation. This aligns with SPP's planned implementation of Performance Based Accreditation which calculates the reserve margin to reflect actual unit performance and reliability. In the IRP, Evergy states that "by shifting to an ACAP PRM, performance risk moves from the overall system to individual units, accrediting them based on demonstrated performance… [T]he overall PRM is reduced, because the buffer that was previously included in the ICAP PRM to cover outage and performance variation is now distributed across individual units."[14] While this approach may be appropriate, this is different than the assumption used for the pre-determination proceedings. Further, Evergy did not include SERVM analysis for the 2025 IRP update[15], which is even more useful in ensuring portfolios meet reliability criteria especially as large loads are added.

[14] *Evergy Missouri Metro 2025 Annual Update Integrated Resource Plan,* p. 26.
[15] *Id.*, p. 109.

Table 3. Evergy Missouri Metro and West Combined Preferred Plan Comparison[16]

Type	2024 Triennial IRP	2025 IRP Annual Update
Retirements	LaCygne 1 in 2032 LaCygne 2 in 2039 Lake Road 4/6 in 2030 Jeffrey 3 in 2030 Jeffrey 2 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039	LaCygne 1 in 2032 LaCygne 2 in 2039 Lake Road 4/6 in 2030 Jeffrey 3 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039
Conversions		Jeffrey 2 to NG in 2030
Total Wind	1500 MW 2024-2035 300 MW 2036-42	1500 MW 2025-2035 900 MW 2036-44
Total Solar Additions	900 MW 2024-2042	615 MW 2025-2035 1800 MW 2036-44
Battery Additions	None	None
Thermal Additions	325 MW CC in 2029 415 MW CT in 2030 415 MW CT in 2032 325 MW CC in 2036 325 MW CC in 2038 325 MW CC in 2039 325 MW CC in 2041	355 MW CC in 2029 440 MW CT in 2030 355 MW CC in 2030 440 MW CT in 2031 355 MW CC in 2032 355 MW CC in 2033 355 MW CC n 2037 355 MW CC in 2039 355 MW CC in 2040 355 MW CC in 2040

5.3 LARGE LOAD PIPELINE REPORTING

The volume and makeup of large load pipelines can change rapidly. While Evergy currently files annual IRP updates, we understand that will not be the case in the future and even if it were, annual IRP updates can delay the transmission of consistent and complete large load information to Commissions. In the evolving new large load growth environment, the Commission will need consistent, complete and up to date large load information for numerous types of proceedings, such as but not limited to IRPs, CCNs predicated on new large load(s), interconnection, any adoption of and/or modification to large load customer rate plans and tariffs, rate cases, and to provide critical insight into making or revising IRP

[16] *Evergy Missouri West 2025 Annual Update Integrated Resource Plan*, Table 3, page 5; *Evergy Metro 2025 Annual Update Integrated Resource Plan*, Table 3, page 4.

rules that can effectively accommodate persistent and/or evolving large load trends. For these same reasons, Evergy's proposal as part of its Large Load Power Service Rate Plan application 'to file an annual compliance report filing with the Commission' is minimally necessary but not sufficient.[17]

We recommend that the Commission establish a quarterly large load reporting requirement within the IRP process. A similar requirement applies to Georgia Power and is required by the Georgia Public Service Commission. Its quarterly report provides both public and confidential information about large loads including, but not limited to, specific company details, load, load ramp, and any changes to project status. We recommend that this reporting requirement be adopted and supplemented with additional information, including classification of the commercial activity of the potential load, e.g., by NAICS code or similar, and the reason for the project dropping out of the pipeline, if applicable.[18] This can provide valuable information to the Commission and to the Company about the volume of large load requests, their progression towards interconnection, and the reasons loads might drop out.

Further, we believe that the current increase in large loads driven primarily by AI, but also driven by electrification, manufacturing and industrial growth, and other more nascent loads is not a temporary phenomenon. Instead, this is the beginning of an expansion and likely multiplication in new large load growth drivers to come. This feasible low-cost reporting recommendation will be indispensable for the Commission to stay attuned to the large load demands as those demands change and their drivers change whether from electrification, manufacturing, or other more nascent loads.

6. INTERCONNECTION STUDY PROCESS IMPROVEMENTS

Evergy's facility interconnection requirements, which would apply to many large loads, require interconnecting customers to complete a set of engineering studies prior to establishing an interconnection.[19] However, the applicability of some requirements, especially in the context of large load interconnections, would benefit from further clarification. It is not explicitly stated whether the Transmission Protection Requirements outlined in the

[17] Missouri PSC Docket No. EO-2025-0154, *Application*, p. 6 (Feb. 14, 2025).
[18] Georgia Public Service Commission, Order Adopting Stipulated Agreement, Attachment A. Accessible at: https://psc.ga.gov/search/facts-document/?documentId=218484.
[19] Evergy, Inc. (2024, May 10). Facility Interconnection Requirements. Accessible at: https://www.evergy.com/-/media/media/evergy-web/footer/partner-with-us/new-construction-transmission-facility-connection.pdf.

document apply to large loads, and additional clarity is needed regarding which other specific studies are required in such cases.

The document mentions that engineering studies should include system impact analysis, breaker/fault duty studies, protection coordination, metering and telecommunication requirements, and facility rating assessments (for connections at 60 kV or higher in accordance with SPP Planning Criteria). It also references Phasor Measurement Unit (PMU) requirements. However, from the Power Quality Impacts section, it is unclear whether studies related to harmonic distortion, voltage flicker, power factor, voltage fluctuation, and ferroresonance risk assessment are formally required for large load interconnection requests.

While the document does state that customers are responsible for submitting the necessary studies, it should also clearly indicate that Evergy and Transource (the Companies) will review and validate all submitted documentation and may request additional analysis as needed.

Additionally, modeling requirements are only implied and should be made explicit. The document should clearly specify the required types of modeling data such as dynamic models, short-circuit models, and load flow files as well as acceptable formats. Other types of studies such as a load ramping impact study, inertia study and frequency response study should be requested.

The current document clearly assigns primary interconnection responsibilities to different entities: generators and transmission interconnections are primarily under the jurisdiction of the Southwest Power Pool (SPP) through its Open Access Transmission Tariff (OATT) and planning criteria, while end-user interconnections fall under the Companies' responsibility, including conducting system adequacy evaluations and necessary studies. However, there is ambiguity regarding operational accountability and design approval. This dual responsibility is understandable but would benefit from more explicit guidance on how conflicts are resolved and who holds final authority. Furthermore, the document references the possibility of allowing facility operation before required system upgrades are completed through a “Limited Operation Interconnection Agreement,” but it does not clearly define whether approval authority lies with the SPP, the Companies, or both, nor does it describe the reliability safeguards required for such temporary operation.

This issue is particularly critical in light of recent large-scale grid disturbances that underscore the risks associated with inadequate planning and ambiguous interconnection standards. For example, in July 2024, a 230 kV transmission line fault in the Eastern Interconnection led to the unexpected disconnection of approximately 1,500 MW of voltage-sensitive data center loads.[20] These loads were not shed by utility equipment but were disconnected by customer-side protection systems responding to voltage disturbances. This event highlighted how such unanticipated load losses can cause frequency and voltage fluctuations, posing significant challenges to grid stability. And as ERCOT has stated,[21]

> *Several incidents have shown that newly connected Large Loads may struggle to stay connected during voltage disturbances. One of the most significant events took place near Odessa on December 7, 2022, at 3:50 AM, when over 1,600 MW of demand—including from data centers, oil and gas operations, and other industrial users—unexpectedly dropped off the grid following a low-voltage event. This caused the system frequency to spike to 60.235 Hz, taking more than 10 minutes to stabilize. Such disconnections illustrate how Large Loads can turn a simple voltage dip into a frequency management challenge.*

These incidents illustrate the necessity for comprehensive and transparent interconnection requirements, especially for large, voltage-sensitive loads. Clear guidelines on necessary engineering studies, protection coordination, and modeling requirements are essential to ensure that such loads do not compromise grid reliability during disturbances. Establishing such standards may well have impacts on the shape, size, and timing of the loads that are ultimately interconnected, which has important ramifications for integrated resource planning.

7. CONSIDERATIONS FOR NEW IRP RULES

As Missouri switches to a new planning paradigm and IRP cadence, it is important to consider deficiencies in the current process that can inform the creation of new IRP rules. It is our position that a transparent and collaborative environment is the foundation for a robust stakeholder process for an IRP. Without transparency on modeling inputs, outputs, and supporting data, as well as understanding Evergy's decision-making process, the opportunities for learning are limited, and the feedback that stakeholders can offer is similarly limited. Utilizing a transparent and collaborative approach for modeling inputs can help ensure that stakeholders can participate in a meaningful way throughout the IRP

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[20] North American Electric Reliability Corporation (NERC). (2025, January 8). Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions [PDF]. NERC. Accessible at: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf.
[21] Electric Reliability Council of Texas (ERCOT). (2023, August 16). *Overview of Large Load Revision Requests for 8-16-23 Workshop* [PowerPoint slides]. ERCOT. Accessible at: https://www.ercot.com/files/docs/2023/11/08/PUBLIC-Overview-of-Large-Load-Revision-Requests-for-8-16-23-Workshop.pptx.

development process, rather than only being able to react to information contained in the modeling files once it is too late for feedback to be incorporated.

We recommend a stakeholder process similar to that of AES Indiana. Ideally, the public stakeholder workshops would address the high-level matters, e.g., the scenarios and sensitivities developed, the major model assumptions, etc., while the technical stakeholder workshops would be for those with signed nondisclosure agreements ("NDAs") to understand and offer feedback on more complicated details of how these elements operate and allow discussion of confidential information. It is not possible to discuss all the consequential details of IRP modeling even in multiple public stakeholder workshops. AES Indiana has implemented an approach where technical stakeholder meetings are regularly held prior to the public meetings so that more in-depth discussions can be held on certain technical or confidential topics. AES Indiana provides data to stakeholders who have signed the NDAs in advance of these meetings pursuant to a schedule published at the beginning of the IRP process. This allows stakeholders opportunities to ask questions and offer feedback on the data during the meetings or shortly thereafter. The figure below gives an example of an AES Indiana IRP schedule. Applicable data is provided by AES Indiana to stakeholders in advance of the meetings.

Figure 2: AES Indiana Public IRP Stakeholder Schedule