BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's 2026 Annual Update to its Chapter 22 Integrated Resource Plan.	))))	Case No. EO-2026-0188
In the Matter of Evergy Missouri West, Inc., d/b/a Evergy Missouri West's 2026 Annual Update to its Chapter 22 Integrated Resource Plan.	))))	Case No. EO-2026-0189

COMMENTS OF THE COUNCIL FOR THE NEW ENERGY ECONOMICS

COMES NOW the Council for the New Energy Economics ("NEE"), and pursuant to 20 CSR 4240-22.080(3)(D) respectfully submits the attached Comments regarding Evergy Metro, Inc. d/b/a Evergy Missouri Metro ("EMM") and Evergy Missouri West, Inc. d/b/a Evergy Missouri West's ("EMW") (together, "Evergy") 2026 Integrated Resource Plan ("IRP") Annual Update.[1]

1. NEE is a non-profit organization committed to helping utilities and energy decision-makers navigate rapidly evolving utility industry economics using neutral data and analysis. NEE's mission is to present stakeholders and decision-makers with complex utility system modeling analysis to assist in determining the most cost-effective path forward for the deployment of energy resources. NEE has participated in Evergy's resource planning proceedings in Missouri and Kansas since 2020 and is a member of the stakeholder group as defined at 20 CSR 4240-22.020(56). Pursuant to the Missouri Public Service Commission's ("Commission") June 8, 2026, *Order Granting Request for Recognizing Parties*, NEE is a party to these Annual Update proceedings.[2]

[1] Missouri Public Service Commission ("PSC") Docket Nos. EO-2026-0188 andEO-2026-0189.
[2] Missouri PSC Docket Nos. EO-2026-0188 and EO-2026-0189, Order Graning Request for Recognizing Parties (Jun. 8, 2026).

2. Upon review of the Annual Update filings, NEE has identified a number of deficiencies and concerns. NEE uses the terms "deficiency" and "concern" as those terms are defined at 20 CSR 4240-22.020(9) and 20 CSR 4240-22.020(6), respectively. Each of these deficiencies and concerns, as well as NEE's proposed remedies, are discussed in the attached Comments and set forth in Tables 8, 9, and 10 herein.

3. In accordance with Evergy's previous designations of confidential information, NEE provides a Confidential and Public version of the attached Comments. Confidential information is marked with asterisks, highlight, and underline.

WHEREFORE, NEE respectfully requests that the Commission accept these Comments, adopt the recommendations described herein, and grant any other relief the Commission deems reasonable and appropriate.

Respectfully submitted,

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NEW ENERGY ECONOMICS

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July 30, 2026

Missouri Public Service Commission
200 Madison Street
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Re: The Council for the New Energy Economics' Comments on Evergy's 2026 IRP Annual Updates – Public Version

In its review of Evergy's 2026 IRP Annual Update filings, NEE has identified a number of deficiencies in the utility's compliance with the requirements set forth in 20 CSR 4240 Chapter 22, together with a range of concerns that, if left unaddressed, are likely to become deficiencies. Most significantly, both preferred resource plans fail to satisfy the Missouri Renewable Energy Standard within the planning horizon, and neither filing incorporates the cost of curing that failure into the net present value of revenue requirements ("NPVRR") upon which every plan ranking in the Annual Update depends.

NEE encourages the Commission to evaluate the resolution of these deficiencies within the context of the rapidly changing energy market dynamics described herein, and within the context of 20 CSR 4240-22.080(18). These contextual considerations are particularly important because the preferred resource plans described in these filings will likely be invoked to support certificate of convenience and necessity applications and other Evergy requests over the coming years.

I. THE CHANGING ELECTRICITY LANDSCAPE HAS MATERIALLY IMPACTED EVERGY'S MISSOURI RESOURCE PLANNING, BUT SEVERAL KEY DATA POINTS AND RISKS ARE ABSENT FROM ITS ANALYSIS.

Over the past 12 to 18 months, the regional and national energy landscape has shifted in ways that are both relevant and economically material to utility integrated resource planning. Both Evergy Metro and EMW present substantially the same account of that shift, stating that "the planning environment in the United States electricity sector has been very dynamic since the 2025 Annual Update" and that "the 2026 Annual Update incorporates forecast revisions consistent with the most recent expectations of load growth and changes to policy and economics."[3] Evergy identifies five discrete themes:

- **Higher Expected Load Growth.** Evergy attributes load growth above the 2025 Annual Update forecast to Large-Load Power Service ("LLPS") tariffs approved in Missouri in November 2025.[4]
- **Continued Focus on Reliability.** Evergy cites the finalized Southwest Power Pool ("SPP") seasonal reserve margin construct accepted by the Federal Energy Regulatory Commission ("FERC") in 2025, increases in summer and winter planning reserve margins, the new Expedited Resource Adequacy Study ("ERAS") process, and Missouri Senate Bill 4.[5]
- **Changes in Environmental Policy and Decarbonization Outlook.** Evergy cites the postponement and potential elimination of federal greenhouse gas rules, an extended timeline for the nitrogen-oxide emissions controls required at the Jeffrey Energy Center, earlier expiration of production tax credit eligibility for new renewable resources, and the limited availability of carbon-free dispatchable options.
- **Continued Increase in New Build Costs, Long Lead Times for Development.** Evergy cites S&P Global's 2025 report of five-to-seven-year gas turbine wait times and cost increases exceeding 200%.[6]

[3] EMM 2026 Annual Update, § 2, at 9; EMW 2026 Annual Update, § 2, at 9.
[4] EMM 2026 Annual Update, § 2.1, at 9 (citing Report and Order, Case No. EO-2025-0154 (Nov. 13, 2025)); EMW 2026 Annual Update, § 2.1, at 9.
[5] EMM 2026 Annual Update, § 2.2, at 11–12; EMW 2026 Annual Update, § 2.2, at 11–12.
[6] EMM 2026 Annual Update, § 2.4, at 18; EMW 2026 Annual Update, § 2.4, at 18.

- **Delay of Coal Retirements Relative to Prior Forecasts.** Evergy explains that "[g]iven these broader market dynamic changes and outlook for federal policy, the 2026 Annual Update delays planned retirement dates relative to the 2025 Annual Update."[7]

The fifth theme is an express acknowledgement that the first four are the cause of Evergy's decision to delay or eliminate every coal retirement within the planning horizon at both Missouri utilities. As discussed in Section IV below, Evergy made those decisions without the reassessment criteria, trigger thresholds, and off-ramps that 20 CSR 4240-22.070(2) and (4) require.

A further trend that appears to have materially affected Evergy's Missouri resource selections is federal action limiting renewable energy development, including the shortened production tax credit ("PTC") eligibility window under the One Big Beautiful Bill Act ("OBBBA"), which Evergy cites directly.[8] Between the 2025 and 2026 Annual Updates, the two Missouri utilities together eliminated 2,400 MW of planned wind and 1,800 MW of planned solar from their preferred plans while adding 1,028 MW of new gas-fired capacity.

A. Evergy's Load and Resource Mix Assumptions Have Substantively Changed Since the 2025 Annual Update.

1. Evergy Forecasts Significant New Load Growth; Evergy Should Make Additional Load Forecast Information Publicly Available.

The rate of projected peak load growth has increased for both Missouri utilities relative to the 2025 Annual Update, which Evergy attributes to data center and artificial intelligence demand and to the newly approved LLPS tariff. EMM's summer peak is now projected to grow from 3.7 GW in 2026 to 4.6 GW in 2032 and 5.4 GW in 2045—approximately 24% and 46% growth,

[7] EMM 2026 Annual Update, § 2.5, at 19; EMW 2026 Annual Update, § 2.5, at 19.
[8] EMM 2026 Annual Update, § 1.3, at 4; EMW 2026 Annual Update, § 1.3, at 4.

respectively.[9] EMW's summer peak is projected to grow from 2.2 GW in 2026 to 2.9 GW in 2032 and 3.2 GW in 2045—approximately 32% and 45% growth.[10]

EMM identifies three large load customers meeting its criteria for inclusion in base load planning, with a combined steady-state peak of approximately 900 MW; two of those customers are located in the Missouri jurisdiction and account for nearly 90% of the total large load incorporated into the Metro forecast.[11] EMW identifies five such customers with a combined steady-state peak of approximately 800 MW.[12] Beyond these committed customers, EMM reports a pipeline of four additional prospective customers and EMW reports four, none of which has completed either Evergy's internal interconnection study or SPP's load addition study.[13]

NEE does not dispute that large load growth is occurring in Evergy's Missouri service territories. The committed customers have executed Energy Service Agreements, and Evergy's stated criteria for including a customer in base load planning are reasonable on their face. NEE's concern is that the aggregate load forecast on which the entire resource plan rests is not available to the public.

Evergy's Table 4 in each filing—the Mid-Case Annual Forecast—is designated confidential in its entirety.[14] The public versions present only Figures 4 and 5, which plot peak and energy forecasts without axis values, and Figures 6 and 7, which plot the large-load contribution on the same basis. A reader of the public filing therefore cannot determine the forecast peak or energy in any year of the planning horizon, cannot verify the 24%, 46%, 32%, and 45% growth

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[9] EMM 2026 Annual Update, § 1.4, at 6.
[10] *Id*.
[11] *Id*., § 3.1, at 23–24.
[12] *Id*., § 3.1, at 23.
[13] EMM 2026 Annual Update, Table 45, at 137; EMW 2026 Annual Update, Table 46, at 133.
[14] EMM 2026 Annual Update, Table 4, at 22; EMW 2026 Annual Update, Table 4, at 22.

figures Evergy states in its narrative, and cannot assess whether the resource additions in the preferred plan are sized appropriately to the load they are said to serve.

This treatment is inconsistent with three provisions of Chapter 22:

- **20 CSR 4240-22.080(2)(E)2** requires the executive summary—which must be "separately bound and suitable for distribution to the public"—to include, "[f]or each major class and for the total of all major classes, the base load forecasts for peak demand and for energy for the planning horizon, with and without utility demand-side resources."
- **20 CSR 4240-22.060(4)(B)9** expressly contemplates that the capacity balance spreadsheets exist in "[p]ublic and highly-confidential forms." The public form of the capacity balance for the preferred plan and each candidate plan is required by 20 CSR 4240-22.080(2)(D). Appendix A in each filing is designated confidential without a public counterpart.[15]
- **20 CSR 4240-22.020(44)** defines "plot" to require that "[t]he data presented in each plot also shall be provided in tabular form." Figures 4 through 7 are plots of data that is withheld in tabular form.

The typical justification for withholding load forecast information—protection of individual customer data—does not apply to an aggregate system-level forecast. Evergy already discloses the number of large-load customers, their combined steady-state peak, their ramp period, and, in the special contemporary issues sections, a customer-by-customer pipeline table with annual MW by year.[16] Having disclosed the more granular information, Evergy cannot justify withholding the aggregate. Named large-load customers in Missouri have been identifiable in prior cycles—including Meta, Google, and Nucor—while the aggregate forecast beyond those customers has not been clearly documented. NEE has recommended quarterly large-load pipeline

[15] EMM 2026 Annual Update, Appendix A; EMW 2026 Annual Update, Appendix A.
[16] EMM 2026 Annual Update, § 14.2 and Table 45; EMW 2026 Annual Update, § 14.2 and Table 46.

reporting modeled on the framework used by Georgia Power and the Georgia Public Service Commission, but Evergy has not adopted that recommendation. Nor do the filings integrate the demand-side and capacity effects of the LLPS rate plan approved in November 2025 into the resource modeling.[17]

NEE further recommends that Evergy add [redacted] to that table. [redacted] allows stakeholders to assess whether the system customers pay for is being used efficiently, and whether further investment in energy efficiency ("EE"), demand-side management ("DSM"), storage, or demand-side rates may improve that utilization. It is directly relevant to the analysis required by 20 CSR 4240-22.050 and cannot be derived from what Evergy currently makes public.

2. The Resource Mix in Evergy's Preferred Plans Has Shifted Substantially Since the 2025 Annual Update.

The changes to both preferred plans between 2025 and 2026 are substantial, and they run consistently in one direction. Tables 1 and 2 below compare the resource additions and retirements in each utility's 2025 and 2026 preferred plans.

Table 1. Evergy Metro planned resource additions and retirements, 2025 Preferred Plan AAAA vs. 2026 Preferred Plan ACAA[18]

Resource	2025 Plan AAAA (MW)	2026 Plan ACAA (MW)	Δ MW
Wind	750	0	−750
Solar	1,950	150	−1,800
Battery storage	150	150	0
Thermal (CCGT / SCGT / RICE)	2,215	2,533	+318
Total new supply-side	**5,065**	**2,833**	**−2,232**
Coal units retired within horizon	La Cygne 1 (Mar. 2033); La Cygne 2 (Mar. 2040); Iatan 1 (Mar. 2040)	La Cygne 1 (Mar. 2038)	−2 units

[17] NEE recommended quarterly large-load pipeline reporting modeled on the framework used by Georgia Power and the Georgia Public Service Commission. The recommendation was not adopted. *See also* Report and Order, Case No. EO-2025-0154 (Nov. 13, 2025) (approving the Large-Load Power Service rate plan).
[18] EMM 2026 Annual Update, Table 3, at 6; Table 34, at 112.

Table 2. Evergy Missouri West planned resource additions and retirements, 2025 Preferred Plan ACAA vs. 2026 Preferred Plan ADAA[19]

Resource	2025 Plan ACAA (MW)	2026 Plan ADAA (MW)	Δ MW
Wind	1,650	0	−1,650
Solar	315	315	0
Battery storage	150	0	−150
Thermal (CCGT / SCGT)	1,505	2,215	+710
Total new supply-side	**3,620**	**2,530**	**−1,090**
Coal units retired within horizon	Lake Road 4/6 (2030); Jeffrey 3 (Mar. 2031); Iatan 1 (Mar. 2040); Jeffrey 1 (Mar. 2040)	Lake Road 4/6 (Mar. 2038); Jeffrey 3 (Mar. 2036)	−2 units

Three observations follow.

First, the renewable reduction is substantial. EMM eliminated 100% of its planned wind and 92% of its planned solar. EMW eliminated 100% of its planned wind and 100% of its planned battery storage, retaining only the 165 MW of certificated solar already under development and a single 150 MW solar addition moved forward one year. Across both utilities, 4,200 MW of planned renewable capacity and 150 MW of planned storage were removed in a single annual update cycle, while gas-fired capacity increased by 1,028 MW.

Second, EMW's 2026 preferred plan contains no storage of any kind and no new wind across the entire twenty-year horizon. Its only non-thermal additions are the 165 MW of certificated solar in 2027 and 150 MW of solar in 2035. As discussed in Section III below, EMW's own alternative resource plans quantify what that exclusion costs to test: ADEA (150 MW of storage in 2029) is ranked $171 million higher, and ADCA (300 MW of storage in 2029 and 2030)

[19] EMW 2026 Annual Update, Table 3, at 6; Table 32, at 110.

$331 million higher, than the preferred plan.[20] Those rankings rest on a storage cost assumption that neither filing sources or benchmarks, and that is designated confidential in its underlying form.

Third, every coal retirement within the planning horizon was delayed, and four of the seven were removed from the horizon entirely. EMM moved La Cygne 1 from March 2033 to March 2038 and moved La Cygne 2 and Iatan 1 from March 2040 to beyond 2045. EMW moved Jeffrey 3 from March 2031 to March 2036, moved Lake Road 4/6 from December 2030 to March 2038, moved Iatan 1 and Jeffrey 1 from March 2040 to beyond 2045, and postponed the Jeffrey 2 natural gas conversion from 2030 to 2035. After these changes, the only coal capacity either Missouri utility plans to retire within twenty years is EMM's 375 MW share of La Cygne 1 and EMW's 59 MW accredited share of Jeffrey 3 and 89 MW accredited share of Lake Road 4/6.[21]

The depth and detail of an Annual Update report must "generally be commensurate with the magnitude and significance of the changing conditions since the last filed triennial compliance filing or annual update filing."[22] A single-cycle revision that removes 4,200 MW of planned renewable capacity, adds more than 1,000 MW of gas, and eliminates four of seven planned coal retirements is a change of the highest magnitude. The analysis supporting it is examined in Sections II through IV.

B. Independent Data Confirms the Conditions Evergy Describes and Identifies Risks the Filings Do Not Address.

NEE has tested the conditions Evergy describes against independent published sources. Those sources support Evergy's account of what has changed: demand is rising sharply, gas turbine

[20] *Id.*, § 10.5, at 79.
[21] EMM 2026 Annual Update, Table 34, at 112; Table 40, at 126; EMW 2026 Annual Update, § 12.3.2, at 113.
[22] 20 CSR 4240-22.080(3)(B).

costs and lead times have increased, and federal policy has moved against renewable resources. NEE does not dispute any of that.

The same sources establish three things the filings do not address. The natural gas market into which Evergy proposes to add approximately 3,600 MW of new capacity is tightening rather than loosening. The region's own market monitor identifies natural gas as the largest single source of forced outage during recent winter events. And the mechanism producing coal retirement deferrals elsewhere in the country does not apply to Evergy's Missouri units.

1. National Natural Gas Demand Is at Record Levels and Rising, Driven Principally by Exports.

The U.S. Energy Information Administration ("EIA") projects that United States dry gas production will rise from a record 107.7 Bcf/d in 2025 to 111.0 Bcf/d in 2026 and 113.6 Bcf/d in 2027, and that domestic consumption will rise from a record 91.9 Bcf/d in 2025 to 95.0 Bcf/d in 2027.[23] Export demand is growing faster than either. EIA estimated United States liquified natural gas ("LNG") exports at 17.9 Bcf/d in March 2026—the second-highest monthly volume on record—and forecasts full-year 2026 exports of 17.0 Bcf/d and 2027 exports of 18.6 Bcf/d, each above the prior annual record of 15.1 Bcf/d set in 2025, against current peak export capacity of 18.3 Bcf/d.[24] Over the longer term, EIA projects LNG exports rising from 15 Bcf/d in 2025 to more than 30 Bcf/d by 2050.[25]

[23] U.S. Energy Information Administration, Short-Term Energy Outlook, June 9, 2026 (projecting dry gas production of 111.0 Bcf/d in 2026 and 113.6 Bcf/d in 2027, against a record 107.7 Bcf/d in 2025, and domestic consumption of 92.1 Bcf/d in 2026 and 95.0 Bcf/d in 2027, against a record 91.9 Bcf/d in 2025). Available at https://www.eia.gov/outlooks/steo/.

[24] U.S. Energy Information Administration, Short-Term Energy Outlook, April 7, 2026 (estimating U.S. LNG exports of 17.9 Bcf/d in March 2026, the second-highest monthly volume on record; forecasting full-year 2026 exports of 17.0 Bcf/d and 2027 exports of 18.6 Bcf/d, each above the prior annual record of 15.1 Bcf/d set in 2025; current peak export capacity of 18.3 Bcf/d). Available at https://www.eia.gov/outlooks/steo/report/natgas.php.

[25] U.S. Energy Information Administration, Annual Energy Outlook 2026, April 2026 (projecting U.S. LNG export volumes rising from 15 Bcf/d in 2025 to more than 30 Bcf/d by 2050 in most cases). Available at https://www.eia.gov/todayinenergy/detail.php?id=67425.

Those volumes tie the price Evergy's customers pay for gas increasingly to international markets. EIA reports that disruptions to LNG shipments through the Strait of Hormuz currently represent over 10 Bcf/d, or roughly 20% of global supply, and that damage sustained at Qatar's Ras Laffan export facility may take up to five years to repair.[26] A domestic utility adding gas-fired capacity across a twenty-year horizon therefore increases ratepayer exposure to a commodity price set in large part by events over which neither it nor this Commission has any influence. Neither filing discusses export-driven demand, and neither treats it as a factor bearing on the probability that gas prices exceed the mid case. This risk weighting is examined in Section III.B below.

2. SPP's Own Market Monitor Identifies Natural Gas as the Largest Source of Forced Outage During Recent Winter Events.

Evergy relies on new gas-fired generation to meet the winter capacity deficits both filings identify as their binding constraint. SPP's Market Monitoring Unit has examined how that resource class actually performed during the region's most recent severe winter event. During the February 2025 event, in which SPP set a record winter peak load of 48,142 MW, forced outages across the region rose from approximately 12,000 MW on average to nearly 17,000 MW, peaking at approximately 18,400 MW. Natural gas resources accounted for the sharpest increase, averaging over 11,000 MW of forced outage during the event. SPP was a net importer of energy in 81 of the 96 hours.[27]

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[26] U.S. Energy Information Administration, Short-Term Energy Outlook, April 7, 2026 (noting that disruptions to LNG exports through the Strait of Hormuz represent over 10 Bcf/d, or 20% of global supply, and that damage to the Ras Laffan facility in Qatar may require up to five years to repair). Available at https://www.eia.gov/outlooks/steo/report/natgas.php.

[27] Southwest Power Pool Market Monitoring Unit, February 2025 Winter Weather Event Review (reporting a record SPP winter peak load of 48,142 MW on February 20, 2025; forced outages rising from approximately 12,000 MW to nearly 17,000 MW on average, peaking at approximately 18,400 MW; natural gas resources averaging over 11,000 MW of forced outage during the event; and SPP operating as a net importer in 81 of the 96 hours of the event). Available at https://www.spp.org/documents/74141/spp_mmu_february_2025_winter_weather_event_report.pdf.

The Market Monitoring Unit concluded that "[w]ithout additional steps to bolster supply adequacy and fuel assurance, the data suggests SPP is susceptible to a load shedding event given an adverse combination of low wind output, precipitation, cold temperatures, and limited energy imports."[28] The North American Electric Reliability Corporation reached a parallel conclusion in its 2025–2026 Winter Reliability Assessment,[29] observing that "grid operators in areas that rely on single-fuel gas-fired generators are exposed to unanticipated generator loss during cold snaps when gas supply interruptions are more prevalent."[30]

NEE raises this not to argue that the addition of any new gas-fired capacity is unreasonable, but because it bears directly on an assumption in both filings. As discussed in Section IV.E, Evergy accredits its new thermal additions using a 3% forced outage rate derived from design specifications, on the stated ground that the units will be highly available and will have firm fuel supply. The regional evidence is that fuel assurance, not equipment availability, is what fails during the winter conditions that drive Evergy's capacity need. A design-specification outage rate does not capture that risk, and neither filing tests the preferred plan against it.

3. Coal Retirement Deferrals Are Occurring Elsewhere, but the Mechanism Driving Them Elsewhere Does Not Apply Here.

EIA reports that the United States electric power sector retired 2.6 GW of coal-fired capacity in 2025 (the least in fifteen years), against 8.5 GW planned at the start of that year, 4.8 GW of planned retirements were delayed, and 1.1 GW were cancelled outright. For comparison,

[28] Southwest Power Pool Market Monitoring Unit, February 2025 Winter Weather Event Review (concluding that "[w]ithout additional steps to bolster supply adequacy and fuel assurance, the data suggests SPP is susceptible to a load shedding event given an adverse combination of low wind output, precipitation, cold temperatures, and limited energy imports"). Available at https://www.spp.org/documents/74141/spp_mmu_february_2025_winter_weather_event_report.pdf.

[29] North American Electric Reliability Corporation, 2025–2026 Winter Reliability Assessment, November 18, 2025. Available at https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[30] *Id*. (statement of Mark Olson, NERC Manager of Reliability Assessment).

operators retired 13.7 GW of coal capacity in 2022.[31] Across all fuel types, operators planned 12.3 GW of retirements in 2025 and completed 4.6 GW, the least since 2008.[32]

EIA attributes the 2025 shortfall principally to emergency orders issued by the United States Department of Energy ("DOE") under the Federal Power Act directing specific units to continue operating. Those orders are involuntary, unit-specific, time-limited, and accompanied by a federal determination of necessity. No such order applies to any Evergy Missouri unit. Evergy's deferrals are voluntary planning decisions, adopted on economic grounds, and they are therefore subject to the analytical requirements of Chapter 22 in a way that a federally ordered deferral would not be.

It is important to note that those orders, and the corresponding delays in retirement, carry significant measurable cost. For example, Consumers Energy reported that compliance with the Department of Energy order covering the J.H. Campbell plant produced $80 million in net costs between May and September 30, 2025 alone—more than $615,000 per day.[33] An independent analysis prepared for several organizations estimated that if comparable orders were issued for all large fossil plants scheduled to retire through 2028, the annual cost to ratepayers could reach $3.1 billion, rising to $5.9 billion under a broader scenario.[34]

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[31] U.S. Energy Information Administration, "U.S. coal-fired generating capacity retired in 2025 was the least in 15 years," April 13, 2026 (reporting 2.6 GW of coal capacity retired in 2025 against 8.5 GW planned, with 4.8 GW of planned retirements delayed and 1.1 GW cancelled, and comparing to 13.7 GW retired in 2022). Available at https://www.eia.gov/todayinenergy/detail.php?id=67427.

[32] U.S. Energy Information Administration, "Retirement delays of U.S. electric generating capacity may continue in 2026" (reporting that operators planned 12.3 GW of retirements in 2025 but retired 4.6 GW, the least since 2008, following emergency orders issued by the U.S. Department of Energy). Available at https://www.eia.gov/todayinenergy/detail.php?id=67206.

[33] CMS Energy Corporation, Quarterly Report on Form 10-Q for the period ended September 30, 2025, at 62. Available at https://d18rn0p25nwr6d.cloudfront.net/CIK-0000811156/2ded8761-a31d-4ff2-8e10-c26bc8a1eaf8.pdf.

[34] Grid Strategies LLC, The Cost of Federal Mandates to Maintain Fossil-Burning Power Plants, August 14, 2025. Available at https://www.edf.org/media/independent-report-finds-trump-administrations-orders-keep-coal-fired-power-plants-running.

II. EVERGY'S PREFERRED RESOURCE PLANS DO NOT COMPLY WITH THE MISSOURI RENEWABLE ENERGY STANDARD, AND THE COST OF COMPLIANCE IS EXCLUDED FROM THE NPVRR ANALYSIS.

The Missouri Renewable Energy Standard ("RES"), adopted by Missouri voters as Proposition C in 2008 and codified at §§ 393.1020–393.1030, RSMo., requires an electric utility to supply no less than fifteen percent of its retail electric sales from renewable energy resources in each calendar year beginning in 2021, with at least two percent of the portfolio requirement derived from solar energy.[35] The Commission's implementing rule is at 20 CSR 4240-20.100.[36] Both 2026 preferred resource plans fail that requirement within the planning horizon. Evergy expressly acknowledges this deficiency in both filings, quantifies the shortfall, and models what curing it would cost—but ultimately adopts preferred plans that do neither. The cost of compliance appears in no NPVRR ranking in either filing, including the retirement analysis on which Evergy's coal extension case rests.

This is the most consequential deficiency NEE has identified in either filing, and it is antecedent to the cost and modeling deficiencies discussed in Sections III and IV. The significance is that the omitted cost does not fall evenly across the plans Evergy compared. The RES obligation is a shortfall in renewable energy, and a portfolio that already contains renewable resources satisfies part of it as a byproduct of its own economics. EMM's preferred plan contains almost none—150 MW of solar and no wind across twenty years—meaning that it carries substantially the entire compliance obligation. The consequence is that bringing compliance inside the model does not raise every plan by the same amount. It raises the preferred plan most and the plans Evergy

[35] Section 393.1030.1 RSMo. (describing the portfolio requirement of no less than fifteen percent in each calendar year beginning in 2021, with at least two percent of each portfolio requirement derived from solar energy). Available at: https://revisor.mo.gov/main/OneSection.aspx?section=393.1030.
[36] Section 393.1030 RSMo.; 20 CSR 4240-20.100. Evergy states the standard as 14.7% of retail sales from non-solar renewable resources and 0.3% from solar (EMM 2026 Annual Update, § 10.8, at 100).

ranked lowest least. Section II.D below sets out what Evergy's own figures indicate that reordering would look like.

A. Both Preferred Plans Fail to Meet the Renewable Energy Standard Within the Planning Horizon.

EMM projects its RES obligation year by year across the planning horizon, rising from 1,378,548 MWh of non-solar renewable energy and 28,134 MWh of solar in 2026 to 2,766,967 MWh and 56,469 MWh respectively in 2045.[37] Against that obligation, EMM states that the 150 MW solar resource added in 2028 satisfies the solar carve-out throughout the horizon, but that "beginning in 2036, Evergy Metro's planned renewable generation falls short of the total target amount," and that because renewable energy credits may be banked for up to three years, "Evergy Metro would need [a] source of renewable energy by 2037 to continue to meet the standard."[38]

EMW reports the same failure one year later, stating that its 2026 Preferred Plan "falls short in 2037."[39] EMW characterizes the 150 MW solar resource it added in 2035 as a resource that "delays the onset of the RES compliance gap," not one that closes it.[40]

The magnitude of the EMM shortfall is not immaterial and does not stabilize. EMM reports that Preferred Plan ACAA is short 246 average hourly MWh by 2045, requiring ten 150 MW solar units or five 150 MW wind units to cure.[41] NEE calculates that shortfall as approximately 2,154,960 MWh annually—roughly 78% of the non-solar obligation Evergy itself projects for that year. The gap widens over time because EMM plans no new renewable generation after 2028 while its existing wind purchased power agreements expire during the same period, a dynamic Evergy

[37] EMM 2026 Annual Update, Table 29, at 101.
[38] *Id.*, § 10.8, at 101.
[39] EMW 2026 Annual Update, § 14.3, at 133.
[40] *Id.*, § 12.3.2, at 113.
[41] EMM 2026 Annual Update, Table 46, at 138. NEE calculates the annual energy equivalent as 246 MWh × 8,760 hours = 2,154,960 MWh, or approximately 78% of the 2,766,967 MWh non-solar requirement Evergy projects for 2045 in Table 29.

acknowledges when it explains that resources added in 2040 and beyond "replace expiring wind PPA contracts."[42]

B. Evergy Did Not Calibrate Its Capacity Expansion Modeling to Achieve Compliance with the RES.

In the special contemporary issues section of each filing, Evergy states that graphs and metrics gauging RES performance are included in the plan workbook workpapers, but that "capacity expansion models were not calibrated to solve for this."[43] Evergy attributes the outcome to "recent policy headwinds favoring dispatchable, base load generation to meet emerging capacity needs."

That explanation confirms the deficiency rather than excusing it. Federal tax policy may have changed the economics of renewable resources, but it has not amended the Missouri Renewable Energy Standard. The RES is a legal mandate within the meaning of 20 CSR 4240-22.020(28), which defines legal mandates to include state legislation and state administrative rules affecting a utility's loads, resources, or resource plans. Chapter 22 does not permit a utility to treat a legal mandate as an optional objective that yields when other planning considerations point elsewhere.

The fundamental objective of the resource planning process requires that the utility provide energy services "in compliance with all legal mandates." A capacity expansion model that is not calibrated to achieve compliance with a legal mandate therefore cannot produce a plan that satisfies it.

[42] *Id*., § 12.3.3, at 115.
[43] *Id*., § 14.3, at 137–138.

C. Neither Filing Develops a Compliance Benchmark Resource Plan or an Optimal Compliance Resource Plan.

20 CSR 4240-22.060(3)(A) requires the utility to develop and document at least one alternative resource plan ("ARP") for each of several enumerated cases. Three are directly implicated in the instant scenario. First, Evergy must examine a case that minimally complies with legal mandates for renewable energy resources, which "constitutes the compliance benchmark resource plan for planning purposes."[44] Second, it must examine a case that optimally complies with those mandates, "where every legal mandate is at least minimally met."[45] Finally, Evergy must examine a case utilizing only renewable energy resources up to their maximum potential capability in each year, which "constitutes the aggressive renewable energy resource plan."[46]

Neither the plan keys nor the base plan descriptions in either filing identify such plans.[47] EMM's fifteen ranked plans consist of three retirement-date variants, four near-term build subtractions, and eight critical uncertain factor ("CUF") endpoint optimizations. EMW's plans have the same architecture. In short, none of Evergy's plans are constructed to comply with the legal mandate of the RES, and none are designated as a compliance benchmark plan.

Plans ACAK and ACAL (EMM) and Plans ADAK and ADAL (EMW) are the closest analogues, but they do not fulfill the requirement. They are presented in a separate section as illustrative compliance options rather than as ARPs carried through the integration and risk analysis. Evergy did not rank these plans among the base plans and similarly did not test these plans across the CUF endpoints as 20 CSR 4240-22.060(4) and (7) require of ARPs. EMM Plans

[44] 20 CSR 4240-22.060(3)(A)1.
[45] 20 CSR 4240-22.060(3)(A)5.
[46] 20 CSR 4240-22.060(3)(A)2.
[47] EMM 2026 Annual Update, Tables 12–14, at 74–75; EMW 2026 Annual Update, Tables 10–12, at 72–73.

ACAK and ACAL add 1.5 GW of solar and 750 MW of wind, respectively, each in a single year.[48] EMW Plans ADAK and ADAL add 600 MW of solar and 450 MW of wind, each in 2037.[49] Evergy states only that "procuring solar additions would be a lower cost option for meeting the RES requirements than wind."[50]

D. The Cost of Compliance Is Excluded from Every NPVRR Ranking, Including the Coal Retirement Comparison.

Evergy excludes the cost of compliance with the Missouri RES requirements from every NPVRR ranking. The consequence of this omission is that every plan ranking in the EMM filing understates the cost of the preferred portfolio by an amount larger than the entire range across which Evergy ranked its plans. Table 3 places Evergy's own figures side by side.

Table 3. Probability-weighted NPVRR of the preferred plans compared to the renewable energy standard compliance plans[51]

Plan	Probability-weighted NPVRR ($ millions)	Difference from Preferred Plan ($ millions)
Evergy Metro		
Plan ACAA — 2026 Preferred Plan	32,839	—
Plan ACAK — RES compliance, solar additions	**34,805**	**+ 1,966**
Plan ACAL — RES compliance, wind additions	**34,924**	**+ 2,084**
Memo: claimed benefit of coal extensions		− 624
Evergy Missouri West		
Plan ADAA — 2026 Preferred Plan	23,277	—
Plan ADAK — RES compliance, solar additions	**23,892**	**+ 615**
Plan ADAL — RES compliance, wind additions	**24,066**	**+ 789**
Memo: claimed benefit of coal extensions		− 128

[48] EMM 2026 Annual Update, § 10.8, at 103–104.
[49] *Id.*, § 10.8, at 99–100 (Plan ADAK tests 600 MW of solar in 2037; Plan ADAL tests 450 MW of wind in 2037); *id.*, Table 28, at 101.
[50] EMM 2026 Annual Update, § 10.8, at 101–102; § 14.3, at 138.
[51] *Id.*, Table 30, at 104; EMW 2026 Annual Update, Table 28, at 101. Evergy reports the ACAL difference as $2,084 million; the tabulated values yield $2,085 million. The memo lines are drawn from EMM 2026 Annual Update, Table 41, at 127, and EMW 2026 Annual Update, § 13.4, at 122.

Three relationships follow from Evergy's numbers. First, EMM's fifteen ranked plans span $639 million from lowest to highest.[52] The lower of the two compliance plans costs $1,966 million more than the Preferred Plan—more than three times the entire spread of the ranking exercise, and $1,342 million more than even the highest-cost plan Evergy ranked. Every compliant portfolio Evergy modeled lies outside the range of every portfolio it evaluated.

Evergy has not run an analysis as to the effects on plan ranking if compliance was properly considered, and NEE cannot run that analysis on the public record. However, Evergy's own published figures indicate the direction and the approximate magnitude. EMM's Preferred Plan ACAA carries 150 MW of solar and requires 1.5 GW more to reach compliance, at $1,966 million. EMM's Plan ACAF—optimized for high gas prices and high carbon costs—carries 2,250 MW of solar, more than the compliance plan adds, and ranks $397 million above the Preferred Plan on the basis Evergy used. On a compliance-inclusive basis those positions reverse, and by a wide margin: roughly $34,805 million for the Preferred Plan against roughly $33,236 million for a plan Evergy ranked thirteenth of fifteen.

NEE does not offer that figure as a conclusive finding, as there are other material variables such as the timing of renewable additions and the value of the obligation measured in capacity that only Evergy can model. NEE offers this figure simply to show that the omission is likely material to the plan rankings. On Evergy's own numbers, the compliance obligation is roughly three times the entire spread of the ranked plans, and it impacts the plan Evergy selected the most.

In addition, renewable resources added for compliance carry accredited capacity. Accredited capacity is the stated justification for both the coal extensions examined in Section IV.A and the approximately 3,600 MW of new gas-fired capacity in the two preferred plans.

[52] EMM 2026 Annual Update, Table 19, at 91.

Resources Evergy must build to satisfy a legal mandate would meet part of that need, and neither filing accounts for it.

Second, the coal retirement analysis is affected directly for both utilities. EMM reports that extending La Cygne 1, La Cygne 2, and Iatan 1 reduces NPVRR by $624 million relative to the 2025 Annual Update retirement schedule, and EMW reports a corresponding benefit of $128 million from extending Jeffrey 3, Lake Road 4/6, Iatan 1, and Jeffrey 1 and postponing the Jeffrey 2 gas conversion.[53] The unmodeled RES compliance obligation is approximately 3.2 times the Metro figure and 4.8 times the EMW figure. A comparison of retirement schedules conducted inside a portfolio that omits a known, quantified, and legally required cost cannot establish which schedule is least cost. The omitted cost interacts with the retirement decision: renewable additions made for compliance purposes carry accredited capacity, and that capacity bears on when replacement for retiring coal is actually needed.

Third, the omission dwarfs the margins on which Evergy made its actual selection. EMM selected Plan ACAA over Plans ACEA and ACCA notwithstanding that those plans rank $15 million lower, explaining that the difference is "less than 0.05% of the 20-year revenue requirement" and is outweighed by execution and permitting risk.[54] NEE does not object to a utility weighing execution risk. But a filing that resolves a $15 million question with one page of qualitative reasoning—while leaving a $1,966 million legal obligation outside the analysis entirely—has not used the minimization of the present worth of long-run utility costs as its primary selection criterion in any meaningful sense.[55]

[53] *Id.*, Table 16, at 79; *id.*, Table 41, at 127.
[54] *Id.*, § 1.3, at 5; *id.*, § 12.2, at 113–114.
[55] 20 CSR 4240-22.010(2)(B).

E. Neither Filing Addresses the Statutory Retail Rate Impact Limitation, Which is the Only Provision that Could Reduce the Compliance Obligation.

Section 393.1030.2(1), RSMo. and 20 CSR 4240-20.100(5) limit the retail rate impact of RES compliance to one percent.[56] The Missouri Court of Appeals has described the provision's purpose as being "to limit the retail rate impact of the RES so that rates at any time would not exceed one percent of what they would otherwise be if there were no renewable resources included in the [portfolio]."[57]

This limitation is the one factor capable of reducing the obligation NEE quantified above, but neither filing mentions it or otherwise calculates its impact. Moreover, neither filing states whether the preferred plans assume a full fifteen percent obligation or an obligation constrained by the rate impact limitation. The two assumptions produce materially different compliance costs and therefore materially different plan rankings.

NEE takes no position at this stage on how the limitation should be calculated for either utility, or on whether it would, in fact, constrain compliance on these facts. The deficiency is that a resource plan which fails a legal mandate, and which quantifies the cost of curing that failure at $615 million to $2,084 million, must state whether it assumes the statutory limitation applies. If Evergy relies on the limitation, the calculation supporting that reliance belongs in the filings. If Evergy does not, the plans must be built to achieve full compliance.

A related omission concerns the in-state multiplier. Section 393.1030.1, RSMo. and 20 CSR 4240-20.100(3)(G) provide that renewable energy generated at facilities located in Missouri

[56] Section 393.1030.2(1), RSMo.; 20 CSR 4240-20.100(5) (limiting the retail rate impact of renewable energy standard compliance to one percent). Available at: https://www.law.cornell.edu/regulations/missouri/20-CSR-4240-20-100.

[57] *Union Electric Co. v. Public Service Commission*, No. WD74896, slip op. at 13 (Mo. Ct. App. 2012) ("4 CSR 240-20.100(5) is consistent with the intent of section 393.1030.2(1), which is to limit the retail rate impact of the RES so that rates at any time would not exceed one percent of what they would otherwise be if there were no renewable resources included in the [portfolio].").

counts toward compliance at a factor of 1.25.[58] Neither filing mentions the multiplier, and neither states whether the compliance plans it models—1.5 GW of solar or 750 MW of wind at Evergy Metro, and 600 MW of solar or 450 MW of wind at EMW—assume in-state or out-of-state siting. The distinction changes the megawatts required to close the gap by roughly a fifth, and therefore changes the compliance cost the filings report.

F. The Compliance Gap Widens Under Every Large Load Contingency Plan.

The RES obligation is calculated as a percentage of retail sales. Because every contingency plan in both filings adds large load customers, every contingency plan increases the obligation while adding little or no renewable generation. EMM quantifies the result, explaining that against the Preferred Plan's shortfall of 246 average hourly MWh by 2045, the shortfall rises to 322 MWh under Plan CCAA, 307 MWh under Plan DCAA, and 448 MWh under Plan ECAA—requiring up to eighteen 150 MW solar units or nine 150 MW wind units.[59] EMW reports the same pattern.[60]

Evergy performed no NPVRR analysis of the contingency plans, stating that the comparison in the base case makes it "evident that fulfilling the RES requirement for the varying large load scenarios would result in much more expensive plans when compared to the Preferred Plan." That observation is correct and is the reason the analysis is necessary, rather than a justification for its omission. Under 20 CSR 4240-22.070(4), contingency resource plans are the plans that become preferred if critical uncertain factors exceed the limits within which the preferred plan is judged appropriate,[61] and each must satisfy the fundamental objective of 20 CSR 4240-22.010(2)—including compliance with all legal mandates. Evergy has identified a set of

[58] Section 393.1030.1, RSMo.; 20 CSR 4240-20.100(3)(G) (applying a factor of 1.25 to renewable energy generated at facilities located in Missouri for purposes of compliance).
[59] EMM 2026 Annual Update, Table 46, at 138.
[60] EMW 2026 Annual Update, Table 47, at 134.
[61] 20 CSR 4240-22.070(4).

contingency plans in which the compliance gap is larger than its legally deficient preferred plan, but has failed to appropriately analyze the cost of those plans.

This material deficiency will have reverberating impacts in future Commission proceedings. Under 20 CSR 4240-22.080(18), Evergy must certify in future proceedings that a requested action is substantially consistent with the preferred resource plan in its most recent annual update.[62] EMM states that it intends to file a certificate of convenience and necessity application for the Mullin Creek #2 simple-cycle gas turbine in May 2026, and both utilities describe further applications to follow. Those certifications will reference preferred plans that do not satisfy RES requirements.

G. Recommended Remedies.

NEE recommends that the Commission direct Evergy to address the following in supplemental workpapers filed in these dockets and in each utility's next annual update or triennial compliance filing:

- Develop and document a compliance benchmark resource plan and an optimal compliance resource plan for each utility, as required by 20 CSR 4240-22.060(3)(A)1 and (3)(A)5, in which the RES is modeled as a binding constraint in the capacity expansion model rather than evaluated after the fact.
- Develop and document an aggressive renewable energy resource plan for each utility as required by 20 CSR 4240-22.060(3)(A)2, utilizing renewable energy resources up to their maximum potential capability in each year of the planning horizon and without the annual build limits discussed in Section III below.

[62] 20 CSR 4240-22.080(18).

- Rank each of the foregoing plans across all CUF endpoints on the same basis as the base plans, and report the probability-weighted NPVRR of each alongside the Preferred Plan.
- Restate the coal retirement comparison—Plans AAAA, ABAA, and ACAA at Evergy Metro, and Plans AAAA through ADAA at EMW—within a portfolio that satisfies the RES, and report whether the ranking of retirement schedules changes.
- Report the RES compliance position and the incremental cost of compliance for each contingency resource plan, consistent with 20 CSR 4240-22.070(4)(C).
- State whether the preferred plans assume a compliance obligation constrained by the retail rate impact limitation at § 393.1030.2(1), RSMo. and 20 CSR 4240-20.100(5); if so, provide the supporting calculation, and if not, confirm that the plans are built to achieve full compliance. State also whether the modeled compliance resources are assumed to be sited in Missouri for purposes of the 1.25 multiplier.

Finally, NEE notes that the captions to EMW Figures 43 and 44 transpose the two compliance plans relative to EMW's own Table 12 and Table 28, which identify Plan ADAK as the solar compliance plan and Plan ADAL as the wind compliance plan.[63] Evergy should correct the figure captions.

III. THE COMMISSION SHOULD DIRECT EVERGY TO RESOLVE PERSISTENT DEFICIENCIES IN ITS RESOURCE PLANNING METHODS AND ASSUMPTIONS.

The deficiencies described in this Section are not new. Indeed, NEE and other stakeholders have raised each of these deficiencies in prior Evergy resource planning proceedings in Missouri,

[63] EMW 2026 Annual Update, Table 12, at 73 and Table 28, at 101, identify Plan ADAK as the RES solar additions plan and Plan ADAL as the RES wind additions plan. The captions to Figures 43 and 44, at 100, reverse those designations. The narrative at § 10.8, at 99–100, agrees with Tables 12 and 28.

Kansas, or both, and each remains unresolved in the 2026 Annual Updates. Several of these deficiencies have now persisted across three consecutive planning cycles.

NEE raises them again here for a specific reason. The inputs discussed below—specifically, the delivered price of gas, the probability weights on the critical uncertain factors, the escalation applied to each resource class, and the annual limits on what the model may build—are key factors that determine which portfolio the capacity expansion model selects. Whether the preferred plans satisfy the fundamental objective of 20 CSR 4240-22.010(2) cannot be assessed until they are resolved.

A. Evergy's Natural Gas Fuel Price Forecast Does Not Reflect Delivered Cost.

This is NEE's longest-running dispute with Evergy's resource planning, and it is the one deficiency from the 2024 Triennial joint filing process that the parties could not resolve. NEE has designated it Deficiency 7 and renewed it in each subsequent cycle, including in Evergy's 2025 Predetermination Application for the Viola and McNew combined-cycle units.[64]

The importance of this deficiency is demonstrable in Evergy's own delivered cost history. Delivered gas costs at Evergy's Missouri generating stations exceeded $8 per MMBtu in five of the past six winters and averaged $6.71 per MMBtu during winter months since 2019. In January 2024, delivered cost ran approximately 170% above the Henry Hub price for that month.[65] A forecast that begins at Henry Hub and applies an undisclosed scalar cannot reproduce that record, and the 2026 filings make no attempt to reconcile the two.

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[64] NEE Comments on Evergy's 2025 Annual Update filings (May 2025). Deficiency 7 was the sole deficiency from the 2024 Triennial joint filing process that could not be resolved, and NEE renewed it in Evergy's 2025 Predetermination Application for the Viola and McNew combined-cycle units.

[65] *Id*. Delivered gas costs at Evergy's Missouri generating stations exceeded $8/MMBtu in five of the past six winters and averaged $6.71/MMBtu during winter months since 2019; delivered cost in January 2024 ran approximately 170% above the Henry Hub price for that month.

Both filings footnote the fuel price discussion in Section 4.1 to 20 CSR 4240-22.040(5) and (5)(A), which is the provision requiring fuel price forecasts "including fuel delivery costs."[66] Having invoked that provision, Evergy presents a forecast that is benchmarked to Henry Hub and translated to delivered cost by a scalar whose values are never stated.

Evergy's methodology is described as follows. Evergy develops an internal budgeting forecast from vendor forecasts and forward markets, drawing on IHS Markit, the EIA, S&P Global Platts, Energy Ventures Analysis, CME Futures, and ICE. Evergy then scales that internal forecast by EIA's fundamental supply and demand forecasts to produce high and low cases, using the "High Oil and Gas Supply" case to derive the low gas price forecast and the "Low Oil and Gas Supply" case to derive the high.[67] Evergy uses a "Henry Hub Natural Gas Scalar" to translate the benchmark into delivered cost at Evergy's generating units. That scalar is presented only as a graph.[68]

This methodology creates three distinct deficiencies. First, the scalar is not quantified. Neither filing states its value in any year, explains how it was derived, or describes how it behaves under stress conditions. A reviewer cannot determine what delivered gas cost Evergy has assumed at any plant in any year of the planning horizon. A forecast of delivered cost that cannot be read is not a forecast of delivered cost for purposes of 20 CSR 4240-22.040(5)(A).[69]

Second, neither filing addresses the basis differential between Henry Hub and the delivery points serving Evergy's Missouri generating fleet, or how that differential has behaved during winter cold events. Regional delivered gas prices during such events have historically diverged sharply from the Henry Hub benchmark, and Section I.B.2 above describes what happened to gas-

[66] EMM 2026 Annual Update, § 4.1.1, at 27 and n.27; EMW 2026 Annual Update, § 4.1.1, at 26 and n.26. Both filings footnote § 4.1 to "20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A)."
[67] EMM 2026 Annual Update, § 4.1.1, at 27; EMW 2026 Annual Update, § 4.1.1, at 26.
[68] EMM 2026 Annual Update, Figure 9, at 29; EMW 2026 Annual Update, Figure 9, at 28.
[69] 20 CSR 4240-22.040(5)(A).

fired generation across SPP during the most recent one. An annual-average forecast anchored to Henry Hub and adjusted by an undisclosed scalar cannot capture that exposure. The exposure grows with each gas-fired addition in the preferred plans.

Third, Evergy only updated the high case scenario. Evergy states that EIA's low and mid natural gas supply cases in the 2025 Annual Energy Outlook "were consistent with the previous 2023 forecasts," and incorporates only the increased high case into the 2026 modeling.[70] The mid case carries a 50% probability weight in both filings and therefore drives the expected cost of every alternative resource plan. That case now rests on fundamentals developed in 2023 and carried through three planning cycles.

B. Evergy Assigns Probability Weights to Critical Uncertain Factors Without Supporting Analysis, and Its Own Sensitivity Shows Those Weights Determine the Outcome.

Evergy does not select one value for each CUF and model a single future. It models every combination, including three natural gas price levels, three carbon cost levels, and three construction cost levels, producing twenty-seven endpoints, and calculates a separate NPVRR for each plan at each endpoint. Evergy then collapses those twenty-seven results into one figure by weighting each endpoint according to the assigned probabilities and averaging. That single probability-weighted NPVRR is the number on which every ranking in both filings rests. The consequence is that the probability weights are an input that determines the ranking directly. A plan that performs well in high-gas futures and poorly in low-gas futures will rank differently depending only on how much weight the low-gas future receives.

Both filings assign the following probability weights to the three CUFs: natural gas price, 35% low, 50% mid, 15% high; CO2 emissions restrictions, 25% low, 60% mid, 15% high; and

[70] EMM 2026 Annual Update, § 4.1.1, at 27; EMW 2026 Annual Update, § 4.1.1, at 26.

construction cost, 25% low, 50% mid, 25% high.[71] Neither filing provides any analysis supporting those figures.

20 CSR 4240-22.060(7)(C)1 requires the utility to provide a discussion of the method used to determine the cumulative probability distribution, including "an explanation of how the critical uncertain factors were identified, how the ranges of potential outcomes for each uncertain factor were determined, and how the probabilities for each outcome were derived," together with "analyses supporting the utility's choice of ranges and probabilities for the uncertain factors."[72] The weights appear in a single table in each filing with no accompanying explanation of how they were derived, no citation to any external source, and no explanation of why a 15% probability is appropriate for a high gas price case in a market Evergy elsewhere describes as subject to unprecedented demand growth.

The significance of that omission is established by Evergy's own analysis. In response to a prior joint agreement, EMM tested how variations in CUF probability weightings would change the relative economics of its resource plans, using seven weighting variations and comparing several plans against Preferred Plan ACAA. One of those comparisons involved Plan ACAI, the plan optimized for the high natural gas price forecast, which substitutes solar for battery storage in 2030, advances the half CCGT from 2032 to 2031, and adds 900 MW of solar later in the horizon.

[71] EMM 2026 Annual Update, Table 15, at 76; EMW 2026 Annual Update, Table 13, at 73.
[72] 20 CSR 4240-22.060(7)(C)1.B.

Table 4. NPVRR difference, Plan ACAI less Plan ACAA, under alternative CUF probability weightings ($ millions)[73]

Probability weighting (Low / Mid / High)	Natural gas price	CO_2 tax	Construction cost
Variation 1 — 75 / 25 / 0	+ 131	+ 202	− 4
Variation 2 — 50 / 50 / 0	+ 124	+ 171	+ 34
Variation 3 — 25 / 75 / 0	+ 117	+ 140	+ 72
Variation 4 — 33 / 33 / 33	+ 39	+ 67	+ 114
Variation 5 — 0 / 75 / 25	+ 49	+ 47	+ 151
Variation 6 — 0 / 50 / 50	**− 11**	**− 15**	**+ 192**
Variation 7 — 0 / 25 / 75	**− 72**	**− 77**	**+ 233**

Under the weights Evergy actually applied, Plan ACAI is $87 million more expensive than the Preferred Plan.[74] Shifting weight toward the high natural gas case narrows and then reverses that result. At a 25% high-case weight, the gap falls to $49 million; at a 50% high-case weight, Plan ACAI becomes the less expensive plan. Evergy states the conclusion itself: Plan ACAI "becomes the cheaper plan when the high and mid forecasts are each at 50% probability, and gains value as the high forecast probability increases for NG price or CO2 tax."[75]

The implication is that the identification of the least-cost plan turns on a probability assignment for which the filings provide no support, and that the direction of the error—if the weights understate upside gas price risk—favors a more thermal-intensive portfolio. Because the weights are outcome-determinative, 20 CSR 4240-22.060(7)(C)1.B requires that they be supported by the analysis Evergy omitted from its filings.

The same pattern appears in the plans optimized for individual futures. At both utilities, the ARP optimized for a high gas price future adds substantial solar and reduces gas-fired

[73] EMM 2026 Annual Update, Table 39, at 124. Evergy presents negative values in parentheses; NEE has restated them with minus signs.
[74] *Id*., Table 19, at 91 (Plan ACAI at $32,926 million; Plan ACAA at $32,839 million).
[75] *Id*., § 13.1, at 125.

additions, and the plan optimized for high gas prices combined with high carbon costs does so more dramatically still.[76] EMW Plan ADAB—the plan optimized for high gas prices combined with high carbon costs—adds approximately 3,000 MW of renewable resources and requires no additional thermal capacity beyond a single half CCGT deferred to 2033.[77] That a portfolio requiring essentially no new thermal capacity is available to EMW at all confirms that the thermal-intensive composition of the preferred plan is a function of the assumed probabilities, not of physical or engineering necessity.

C. Evergy's Resource Cost Escalation Assumptions Are Unsourced, Unreviewable, and Applied to Renewable and Thermal Resources in a Ratio Opposite to Published Data.

Evergy states that total costs for new natural gas-fired additions are "about 20-25% higher than forecasted in the 2025 Annual Update," that costs for developing new wind and solar projects "have increased by about 30%," and that storage project costs "have increased by about half as much" as renewables, or roughly 15%.[78] Those three figures determine the relative economics of every alternative resource plan in both filings. Neither filing identifies the source of any of them.

1. The Assumptions Are Neither Sourced nor Testable.

Evergy attributes its cost updates generally to the 2025 all-source request for proposals, recent development experience, and forecasts published by the Energy Information Administration and the National Renewable Energy Laboratory.[79] No filing states which input produced which escalation figure, provides the derivation, or compares any figure to a published benchmark. The underlying cost curves—Figures 19 and 22 in each filing—are designated confidential in their

[76] *Id*., § 10.6, at 87 and Figure 36, at 87; EMW 2026 Annual Update, § 10.6, at 83 and Figure 37, at 83.
[77] EMW 2026 Annual Update, § 10.6, at 85; § 13.1, at 120. The two passages describe the composition of Plan ADAB inconsistently — § 10.6 states 2,550 MW of solar and 600 MW of wind, while § 13.1 states 2,400 MW of solar and 600 MW of wind.
[78] EMM 2026 Annual Update, § 2.4, at 18; EMW 2026 Annual Update, § 2.4, at 18.
[79] EMM 2026 Annual Update, § 6, at 44; EMW 2026 Annual Update, § 6, at 43.

entirety,[80] so the percentages recited in the narrative are the only cost information available to the public.

NEE does not object to confidential treatment of project-specific pricing. But 20 CSR 4240-22.040(5)(B) requires the utility to develop, describe, and document estimated capital costs for each supply-side candidate resource option, and 20 CSR 4240-22.060(4) requires that costs be quantified "at a similar level of detail and precision for all resource types." An escalation rate stated as a single percentage in a narrative sentence, without source, vintage, or methodology, does not permit the Commission or stakeholders to assess whether resource types have been treated consistently.

EMW's ARPs illustrate this issue. At EMW, the ARPs adding 150 MW and 300 MW of storage rank $171 million and $331 million above the preferred plan respectively,[81] and no storage of any kind appears in the EMW preferred plan across the twenty-year horizon. Those rankings are a direct function of a storage cost input that is not documented and cannot be examined.

2. Where Public Data Exists, the Relative Escalation Cuts the Other Way.

Evergy escalates renewable resource costs at roughly one and a half times the rate it escalates thermal resource costs—approximately 30% against 20 to 25%. Publicly available capital cost data points in the opposite direction.

Evergy's thermal resource cost escalation assumptions have formed a persistent deficiency in its recent IRP filings. Working with Energy Futures Group, NEE previously found Evergy's combined-cycle capital cost estimates below peer benchmarks in every filing cycle since 2023—against the Orange County Advanced Power Station at $1,052 per kW in 2023, and against

[80] EMM 2026 Annual Update, Figures 19 and 22, at 46 and 50; EMW 2026 Annual Update, Figures 19 and 22, at 45 and 49.
[81] EMM 2026 Annual Update, § 2.4, at 19; EMW 2026 Annual Update, § 2.4, at 18–19.

comparable single-train configurations at Dominion Energy South Carolina and Santee Cooper at approximately $1,547 per kW as adjusted in 2024.[82] The 2026 assumptions continue that pattern. BloombergNEF reports that the average capital cost of a United States combined-cycle gas plant rose from under $1,500 per kilowatt in 2023 to $2,157 per kilowatt in 2025, an increase of 66% over two years, or approximately 29% per year compounded.[83] Lazard's 2026 Levelized Cost of Energy+ report, released in July 2026, states that United States utility-scale solar construction costs rose approximately 18% year over year, and places the levelized cost of combined-cycle gas generation at $90 per megawatt-hour against $78 a year earlier—the highest level in the nineteen years the analysis has been published.[84]

Those figures demonstrate that thermal capital costs are escalating at a higher annual rate than utility-scale solar, not a lower one. Evergy's assumptions invert that relationship. NEE does not contend that any particular published figure should be substituted for Evergy's own; project-specific costs legitimately differ from national averages, and Evergy has access to bid data that no public source has. The deficiency is that neither filing acknowledges the divergence, identifies the data on which its figures rest, or explains why its relative treatment of the two resource classes differs from the direction of the public record.

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[82] Energy Futures Group analysis submitted on behalf of NEE (2023), benchmarking against the Orange County Advanced Power Station at $1,052/kW; Energy Futures Group analysis (2024), comparing Evergy's estimates to comparable 1x1 combined-cycle configurations at Dominion Energy South Carolina and Santee Cooper at approximately $1,547/kW as adjusted.

[83] BloombergNEF analysis, as reported in Bloomberg, "Cost to Build Natural Gas-Fired Power Plant Surges 66%, BNEF Says," April 23, 2026 (average US combined-cycle project cost of $2,157/kW in 2025, against under $1,500/kW in 2023). Available at: https://www.bloomberg.com/news/articles/2026-04-23/cost-to-build-natural-gas-fired-power-plant-surges-66-bnef-says.

[84] Lazard, Levelized Cost of Energy+ (19th ed.), released July 13, 2026 (combined-cycle gas LCOE of $90/MWh against $78/MWh a year earlier, the highest in the series; US utility-scale solar construction costs up approximately 18% year over year; solar and onshore wind LCOE each up more than 10%). Available at: https://www.lazard.com/research-insights/levelized-cost-of-energyplus-lcoeplus/.

Storage warrants a separate discussion. Published storage cost data moved sharply during the period these filings cover, and it moved in both directions. Wood Mackenzie and the American Clean Power Association reported in December 2025 that utility-scale battery system prices had fallen 11% year over year through the third quarter, from $1,050 to $938 per kilowatt. In March 2026 the same partnership reported that those prices had risen 23% year over year across full-year 2025.[85] Evergy's approximately 15% increase falls within that range. NEE therefore does not contend that Evergy's storage assumption is directionally wrong. Instead, NEE contends that an input this volatile that determines whether EMW adds any storage at all, and that carries a cost difference of $171 million to $331 million at EMW, must be stated with its source and vintage rather than as an unattributed percentage.

Finally, Evergy attributes part of its storage cost assumption to sourcing restrictions on components from foreign entities of concern, which it estimates elsewhere at a premium of 10 to 15% or more.[86] That is a real and quantifiable cost pressure, and NEE does not dispute it. However, it should be presented as a discrete adder above a stated market baseline so that the baseline and the premium can each be evaluated, rather than folded into a single undifferentiated escalation figure.

[85] American Clean Power Association and Wood Mackenzie, US Energy Storage Monitor (Q3 2025 edition, released December 16, 2025) (utility-scale battery system prices down 11% year over year, from $1,050/kW to $938/kW); American Clean Power Association and Wood Mackenzie, US Energy Storage Monitor (full-year 2025 edition, released March 24, 2026) (utility-scale battery system price per kW increased 23% year over year). Available at: https://cleanpower.org/news/us-energy-storage-monitor-q3-2025-woodmackenzie-acp/ and https://www.woodmac.com/press-releases/2025-u.s.-energy-storage-installations-set-new-record-surpass-2024-by-52.

[86] EMM 2026 Annual Update, § 12.4.2, at 119; EMW 2026 Annual Update, § 6.1, at 44.

D. Evergy Applies Binding Annual Build Limits to Renewable and Storage Resources That It Relaxes Only Outside the Economic Analysis.

Both utilities publish their annual build limits for the various resource types. EMM's are reproduced in Table 5 below. EMW's are materially the same: wind capped at 150 MW per year from 2030 forward, solar at 150 MW per year through 2031 and 300 MW thereafter, and storage on the same schedule—against 355 MW of combined cycle, 440 MW of combustion turbine, and 373 MW of reciprocating engine capacity per year from 2033.[87,88]

Table 5. Evergy Metro base build limit assumptions (MW per year)

Year	Solar	Wind	Battery	CC	CT	RICE
2027	—	—	—	—	—	—
2028	150 (PTC)	—	—	—	—	—
2029	150	—	150	—	—	—
2030	150	150	150	—	—	—
2031	150	150	150	710	Mullin Creek #2	373
2032	300	150	300	710	—	373
2033+	300	150	300	355	440	373

Table 5 illustrates the structural asymmetry these build limits create. From 2033 forward, the model may select up to 1,168 MW per year of thermal capacity across three technologies, against 750 MW per year of solar, wind, and storage combined. Wind is unavailable entirely until 2030 and capped at 150 MW per year for the remaining fifteen years of the horizon. This limit alone forecloses any portfolio resembling the 1.5 GW of wind Evergy selected between 2031 and 2042 in its 2025 preferred plan for EMW, or the 450 MW it selected for EMM.

These arbitrary and unsubstantiated build limits have persisted across four filing cycles, and the wind, solar, and storage limits have been binding in substantially every ARP Evergy has

[87] EMW 2026 Annual Update, Table 9, at 71.
[88] EMM 2026 Annual Update, § 12.4.2, at 119; EMW 2026 Annual Update, § 6.1, at 44.

tested. This means the model has been prevented from selecting additional clean resources in cases where it otherwise would have.[89]

Evergy describes these limits as reflecting project availability and the need to maintain financial metrics and an investment-grade credit rating. However, neither claimed justification is adequately explained or supported. Moreover, a constraint that binds only on one side of the resource comparison does not test whether renewable and storage resources are economic; rather, it assumes an answer. Further, a constraint justified by credit metrics should be applied to capital deployment generally, not to particular technologies—the thermal additions permitted in the same years are larger in both megawatts and dollars.

The most direct evidence that these limits are not binding constraints in fact is that Evergy relaxed them itself. The renewable energy standard compliance plans discussed in Section II add 1.5 GW of solar in a single year in Plan ACAK and 750 MW of wind in a single year in Plan ACAL.[90] Those additions are five times the annual solar limit and five times the annual wind limit that constrained every economic alternative resource plan in the EMM filing. The same is true at EMW, where Plan ADAK adds 600 MW of solar in 2037 against a 300 MW annual limit and Plan ADAL adds 450 MW of wind against a 150 MW annual limit.[91] Evergy therefore demonstrated at both utilities that its model can select renewable resources at these volumes, and elected not to test whether doing so would be economic.

This is also why no aggressive renewable energy resource plan appears in either filing. 20 CSR 4240-22.060(3)(A)2 requires an ARP utilizing renewable energy resources "up to the

[89] NEE Comments on Evergy's 2024 Triennial Compliance Filing and 2025 Annual Update filings. Build limits on wind, solar, and storage have been binding in substantially every alternative resource plan tested across four filing cycles.
[90] EMM 2026 Annual Update, § 10.8, at 103–104; Figures 42 and 43, at 103–104.
[91] *Id.*, § 10.8, at 103–104; EMW 2026 Annual Update, § 10.8, at 99–100 (Plan ADAK tests 600 MW of solar in 2037; Plan ADAL tests 450 MW of wind in 2037); EMW 2026 Annual Update, Table 28, at 101.

maximum potential capability of renewable resources in each year of the planning horizon."[92] A plan constrained to 150 MW of wind per year is not that plan, and no such plan can be developed while those limits remain in place.

E. Evergy Models No EE Programs After 2026 and Relies on a Potential Study Now in Its Fourth Planning Cycle.

Evergy's demand-side analysis has three related deficiencies. First, both utilities modeled the approved MEEIA Cycle 4 portfolio, but nothing beyond it. Evergy states that it "did not model any additional energy efficiency programs after the approved cycle ends in 2026," citing "the uncertainty of future MEEIA programs given the tenor of Staff, OPC, and Commission comments during the filing."[93] The consequence is visible in the base case impacts. EMM's Missouri jurisdictional energy savings decline from 18,940 MWh in 2027 to 1,099 MWh in 2044, a reduction of approximately 94% across the planning horizon; EMW's decline from 10,565 MWh to 228 MWh over the same period, a reduction of approximately 98%.[94]

An integrated resource plan is the analysis that determines what level of demand-side investment is cost-effective. Declining to model future energy efficiency because future program approval is uncertain inverts that relationship, removing the record on which those targeted investments are proposed and evaluated. Chapter 22 does not permit the analysis to be omitted on the ground that its conclusions might not be adopted.

Second, neither filing develops the aggressive demand-side resource plan required by 20 CSR 4240-22.060(3)(A)3—a plan utilizing demand-side resources "up to the maximum

[92] 20 CSR 4240-22.060(3)(A)2.
[93] EMM 2026 Annual Update, § 9, at 66.
[94] *Id.*, Table 8, at 68; EMW 2026 Annual Update, Table 8, at 67. NEE calculates the declines as approximately 94% (Metro, from 18,940 MWh in 2027 to 1,099 MWh in 2044) and 98% (EMW, from 10,565 MWh to 228 MWh).

achievable potential of demand-side resources in each year of the planning horizon."[95] No ARP in either filing tests a higher level of demand-side investment than the approved MEEIA Cycle 4 portfolio. The preferred plan is therefore not tested against the demand-side alternative in accordance with 20 CSR 4240-22.070(1)(C), which requires the preferred plan to utilize demand-side resources to the maximum amount consistent with legal mandates and the public interest.[96]

Third, the demand-side analysis in both filings rests on a market potential study prepared in 2023.[97] That study now underpins the 2024 Triennial Compliance Filing and the 2025 and 2026 Annual Updates. 20 CSR 4240-22.050(2) requires the utility to conduct market research "as necessary to estimate the maximum achievable potential, technical potential, and realistic achievable potential of potential demand-side resource options," and to provide descriptions of studies "that are planned or in progress and the scheduled completion dates."[98] Neither filing identifies a planned or in-progress update, or a scheduled completion date for one.

F. Evergy Models Thermal Resource Ownership at Only Two Levels.

20 CSR 4240-22.040(1) requires the utility to evaluate potential supply-side resource options including "full *or partial* ownership of new plants using existing generation technologies" and "full *or partial* ownership of new plants using new generation technologies."[99] The rule expressly contemplates fractional ownership as a distinct resource option.

Both filings model thermal ownership at two levels only: full ownership, and the 50% share reflected in the "half CCGT" construct that appears throughout both preferred plans.[100] No ARP tests a 25% or 75% share, and neither filing explains why intermediate shares were not evaluated.

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[95] 20 CSR 4240-22.060(3)(A)3.
[96] 20 CSR 4240-22.070(1)(C).
[97] EMM 2026 Annual Update, Appendix C; EMW 2026 Annual Update, Appendix C.
[98] 20 CSR 4240-22.050(2).
[99] 20 CSR 4240-22.040(1) (emphasis added).
[100] EMM 2026 Annual Update, § 12.3.1, at 115; EMW 2026 Annual Update, § 12.2, at 111.

NEE raised this formally in its May 2025 comments and again in testimony in Evergy's 2025 CCN Application, and it has not been addressed. Evergy has held fractional interests in generating assets at other proportions—EMW's existing portfolio includes a 22.2% interest in the Dogwood Energy Center,[101,102] meaning the structure is neither novel nor impracticable for these utilities.

This deficiency is material and has cascading impacts on Evergy's resource planning processes. A smaller ownership share in a thermal project frees capital that could be deployed to storage, solar, or demand-side resources within the same annual build and credit-metric limits Evergy cites as the basis for its build constraints. Modeling ownership at 25%, 50%, 75%, and 100% would allow the capacity expansion model to identify that tradeoff rather than presenting it as unavailable.

G. Neither Filing Identifies the Models Used or Reports the Reliability Results the Rule Requires.

20 CSR 4240-22.060(4)(H) requires that the analysis of alternative resource plans include "a description of the computer models used in the analysis of alternative resource plans."[103] Neither filing names its capacity expansion model, its production cost model, or any reliability model, and neither describes model configuration, temporal resolution, or dispatch settings. A reviewer cannot determine what tool produced the rankings on which both preferred plans rest. That is a step backward. Indeed, in prior cycles Evergy identified PLEXOS as its capacity expansion and production cost model and SERVM as its reliability model, and stakeholders were able to engage with the settings applied to each.

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[101] NEE Comments on Evergy's 2025 Annual Update filings (May 2025); NEE testimony in Evergy's 2025 CCN Application. Evergy Missouri West's existing portfolio includes a 22.2% interest in the Dogwood Energy Center.
[102] EMW 2026 Annual Update, § 1.4, at 7.
[103] 20 CSR 4240-22.060(4)(H).

The omission forecloses review of two questions NEE has pursued since 2023. The first is chronological resolution. Working with Energy Futures Group, NEE identified that Evergy's Partial Chronology setting—two-hour global slicing—cannot capture the multi-hour state-of-charge dynamics that determine the dispatch value of battery storage, and recommended Fitted Chronology with day-level curve fitting. The setting was unchanged through the 2025 Annual Update.[104] Because the 2026 filings disclose neither the model nor its settings, neither the Commission nor stakeholders can determine whether that recommendation was adopted—a question of direct consequence given that storage is absent from the EMW preferred plan entirely.

The second concerns how reliability testing is sequenced. Evergy introduced SERVM in the 2024 Triennial Compliance Filing, but used it to test portfolios after the capacity expansion model had already selected them rather than iterating between the two. When the High Renewables Plan failed the loss-of-load-expectation standard—with approximately 97% of unserved energy falling in summer months—Evergy treated that outcome as support for additional thermal capacity rather than adjusting the portfolio and re-testing. SERVM did not appear in the 2025 Annual Update, and no reliability model is identified in either 2026 filing.[105]

20 CSR 4240-22.060(7)(C)4 separately requires "a plot of the expected level of annual unserved hours for each alternative resource plan over the planning horizon."[106] Neither filing contains that plot for any plan. Every reference to loss of load expectation in both filings is to

[104] NEE and Energy Futures Group first identified the PLEXOS Partial Chronology setting in 2023 and recommended Fitted Chronology with day-level curve fitting. The setting was unchanged through the 2025 Annual Update.
[105] Evergy introduced SERVM in the 2024 Triennial Compliance Filing. When the High Renewables Plan failed the loss-of-load-expectation test with approximately 97% of unserved energy occurring in summer months, Evergy treated that result as support for additional thermal capacity rather than iterating the capacity expansion model toward a portfolio that satisfies the reliability constraint. SERVM does not appear in the 2025 Annual Update.
[106] 20 CSR 4240-22.060(7)(C)4.

SPP's regional studies, which SPP uses to set the planning reserve margin that Evergy applies as an input constraint.[107] A region-wide reserve margin applied uniformly to all load responsible entities is not a portfolio-specific reliability test. It cannot indicate whether the particular mix, duration, and siting of resources in Evergy's preferred plans produces unserved hours, because it is an assumption applied to the plan rather than a result derived from it.

Relatedly, 20 CSR 4240-22.070(1)(D) requires that the preferred plan, in the judgment of utility decision-makers, have sufficient resources to serve load forecasted under the extreme weather conditions developed pursuant to 20 CSR 4240-22.030(8)(B), and provides that if the utility cannot affirm that sufficiency it shall consider an alternative plan or modifications that can meet those conditions.[108] Neither filing makes that affirmation or presents the underlying extreme weather load forecast.

H. Recommended Remedies.

NEE recommends that the Commission direct Evergy to address the following:

- Quantify the Henry Hub Natural Gas Scalar by year, describe its derivation, and state how it adjusts under stress conditions; describe the basis differential between Henry Hub and the delivery points serving each Missouri generating station, including observed behavior during past winter cold events; and confirm whether local basis premiums are included in the fuel cost assumptions used in these filings.
- Update the low and mid natural gas price cases to current fundamentals rather than carrying forward the 2023 outlook, and model intra-year gas price stress scenarios in addition to annual-average cases.

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[107] EMM 2026 Annual Update, § 5.2, at 41; EMW 2026 Annual Update, § 5.2, at 40.
[108] 20 CSR 4240-22.070(1)(D); 20 CSR 4240-22.030(8)(B).

- Provide the analysis supporting the probability weights assigned to each critical uncertain factor, as required by 20 CSR 4240-22.060(7)(C)1.B, including the basis for a 15% weight on the high natural gas price case; and report the probability-weighted ranking of all alternative resource plans under at least one alternative weighting that assigns the high case a minimum of 25%.
- Benchmark thermal, renewable, and storage capital cost assumptions against current independent market data, explain any divergence in direction or magnitude, and present any sourcing premium applied to storage as a discrete quantified adder above a market baseline.
- Rerun the capacity expansion model for each utility without the annual build limits on renewable and storage resources and present the results as alternative resource plans ranked alongside the base plans; alternatively, apply an equivalent annual limit to thermal additions and document the basis for each limit.
- Develop and document the aggressive renewable energy resource plan required by 20 CSR 4240-22.060(3)(A)2 and the aggressive demand-side resource plan required by 20 CSR 4240-22.060(3)(A)3.
- Model energy efficiency programs beyond the approved MEEIA Cycle 4 portfolio across the full planning horizon, and complete and file an updated demand-side market potential study with a stated completion date.
- Model thermal resource ownership at 25%, 50%, 75%, and 100% shares in the capacity expansion model.

- Identify and describe the capacity expansion, production cost, and reliability models used, including the chronological resolution at which battery storage is dispatched, as required by 20 CSR 4240-22.060(4)(H).
- Provide the plot of expected annual unserved hours for each alternative resource plan required by 20 CSR 4240-22.060(7)(C)4, and the extreme weather sufficiency affirmation required by 20 CSR 4240-22.070(1)(D).

IV. NEW DEFICIENCIES ARISING FROM THE 2026 ANNUAL UPDATES.

The deficiencies in this Section arise from analysis NEE performed for the first time in the 2026 Annual Updates and center on the decision to delay or eliminate every coal retirement within the planning horizon at both utilities and on the accreditation and constraint assumptions that accompany that decision. NEE addresses this overarching decision first, and at length, because it is the largest change in either filing and because the supportive analysis does not carry the weight of justifying such a substantive change.

A. The Reported Benefit of Extending the Coal Fleet Consists Principally of Deferred Capital and Deferred Retirement Costs Rather Than Avoided Operating Costs.

Both filings present the coal extensions as producing a customer benefit—*i.e.*, $624 million at EMM and $128 million at EMW on a probability-weighted basis. Both filings also break that benefit into its component costs at what Evergy calls the midpoint endpoint, which is the single combination of mid-range natural gas price, carbon cost, and construction cost assumptions, which Evergy labels M2C. Those components do not support the characterization.

Table 6. Components of the reported coal extension benefit, midpoint (M2C) endpoint ($ millions; negative values reduce NPVRR)[109]

Component	Evergy Metro (Plan ACAA vs. AAAA)	EMW (Plan ADAA vs. AAAA)
Cost to load	+ 4	0
Total fixed costs	− 354	+ 11
Generation cost	− 269	− 81
Emissions cost	+ 222	+ 30
Generator pool revenue	+ 30	+ 17
Generator retirement cost	**− 140**	**− 41**
Net change in NPVRR	**− 567**	**− 98**

Beginning with EMM, it is important to note that the largest single component of its claimed savings is a $354 million reduction in fixed costs, which Evergy explains is "the net of $880 million in reductions due to the elimination and timing differences for new builds and $526 million in increases due to the extension of the coal generators ($482 million) and the RICE addition ($44 million)."[110] The key driver of the result is therefore $880 million of new generation that the extension plan does not build, or builds later. That is a deferral of capital, not an avoidance of cost. The capacity those units would have provided is still required after the extended coal units eventually retire; the analysis simply does not extend far enough to record it.

For EMM, $468 million of the $624 million benefit—*i.e.*, 75%—comes from moving La Cygne 2 and Iatan 1 from March 2040 to "beyond 2045," the final year of the planning horizon. At EMW, $67 million of the $128 million benefit—*i.e.*, 52%—comes from the corresponding treatment of Iatan 1 and Jeffrey 1.[111] Once a unit is placed beyond the horizon, it incurs no

[109] EMM 2026 Annual Update, Table 42, at 128; EMW 2026 Annual Update, Table 43, at 124. Both are stated at the M2C midpoint endpoint. Evergy reports the corresponding probability-weighted benefits as $624 million (Metro) and $128 million (EMW). NEE reproduces Evergy's reported difference column; two EMM line items (emissions cost and generator pool revenue) differ by one million dollars from the difference of the two columns as rounded in the filing.
[110] EMM 2026 Annual Update, § 13.4, at 128.
[111] *Id.*, § 13.4, at 126–127; EMW 2026 Annual Update, § 13.4, at 122.

retirement cost and triggers no replacement capital within the analysis. The majority of the reported benefit at both utilities is produced by relocating costs past the analytical boundary rather than by eliminating them.

NEE's second concern confirms these methodological flaws. Evergy books a $140 million reduction in "generator retirement cost" for EMM and a $41 million reduction for EMW, which Evergy attributes directly to "the extension of operations for the coal resources."[112] Retirement costs are not avoided by operating a unit longer; they are simply incurred later. Counting the deferral as a benefit accounts for 25% of the EMM figure and 42% of the EMW figure. Removing it alone reduces the midpoint benefit from $567 million to $427 million for EMM, and from $98 million to $57 million for EMW.

The EMW figures are the clearer illustration because the plan is smaller. Of EMW's $98 million midpoint benefit, $41 million is deferred retirement cost and $81 million is lower generation cost, offset by fixed costs that rise $11 million and emissions costs that rise $30 million. Extending the EMW coal fleet increases both the fixed cost of the portfolio and its emissions cost. The reported benefit survives only because the retirement deferral and the production cost reduction outweigh those increases.

The comparison is also silent on how the cost of operating these units changes as they age. However, this relationship is well documented. The Sargent & Lundy analysis prepared for the EIA, drawing on FERC Form 1 data, found fixed operations and maintenance costs for operating coal units in the range of $30 to $60 per kW-year during a unit's first thirty years of service. That range rises to $60 to $100 per kW-year in the thirty-to-fifty-year band, and approaches or exceeds

[112] EMM 2026 Annual Update, § 13.4, at 128.

$100 to $120 per kW-year beyond fifty years.[113] EPRI research documents that the escalation accelerates after roughly forty years, as thermal cycling, tube fouling, and deferred maintenance compound.[114]

That relationship will directly impact the units at issue. Missouri operates the largest coal fleet among the five states examined in a recent New Energy Economics assessment—9,048 MW across seventeen units—with an average age of 46.7 years and ten of those seventeen units in the fifty-to-fifty-nine-year cohort, the largest single age concentration in that sample.[115] The units Evergy proposes to operate past 2045 are within or approaching the band in which the published cost curves turn sharply upward. Neither filing models an age-related escalation in fixed operations and maintenance cost for any extended unit, and neither explains why this well-documented relationship should not apply.

The interaction with utilization compounds the effect. Because fixed costs are incurred whether or not a unit runs, each megawatt-hour absorbs a larger share of the same fixed dollars as capacity factor falls. For example, a unit carrying $80 per kW-year in fixed cost allocates that cost at roughly $15 per MWh at a 60% capacity factor and roughly $46 per MWh at 20%.[116] A

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[113] Sargent & Lundy, LLC, Generating Unit Annual Capital and Life Extension Costs Analysis, Project No. 13651-001, prepared for the U.S. Energy Information Administration (published December 2019), analyzing FERC Form 1 data for U.S. coal plants 2002–2016. Available at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[114] Electric Power Research Institute, "Understanding the Price of Flexible Operations," EPRI Journal (August 2022). Available at: https://eprijournal.com/understanding-the-price-of-flexible-operations/.

[115] Alex Hopkins and Bamadou Ouattara, The Economics of Coal-Fired Generation: An Assessment of Ratepayer Risk (New Energy Economics, June 2026), at 22–24, analyzing U.S. Energy Information Administration Form EIA-860, Annual Electric Generator Report, final 2024 release (Missouri: 9,048 MW across 17 units at 8 plants, average age 46.7 years, with 10 of 17 units in the 50–59 year cohort — the largest single age-state concentration in the five-state sample). Available at: https://newenergyeconomics.org/wp-content/uploads/2026/06/NEE-The-Economics-of-Coal-Fired-Generation.pdf. The underlying EIA data is available at: https://www.eia.gov/electricity/data/eia860/.

[116] Alex Hopkins and Bamadou Ouattara, The Economics of Coal-Fired Generation: An Assessment of Ratepayer Risk (New Energy Economics, June 2026), at 11–12 and n.27. Available at: https://newenergyeconomics.org/wp-content/uploads/2026/06/NEE-The-Economics-of-Coal-Fired-Generation.pdf.

retirement comparison conducted at constant fixed cost per kilowatt-year, with no sensitivity on capacity factor, does not capture the mechanism most likely to drive the economics of an aging unit over a twenty-year extension.

Two further omissions undercut the reliability of Evergy's analysis. First, NEE explained in 2024 that Evergy was booking retirement costs as lump sum charges in the year following retirement rather than amortizing capitalized costs across an appropriate schedule, which distorts the comparative economics of retirement scenarios. The issue was nominally resolved through the joint filing process. Neither 2026 Annual Update discloses whether that modeling convention actually changed and whether retirement-related capitalized costs are now treated as a lump sum charge in the year of retirement or as an obligation amortized across the remaining horizon.[117] This distinction is material due to the magnitude of retirement costs at issue. A lump sum treatment maximizes the apparent benefit of pushing the charge outward in time, while an amortized treatment substantially reduces it. On a $140 million line at EMM and a $41 million line at EMW, the modeling convention is capable of moving the result by more than the margin separating several of the ranked plans.

The second concerning omission is the absence of any alternative combining earlier retirement with securitization financing. Evergy compared retirement on the 2025 schedule against extending, but did not compare either against retiring and securitizing the remaining balance. Securitization is the financing pathway that Missouri law makes available for exactly these costs, which carries a statutory replacement-resource mechanism, and which changes the customer cost of retirement without changing the operating characteristics of any unit. More specifically,

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[117] The lump sum versus amortized treatment of retirement-related capitalized costs was raised by NEE in 2024 and nominally resolved through the joint filing process. Neither 2026 Annual Update discloses whether the modeling convention was in fact changed.

Missouri authorizes securitized utility tariff bonds for "energy transition costs," expressly defined to include the undepreciated investment in a generating facility that is retired or abandoned "or to be retired or abandoned."[118] The statute requires a utility petitioning for a financing order to supply "a comparison between the net present value of the costs to customers that are estimated to result from the issuance of securitized utility tariff bonds and the costs that would result from the application of the traditional method of financing and recovering the undepreciated investment."[119] Missouri law further provides that, on a concurrent petition, the Commission shall approve replacement resource investment approximately equal to the undepreciated investment in the retired facilities.[120]

NEE has advocated since 2023 that securitization of coal plant net book value be incorporated into the evaluation of accelerated retirement scenarios, and Evergy has declined on the stated ground that doing so would artificially advantage early retirement.[121] But that objection makes little sense given the existing statutory requirements. Indeed, Section 393.1700 requires the petitioning utility to supply the net present value comparison between securitized and traditional financing. This means that the analysis is not a thumb on the scale, but rather is the comparison

[118] Section 393.1700, RSMo. (authorizing securitized utility tariff bonds and financing orders for energy transition costs, effective August 28, 2021). "Energy transition costs" are defined to include pretax costs with respect to a retired or abandoned "or to be retired or abandoned" electric generating facility, including the undepreciated investment in that facility.

[119] Section 393.1700.2, RSMo. (requiring a petition for a financing order to include "a comparison between the net present value of the costs to customers that are estimated to result from the issuance of securitized utility tariff bonds and the costs that would result from the application of the traditional method of financing and recovering the undepreciated investment of facilities that may become securitized utility tariff costs from customers").

[120] Section 393.1705, RSMo. (providing that, on a concurrent petition, the commission "shall approve investment in replacement resources by the electrical corporation of an amount that is approximately equal to the undepreciated investment in the electric generating facilities covered by such petition"); Section 393.1715, RSMo. (ratemaking principles applicable to the retirement of generating facilities).

[121] NEE has advocated since 2023 that securitization of coal plant net book value be incorporated into the evaluation of accelerated retirement scenarios. Evergy has declined, on the stated ground that doing so would artificially advantage early retirement.

the legislature specified. Further, 20 CSR 4240-22.060(3) requires a set of ARPs based on substantively different mixes and timing so their relative performance can be assessed, meaning this type of analysis is precisely what both the legislature and the Commission contemplated as part of the IRP process.

Evergy may argue that its coal fleet and corresponding retirement decisions are distinguishable from national examples. Indeed, among the five states examined in NEE's assessment, Missouri's coal fleet is the most resilient. Its capacity factor fell from 66.9% in 2014 to 48.3% in 2024—a decline of 28% in relative terms, against a five-state fleet-wide decline of 44%—and Missouri is the only state in that sample to hold a fleet capacity factor above 48%. Missouri plants also pay among the lowest delivered fuel costs in the sample, at $1.84 per MMBtu in real 2024 dollars, down 27% from 2014, reflecting Powder River Basin sourcing.[122] Evergy's Missouri coal units are therefore better positioned than the national or regional averages would suggest, and NEE does not contend otherwise.

However, this reality is a reason for more careful analysis. Where a fleet retains meaningful utilization and low fuel cost, the retirement question turns on precisely the variables the filings do not model. For example, how fixed cost per kilowatt-year escalates with age, how accreditation responds to a lengthening outage history, and what compliance capital is required to operate past December 2034. A favorable starting position alone does not establish that a twenty-year extension is least cost. It simply establishes that the comparison is close enough to be worth doing properly.

[122] Alex Hopkins and Bamadou Ouattara, The Economics of Coal-Fired Generation: An Assessment of Ratepayer Risk (New Energy Economics, June 2026), at 28–34, analyzing U.S. Energy Information Administration Forms EIA-860 and EIA-923 (Missouri fleet capacity factor of 48.3% in 2024 against a five-state fleet-wide average of 33.3%; Missouri delivered coal cost of $1.84/MMBtu in real 2024 dollars, a 27% real decline from 2014). Available at: https://newenergyeconomics.org/wp-content/uploads/2026/06/NEE-The-Economics-of-Coal-Fired-Generation.pdf.

None of these analytical gaps definitively establish that the extensions are imprudent. Rather, they demonstrate that the customer benefit of the extensions may be much less than the utility suggests and that a decision of this magnitude should not rest on a comparison whose result is substantially a product of the twenty-year planning window.

B. Environmental Compliance Costs Are Assumed to Be Zero Although the Retirement Changes Move Units Out of a Less Stringent Federal Subcategory and Into a Zero-Discharge Requirement.

Both filings state that "[i]t is assumed for this IRP that no significant air quality control equipment is required to be added," and that remediation costs including those associated with coal combustion residuals "are fully dependent on prior operations and *do not vary based on electric generating unit retirement decisions*."[123] The italicized proposition is incorrect with respect to how the governing federal rule is structured, and the 2026 retirement changes make the error consequential.

In May 2024, the U.S. Environmental Protection Agency ("EPA") finalized revised effluent limitations guidelines for the steam electric power generating point source category, codified at 40 C.F.R. part 423.[124] The rule established zero-discharge limitations for flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate. Evergy summarizes the compliance date accurately, indicating that those wastewater streams at operating facilities must achieve zero liquid discharge no later than December 2034.[125] However, the filings

[123] EMM 2026 Annual Update, § 13.3, at 125 (emphasis added); EMW 2026 Annual Update, § 13.3, at 121 (emphasis added).
[124] Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 89 Fed. Reg. 40198 (May 9, 2024) (codified at 40 C.F.R. pt. 423), effective July 8, 2024. Available at: https://www.federalregister.gov/documents/2024/05/09/2024-09185/supplemental-effluent-limitations-guidelines-and-standards-for-the-steam-electric-power-generating.
[125] EMM 2026 Annual Update, § 7.2.1, at 57; EMW 2026 Annual Update, § 7.2.1, at 56.

omit the rule's subcategory structure, which ties compliance cost directly to the retirement decision.

The 2024 rule established a distinct subcategory for generating units "permanently ceasing coal combustion by December 31, 2034." For units in that subcategory, EPA has explained, "less stringent limitations and standards apply" to flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate "than limitations applicable to non-closing or non-repowering sources in this source category." Those less stringent standards are those that applied under the 2020 rule.[126] Election into the subcategory is made by filing a notice of planned participation, and EPA has since extended both that notice date and the underlying compliance deadlines and has proposed to expand the provisions permitting facilities to transfer between the zero-discharge requirements and the cessation subcategory.[127]

The consequence of this rule is directly apparent. Whether a coal unit is subject to zero-discharge limitations or to the materially less stringent 2020-rule limitations depends on whether that unit permanently ceases coal combustion by December 31, 2034. The applicable federal standard, and therefore the compliance cost, varies with the retirement decision—contrary to Evergy's assertion otherwise.

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[126] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category—Initial Notification Date Extension, 90 Fed. Reg. (Oct. 2, 2025) ("In the 2024 rule, the EPA established a subcategory for EGUs permanently ceasing coal combustion by December 31, 2034. For these EGUs, less stringent limitations and standards apply for discharges of pollutants found in flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate (CRL) than limitations applicable to non-closing or non-repowering sources in this source category."). Available at: https://www.federalregister.gov/public-inspection/2025-19269/effluent-limitations-guidelines-and-standards-for-the-steam-electric-power-generating-point-source.

[127] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category—Deadline Extensions, 90 Fed. Reg. (Oct. 2, 2025) (proposing to extend seven deadlines in the 2024 rule and to expand the transfer provisions at 40 C.F.R. § 423.13(o) to permit facilities to switch between the zero-discharge requirements and the permanent-cessation subcategory). Evergy notes the December 2025 finalization at EMM 2026 Annual Update, § 7.2.1, at 57. Available at: https://www.federalregister.gov/documents/2025/10/02/2025-19268/effluent-limitations-guidelines-and-standards-for-the-steam-electric-power-generating-point-source.

Three units crossed that critical deadline in the 2026 Annual Updates. Under the 2025 preferred plans, EMM's La Cygne 1 was scheduled to retire in March 2033, EMW's Jeffrey 3 in March 2031, and EMW's Lake Road 4/6 in December 2030. Each of those dates precedes December 31, 2034, and each unit would therefore have been eligible for the cessation subcategory. Under the 2026 preferred plans La Cygne 1 retires in March 2038, Jeffrey 3 in March 2036, and Lake Road 4/6 in March 2038. All three now operate past the subcategory date. La Cygne 2, Iatan 1, Iatan 2, Jeffrey 1, and Hawthorn 5 operate past it as well, and beyond the planning horizon entirely.

Evergy has assigned no incremental compliance cost to any of those delays, and neither filing discusses the subcategory, the notice of planned participation, or the transfer provisions. NEE does not contend that Evergy must elect the cessation subcategory, or that the cost of zero-discharge compliance at any particular unit is large. However, the cost is not zero, it is a function of the retirement dates the filings changed, and it must be included in the retirement comparison.

The magnitude is also not self-evidently immaterial because compliance capital must be recovered across whatever operating life remains. NEE's analysis indicates that a retrofit on the order of $400 per kW amortizes at roughly $30 to $40 per kW-year where twenty or more years of operating life remain. Where ten years or less remain, the same retrofit costs roughly $50 to $70 per kW-year—by itself exceeding the entire fixed-cost burden of an unstressed coal unit.[128] The three units that crossed the subcategory date have between ten and twelve years of remaining life under the 2026 preferred plans: Jeffrey 3 to March 2036, and La Cygne 1 and Lake Road 4/6 to

[128] Alex Hopkins and Bamadou Ouattara, The Economics of Coal-Fired Generation: An Assessment of Ratepayer Risk (New Energy Economics, June 2026), at 14 (a $400/kW retrofit amortizes at approximately $30–$40/kW-year across 20 or more years of remaining life, but at approximately $50–$70/kW-year where ten years or less remain). Available at: https://newenergyeconomics.org/wp-content/uploads/2026/06/NEE-The-Economics-of-Coal-Fired-Generation.pdf.

March 2038. Those are precisely the remaining-life bands in which a compliance obligation is least recoverable, and in which the retrofit-or-retire question is most likely to be outcome-determinative. Evergy has neither quantified the obligation nor tested whether it alters the retirement comparison.

20 CSR 4240-22.040(2)(B) requires the utility to quantify probable environmental costs by identifying the pollutants for which legal mandates may be imposed, specifying a subjective probability for each, and calculating an expected mitigation cost.[129] A statement that costs are not believed to be material, offered without a plant-specific estimate, a probability, or an expected value, does not satisfy that provision, particularly where the filings rest that statement on a premise the governing rule contradicts. This compliance gap is the more notable because Evergy did quantify the *operating* environmental cost of running coal longer, finding that emissions costs rise $222 million for EMM and $30 million for EMW in the same tables that report the retirement benefit. In sum, Evergy has counted the carbon cost of the extensions and assumed away the compliance capital.

C. Neither Filing Establishes Reassessment Criteria or Off-Ramps for the Extended Units.

Both filings move units to "Beyond 2045" and treat the matter as settled.[130] Neither filing identifies the conditions under which the extension would be revisited, the capital expenditure thresholds that would trigger reconsideration, or the point at which continued operation would cease to be economic.

Chapter 22 requires each of those things. 20 CSR 4240-22.070(2) requires the utility to specify the ranges or combinations of outcomes for the CUFs that define the limits within which

[129] 20 CSR 4240-22.040(2)(B).
[130] EMM 2026 Annual Update, Table 40, at 126; EMW 2026 Annual Update, Table 41, at 122.

the preferred plan is judged appropriate, and to explain how those limits were determined. 20 CSR 4240-22.070(4) requires contingency resource plans identifying which alternative plans become preferred if those limits are exceeded, together with the point at which the utility would move to each. Finally, 20 CSR 4240-22.070(6)(D) requires the implementation plan to identify critical paths and major milestones for each supply-side resource, "including decision points for committing to major expenditures."

One element of the 2026 changes is a reversal of a resolved item. Coal-to-gas conversion was committed to as a standalone retirement-economics tool in 2023, omitted from the 2024 Triennial Compliance Filing, and restored in the 2025 Annual Update through the Jeffrey 2 conversion in EMW's preferred plan.[131] The 2026 Annual Update postpones that conversion by five years and does not treat it as a trigger or off-ramp within the retirement analysis. A commitment that was made, withdrawn, restored, and then deferred without an accompanying decision framework is a clear illustration of a deficiency in Evergy's filing under 20 CSR 4240-22.070(2) and (4).

Extending three coal units at EMM and four at EMW past the point at which they were previously scheduled to retire, together with deferring the Jeffrey 2 natural gas conversion by five years, commits customers to continued capital and maintenance expenditure at aging facilities. The filings identify no decision points governing that expenditure and no criteria under which the extensions would be unwound.

[131] Coal-to-gas conversion was committed to as a standalone retirement-economics tool in 2023, omitted from the 2024 Triennial Compliance Filing, and restored in the 2025 Annual Update through the Jeffrey 2 conversion in EMW's preferred plan.

D. EMM Relies on a Regulatory Development Affecting a Generating Station in Which It Has No Ownership Interest.

Among the five drivers EMM identifies for its reassessment of coal retirement risk is the "[t]imeline for required investment in Jeffrey Energy Center nitrogen-oxide ("Nox") emissions controls being extended."[132] EMM has no ownership interest in the Jeffrey Energy Center. Its coal fleet consists of Iatan 1, Iatan 2, La Cygne 1, La Cygne 2, and Hawthorn 5.[133] EMW, by contrast, holds interests in Jeffrey 1, 2, and 3, and tests their retirement dates in its own filing.[134]

A Regional Haze development at a station EMM does not own cannot support EMM's decision to delay La Cygne 1 by five years and to move La Cygne 2 and Iatan 1 outside the planning horizon. In fact, the relevant passage in EMM's filing appears to be carried over from the filings of the affiliated utilities. Because 20 CSR 4240-22.070(2) requires the utility to explain the basis on which the preferred plan is judged appropriate, and because the stated basis is inapplicable to the fleet at issue, EMM should identify the facts actually supporting the EMM retirement changes or withdraw the rationale.

E. Accreditation Assumptions Are Applied Conservatively to Demand-Side Resources and Favorably to New Thermal Resources.

Evergy states that its 2026 Annual Update "continues to assume that demand response receives accredited capacity equal only to its expected tested capability rather than receiving credit as a full net reduction to load," describing the assumption as conservative and as preparation "for potential future policy changes" that SPP has not adopted.[135] In the same filings, new thermal generation is assigned a 3% forced outage rate for accreditation purposes on the stated ground that

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[132] EMM 2026 Annual Update, § 2.3, at 13.
[133] *Id.*, Table 40, at 126; *id.*, § 10.2.2, at 74 (identifying Iatan 2 and Hawthorn 5 as EMM coal resources projected to operate beyond the planning horizon); *id.*, Table 2, at 2.
[134] *Id.*, Table 40, at 126; EMW 2026 Annual Update, Table 41, at 122.
[135] EMM 2026 Annual Update, § 5.6, at 43; EMW 2026 Annual Update, § 5.6, at 42.

"these resources are designed to be highly available and will have firm fuel supply," with accreditation "calculated based on design specifications."[136]

The second problem concerns the units at the other end of the fleet. The 3% assumption applies to new thermal resources, which Evergy accredits on design specifications because no operating history exists. Evergy's existing units are accredited differently under SPP's performance-based methodology, wherein a thermal resource's accredited capacity reflects its availability during peak-risk hours based on multi-year seasonal forced outage history.

Evergy has extended three coal units at EMM and four at EMW past the dates on which they were previously scheduled to stop operating, and one unit at each utility beyond the planning horizon entirely. Under a methodology driven by accumulated outage history, the accredited capacity of those units should be expected to decline as they age. NERC reports that the average unplanned outage rate for coal units rose from approximately 8% over 2014–2017 to 11.4% over 2020–2023, against 7.7% for natural gas and 2% for nuclear. Neither filing models a declining accreditation trajectory for any extended unit, or tests what such a decline would mean for reserve margin compliance and for the timing and cost of replacement capacity. In sum, new thermal is credited at its design specification; existing thermal is credited as though its performance history will not deteriorate.

Conversely, Evergy treats demand-side resources the other way, unreasonably constraining the accreditation of those resources based on rules that do not yet exist. Evergy states that SPP stakeholders "are evaluating whether future accreditation should account for availability constraints such as event frequency, duration, and seasonal limitations." In other words, whether demand response should receive less accreditation than its tested performance would support. SPP

[136] EMM 2026 Annual Update, § 6.4.2, at 50; EMW 2026 Annual Update, § 6.4.2, at 49.

has not adopted any such change, but Evergy has nonetheless assumed it. As a result, Evergy credits demand response only at expected tested capability rather than as a full net reduction to load and describes the assumption as preparation "for potential future policy changes."

This asymmetry is the key deficiency NEE has identified. For new thermal resources Evergy assumes the most favorable accreditation the methodology permits. For demand-side resources it assumes an adverse accreditation rule that SPP has not adopted. Both assumptions are defensible in isolation, but applied together they structurally disadvantage demand-side resources against thermal. That is inconsistent with 20 CSR 4240-22.010(2)(A), which requires demand-side, renewable, and supply-side resources to be considered and analyzed on an equivalent basis, and with 20 CSR 4240-22.060(4), which requires that costs, benefits, and risks be quantified at a similar level of detail and precision for all resource types.

Evergy further employs assumptions that disadvantage renewable and storage accreditation. Evergy states that it "tweaked its previous degradation curves that were based on SPP's 2022 ELCC Study," and that the adjustment "lessened the overall degradation of renewable and storage resources to coincide with more recent market and policy dynamics surrounding the preference for thermal resources."[137] The stated basis for the adjustment is an expectation about future resource mix rather than a modeled penetration level. Penetration is the variable that drives effective load carrying capability ("ELCC") degradation. SPP's own accreditation methodology explains that as installed capacity of a resource type rises, its ELCC percentage falls, and illustrates the relationship with a decline in wind ELCC from 19.9% at 19,339 MW installed to 14.6% at 38,678 MW installed.[138] Evergy further reports that the adjustment produced worse summer

[137] EMM 2026 Annual Update, § 6.3, at 48; EMW 2026 Annual Update, § 6.3, at 47.
[138] Southwest Power Pool, Solar and Wind ELCC Accreditation, August 2019 (explaining that effective load carrying capability declines as penetration of the resource increases, and illustrating a decline in wind ELCC from 19.9% at 19,339 MW installed to 14.6% at 38,678 MW installed); SPP Planning Criteria §

accreditation for new solar and battery resources in the early years of the horizon—the years in which both utilities identify their most acute capacity deficits and in which the preferred plans decline to add those resources. SPP publishes those curves in periodic studies, most recently its 2022 and 2024 ELCC reports,[139,140] and Evergy states that it began from the 2022 curves and adjusted them. The adjustment is therefore a departure from a published SPP methodology and should be documented as such under 20 CSR 4240-22.040(5) and 20 CSR 4240-22.060(4), with the underlying penetration assumptions stated and the results reported using the unadjusted SPP curves alongside.

F. Market Purchases Are Capped Without Justification.

Both filings state that "[b]eginning in 2030, market purchases and sales are limited to 200 MW per hour," and explain that the constraint ensures a portfolio is developed around customer energy needs rather than forecast market prices. That rationale is sound as applied to sales, but as applied to purchases the limit operates differently. Purchased power is the direct substitute for owned thermal capacity, meeting the same reliability need without committing customers to a long-lived asset. Capping purchases at 200 MW per hour therefore removes the principal competitor to the gas-fired additions the preferred plans select, in the same years those additions are being justified.

20 CSR 4240-22.040(1) requires the utility to evaluate "purchased power from bi-lateral transactions and from organized capacity and energy markets" as a potential supply-side resource

7.1.6.1. Available at: https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf.

[139] Southwest Power Pool, 2022 ELCC Wind and Solar Study Report, November 2022. Available at: https://www.spp.org/documents/68289/2022%20spp%20elcc%20study%20wind%20and%20solar%20report.pdf.

[140] Southwest Power Pool, 2024 ELCC Wind, Solar and ESR Study Report, September 2024. Available at: https://www.spp.org/documents/72346/2024%20spp%20elcc%20wind%20solar%20&%20esr%20report.pdf.

option, and 20 CSR 4240-22.040(3)(A)6 requires analysis of opportunities for long-term power purchases and short-term purchases "that may be required for bridging the gap between other supply options."[141] Both utilities rely on market capacity as precisely such a bridge through 2031. Neither explains why 200 MW per hour is the appropriate limit, nor tests the sensitivity of the preferred plan to one with greater market purchases.

G. The Basis for Selecting a Plan Other Than the Lowest-Cost Plan Is Not Quantified and the Decision-Makers Are Not Identified.

EMM selected Plan ACAA notwithstanding that Plans ACEA and ACCA rank $15 million lower, explaining that those plans carry "materially higher execution and deliverability risk that is not captured in the capacity expansion model"—construction concentration in a single year, solar permitting exposure in Missouri, and the winter accreditation of storage.[142] NEE regards each of those considerations as legitimate, but the deficiency is that none of those considerations are quantified.

20 CSR 4240-22.010(2)(C) requires the utility to "[e]xplicitly identify and, where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process, but which may constrain or limit the minimization of the present worth of expected utility costs," and to describe and document the process and rationale used by decision-makers to assess the tradeoffs. Each of the three risks Evergy cites is susceptible to quantification: 1) a probability of permitting failure, 2) a probability and cost of construction delay, and 3) a capacity value differential between storage and solar in the deficit winters. Evergy quantified none of them, and so its filings do not establish whether the $15 million premium is too small or too large.

[141] 20 CSR 4240-22.040(1).
[142] EMM 2026 Annual Update, § 1.3, at 5; § 12.2, at 113–114.

Separately, 20 CSR 4240-22.070(1) requires that the utility "provide the names, titles, and roles of the utility decision–makers in the preferred resource plan selection process."[143] Neither filing identifies any individual. Because the selection by EMM turned on judgment rather than on the model output, the identity and role of the decision-makers is of more consequence in this filing than it would ordinarily be.

H. Storage Is Evaluated at a Single Duration and the Surplus Interconnection Analysis Was Not Filed in Missouri.

EMM describes the storage resource in its preferred plan as "a nominally 150 MW, 4-hour lithium-ion battery energy storage system."[144] No alternative duration appears anywhere in either filing. Because ELCC accreditation is a function of duration, and because both utilities identify winter capacity as their binding constraint, six- and eight-hour configurations are the products most likely to address the deficit Evergy has identified. 20 CSR 4240-22.040(4) requires the supply-side candidate options carried into the integration analysis to "represent a wide variety of supply-side resource options with diverse fuel and generation technologies." A single duration of a single storage technology does not meet that standard, and no storage of any duration appears in EMW's preferred plan at all. Importantly, this limitation is not a result of the accreditation framework. SPP's 2025 ELCC study scope establishes separate accreditation treatment for four-hour, six-hour, and eight-hour storage durations, allocated by transmission service tier.[145] Accredited capacity values for the longer durations Evergy did not evaluate are therefore published and available.

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[143] 20 CSR 4240-22.070(1).
[144] EMM 2026 Annual Update, § 12.4.2, at 118.
[145] Southwest Power Pool, 2025 Wind/Solar/ESR Effective Load Carrying Capability Study Scope, January 2025 (establishing separate accreditation treatment for four-hour, six-hour, and eight-hour energy storage resource durations, allocated by tier). Available at: https://www.spp.org/documents/73277/2025%20spp%20elcc%20study%20scope.pdf.

SPP has published what the duration choice is worth. In its 2024 study, SPP accredited four-, six-, and eight-hour storage independently at a 1,000 MW penetration level against the same 1-day-in-10-years threshold it uses to set the planning reserve margin. The results are reproduced below.[146]

Table 7. SPP effective load carrying capability by energy storage resource duration

ESR duration	Summer ELCC	Winter ELCC	Accredited MW on a 150 MW battery (summer / winter)
8-hour	**100.0%**	**74.9%**	**150.0 / 112.3**
6-hour	94.4%	74.9%	141.6 / 112.3
4-hour	**65.2%**	**47.7%**	**97.8 / 71.5**

The gap is largest in the season in which both utilities identify their binding constraint. A four-hour battery receives 47.7% winter accreditation; an eight-hour battery of the same nameplate receives 74.9%. On the 150 MW resource in EMM's preferred plan, that is a difference of roughly 41 MW of accredited winter capacity from a duration choice Evergy did not test. In summer the spread is wider still—65.2% against 100%.

NEE notes two qualifications. These values were informational rather than binding when published, and SPP recorded that discussion of the correct modeling approach was continuing in its Supply Adequacy Working Group. Sensitivity cases narrow the gap considerably: removing demand response from the model raises four-hour accreditation to 88.7% in summer and 70.0% in winter, and holding hydro output constant raises every duration to 96.4% or above.[147] That range

[146] Southwest Power Pool, 2024 ELCC Wind, Solar and ESR Study Report, August 2024, Table 17 (base case; 4-, 6-, and 8-hour durations each studied independently at 1,000 MW of penetration against a 1-day-in-10-years threshold). Available at: https://www.spp.org/documents/72346/2024%20spp%20elcc%20wind%20solar%20&%20esr%20report.pdf. Accredited megawatt figures in the final column are NEE calculations applying the published percentages to a 150 MW nameplate resource.

[147] *Id.*, Tables 18 and 19. Removing demand response from the base and change cases raises four-hour accreditation to 88.7% summer and 70.0% winter; holding hydro output constant in addition raises all durations to 96.4% or above. SPP notes that discussion of the correct modeling approach was continuing in

is itself the point. The accredited value of a four-hour battery relative to a longer-duration alternative varies by tens of percentage points depending on modeling assumptions that SPP is actively debating, and Evergy committed to a single duration without evaluating the alternatives or acknowledging the uncertainty.

The contrast with the other large investor-owned utility subject to these rules is instructive. Ameren Missouri plans battery storage totaling 1,000 MW by 2030 and 1,800 MW by 2042, and this Commission approved a hybrid natural gas and 400 MW storage facility in February 2026.[148] Ameren Missouri operates under the same Chapter 22 requirements, in the same state, before the same Commission, and in a load-growth environment its filings describe in substantially the same terms Evergy uses. NEE does not suggest that Evergy must match another utility's portfolio. NEE simply observes that a resource Evergy's modeling rejects at every duration is one that a comparable Missouri utility is deploying at scale, and that the divergence is traceable to inputs Evergy has not disclosed.

Both filings also state that Evergy "has also explored options for locating storage at existing resource sites that have surplus interconnection available," without providing the results of that exploration.[149] Surplus interconnection is a material cost advantage. Co-location at an existing site avoids new substation and transmission equipment with procurement lead times Evergy elsewhere describes as two to three years, and EMM states that it can reduce development timelines by two

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the Supply Adequacy Working Group and that a final direction would be set in the 2025 ELCC Study Scope.

[148] Ameren Missouri, 2025 Integrated Resource Plan Annual Update, File No. EO-2026-0088 (Oct. 30, 2025). Ameren Missouri has announced battery storage targets totaling 1,000 MW by 2030 and 1,800 MW by 2042. *See* Ameren Corporation, "Ameren Missouri Unveils New Hybrid Energy Center Combining Natural Gas and Energy Storage," press release (announcing a 400 MW battery storage installation), and "Missouri Approves First-of-Its-Kind Resource to Boost Energy Reliability," February 11, 2026. Available at: https://ameren.mediaroom.com/2026-02-11-Missouri-approves-first-of-its-kind-resource-to-boost-energy-reliability.

[149] EMM 2026 Annual Update, § 13.2, at 125; EMW 2026 Annual Update, § 13.2, at 121.

to three years. Consistent with the economic advantages of this approach, Ameren Missouri agreed in the Castle Bluff proceeding to seek approval for 200 MW of battery storage by the end of 2027 and to site at least a portion of it at an existing energy center, having identified both an operating station and a retired one as candidate locations in its 2023 resource plan.[150] The sites at which the same advantage would arise for Evergy include Missouri jurisdictional generating stations. This analysis is therefore a critical piece of missing information within Evergy's 2026 Annual Update filings.

I. The Gas Consumption and Cost Exposure of the New Thermal Additions Is Not Disclosed.

The two preferred plans collectively add approximately 3,600 MW of new gas-fired capacity beyond the resources already certificated (2,533 MW at EMM and 1,065 MW at EMW). Neither filing discloses the annual natural gas consumption of those units in MMBtu, the annual cost of that gas in dollars, or how either varies across the low, mid, and high gas price cases.

That disclosure is the direct output of the fuel price forecast required by 20 CSR 4240-22.040(5)(A) and of the production cost modeling required by 20 CSR 4240-22.060(4). Without it, neither the Commission nor stakeholders can determine the magnitude of the commodity exposure the preferred plans create, evaluate that exposure against the delivered-cost deficiency described in Section III.A, or assess what a sustained period of elevated gas prices would mean for customer bills.

[150] Stipulation and Agreement approved in Case No. EA-2024-0237 (the Castle Bluff proceeding), under which Ameren Missouri agreed to seek Commission approval to construct 200 MW of battery energy storage by the end of 2027 and to locate at least a portion of that capacity at the Castle Bluff Energy Center site. Ameren Missouri's 2023 Integrated Resource Plan identified the Meramec Energy Center site (now Castle Bluff) and the retired Rush Island Energy Center as candidate locations for battery storage. *See also* Application, Case No. EA-2026-0183 (seeking certificates of convenience and necessity for renewable generation facilities and battery energy storage systems).

J. Recommended Remedies.

NEE recommends that the Commission direct Evergy to address the following:

- Restate the coal retirement comparison at both utilities separately identifying, for each retirement schedule, the deferred generator retirement cost and the deferred or avoided new-build capital, so that the portion of the reported benefit attributable to timing rather than to avoided cost is visible.
- Extend the retirement analysis beyond the twenty-year horizon or otherwise report the replacement capital required after the extended units retire, for each unit moved to "Beyond 2045."
- Provide plant-specific estimates of Effluent Limitation Guidelines and coal combustion residual compliance costs for each unit now scheduled to operate past the December 2034 zero-liquid-discharge deadline, with the subjective probabilities and expected mitigation costs required by 20 CSR 4240-22.040(2)(B) and rerun the retirement comparison including them.
- Specify, for each extended unit, the critical uncertain factor ranges and capital expenditure thresholds that would trigger reconsideration of the extension, and identify the corresponding contingency resource plans, as required by 20 CSR 4240-22.070(2), (4), and (6)(D).
- Identify the facts supporting Evergy Metro's coal retirement changes that pertain to units Evergy Metro owns, or withdraw the Jeffrey Energy Center rationale.
- Apply consistent accreditation treatment to demand-side and supply-side resources, and document the penetration assumptions and analytical basis for the adjustment made to the SPP effective load carrying capability degradation curves.

- Explain the basis for the 200 MW per hour market purchase limit and report the sensitivity of each preferred plan to a higher limit.
- Quantify the execution, permitting, and accreditation risks relied upon in selecting Plan ACAA over the lower-cost alternatives, and provide the names, titles, and roles of the preferred resource plan decision-makers as required by 20 CSR 4240-22.070(1).
- Evaluate six-hour and eight-hour storage configurations as supply-side candidate resource options at both utilities, and file the surplus interconnection storage analysis in these dockets.
- Report, for each new gas-fired resource in each preferred plan, the projected annual natural gas consumption in MMBtu and the projected annual fuel cost in dollars under the low, mid, and high natural gas price cases.
- File the public form of the capacity balance spreadsheet for each preferred plan and each alternative resource plan, updated for the retirement changes, as required by 20 CSR 4240-22.080(2)(D) and (3)(B).

V. CONCLUSION AND SUMMARY OF DEFICIENCIES AND CONCERNS.

Evergy's 2026 Annual Updates respond to a changed planning environment. Load growth in both Missouri service territories is real and documented, SPP's resource adequacy requirements have tightened, and federal tax and environmental policy has moved against renewable resource economics. NEE does not dispute those conditions and does not contend that the resulting resource plans are necessarily unreasonable.

NEE's concern is that the analysis supporting the plans does not meet the standards set forth in Chapter 22. Both preferred plans fail to comply with a state legal mandate within the planning horizon and the cost of satisfying it appears in no ranked plan in either filing. The comparison used to justify eliminating four of seven planned coal retirements measures deferred capital and deferred retirement costs rather than avoided costs and derives the majority of its result from moving units past the end of the analytical window. The probability weights that determine which portfolio ranks first are supplied without the supporting analysis the rule requires. Renewable and storage resources are constrained by unsubstantiated annual build limits that Evergy relaxed when it needed to, but only outside the economic analysis. And several of the disclosures that would allow the Commission and stakeholders to test these judgments—the load forecast, the capacity balance, the identity of the models, the unserved-hours results, the fuel consumption of the new gas fleet—are not present within Evergy's filings.

The tables that follow summarize the deficiencies and concerns NEE has identified, together with the provision of Chapter 22 to which each relates and at least one suggested remedy for each. NEE uses the terms "deficiency" and "concern" as defined at 20 CSR 4240-22.020(9) and (6) respectively.[151]

A. Priority of Recommendations.

NEE offers forty recommendations, set out by category in Table 8. These recommendations are not of equal weight, and NEE does not suggest the Commission treat them as such. However, three priority findings are key to determine whether the preferred resource plans can be relied upon.

First and above all others: neither preferred plan satisfies the Missouri Renewable Energy Standard, and the cost of compliance ($1,966 million for EMM and $615 million for EMW) appears in no ranked plan in either filing. Until the RES is modeled as a binding constraint and the plans are re-ranked on a compliant basis, no comparison in either filing

[151] 20 CSR 4240-22.020(9) (deficiency); 20 CSR 4240-22.020(6) (concern). Consistent with 20 CSR 4240-22.080(8), NEE provides at least one suggested remedy for each item identified.

establishes which portfolio is least cost. This deficiency is curable: the modeling exists and Evergy has already built the compliance plans that should be carried into the analysis.

That omission materially impacts both preferred plans. Based on EMM's published numbers, a plan ranked thirteenth of fifteen becomes roughly $1.6 billion cheaper than the selected plan once compliance is counted. NEE does not ask the Commission to accept that figure, but does request that the Commission require Evergy to produce it.

Second: the comparison used to justify eliminating four of seven planned coal retirements measures deferred capital and deferred retirement cost rather than avoided cost. Seventy-five percent of the reported benefit at EMM and fifty-two percent at EMW is produced by moving units past the end of the twenty-year window. A further twenty-five and forty-two percent respectively is deferred retirement cost counted as a saving.

Third: the probability weights that determine which portfolio ranks first are supplied without the supporting analysis 20 CSR 4240-22.060(7)(C)1.B requires, and Evergy's own sensitivity shows the ranking reverses within the plausible range.

The recommendations related to these three priority deficiencies are identified in Table 8 below. NEE recommends the Commission direct Evergy to address these deficiencies in supplemental workpapers filed in these dockets, and the remainder in each utility's next annual update or triennial compliance filing.

B. Internal Inconsistencies Identified in the Filings.

In the course of this review, NEE identified several internal inconsistencies within Evergy's filings. None of the internal inconsistencies are individually significant, but together they bear on whether the Annual Updates were prepared with the care 20 CSR 4240-22.080(3)(B) requires given the magnitude of the changes they make. NEE identifies them so that Evergy may correct them and confirm the values on which the analysis relies:

- EMW § 10.2.2 lists "Jeffrey 3 retires after 2045" three bullets after listing "Jeffrey 3 retires March 2036." The second entry appears to refer to Jeffrey 1.
- The captions to EMW Figures 43 and 44 transpose the two renewable energy standard compliance plans relative to EMW Table 12 and Table 28, which identify Plan ADAK as the solar plan and Plan ADAL as the wind plan.
- EMW describes the composition of Plan ADAB inconsistently: § 10.6 states 2,550 MW of solar and 600 MW of wind, while § 13.1 states 2,400 MW of solar and 600 MW of wind.
- EMW § 1.3 states that large load approaches 350 MW by 2032, while § 12.2 states that it approaches 800 MW by 2032.
- EMM § 10.4 refers to "the 375 MW La Cygne 2 retirement in March 2033." Under Plan AAAA it is La Cygne 1 that retires in March 2033.
- The 2033 column of EMM Table 45 totals 661 MW; the entries in that column sum to 2,416 MW.
- EMM Appendix A is titled "Metro West Plans Capacity Balance."

NEE appreciates the opportunity to participate in these proceedings and is available to discuss any of the matters raised in these Comments with the Commission, Staff, the Office of the Public Counsel, Evergy, and other stakeholders.

Table 8. Recommendations

★ *denotes a recommendation bearing on one of the three priority findings described in Section V.A.*

Category	Priority	Recommendation
Renewable Energy Standard	★	Develop, document, and rank a compliance benchmark resource plan and an optimal compliance resource plan for each utility, modeling the RES as a binding constraint in the capacity expansion model rather than evaluating compliance after the fact.
Renewable Energy Standard	★	Develop an aggressive renewable energy resource plan using renewable resources up to maximum potential capability in each year, without the annual build limits, as 20 CSR 4240-22.060(3)(A)2 requires.
Renewable Energy Standard	★	Rank the compliance plans across all CUF endpoints on the same basis as the base plans and report the probability-weighted NPVRR of each alongside the preferred plan.
Renewable Energy Standard	★	Restate the coal retirement comparison at both utilities within a portfolio that satisfies the RES, and report whether the ranking of retirement schedules changes.
Renewable Energy Standard		State whether the preferred plans assume a compliance obligation constrained by the retail rate impact limitation at § 393.1030.2(1), RSMo and 20 CSR 4240-20.100(5). If so, provide the supporting calculation. If not, confirm the plans are built to full compliance. State also whether modeled compliance resources are sited in Missouri for purposes of the 1.25 multiplier.
Renewable Energy Standard		Report the RES compliance position and the incremental cost of compliance for each contingency resource plan, consistent with 20 CSR 4240-22.070(4)(C).
Natural Gas Fuel Price Forecasting		Quantify the Henry Hub Natural Gas Scalar by year under normal and stress conditions and document its derivation.
Natural Gas Fuel Price Forecasting		Document the basis differential between Henry Hub and the delivery points serving each Missouri generating station, including observed behavior during Winter Storm Uri, Winter Storm Elliott, and the February 2025 SPP winter event, and confirm whether local basis premiums are included in the fuel cost assumptions used in these filings.
Natural Gas Fuel Price Forecasting		Model intra-year gas price spike scenarios testing Henry Hub prices of $8 to $15 per MMBtu across five-day and ten-day winter windows, and report the impact on the preferred plan and on alternative plans with higher renewable and demand-side content.
Natural Gas Fuel Price Forecasting		Update the low and mid natural gas price cases to current fundamentals rather than carrying forward the 2023 outlook.
Natural Gas Fuel Price Forecasting		Disclose the expected annual natural gas consumption in MMBtu and in dollars, at the low, mid, and high gas price cases, for each new thermal resource in each preferred plan.

Category	Priority	Recommendation
Resource Cost Assumptions	★	Provide the analysis supporting the probability weight assigned to each critical uncertain factor, as 20 CSR 4240-22.060(7)(C)1.B requires.
Resource Cost Assumptions	★	Assign a minimum 25% probability to the high natural gas price case and to the high construction cost case, with written justification documenting how each weight reflects current market conditions, and report the resulting rankings.
Resource Cost Assumptions		State the source, vintage, and derivation of each cost escalation figure, and present any foreign-entity sourcing premium as a discrete quantified adder above a stated market baseline.
Resource Cost Assumptions		Benchmark thermal, renewable, and storage capital cost assumptions against current independent data including BloombergNEF, Lazard, and the ACP/Wood Mackenzie storage monitor, and explain the divergence in relative treatment between resource classes.
Coal Plant Retirement Planning	★	Restate the retirement comparison at both utilities separately identifying, for each schedule, the deferred generator retirement cost and the deferred or avoided new-build capital, so that the portion of the reported benefit attributable to timing rather than to avoided cost is visible.
Coal Plant Retirement Planning	★	Extend the retirement analysis beyond the twenty-year horizon, or report the replacement capital required after each extended unit retires, for every unit moved to "Beyond 2045."
Coal Plant Retirement Planning		Quantify Effluent Limitation Guidelines and coal combustion residual compliance costs for each unit now operating past December 31, 2034, including analysis of the permanent-cessation subcategory at 40 C.F.R. pt. 423, with the subjective probabilities and expected mitigation costs 20 CSR 4240-22.040(2)(B) requires, and rerun the retirement comparison including them.
Coal Plant Retirement Planning		Specify, for each extended unit, the critical uncertain factor ranges and capital expenditure thresholds that would trigger reconsideration, and identify the corresponding contingency resource plans.
Coal Plant Retirement Planning		Treat the Jeffrey 2 coal-to-gas conversion as a decision point within the retirement analysis, identifying the conditions under which the conversion would be advanced or further deferred.
Coal Plant Retirement Planning		Disclose whether retirement-related capitalized costs are modeled as lump-sum charges in the year of retirement or as amortized obligations, and provide a sensitivity showing the NPVRR impact of the alternative treatment.
Coal Plant Retirement Planning		Model an alternative resource plan combining earlier coal retirement with securitization financing, so the Commission has a complete picture of retirement economics including the cost of financing remaining plant balances over an extended term.
Coal Plant Retirement Planning		Provide plant-specific forced outage rate escalation curves for each unit with an extended retirement date, and model the effect of declining performance-based accreditation on reserve margin compliance and on the cost of replacement capacity across the horizon.

Category	Priority	Recommendation
Coal Plant Retirement Planning		Identify the facts supporting Evergy Metro's retirement changes that pertain to units Evergy Metro owns, or withdraw the Jeffrey Energy Center rationale.
Storage and Clean Resources		Evaluate six-hour and eight-hour storage configurations alongside four-hour in multiple alternative resource plans, with and without build limits, and price the relative risk of future accreditation reductions as SPP-wide storage penetration grows, using SPP's published ELCC curves.
Storage and Clean Resources		Explain the divergence between the storage volumes Evergy's modeling selects and those being deployed by comparable Missouri utilities under the same rules, identifying the input assumptions that account for the difference.
Storage and Clean Resources		Raise storage build limits to reflect the viable capacity identified in Evergy's surplus interconnection evaluation, rerun the capacity expansion model, and file a public summary of that evaluation identifying the sites assessed and their aggregate developable capacity.
Storage and Clean Resources		Rerun capacity expansion without the annual build limits on renewable and storage resources, or apply an equivalent annual limit to thermal additions and document the basis for each limit.
Storage and Clean Resources		Model thermal resource ownership at 25%, 50%, 75%, and 100% shares, as 20 CSR 4240-22.040(1) contemplates.
Storage and Clean Resources		Explain the basis for the 200 MW per hour market purchase limit and report the sensitivity of each preferred plan to a higher limit.
Demand-Side Resources		Model energy efficiency programs across the full planning horizon independent of the approval status of any particular program cycle, and develop the aggressive demand-side resource plan 20 CSR 4240-22.060(3)(A)3 requires.
Demand-Side Resources		Establish quarterly large-load pipeline reporting on the framework used by Georgia Power and the Georgia Public Service Commission, identifying committed, near-committed, and prospective large loads by customer type and expected ramp schedule, and integrate the demand-side and capacity effects of the Large-Load Power Service rate plan into the resource modeling.
Demand-Side Resources		Complete and file an updated demand-side market potential study with a stated completion date, studying multiple and higher levels of demand-side investment than historically assumed, and test the present worth of higher levels against the preferred plan.
Modeling and Reliability		Identify and describe the capacity expansion, production cost, and reliability models used, including the chronological resolution at which battery storage is dispatched, as 20 CSR 4240-22.060(4)(H) requires.
Modeling and Reliability		Provide the plot of expected annual unserved hours for each alternative resource plan required by 20 CSR 4240-22.060(7)(C)4, and the extreme weather sufficiency affirmation required by 20 CSR 4240-22.070(1)(D).

Category	Priority	Recommendation
Modeling and Reliability		Apply consistent accreditation treatment across demand-side and supply-side resources, and document the penetration assumptions and analytical basis for the adjustment made to SPP's published ELCC degradation curves, reporting results on the unadjusted curves alongside.
Transparency and Process		Provide the aggregate peak and energy forecast by major class and in total in the public version of each filing, and add [redacted]
Transparency and Process		File the public form of the capacity balance spreadsheet for each preferred plan and each alternative resource plan, updated for the retirement changes.
Transparency and Process		Quantify the execution, permitting, and accreditation risks relied upon in selecting a plan other than the lowest-cost plan, and provide the names, titles, and roles of the preferred resource plan decision-makers as 20 CSR 4240-22.070(1) requires.
Transparency and Process		Correct the internal inconsistencies identified in these Comments and confirm the values on which the analysis relies.

Table 9. Deficiencies identified by NEE

No.	Deficiency	Chapter 22 provision	Utility	Suggested remedy
D-1	Both preferred resource plans fail to satisfy the Missouri Renewable Energy Standard within the planning horizon (Evergy Metro from 2036; EMW from 2037).	22.010(2); 22.070(1)	Both	Develop a preferred resource plan that satisfies the RES in every year of the planning horizon, or document the compliance mechanism relied upon and its cost.
D-2	No compliance benchmark resource plan minimally complying with the RES was developed.	22.060(3)(A)1	Both	Develop, document, and rank a compliance benchmark resource plan.
D-3	No optimal compliance resource plan was developed.	22.060(3)(A)5	Both	Develop, document, and rank an optimal compliance resource plan.
D-4	No aggressive renewable energy resource plan was developed; renewables are capped by annual build limits in every ARP.	22.060(3)(A)2	Both	Develop an ARP using renewable resources up to maximum potential capability in each year, without the annual build limits.
D-5	No aggressive demand-side resource plan was developed; no ARP tests DSM above the approved MEEIA Cycle 4 portfolio.	22.060(3)(A)3	Both	Develop an ARP using demand-side resources up to maximum achievable potential in each year.

No.	Deficiency	Chapter 22 provision	Utility	Suggested remedy
D-6	The capacity expansion model was not calibrated to the RES, a legal mandate.	22.010(2); 22.020(28)	Both	Model the RES as a binding constraint in the capacity expansion model rather than evaluating compliance after the fact.
D-7	The cost of RES compliance is excluded from every NPVRR ranking, including the coal retirement comparison.	22.060(2)(A)1; 22.060(4)	Both	Restate all plan rankings, including the retirement comparison, within a portfolio that satisfies the RES.
D-8	Contingency resource plans are not evaluated for RES compliance or compliance cost, although each widens the shortfall.	22.070(4)(C)	Both	Report the RES position and incremental compliance cost for each contingency resource plan.
D-9	The natural gas price forecast is benchmarked to Henry Hub and translated by a scalar that is never quantified; no basis differential is addressed.	22.040(5)(A)	Both	Quantify the scalar by year, document its derivation, and state the basis differential at each generating station, including behavior during winter cold events.
D-10	The low and mid natural gas price cases remain anchored to 2023 EIA fundamentals; only the high case was updated.	22.040(5)(A); 22.060(5)(D)	Both	Update all three cases to current fundamentals and model intra-year gas price stress scenarios.
D-11	Probability weights assigned to the critical uncertain factors are stated without supporting analysis, and determine which plan ranks first.	22.060(7)(C)1.B	Both	Provide the analysis supporting each weight and report rankings under at least one alternative weighting assigning the high case a minimum of 25%.
D-12	The thermal, renewable, and storage cost escalation assumptions are stated as unattributed percentages with no source, vintage, or derivation, and the underlying cost curves are confidential in their entirety.	22.040(5)(B); 22.060(4)	Both	State the source, vintage, and derivation of each escalation figure, and present any foreign-entity sourcing premium as a discrete adder above a stated market baseline.
D-12a	Renewable costs are escalated at roughly one and a half times the rate applied to thermal costs, a relative treatment opposite in direction to published capital cost data.	22.040(5)(B); 22.060(4); 22.010(2)(A)	Both	Compare each escalation assumption to current published benchmarks and explain the divergence in relative treatment between resource classes.
D-13	Binding annual build limits constrain renewable and storage resources in every economic ARP, but were relaxed by factors of two to five in the RES compliance plans.	22.060(3)(A)2; 22.010(2)(A)	Both	Rerun capacity expansion without the renewable and storage build limits, or apply an equivalent limit to thermal additions and document the basis for each.

No.	Deficiency	Chapter 22 provision	Utility	Suggested remedy
D-14	No energy efficiency programs are modeled after MEEIA Cycle 4 ends in 2026; savings decline 94% (Metro) and 98% (EMW) across the horizon.	22.050(2); 22.070(1)(C)	Both	Model energy efficiency across the full planning horizon independent of the approval status of any particular program cycle.
D-15	The demand-side market potential study is dated 2023 and now supports a fourth planning cycle; no update is identified or scheduled.	22.050(2)	Both	Complete and file an updated potential study and state its completion date.
D-16	Thermal resource ownership is modeled at 50% and 100% only.	22.040(1)	Both	Model ownership at 25%, 50%, 75%, and 100% shares.
D-17	Neither filing identifies or describes the capacity expansion, production cost, or reliability models used.	22.060(4)(H)	Both	Identify and describe each model, including the chronological resolution at which storage is dispatched.
D-18	No plot of expected annual unserved hours is provided for any alternative resource plan.	22.060(7)(C)4	Both	Provide the required plot for each ARP over the planning horizon.
D-19	Neither filing affirms resource sufficiency under extreme weather conditions or presents the underlying forecast.	22.070(1)(D); 22.030(8)(B)	Both	Provide the extreme weather load forecast and the sufficiency affirmation, or the alternative plan the rule requires.
D-20	The reported coal extension benefit consists principally of deferred new-build capital and deferred retirement cost rather than avoided cost.	22.060(4); 22.020(22)	Both	Restate the retirement comparison separately identifying deferred retirement cost and deferred or avoided new-build capital.
D-21	The majority of the reported benefit (75% Metro; 52% EMW) is produced by moving units beyond the twenty-year horizon.	22.060(4); 22.020(43)	Both	Extend the analysis beyond the horizon or report the replacement capital required after each extended unit retires.
D-22	Environmental compliance costs are assumed immaterial on the stated premise that they do not vary with retirement decisions. Under 40 C.F.R. pt. 423 the applicable standard turns on whether a unit ceases coal combustion by December 31, 2034; three units previously scheduled to retire before that date now operate past it.	22.040(2)(B)	Both	Provide plant-specific compliance cost estimates, subjective probabilities, and expected mitigation costs for each unit now operating past the subcategory date, and rerun the retirement comparison including them.

No.	Deficiency	Chapter 22 provision	Utility	Suggested remedy
D-23	No reassessment criteria, capital expenditure thresholds, or off-ramps are established for any extended unit.	22.070(2); 22.070(4); 22.070(6)(D)	Both	Specify the CUF ranges and expenditure thresholds that would trigger reconsideration, and identify the corresponding contingency plans.
D-24	Evergy Metro relies on a Regional Haze development at the Jeffrey Energy Center, in which it holds no ownership interest, to support its retirement changes.	22.070(2)	Metro	Identify the facts supporting the Metro retirement changes that pertain to units Evergy Metro owns, or withdraw the rationale.
D-25	Demand response accreditation is discounted for a policy change SPP has not adopted, while new thermal resources are accredited at design specification.	22.010(2)(A); 22.060(4)	Both	Apply consistent accreditation treatment across demand-side and supply-side resources.
D-26	SPP ELCC degradation curves were adjusted on the basis of an expected resource mix rather than a modeled penetration level, without documentation.	22.040(5); 22.060(4)	Both	Document the adjustment, state the underlying penetration assumptions, and report results using the unadjusted SPP curves.
D-27	Market purchases are capped at 200 MW per hour from 2030 without justification, constraining the resource that competes most directly with owned thermal capacity.	22.040(1); 22.040(3)(A)6	Both	Explain the basis for the limit and report the sensitivity of each preferred plan to a higher limit.
D-28	Evergy Metro selected a plan ranking $15 million above the lowest-cost plan on execution and permitting grounds that are not quantified.	22.010(2)(C)	Metro	Quantify each risk relied upon, including probability of permitting failure, cost of construction delay, and the capacity value differential.
D-29	Neither filing provides the names, titles, and roles of the preferred resource plan decision-makers.	22.070(1)	Both	Provide the required identification of decision-makers.
D-30	Battery storage is evaluated at a single four-hour duration; EMW models no storage in its preferred plan.	22.040(4)	Both	Evaluate six-hour and eight-hour configurations as supply-side candidate resource options.
D-31	Neither filing discloses the annual gas consumption or fuel cost of the approximately 3,600 MW of new gas-fired capacity in the preferred plans.	22.040(5)(A); 22.060(4)	Both	Report annual consumption in MMBtu and annual fuel cost in dollars for each new thermal resource under each gas price case.

Table 10. Concerns identified by NEE

No.	Deficiency	Chapter 22 provision	Utility	Suggested remedy
C-1	The aggregate mid-case load forecast is designated confidential in its entirety, so the forecast underlying both plans cannot be reviewed publicly.	22.080(2)(E)2; 22.060(4)(B)9; 22.020(44)	Both	Provide the aggregate peak and energy forecast by major class and in total in the public filing.
C-2	[redacted] is not reported.	22.050	Both	Add [redacted] to the load forecast table.
C-3	The public form of the capacity balance spreadsheet was not filed for the preferred plan or any candidate plan.	22.080(2)(D); 22.080(3)(B)	Both	File the public capacity balance spreadsheet for each plan, updated for the retirement changes.
C-4	The surplus interconnection storage analysis referenced in both filings was not provided.	22.040(1); 22.080(11)	Both	File the surplus interconnection analysis in these dockets.
C-5	The large-load customer pipeline is reported only as a static table in the special contemporary issues section.	22.030(7)(A); 22.080(3)(B)	Both	Report pipeline status, interconnection study progress, and load ramp on a recurring basis between filings.
C-6	Flexibility available under the Large-Load Power Service tariff is not reflected in the load forecast or the capacity expansion analysis.	22.050(4)(F); 22.060(5)(K)	Both	Model contractual curtailment and flexibility provisions as demand-side resources.
C-7	Both filings cite Missouri Senate Bill 4 in support of firm dispatchable additions without analysis of what the statute requires.	22.020(28)	Both	Document the specific statutory obligations relied upon and how the preferred plan satisfies them.
C-8	Several internal inconsistencies appear in the filings, including transposed figure captions, a coal unit listed with two different retirement dates, inconsistent plan compositions, and pipeline totals that do not sum.	22.020(14)	Both	Correct the identified inconsistencies and confirm the values on which the analysis relies.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing document was served upon all counsel of record by email this 30th day of July, 2026.

/s/Alissa Greenwald
Alissa Greenwald