FILED
June 4, 2025
Missouri Public
Service Commission

Exhibit No. 500

Renew Missouri – Exhibit 500
Testimony of William "Nick" Jones
Rebuttal
File No. EA-2025-0075

Exhibit No.:	
Issue(s):	Economic feasibility, failure to consider alternatives, public interest
Witness:	William "Nick" Jones
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Renew Missouri Advocates
File No.:	EA-2025-0075
Testimony Filed:	April 25, 2025

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO.

EA-2025-0075

DIRECT TESTIMONY

OF

WILLIAM "NICK" JONES

ON

BEHALF OF

RENEW MISSOURI

APRIL 25, 2025

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I. INTRODUCTION

Q: Please state your name and business address.

A: Nick Jones. 1121 Military Cutoff Road, Suite C #205, Wilmington, NC 28405.

Q: By whom are you employed and in what capacity?

A: I am employed by the Council for the New Energy Economics (NEE) as Utility Economics Senior Analyst.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Renew Missouri Advocates d/b/a Renew Missouri. Renew Missouri is an advocacy group appearing before regulatory agencies such as the Missouri Public Service Commission ("PSC" or the "Commission"), the Kentucky Public Service Commission, and the Kansas Corporation Commission in the role as expert witnesses on clean energy, energy efficiency, and transmission development policy. Renew Missouri's work involves engaging as intervenors on utility rate cases, applications for certificates of convenience and necessity ("CCNs"), mergers and acquisitions, Accounting Authority Orders ("AAOs"), and energy efficiency investment portfolios. Renew Missouri also routinely engages in workshops and rulemaking by providing comments.

Q: Please describe your educational background.

A: I completed the liberal arts program at Deep Springs College before earning my BA in economics and statistics from the University of Michigan, Dearborn.

Q: Please describe your professional background.

A: Prior to joining NEE, I was an energy analyst for BTU Analytics – an energy market data and research firm which was purchased by FactSet during my tenure. Some of my primary responsibilities included contributing to forecasts for natural gas supply, demand, and pricing. To this end, I built the firm's model for forecasting power sector fuel demand. Under our consultancy business, I contributed to valuations of pipelines and other energy infrastructure for some of the world's largest energy companies and asset managers. I also helped develop and bring into operation the firm's first research team dedicated to 'energy transition' markets. Some projects under that team included modeling techno-economics and risk factors for emerging technologies like carbon capture and hydrogen. In 2024, I started with NEE in the senior analyst role. Since then, I have contributed to testimony and comments in a variety of regulatory venues, including proceedings in Kansas, Missouri, and Georgia. I also served as lead author on NEE's first research report, which addressed the risks of natural gas for power utilities. My curriculum vitae is included as Schedule NJ-1 to my Direct Testimony.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain that Evergy[1] has not demonstrated the proposed Viola, McNew, and Mullin Creek gas plants to be the most economically feasible resources for meeting capacity needs nor the best resources for promoting the public interest – as is required under the Tartan criteria. Specifically, I testify that the proposed plants may not be economically feasible due to their reliance on the high-risk natural gas market, that they may not be needed due to the availability of alternatives with lower costs and lower risks, and that the public interest would be better served by a plan that utilizes such alternatives.

I will present analysis that shows that the natural gas required to fuel these plants will represent a significant cost to ratepayers. I will show that uncertainty in the natural gas market could drive these costs still higher and that the Company has not adequately

[1] "Evergy" or "the Company" refers collectively to the Applicant, Evergy Missouri West, Inc. and Evergy Missouri Metro, Inc.

measured the market risks to which these plants will expose ratepayers. I will also explain why the Company's supply plan does not adequately manage these risks to ensure reasonable fuel costs for ratepayers. I will show that a specific claim made by Evergy – that these plants will serve the public interest by hedging against volatility in the wholesale power market[2] – is not supported by data.

In the alternative, the public interest could be better served by reducing the net-owned capacity held by Evergy Missouri West (EMW) in these three plants and instead investing in concurrent deployment of battery storage. I show that such an alternative could reduce capital costs, reduce operating costs, and reduce exposure to risky commodity markets – all factors which would make such an alternative more economically feasible and preferable for ratepayers and the public interest. Under such an alternative, system reliability could be maintained and potentially improved – also promoting the public interest. Finally, adding capacity through new or revised renewable energy subscription programs could yield further opportunities to reduce reliance on natural gas and therefore reduce fuel costs and related risks for the general ratepayer.

Q: Please provide a summary of your recommendations to the Missouri Public Service Commission in this proceeding.

A: My recommendations for the Commission can be summarized as follows:

1. The Commission should consider fuel costs associated with the proposed plants in determining their impact on ratepayers and whether they result in the plants not being economically feasible.

[2] *Direct Testimony of Kevin Gunn,* p. 22-23; *Direct Testimony of Cody VandeVelde*, p. 8-9.

2. The Commission should evaluate the impact on revenue requirements under a range of natural gas price scenarios to determine whether the public is exposed to undue fuel market risk.
3. The Commission should consider Evergy's fuel supply plan to be inadequate for minimizing ratepayer exposure to fuel market risk.
4. The Commission should reject Evergy's claim that the proposed plants will serve the public interest through lowering exposure to wholesale power market risk.
5. Evergy should commit to adding battery storage capacity as a substitute for a portion of planned natural gas capacity in order to optimize the economic feasibility and better serve the public interest.
6. Evergy should evaluate the potential for expanded customer subscription programs to fund incremental renewable projects as a risk-minimizing complement for new natural gas generation, and further the public interest customers have expressed in participating in customer subscription programs.

Q: Generally, what is your understanding of how the Commission evaluates whether to grant a requested certificate of convenience and necessity?

A. It is my understanding that the Commission ultimately must find that a proposed project is in the public interest. To assess whether a project is in the public interest, the Commission historically has applied guidelines known as the "Tartan Factors." The Tartan Factors are: (1) need for the project; (2) economic feasibility of the project; (3) ability of the applicant to finance the project; (4) qualifications of the applicant to construct the project; and (5) whether the project is in the public interest. Typically, if the Commission finds that the first four factors have been demonstrated by the applicant, the fifth factor, whether the project is in the public interest, is deemed satisfied. In my testimony, I focus extensively on the failure of Evergy to adequately satisfy the economic feasibility factor. Due to the economics of these gas plants weighing heavily on the public interest in utilizing these specific plants, I address both public interest and economic feasibility together as appropriate. I also discuss whether the public interest in reliability and other ancillary benefits is adequately met by these gas plants and suggest alternatives that would better satisfy the public interest factor.

II. THE COMMISSION SHOULD EVALUATE IMPACTS ON REVENUE REQUIREMENTS AND RETAIL RATES WITH FUEL COSTS INCLUDED

Q: Why should the Commission consider fuel costs in determining whether the proposed plants are economically feasible and serve the public interest?

A: Fuel costs will ultimately be a large part of how the proposed plants impact customer bills through the Fuel Adjustment Charge (FAC) mechanism. Fuel costs and associated market risks are material to determining whether the plants are the most economically feasible option for meeting system needs and whether they ultimately serve the public interest better than alternatives. This is particularly true when comparing the proposed gas plants to potential alternative resources that would not require fuel.

While fuel costs are included in portfolio evaluation during the IRP process, many conditions assumed during the IRP process require updates by the time a specific plant is proposed. In this docket, the need to critically review IRP results is already very apparent. The marketplace is undergoing a uniquely dynamic period where many conditions have changed, some of which are acknowledged by Evergy and some of which are not. They include inflation in the capital cost for natural gas plants,[3] potential exacerbation of that inflation caused by new tariffs,[4] the new expectation of increased load growth,[5] and the reduction in capital costs associated with other resource types like batteries. At least one of these factors – higher than previously expected load growth – has led Evergy to apply for capacity beyond what was included under its preferred portfolio in the 2024 IRP with its proposed 50% ownership in the McNew combined cycle gas turbine (CCGT). In considering Evergy's application in light of these updates, expected fuel costs should be included for the sake of fully assessing the relative feasibility for the proposed plants. This is especially true in the case of McNew, which has not been fully vetted through IRP analysis.

Failing to analyze the effect of fuel costs could understate the net-cost of these plants for ratepayers, particularly in the event of fuel costs exceeding expectations. As described in this testimony, many factors could drive fuel costs up to or beyond Evergy's high-case gas price scenario. It is critical that the Commission be able to review the full extent to which these specific plants would be expected to impact revenue requirements and the market risk exposure they represent, including risk from fuel costs.

Q: How do you suggest the Commission consider fuel costs in determining whether Evergy's proposed plants are the most economically feasible option for serving the public interest?

A: I suggest that the Commission include fuel in weighing the economic costs, benefits, and risks of the proposed plants versus alternatives. For instance, as I will explore in greater

[3] *Direct Testimony of Jason Humphrey,* p. 18.
[4] *Supplemental Testimony of Jason Humphrey,* p. 6-7.
[5] *Supplemental Testimony of Kevin Gunn*, p. 5.

detail in this testimony, battery energy storage systems (BESS) are increasingly cost competitive as an alternative form of dispatchable capacity. A large part of their competitive edge stems from their not requiring fuel as a direct operational input. Therefore, to determine whether a specific natural gas resource addition is economic compared to BESS requires accounting for fuel costs. I suggest that the most straightforward way to do so, in line with the standard for IRP analysis, is to compare the net-present-value revenue requirement (NPVRR) of the proposed plants, with fuel costs included, to that of alternatives. While similar comparisons of resource NPVRR are conducted during the IRP process, they are performed in aggregate, which can obscure the full cost and risks incurred from individual portfolio choices. Additionally, I note above that many of the estimated cost inputs have changed dramatically from those used in the IRP process and that the McNew plant was not included in the 2024 IRP. It is therefore worth re-evaluating this metric.

Lastly, fuel costs and their associated risks are material in evaluating some specific claims made in this docket concerning these plants. For instance, Evergy has testified that the proposed plants are in the public interest because they will decrease EMW's reliance on purchased power and therefore reduce costs and risks associated with relying on the wholesale power market.[6] I contend that this claim does not acknowledge that the proposed plants will rely on fuel procured in the natural gas market and therefore will still be exposed to market risk, albeit that risk will be shifted from the power market to the gas market. A specific accounting of fuel costs for the proposed plants is necessary to compare the full expected cost of power to be generated at these facilities versus power available via the

[6] *Direct Testimony of Kevin Gunn,* p. 22-23; *Direct Testimony of Cody VandeVelde*, p. 8-9.

wholesale market, and to determine whether these plants are likely to serve the public interest on the grounds of reducing costs and market risk. I have performed analysis on the relative success of using natural gas generation capacity to hedge against wholesale power prices, the results of which I report later in this testimony.

Q: Have you performed any analysis of the proposed plants' impact on revenue requirement when fuel costs are included?

A: Yes. I have calculated the fuel costs for each proposed plant according to Evergy's natural gas price forecasts. I have also calculated revenue requirements in each plant's respective first year of operations with fuel costs included to illustrate the full cost of these plants as well as the level of exposure to fuel market risk.

Q: Please briefly describe the methodology used in producing your analysis of the proposed plants' impact on revenue requirement.

A: To measure the effect of fuel costs, it is necessary to measure against a baseline cost that would otherwise be expected for fuel or purchased power. I assume that, without the inclusion of the new plants, the Company's current average cost for fuel and purchased power would be maintained.

In its most recent Missouri rate case, Evergy Missouri West has provided a "base factor" charge of $23.09 per MWh.[7] I take this to be an adequate proxy for the fuel adjustment rate going forward. I consider that carrying this rate forward is a conservative modeling assumption because the Company's generation mix is forecasted to shift from thermal generation toward renewable generation, which should allow a reduction in FAC between now and 2029.

[7] In the Matter of Evergy Missouri West, Inc., d/b/a Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service, File No. ER-2024-0189, *Tariff Revision,* p. 36 .

I then calculated the per MWh costs of fuel for each proposed plant according to annualized versions of the Company's natural gas forecasts, the stated heat rate for the proposed plants, the capacity factor used in the Company's financial model workpaper, and an assumed $0.30 per MMBtu firm transport reservation, roughly in line with posted FTS tariffs from regional pipelines.[8] **____

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__________.[9]** I then took the difference between the per MWh fuel cost for each plant and the $23.09 per MWh baseline in order to find the net impact of fuel costs related to these plants.

Q: What were the modeled fuel costs for the plants and how did this compare with the baseline fuel costs that would otherwise be expected?

A: **____

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[8] Note: Southern Star used as an example due to its use at Hawthorn. *See* Southern Star Central Gas Pipeline, FERC Gas Tariff (Feb. 28, 2023). Accessible at: https://csimain.southernstar.com/EBBPostingDocs/other/TariffShark/tariff.pdf#toolbar=1&nameddest=ftssftrates.

[9] EMW's response to the Staff of the Missouri Public Service Commission ("Staff") Data Request (DR) 16.

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Q: Both your analysis and the Company's analysis are premised on the same generic capacity factors. Did you model fuel costs for other capacity factors that resulted from the Company's resource models?

A: Yes. I computed 10-year NPVRR impact of modeled fuel consumption for these plants using the modeling output provided by Evergy. Due to the Company's model producing varying capacity factors year-to-year, I determined that calculating revenue requirements for each plant's respective first year of operation would be less meaningful than calculating a cumulative revenue requirement over the first several years of operation. This better captures the expected cost of fuel for ratepayers during normal plant operations in the Company's resource model. My chosen horizon, from 2025-2034, captures just the 10-year NPVRR impact of cumulative fuel costs for the first five years of operations at Viola and the first four years of operations at McNew and Mullin Creek. By deflating these costs to today's NPV, I avoid overstating the impact of fuel costs in comparison to the Company's portfolio cost analysis. The Company's assumed weighted-average cost of capital (WACC) was used as the discount rate in this analysis, again to maintain consistency with the Company's portfolio cost analysis. As in the foregoing analysis, I used a $23.09 per MWh baseline to find the incremental cost of fueling the proposed plants.

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Q: How should the Commission interpret your analysis on impacts to revenue requirements in determining whether the proposed plants are in the public interest?

A: My intention in analyzing revenue requirements for this docket is to demonstrate that there are other resources and strategies, not adequately modeled in the IRP nor in this docket, which Evergy could use as substitutes or complements to the proposed natural gas plants. **____ ____ ___________________________.** The Commission should consider impacts on base rate and FAC revenue requirements with fuel costs fully accounted for, particularly when comparing the proposed resource to alternatives that may not directly require fuel. Doing so casts doubt on whether ratepayer interests are best served by this application in its current form. Later in this testimony, I will present two pathways which could allow the Company to reduce fuel costs and related risk by enhancing its portfolio of zero-fuel resources and reducing its net ownership of the proposed CCGT plants or the proposed CT plant.

III. THE COMMISSION SHOULD EVALUATE THE IMPACT ON RATEPAYERS UNDER A RANGE OF NATURAL GAS PRICE SCENARIOS

Q: Why is scenario analysis important for evaluating power plants fueled by natural gas?

A: Natural gas markets are famously volatile and unpredictable. Price forecasts for natural gas can fail to predict major shocks which can fundamentally alter the supply and demand of the market. One such example would be forecasts from the early 2000s that failed to anticipate the rise in gas production from shale basins. Another would be forecasts from the early 2010s which failed to anticipate the rise of US LNG exports. With the knowledge that any single forecast is likely to error, scenario planning uses multiple different price forecasts to determine a range of potential fuel costs that a new resource is likely to incur. I argue that the Commission should evaluate this range of potential costs – and compare them to alternatives – to evaluate whether the proposed plants are the most economically feasible resource option and whether they are in the public interest.

Q: What are the potential consequences for ratepayers if fuel prices ultimately exceed the forecast assumed during planning?

A: If fuel prices ultimately exceed Evergy's mid-case forecast, the revenue requirements for natural gas plants would be greater than the assumptions under which they are planned. They risk becoming uneconomic assets at the expense of ratepayers. Fuel and related costs are generally the largest operational cost for thermal power plants, making them consequential in determining the ultimate cost of the energy produced.

The question of fuel costs is particularly consequential in this case due to recent market developments described in the previous section. The current period is uniquely dynamic and emerging conditions necessitate a re-evaluation of the Viola, McNew, and Mullin Creek plants against alternative resource options. Under alternative natural gas price scenarios, model output could be further shifted. Given the high level of uncertainty and unpredictability specific to natural gas markets, it is critical to consider whether the proposed plants are reasonably likely to remain the most economically feasible and the best option for promoting the public interest even when prices exceed the Company's mid-case forecast.

Q: What natural gas price forecast has Evergy used in this docket for modeling the economic efficiency of their proposed plants?

A: Evergy used the mid-case natural gas forecast submitted in their 2024 Triennial IRP.

Q: Are there reasons to doubt that Evergy's mid-case natural gas forecast from the 2024 IRP remains the best forecast for evaluating new resources?

A: Yes. Recent market developments have rendered Evergy's forecast outdated. As Evergy has acknowledged, the 2024 Triennial IRP was prepared before the Company had fully appreciated the potential for large load customers driving rapid load growth in the EMW territory.[10] Spurred largely by AI computing and data centers, the need to accommodate new large loads has become an issue for utilities nationwide.

The anticipation of this new load has led to a national surge of interest in new natural gas plants.[11] This surge will have knock-on effects; one such effect is the inflated

[10] *Direct Testimony of Kevin Gunn,* p. 26-27.
[11] FactSet, "Natural gas power plant applications surged in 2024" (Jan. 7, 2025). Accessible at: https://insight.factset.com/natural-gas-power-plant-applications-surged-in-2024.

prices and longer lead times for natural gas power plant equipment, to which Evergy has provided evidence in this proceeding.[12] Logical consistency would require that, if the rush to build new gas plants is enough to inflate the price of equipment, the rush will also be enough to inflate the cost of fuel once these plants are built. More natural gas plants will result in more demand for natural gas, which means fuel prices will rise.

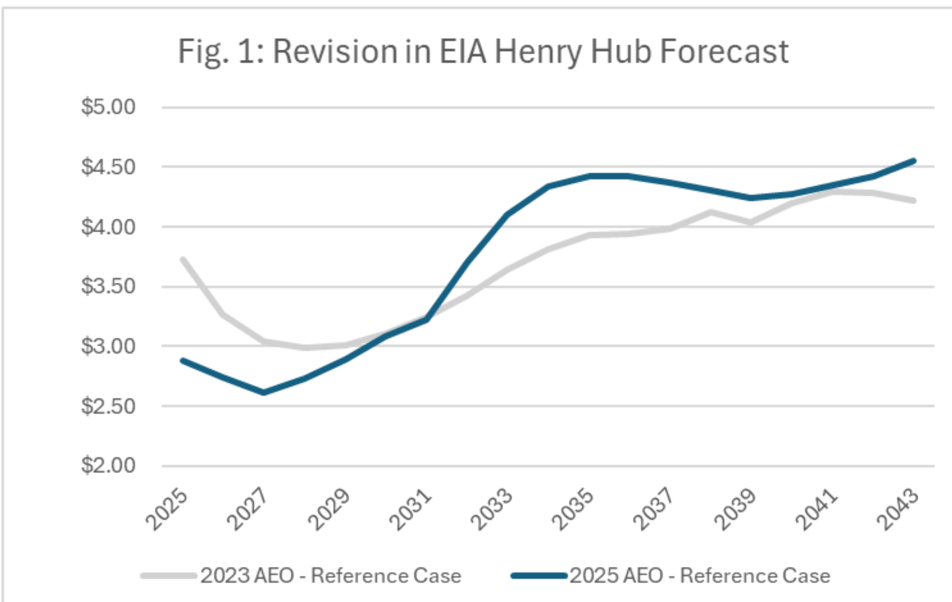
Also potentially contributing to increased demand, recent national regulatory changes have encouraged greater development of natural gas power plants and Liquified Natural Gas (LNG) export facilities while slowing the development of other energy resources like wind power. These changes are expected to increase national demand for natural gas.

Thus, the mid-case forecast produced for the 2024 IRP is not sufficient for assessing the likely fuel cost related to the proposed plants. At a minimum, the high-case forecast should be used as an additional reference to evaluate the risk for ratepayers if the factors mentioned above cause natural gas prices to exceed Evergy's base-case expectations.

[12] *Direct Testimony of Cody VandeVelde*, p. 10; *Direct Testimony of Kyle Olson*, p. 32

Q: Do any credible forecasts or analysis from other sources support your outlook on natural gas prices?

A: Yes. Two recent publications support my view that market developments are likely to drive prices above previous expectations. The Annual Energy Outlook (AEO) 2025 has been published by the Energy Information Administration, with natural gas prices significantly revised upward in the 2030s.[13] The AEO is a trusted resource and one of the forecasts that Evergy has previously used in building its IRP price forecasts. As can be seen in Fig. 1, a sharp increase in prices is now expected in the early 2030s when the proposed natural gas plants will come online.



Source: Energy Information Administration, Annual Energy Outlook 2025, Accessible at: https://www.eia.gov/outlooks/aeo/

Secondly, the Kansas City Federal Reserve has recently published its quarterly survey of oil & gas executives in the Midcontinent region.[14] In that survey, executives were

[13] Energy Information Administration, Annual Energy Outlook 2025, Accessible at: https://www.eia.gov/outlooks/aeo/

[14] The 'Midcontinent' refers to oil and gas basins in central areas of the US, including major production basins in Oklahoma and North Dakota.

asked what natural gas price they anticipated five years from today. The average response was $4.78 per MMBtu,[15] roughly $1 per MMBtu higher than Evergy's mid-case forecast for 2030. At least one respondent answered that natural gas would be $10 per MMBtu in 2030. When asked what price would allow their companies to substantially expand production – with a substantial increase in production likely to be necessary to meet the demand growth described above – responses averaged $5.10 per MMBtu. Both these publications support my view that Evergy's mid-case forecast is too low relative to market developments.

Q: In this docket, has Evergy modeled the cost of proposed plants under alternative scenarios with higher natural gas forecasts?

A: Yes. The Company has made NPVRR calculations for the preferred portfolio across differing scenarios. However, by only presenting NPVRR results in aggregate across the entire portfolio, it has obscured the exact impact of natural gas prices on the cost of these plants.

Q: What does Evergy's lack of plant-specific scenario analysis under this docket mean for measuring and managing the risks associated with fuel markets?

A: Reasonably managing risk depends on projecting a variety of potential future conditions and measuring their effect on outcomes. In this context, scenario analysis allows for decision making which accounts for whether a planned resource is likely to remain economically feasible and serve the public interest even if conditions end up differing from initial expectations. Further, this analysis allows for weighing the probability and impact of various risks in order to assess how risk to the public can be reasonably managed. While

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

this is important to consider at a portfolio level, it is also important at the level of individual plants. This is particularly true because the Company will ultimately be responsible for effecting a fuel supply plan for each individual facility to manage risk.

Without such analysis, there is no measurement of the liability for the public that is entailed by each of these plants if natural gas prices are higher than forecasted. Lacking this analysis hampers any effort to design reasonable risk management strategies to protect the public from undue risk, further casting doubt that the proposed plants meet the public interest standard.

IV. THE COMMISSION SHOULD CONSIDER EVERGY'S FUEL SUPPLY PLAN INADEQUATE FOR MINIMIZING RISK TO RATEPAYERS

Q: Why is Evergy's fuel supply plan important to consider in this proceeding?

A: As described above, forecasts for future fuel prices are always susceptible to errors which could lead actual costs to be significantly greater than expected when a plant is first considered. The Company's fuel supply plan provides an opportunity to manage risks and minimize unforeseen costs. The fuel supply plan in large part determines if a plant will be economically feasible and in service of the public interest even when market conditions change unexpectedly. Compared to other fuels, natural gas is especially susceptible to market volatility and supply challenges which makes such supply plans even more critical.

Q: Please describe why natural gas is more susceptible to market volatility and supply challenges than other fuels like coal.

A: Natural gas cannot be easily stockpiled on site, as is common practice for coal. Nor can natural gas be delivered through multiple modes of transport, as can be done for coal. Nor is natural gas marketed almost exclusively to the power sector, as is the case for thermal coal. In contrast to coal markets, natural gas markets rely on centralized storage and delivery to end-users via pipelines. This combination of factors makes natural gas a 'just-in-time' fuel for which the timing and volume of deliveries must coincide exactly with the needs of the power plant. Therefore, procuring natural gas inherently requires more sophisticated methods and leaves less room for error than procuring coal. The reliance of natural gas on intricate pipeline networks creates the possibility of unexpected market shocks and even reliability risks caused by pipeline congestion or outages.[16] Also distinguishing it from coal, natural gas is widely used across multiple sectors, adding complexity and unpredictability to the market. Lastly, the United States' capacity for exports has grown rapidly in recent years and is poised to grow further with new LNG terminals. This means that international markets are increasingly drawing supply from the US market, exposing domestic gas buyers to higher prices.

All of these factors help to explain why natural gas prices are definitively more volatile and difficult to predict than coal prices. Additionally, these factors explain why how an effective supply plan for natural gas is indispensable for ensuring economic feasibility.

Q: Does the Company's specific plan for procuring natural gas for the proposed plants effectively address concerns regarding fuel costs?

A: The Company has said that "the details of a fuel procurement plan are still being developed."[17] Descriptions so far presented in testimony from Evergy witness Kyle Olson[18]

[16] As an illustration of this risk, the El Paso Line 2000 suffered an explosion in August 2021 and did not return to service until early 2023. In the intervening months, natural gas supply in Southern California and across the Southwest was severely constrained.
[17] EMW Response to Renew Missouri DR 7.
[18] *Direct Testimony of Kyle Olson,* p. 34-35.

and discovery responses are not sufficient to demonstrate that ratepayers will be protected against short-term volatility and the potential for long-term increases in fuel costs.

Q: As the Company develops a fuel procurement plan for the proposed plants, is it likely that the declared strategies will effectively control fuel costs and minimize risks?

A: No. Though Evergy has not provided a definite procurement plan, the strategies currently under consideration do not adequately control costs or minimize risks over short-term or long-term horizons. **____**[19] descriptions of the plan being developed are generally non-committal. A range of possible strategies are being evaluated, **____ ____________________________**[20] However, the options described appear likely to leave ratepayers risk-exposed, potentially to a large degree.

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[19] EMW Response to Staff DR 16.
[20] EMW Response to Renew Missouri DR 7.

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________.**[21,22,23,24,25,26] NEE has attested elsewhere that major financial institutions are willing to provide quotes on multi-year hedges for planned power plants, potentially even covering the full book life of a plant.[27]

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_________** Importantly, such quotes also provide an opportunity for the Company to benchmark its own natural gas forecast against risk-adjusted forecasts produced by expert commodity analysts. This should contribute to a more accurate price forecast.

Q: Are any plants currently operated by the Company comparable to the proposed Viola and McNew CCGT plants?

A: Yes. The Commission should consider precedent for Evergy's natural gas procurement practices at a similar plant – the Hawthorn Station in Kansas City, Missouri. At Hawthorn, Evergy Missouri Metro has operated a 313 MW combined-cycle unit for 27 years, alongside a 569 MW coal steam unit with natural gas co-firing capability and two 82 MW

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[21] *Id*.
[22] *Id*.
[23] *Id*.
[24] *Id*.
[25] *Id*.
[26] *Direct Testimony of Kyle Olson,* p.35.
[27] North Carolina Utility Commission Docket No. e-100, sub 19, *Testimony of R. Brent Alderfer and Ivan Urlaub on behalf of Clean Energy Buyers Association*, p. 47 (May 28, 2024).

simple cycle natural gas units.[28] While the simple cycle units presumably act as peakers, the combined-cycle and co-fired steam units would conventionally be considered baseload resources, similar to the proposed CCGT plants.

Q: How can historical procurement data from the Hawthorn plant be compared to the procurement plan for the proposed combined-cycle plants?

A: In public data from the Energy Information Administration, natural gas purchases for the entire complex are reported in aggregate. However, data on gas consumption is reported by generator type, revealing that the majority of natural gas purchased for Hawthorn Station is consumed by the combined-cycle and coal/gas co-fired steam plant.[29] As both of these units would be expected to operate as baseload generation, historical costs at Hawthorn provide insight into how Evergy has managed natural gas procurement for baseload generation.

Furthermore, Hawthorn reports receiving 100% of its gas supply via firm transport for the last 17 years[30] – the entirety of data available for analysis in this testimony. Firm transport is provided to Hawthorn by the Southern Star gas pipeline. During the period from June 2022 through July 2024, 100% of gas purchased for Hawthorn was reported as being bought on advanced contracts.[31] Therefore, in addition to partial similarities in plant characteristics, gas procurement for Hawthorn during that 26-month period appears to employ risk management strategies similar to what is proposed for the Viola and McNew

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[28] Energy Information Administration, Form EIA-860 M Detailed Data Schedule 3 'Generator Data.' Accessible at: https://www.eia.gov/electricity/data/eia860/.

[29] Energy Information Administration, Form EIA-923 Detailed Data Schedule 2. Accessible at: https://www.eia.gov/electricity/data/eia923/.

[30] *Id.*

[31] *Id.*

plants. This means that the historical data from Hawthorn is an indicator for the likely effectiveness of the proposed strategies moving forward.

Q: Has the Company successfully managed risks and costs in procuring natural gas for the Hawthorn complex?

A: No. The Company's management of natural gas procurement at Hawthorn has neither protected ratepayers from sustained increases in fuel costs nor short-term price spikes.

To supply natural gas generators at Hawthorn, the Company has generally paid more than was forecasted. To preface this analysis, it is important to note that though the outbreak of war in Ukraine destabilized domestic energy markets,[32] markets had mostly stabilized by early 2023. My period of analysis for Hawthorn's gas purchases runs from June 2022 through July 2024, a period that only partially overlaps with the effects of this destabilization. In addition, macro-level price shocks like that caused by the war in Ukraine are a component of the market risks that 'high-case' natural gas forecasts ought to capture. During my period of analysis, when Hawthorn was utilizing both firm transport and advanced contracts to purchase natural gas, the plant paid an average delivered cost of $3.84 per MMBtu.[33] This is roughly 40% more than the Company's mid-case and 15% more than the Company's high-case price forecasts for 2022-2024 as presented in its 2021 Triennial IRP.[34] I note here that, though advanced contracts can protect against price fluctuations, such contracts are also sometimes arranged with variable pricing, which makes them less protective against market risks. While transport charges are included in

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[32] Energy Information Administration, "Energy commodity prices in 2022 showed effects of Russia's full-scale invasion of Ukraine" (Jan. 3, 2023). Accessible at: https://www.eia.gov/todayinenergy/detail.php?id=55059.

[33] Energy Information Administration, Form EIA-923 Detailed Data Schedule 2. Accessible at: https://www.eia.gov/electricity/data/eia923/.

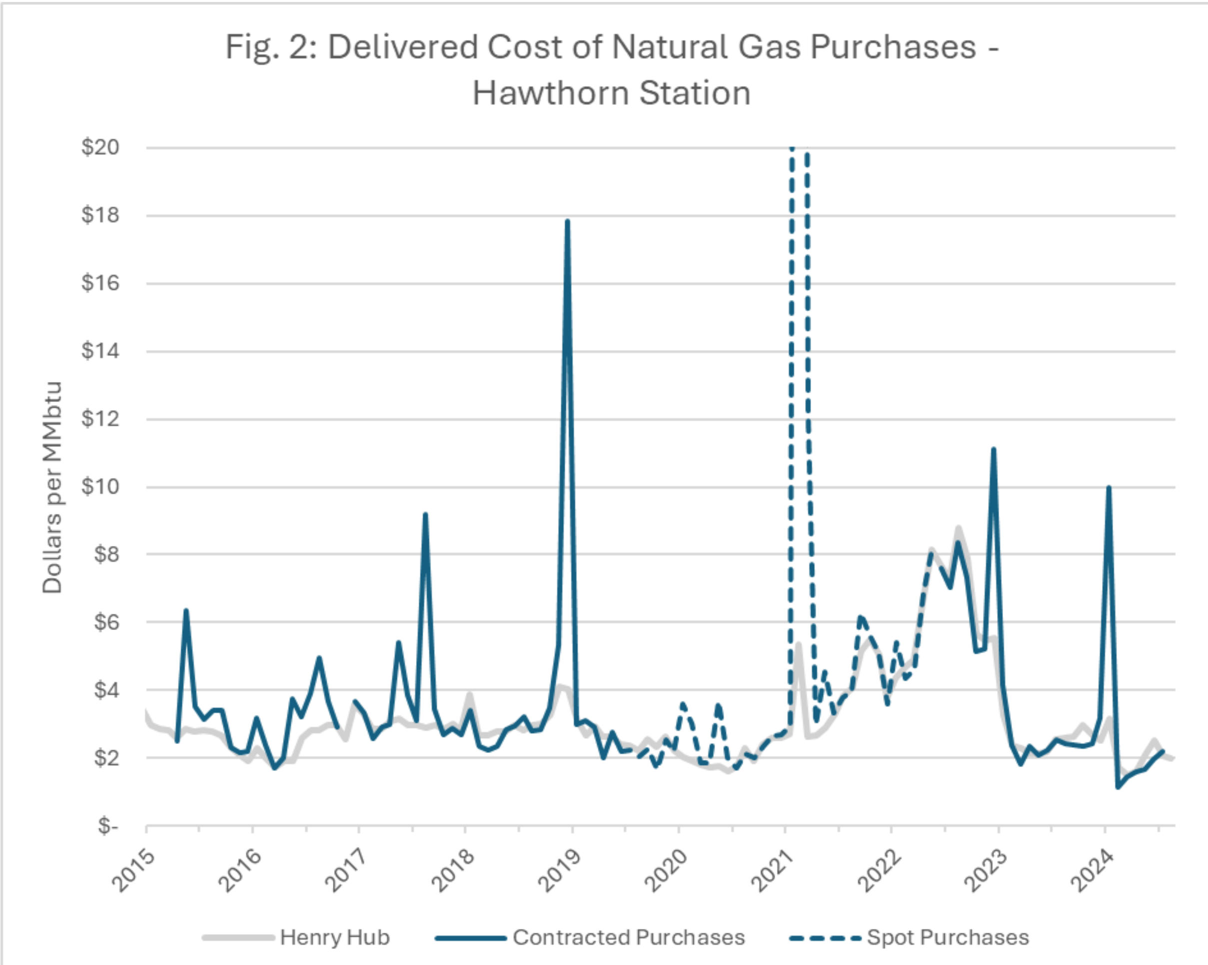
[34] In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's 2021 Triennial Compliance Filing Pursuant to 20 CSR 4240-22, File No. EO-2021-0035, *Evergy Missouri Metro Letter of Transmittal and Integrated Resource Plan - Volume 4: Supply-Side Resource Analysis*, pg. 47.

delivered fuel costs and can explain a part of the discrepancy, maximum fees for firm transport reservations on the pipeline that supplies Hawthorn sat below $0.22 per MMBtu during that period[35] – a rate which could likely only account for a minority of the discrepancy. Because Evergy has held a firm transport subscription for Hawthorn over several decades, the actual transportation fees would be expected to be an even smaller portion of the discrepancy between forecasted prices and delivered costs. I have estimated that roughly 3% of fuel costs for Hawthorn during this period were attributable to transportation. Evaluated on a multi-year horizon, it is clear that Evergy's procurement strategy did not succeed in keeping long-term costs to a level anticipated in its resource planning.

Contributing to the higher-than-forecasted costs are periodic price spikes, which can greatly raise the long-run average cost of fuel. Notably, these spikes can occur outside of macro-level market events, like the effects of the war in Ukraine described above. Short-term price shocks often occur during months with extreme weather events, when power plant operators compete for fuel supply on constrained pipeline systems to serve peak electrical load. In the case of cold weather events, local gas distributors are also fully utilizing their subscribed transport capacity, which can contribute to strained infrastructure and elevated regional pricing. Even when gas supply has been pre-arranged by contract, some contract designs may not effectively cap costs. To illustrate, even with contracted supply and firm transportation, fuel costs at Hawthorn averaged $11.13 per MMBtu during

[35] Southern Star Central Gas Pipeline, April 2022 Rate Card – Full Sheet (Jun. 6, 2022). Accessible at: https://csi.southernstar.com/infoPosting/api/Posting/GetPostingDocument?p=141112&b=70.

December 2022 and $10.00 per MMBtu during January 2024,[36] both months which saw particularly extreme cold from winter storms.



Source: Energy Information Administration, Form EIA-923 Detailed Data Schedule 2. Accessible at: https://www.eia.gov/electricity/data/eia923/ ; Energy Information Administration/Thomson Reuters, Henry Hub Natural Gas Spot Price. Accessible at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

Q: What historical evidence exists for Evergy's procurement of natural gas through spot purchases, such as those which might be expected to supply the Mullin Creek plant?

A: **____

____

[36] Energy Information Administration, Form EIA-923 Detailed Data Schedule 2. Accessible at: https://www.eia.gov/electricity/data/eia923/.

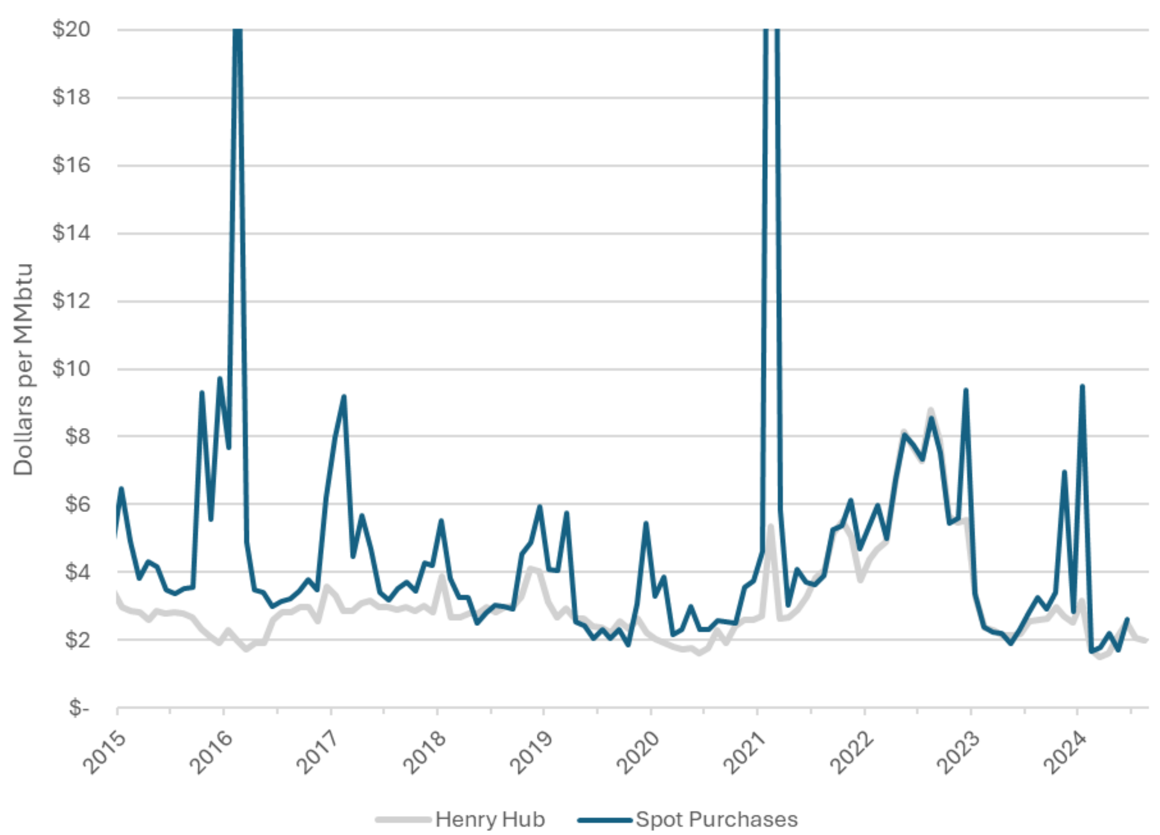
______________________________**[37] There is abundant data regarding Evergy's procurement of natural gas through spot purchases. High heat-rate simple cycle plants such as Mullin Creek have historically made up the bulk of the gas fleet Evergy operates. As these plants have generally operated at low-capacity factors, it is to be expected that the Company has maintained procurement flexibility by using primarily spot purchases. However, spot purchases clearly expose Evergy to the risk of high prices, particularly during extreme weather events.

I performed analysis of the Company's historical fuel costs associated with spot purchases, across the whole of the Company's tri-state gas fleet,[38] to measure the risk of relying on spot purchases in future procurement plans. As shown in Figure 2, Evergy's spot purchases have been subject to frequent spikes in delivered cost, often much higher than average monthly prices at Henry Hub.[39] These spikes have been pernicious, driving delivered costs to high levels even when national prices are stable or even relatively low. Note specifically that the weighted monthly averages spiked above $8 per MMBtu in three of the four most recent winters for which data is available, including the winter of 2023-2024 when national prices were low. When compared to Figure 1, which only shows deliveries to Hawthorn, the Company's fleet-wide spot purchases of natural gas differ in that their unit costs tend to more frequently be higher than monthly averages at Henry Hub. Taken on a longer term, from the beginning of 2021 to the end of available data in mid-2024, Evergy spent more than $207 M on spot-purchased natural gas to supply its fleet.[40]

[37] EMW Response to Renew Missouri DR 7.
[38] Missouri, Kansas, and Oklahoma.
[39] Energy Information Administration, Form EIA-923 Detailed Data Schedule 2. Accessible at: https://www.eia.gov/electricity/data/eia923/; Energy Information Administration/Thomson Reuters, Henry Hub Natural Gas Spot Price. Accessible at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.
[40] Energy Information Administration, Form EIA-923 Detailed Data Schedule 2. Accessible at: https://www.eia.gov/electricity/data/eia923/.

At $5.44 per MMBtu during this period, the average unit cost of these spot purchases was roughly double the average of annual prices forecasted for 2021-2024 under Evergy's mid-case and 65% higher than Evergy's high-case from the 2021 Triennial IRP.[41] In absolute values, this means that Evergy's spot purchases cost roughly between $80 M and $100 M more than they would have according to the Company's forecast during this period.[42]

Fig. 3: Delivered Cost of Natural Gas Spot Purchases: All Evergy-Operated Plants



Source: Energy Information Administration, Form EIA-923 Detailed Data Schedule 2. Accessible at: https://www.eia.gov/electricity/data/eia923/ ; Energy Information Administration/Thomson Reuters, Henry Hub Natural Gas Spot Price. Accessible at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

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[41] *Id.*; In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's 2021 Triennial Compliance Filing Pursuant to 20 CSR 4240-22, File No. EO-2021-0035, *Evergy Missouri Metro Letter of Transmittal and Integrated Resource Plan - Volume 4: Supply-Side Resource Analysis*, pg. 47.

[42] *Id.*

Q: Has Evergy successfully managed risks and costs for procuring natural gas at spot prices?

A: No. As evidenced above, Evergy has been subject to both high costs and high risk in procuring natural gas through spot prices. However, this is not surprising: spot purchases are definitionally exposed to the maximum amount of market risk. Barring the case that spot purchases are hedged through a financial instrument, the only other means of managing risk from spot purchases is to maintain a diversified fleet with other types of dispatchable resources which do not rely on the same fuel.

Q: Is there reason to think that fuel market risks for the proposed plants will differ from these historical datasets?

A: Yes. The proposed plants reflect risk distinct from existing gas plants in that they will increasingly be relied upon to generate even when fuel prices are high. Historically, the effect of short-term price spikes in Evergy's natural gas supply has been softened by the Company's ability to shift generation to other resource types. When natural gas-fired plants represent only a small portion of system capacity, it can be more economic to ramp up coal or petroleum plants during natural gas price spikes so that gas consumption can be kept to a minimum. However, such fuel-switching will be more difficult as coal plants are retired and natural gas becomes the predominant fuel used by Evergy's fleet. Evergy will become a captive buyer, having to purchase large amounts of natural gas even when prices are high.

To make matters worse, these short-term spikes could become more common in the future, as recent NEE research on gas markets has found that natural gas prices have become increasingly prone to sudden upward movements.[43] Factors likely contributing to this trend include the increase of natural gas power plants like the proposed plants which operate as 'must-run' facilities in peak load events, the price insensitivity of power plant operators who can generally pass-through fuel costs to retail rates, the price insensitivity of local gas distributors who also pass through fuel costs to retail rates, and the growing influence on gas prices by high-margin LNG exporters. In analyzing regions where the power sector drives natural gas prices, NEE has found that delivered costs tend to be highest during the times when power plants consume the most fuel. As this correlation grows, it makes periods of peak demand disproportionately expensive and compounds the effect of short-term price spikes on ratepayer bills.

Therefore, there is significant potential for natural gas price volatility to become an even greater risk for Evergy in the future compared to historical data. These dynamics will particularly affect the realized cost of spot purchases but would also be expected to impact other procurement methods such as indexed-price contracts.

Q: Because there is not yet a definite procurement plan, how do you suggest the Commission assess whether the Company's fuel procurement is likely to ensure economic feasibility and to protect the public interest from undue market risk?

A: Lacking a definite and clearly differentiated procurement plan, it is reasonable to assume that Evergy's ultimate approach to procurement will reflect practices of those the Company has employed very recently at the Hawthorn plant or its gas fleet at large. As demonstrated, those strategies have not successfully controlled fuel costs and have not maintained risk exposure to a reasonable level. Emerging trends in the market suggest that some of these

[43] New Energy Economics, "Consumers face greater risk as electric utilities double down on natural gas." Accessible at: https://newenergyeconomics.org/consumers-face-greater-risk-as-electric-utilities-double-down-on-natural-gas/.

strategies, particularly relying on spot purchases, will perform even worse in the future. To ensure economic feasibility and the public interest supporting these plants is justified, the Company should demonstrate more robust risk management strategies for the proposed plants before moving forward with all proposed capacity. Alternatively, the Company could manage these risks through diversifying its capacity additions to include resource-types that do not directly consume fuel.

V. THE COMMISSION SHOULD REJECT EVERGY'S CLAIM THAT THE PROPOSED PLANTS WILL SERVE THE PUBLIC INTEREST THROUGH LOWERING EXPOSURE TO WHOLESALE POWER MARKETS

Q: Why has Evergy named risk in wholesale electricity markets as a justification for these proposed plants?

A: My understanding is that this line of argument, laid out in testimony from several Evergy witnesses,[44] is meant to respond to previous positions taken by the Staff, and the Office of the Public Counsel, as well as Commission precedent. These entities have expressed concern and criticism in certain instances where utilities have exposed ratepayers to market risk through a lack of sufficient owned capacity. I support efforts to reduce risk for ratepayers generally and I have no specific reason to be against utility-owned capacity as a general means to hedge risk in the wholesale power market. However, it is important to investigate deeper into the specific mechanism by which such a hedge should work. Evergy has not produced any evidence why these specific plants would be an efficient means of achieving a reduction of costs or risks for ratepayers.

[44] *Direct Testimony of Kevin Gunn,* p. 22-23; *Direct Testimony of Cody VandeVelde*, p. 8-9.

Q: Have you analyzed whether the proposed plants are likely to reduce costs or risk for ratepayers?

A: Yes. I analyzed hourly lambda (the marginal cost of generation) in SPP in 2023 as a proxy for wholesale power market prices. I then compared this with an assumed cost to generate at a generic combined cycle or combustion turbine with gas purchased at daily Henry Hub prices with an additional 30 cents per MMBtu added to account for variable transportation or regional basis pricing. I modeled the savings that would result from dispatching each of these resources rather than buying wholesale power at the SPP lambda price. This is a crude method that does not consider factors that could lower the cost of generation, such as effective advanced procurement of fuel, nor factors that could raise the cost of generation such as regional congestion on gas pipelines. However, by comparing these datasets, I can evaluate how effective natural gas capacity would be at hedging risk from the wholesale power market.

Q: What were the findings of that analysis?

A: Unsurprisingly, natural gas prices and SPP lambda are generally correlated. This is to be expected because natural gas-fired power plants are frequently the marginal[45] plant-type and therefore natural gas prices frequently set the marginal cost of generation and wholesale power prices. This lessens the degree that natural gas generation can act as a hedge against wholesale power prices as the two variables are likely to follow one another much of the time.

However, other factors besides fuel costs can also drive up wholesale power prices. This means the cost of generating at utility-owned gas plants can still sometimes be cheaper

[45] At a specific point in time, a plant is said to be marginal, if all cheaper technologies are already fully employed and the plant is the least-cost available option to satisfy the remaining demand.

than wholesale power prices. In my analysis of the 2023 period,[46] a combined cycle would be expected to economically dispatch at a capacity factor of 44%. Before considered capital and fixed operating costs, this would represent a gross savings of $60 per KW of capacity compared to purchasing wholesale power. While this would initially appear to be a successful strategy for hedging against power market risks, the benefits are erased once capital costs and fixed operating costs are included. The Company has provided a levelized cost of capacity (LCOC) estimate for the McNew plant of **_____** per KW-month, which equates to **___** per KW-year. Compared to the gross savings modeled above, this would imply that operating a utility-owned CCGT during this period would have cost **____**

A combustion turbine would also fare poorly in this analysis. Dispatching economically at a capacity factor of just 12%, such a plant would result in gross savings of about $25 per KW during 2023. **____ ____**

While power market dynamics will evolve, it is likely that wholesale market prices will continue to be closely correlated with natural gas prices for the structural reasons described above. Therefore, new natural gas capacity is not a strong hedge against wholesale power market risk. The Commission should reject the claim that the specific plants proposed will benefit the public interest through reducing the need to purchase power.

[46] 2023 is the most recent year for which SPP lambda data was available.

Q: Are there alternative resources that would be expected to hedge more effectively against power market risks and allow for a greater reduction in costs for the public?

A: Yes. BESS would be expected to outperform natural gas plants in hedging against wholesale power market risks. Similar to the analysis performed above, I analyzed how a 4-hour duration BESS plant would dispatch during 2023 in SPP. I assumed a conservative 'round-trip' efficiency of 85%. I also assumed that the batteries would charge and discharge based on a simple algorithm that compared each hour's market price to the prices observed over the previous 24 hours, charging the batteries when prices are low and discharging the batteries when prices are high.[47]

Before considering capital costs and fixed operating costs, I found that a BESS system would produce greater savings than a combustion turbine in 78% of the months analyzed. The total gross savings for the year were $25 per KW before capital costs and fixed costs, comparable to the modeled combustion turbine. However, once fixed costs are applied the savings become more apparent. Evergy has provided 2023 RFP results showing offers to construct BESS at rates between **______________** per KW-month. Using a midpoint of these offers, we assume a cost of **___** per KW-year. This would mean that net-costs for a battery system would be **_____________________________________ ____ _______**

It is worth noting that none of these options yield net-savings compared to buying wholesale power. However, BESS ultimately fares the best. These results should be cause

[47] Specifically, my model assumed that batteries would charge whenever system lambda sunk below the 40th percentile when compared to the previous 24 hours and discharge whenever system lambda rose above the 75th percentile when compared to the previous 24 hours. It is worth noting that this is a very crude dispatch strategy and that an operator would be likely to see significantly greater economic benefit through using more sophisticated strategies.

for skepticism of Evergy's claim that the proposed gas plants would specifically be the best means of reducing costs and risk associated with the wholesale power market.

Q: Would you expect these findings to hold in the future?

As noted above, critical to this discussion is how such dynamics would be expected to evolve in the future. I have already described why the linkage between natural gas prices and wholesale power prices would be expected to remain persistent, which undermines the ability of natural gas capacity to act as a strong hedge for wholesale power prices. If BESS capacity were used to hedge against wholesale prices, however, the hedge would be operating on a different principle – an arbitrage of the short-term, typically intraday spread of marginal power prices. Unlike with natural gas, the opportunity for this form of arbitrage would be expected to grow in future years as Evergy and other regional utilities build out renewable resources and particularly solar. By generating only during the daytime, solar lowers the cost of power during these hours. However, power would be expected to continue trading at a high price during evenings when solar is not generating. Therefore, BESS presents the opportunity to store cheap power from solar in the daytime and dispatch it in the evening to avoid paying for high-priced wholesale power during peak times. For this simple reason, BESS can be expected to become increasingly effective as a hedge against wholesale power prices, unlike natural gas power.

VI. EVERGY SHOULD COMMIT TO ADDING BATTERY STORAGE CAPACITY AS A SUBSTITUTE FOR A PORTION OF PLANNED NATURAL GAS CAPACITY

Q: Why is the consideration of alternative resources material in this docket?

A: The consideration of alternatives is particularly material in this docket because EMW's 50% ownership of the McNew plant is not included in the Company's previous IRP filings.

Need for this investment is being justified outside of the normal procedure and therefore is bypassing the typical diligence that would be required for illustrating that the McNew plant, among other Tartan factors, is meeting a demonstrated need, is the most economically feasible means to meet that need and is serving the public interest. I am neither endorsing nor opposing the Company's assertion that there exists need for new capacity, but I can show that alternative resources could potentially be more economically feasible and better serve the public interest.

Additionally, even capacity additions that were modeled in the Company's 2024 preferred portfolio may no longer meet Tartan criteria. Recent developments have significantly altered a range of other input values used for resource modeling and could lead to models producing a different set of lowest-cost portfolios than those selected in the 2024 IRP. Not all of these developments are sufficiently captured in the updated modeling runs submitted in Mr. VandeVelde's testimony. For instance, emerging factors mentioned earlier in my testimony may increase future natural gas prices. The current period is uniquely dynamic, and emerging conditions require a re-evaluation of the Viola and Mullin Creek plants against alternative resource options.

Q: Are there alternatives to the proposed CCGT and CT plants that could help meet capacity and energy needs without increasing ratepayer exposure to risk in the natural gas market?

A: Yes. BESS are a clear alternative. While BESS are not a one-to-one substitute for gas generation, they can be dispatched nearly instantaneously to meet peak load. Beyond providing quick-ramp and dispatchable capacity, BESS can also provide ancillary services and help smooth intermittent renewable generation to reduce curtailments and better utilize transmission. Not requiring a direct fuel supply also means that BESS are unaffected by service outages on gas pipelines or upstream interruptions in gas production, two risks to the reliability of natural gas plants. For all of these reasons, a strong case can be made that BESS not only contribute to meeting capacity needs but that, as part of a diversified portfolio, they support system resilience in ways that other resources cannot.[48]

BESS are also advantaged in their modular, zero-fuel, and zero-emissions characteristics, which mean they can be more easily sited, more easily permitted, and more easily constructed than natural gas plants. **____

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________[49]** Furthermore, zero-emissions characteristics future proof BESS for any potential increased regulations regarding greenhouse gases or other emissions through its life. In contrast, natural gas plants face risk that increased environmental regulations, even five or ten years in the future, may reduce capacity factors or increase operational costs for the remainder of their lifespan. Lastly and of direct relevance to the preceding testimony, the inclusion of BESS in portfolios reduces ratepayer exposure to commodity fuel markets.

Q: Can BESS economically compete with new CCGT or CT capacity?

A: Yes. BESS capital costs have fallen steadily in recent years, which, combined with investment tax credits, allow their upfront capital costs to rival thermal plants. The National Renewable Energy Laboratory (NREL) published a moderate-case CAPEX estimate of $1938 per KW for four-hour duration BESS in 2024.[50] Compare this to Evergy's estimated

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[48] Utility Dive, "Using energy storage to bridge gaps in gas-electric coordination." Accessible at: https://www.utilitydive.com/news/gas-electric-coordination-energy-storage-acp-zalewski/739341/.

[49] EMW Response to Staff DR 23; "Q0023_CONF_New Build Renewables 2024".

[50] National Renewable Energy Laboratory (NREL), Electricity Annual Technology Baseline (ATB) Data. Accessible at: https://atb.nrel.gov/electricity/2024/data.

CAPEX for the Viola plant at **__________ **.[51] As battery technology continues to mature, costs are expected to decline further. NREL's moderate-case forecast shows a 25% decline by 2030, with CAPEX modeled to be $1451 per KW in that year for four-hour duration BESS.[52] Goldman Sachs recently published research showing that lithium battery prices in other industries could fall by 42% between 2024 and 2030.[53]

Of course, these modeled estimates are not as reliable as real-world RFP bids. In response to discovery, Evergy has provided a list of bids received in recent all-source procurement RFP. **____

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[51] EMW Response to Staff DR 7; Q0007.1_CONF_Viola_McNew CCGT_Mullin Creek SC_MOW Model_02.06.25'

[52] NREL, Electricity Annual Technology Baseline (ATB) Data.

[53] Goldman Sachs, "Electric vehicle battery prices are expected to fall almost 50% by 2026." Accessible at: https://www.goldmansachs.com/insights/articles/electric-vehicle-battery-prices-are-expected-to-fall-almost-50-percent-by-2025.

[54] EMW Response to Staff DR 23; "Q0023_CONF_New Build Renewables 2024"

[55] *Id.*

[56] *Id.*

[57] EMW Response to Staff DR 7; Q0007.1_CONF_Viola_McNew CCGT_Mullin Creek SC_MOW Model_02.06.25'

[58] *Id.*

The cost advantages of these bids are sufficient enough to compare favorably even once adjusted for each resource's respective ELCC accreditation. The cost of owning 100 MW of net capacity in a CCGT facility could be swapped for 150 MW of BESS while slightly reducing levelized capacity costs, even before the cost of fuel. This ratio would allow for winter accredited capacity to be maintained even if SPP reduced the ELCC for energy storage below 70% of nameplate capacity. **______________________________

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Additionally, swapping 100 MW of natural gas capacity for 150 MW of BESS would mean that EMW's need for firm natural gas transport could be reduced. Assuming a $0.30 per MMBtu tariff rate, this would represent an additional **_____** in savings in the case of the CCGT plants and **____** in savings in the case of the CT. This means that, even before considering the cost of fuel burned at each proposed facility, the cost of swapping a portion of the proposed gas capacity for its accredited equivalent in BESS capacity is roughly equal or slightly less.

Q: Has Evergy thoroughly considered BESS as an alternative to the proposed CCGT or CT plants?

A: BESS are included as an expansion option in the Company's resource modeling but have not yet been added to the preferred portfolio.[59] As expressed in comments on Evergy's 2024 Triennial IRP, Renew Missouri has viewed the Company's evaluation of BESS potential as deficient on multiple counts.[60] For instance, Evergy appears not to be taking account of the full claimable tax credits that would be possible with creative siting and sizing. A better

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[59] *Supplemental Testimony of Cody VandeVelde,* p. 12

[60] In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2024 Triennial Compliance Filing Pursuant to 20 CSR 4240-22, File No. EO-2024-0154, *Comments of Renew Missouri Advocates,* p. 7-8.

analysis of these opportunities would help BESS to achieve 30% investment tax credits and potentially faster interconnection, two factors that could lead to more BESS being selected in the Company's preferred portfolio.[61]Furthermore, NEE's view, expressed in its independent comments on Evergy's 2024 Triennial IRP, is that specific modeling practices have biased resource models toward understating the benefits of BESS.[62] We are encouraged by Evergy's willingness to reach a resolution on some of these concerns to address in future IRP dockets. However, without those valuable modeling results now, we encourage the Commission to exercise caution in adopting plants not subjected to an updated and supply side neutral comparison.

Despite this progress, arbitrary limits may still be biasing models toward selecting natural gas capacity rather than BESS. Namely, Evergy may not have considered EMW taking net ownership shares of less than 50% in the CCGT plants or less than 100% for the CT plant proposed in this docket. I have two potential recommendations, for instance, that do not appear to have been considered by Evergy previously.

The first is that EMW's net ownership in the McNew plant could be reduced to just 252 MW – a 36% share in the plant, representing a 100 MW reduction from the current plan – with the Company instead investing capital in a 150 MW BESS facility to be built concurrently. This would increase EMW's nameplate capacity by 50 MW while, as I will show, reducing costs and risk associated with the natural gas projects. Alternatively, in my second recommendation, Evergy could sell equity in the Mullin Creek #1 project and reduce its net ownership to just 340 MW while investing capital in a 150 MW BESS facility

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[61] *Id.*

[62] In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2024 Triennial Compliance Filing Pursuant to 20 CSR 4240-22, File No. EO-2024-0154, *The Council for the New Energy Economics' Comments on Evergy's 2024 Integrated Resources Plan*.

to be built concurrently. As in the first recommendation, this second option would increase nameplate capacity while reducing anticipated costs and risk.

Given current market conditions, it is reasonable to conclude that Evergy could readily find a joint venture partner interested in purchasing outstanding equity created by a reduction in EMW's net ownership of the proposed plants. Replacing the planned gas capacity with BESS would reduce EMW ratepayers' exposure to natural gas fuel costs and associated risks while maintaining total capital outlay at or below the level entailed by this application.

Q: Why have you chosen to focus on the McNew plant in presenting your first alternative proposal?

A: I have chosen to focus on the McNew plant, as opposed to a recommendation that would impact the Viola plant or both plants, because McNew is planned to have a later groundbreaking date and a later in-service date than Viola. Given this additional time, there ought to be more flexibility for Evergy to act on these recommendations without necessarily causing delays or undue obstacles for the project.

Q: Including fuel costs, can you provide an estimate of the potential savings if EMW reduced its net ownership in the proposed McNew plant and instead invested in a 150 MW BESS facility?

A: Yes. I can model the savings related to fuel costs by making several assumptions with regards to the cost of power used to charge BESS. From my previous analysis on BESS as a potential hedge for wholesale power prices, my model found that the average cost for charging a BESS would have been \$17.60 per MWh in 2023. Adjusted for round-trip efficiency at an assumed rate of 85%, this equates to \$20.70 per MWh of power dispatched from the BESS. As described above in this testimony, my model was based on a crude strategy and an actual plant could likely achieve lower costs through more sophisticated strategies.

In contrast, the McNew plant during its first operational year would be modeled to incur average direct fuel costs around **_____________ ** in 2030 under Evergy's mid-case natural gas forecast and **_____________** under Evergy's high-case. For each MWh that the BESS system dispatched instead of the McNew plant, I would therefore expect an average net-savings between **_______________________**

Further assuming a 150 MW BESS facility would maintain a capacity factor near 15%, which was the result of my modeled BESS performance in 2023, I would model that it dispatches 197,100 MWh per year, representing up to **____ ** in 2030 in net savings at Evergy's high-case natural gas price.

If I combine these fuel savings with the lower cost of capacity described above, I find that meaningful savings would be achieved despite the alternative having a higher nameplate capacity **____

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_______** Savings would be expected to remain persistent in subsequent years, particularly as natural gas prices are forecasted to increase and drive higher savings from avoided fuel use. Besides reducing costs, such an alternative would reduce exposure to fuel market risk.

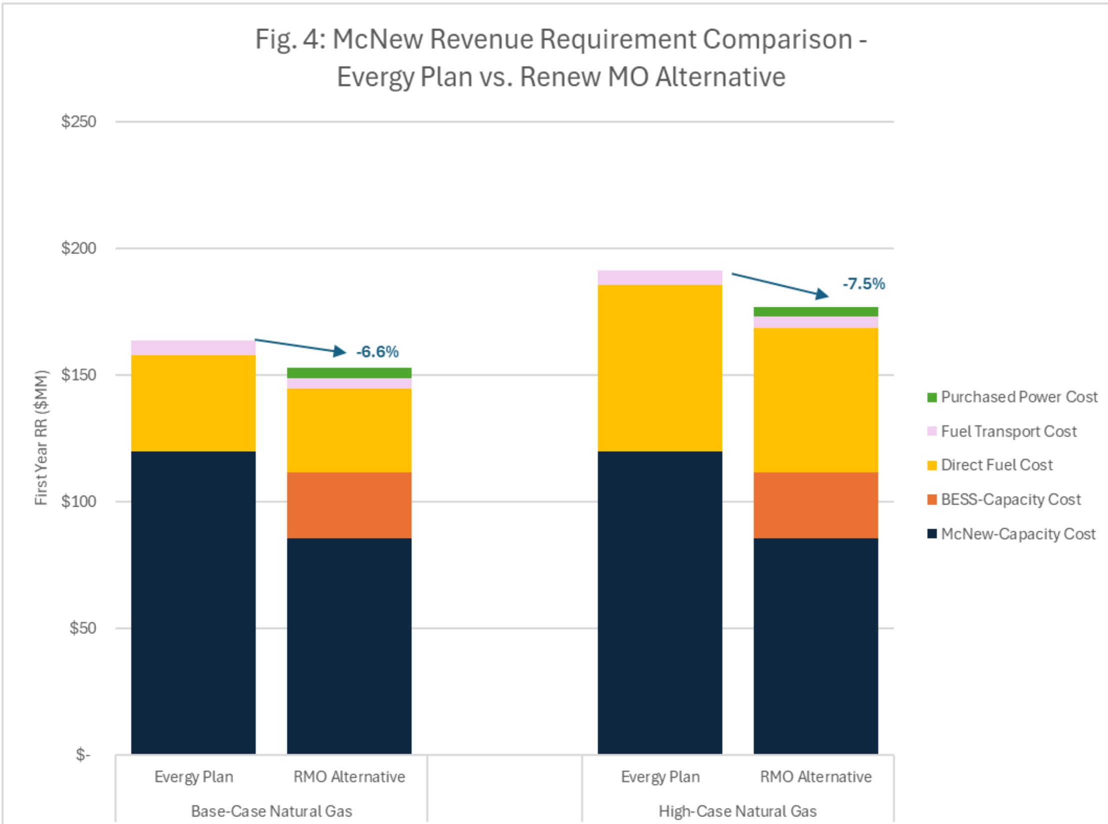


Table 1 is confidential in its entirety.

Q: Could a similar alternative plan be considered for the Mullin Creek #1 CT plant?

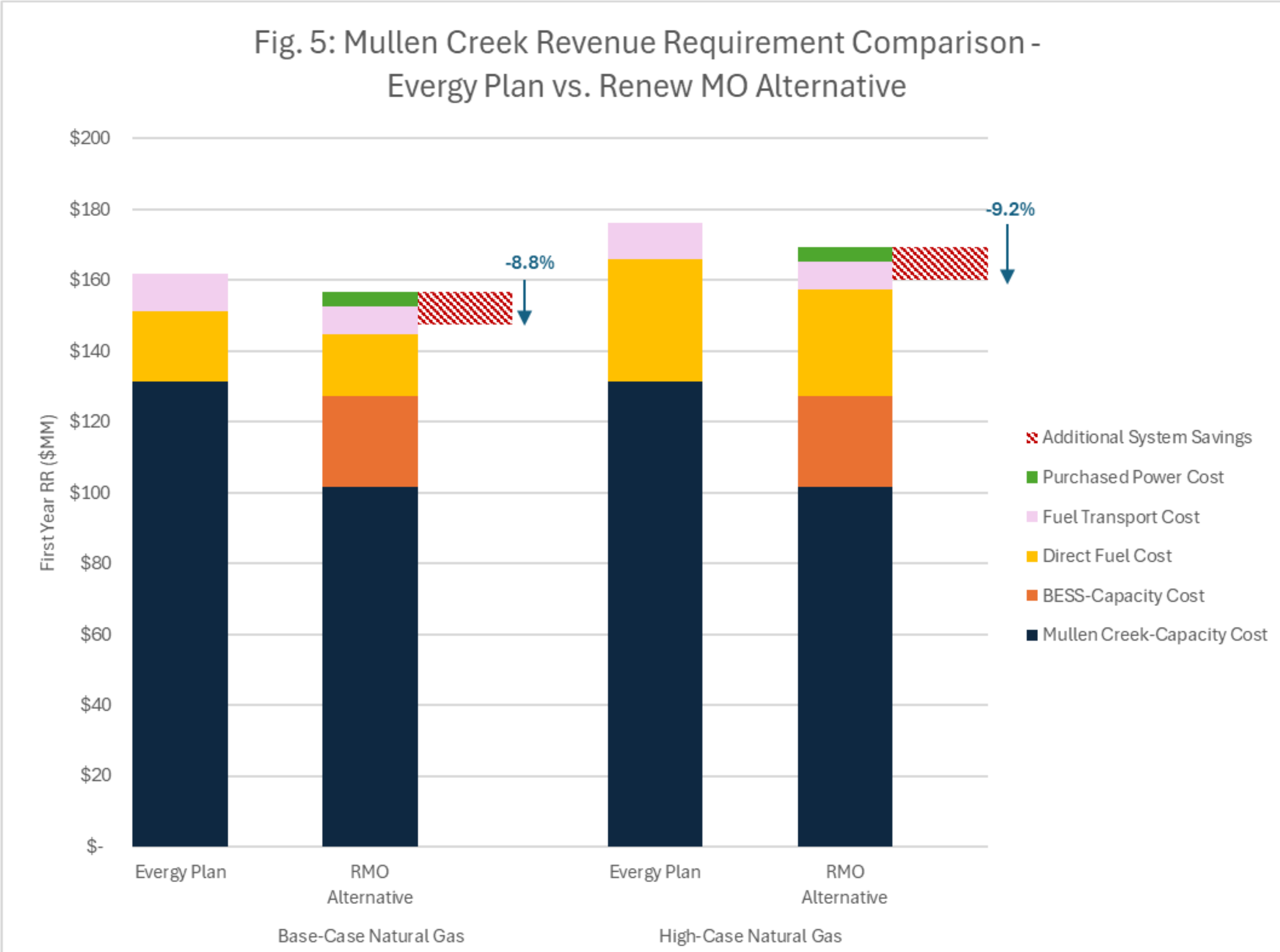
A: Yes, a similar strategy could be considered for reducing costs and fuel market risks for the Mullin Creek #1 plant. EMW could sell a portion of the capacity of Mullin Creek #1 to another entity and instead invest in alternative capacity such as BESS. In some ways, this would be a more intuitive substitution than the first alternative described above because both the Mullin Creek and a potential BESS alternative would be expected to serve peak demand rather than baseload.

Q: Can BESS economically compete with new CT capacity?

A: Yes, BESS is economically competitive with CT plants though the economics are different from those of CCGT plants. CT plants, being less capital intensive than CCGT plants, compare more directly to the capital cost of BESS so there is less opportunity to reduce initial costs through a substitution. The cost of capacity for BESS may even be slightly higher than for CT plants once capacity is adjusted to reflect differing ELCCs. However, this initial difference in cost would be offset by reductions in other costs. CT plants have higher heat rates than CCGT plants and thus consume more fuel for each MWh of generation. Therefore, each MWh of CT generation which can be displaced through dispatch of a BESS facility will result in greater fuel cost savings than would be the case with CCGT.

Using similar assumptions as outlined in the above analysis for my first alternative proposal, I was able to model the year-one revenue requirements for an additional proposal. In this case, EMW's would own 77% of Mullin Creek #1 compared to the 100% ownership that they have applied for. This amounts to a reduction of 100 MW in net-owned capacity. To address capacity needs, a 150 MW BESS plant would be added to the EMW fleet. As with the first alternative, overall costs are reduced through reduced fuel consumption and reduced need for firm transport reservations. Evaluated in isolation, this would be modeled to yield savings of roughly **__**.

However, unlike with the first alternative, there are additional savings through system benefits because a combination of CT and BESS capacity would be modeled to dispatch more MWh than Mullin Creek #1 would otherwise generate on its own. I note that I used my previously described modeling of hourly dispatch to estimate the frequency that the BESS plant would be directly displacing generation from the CT plant. I found that both resources would be expected to have similar annual capacity factors (around 15%) but that these would not always overlap. Around 2 out of every 5 MWh that the BESS dispatched would be expected to directly reduce CT generation. This means that 3 out of every 5 MWh dispatched from the BESS would not directly displace CT generation and would instead add incremental value for ratepayers. The combined output for the two assets would be higher than what Evergy assumed in its financial model for Mullin Creek #1 by **___** MWh per year. This additional dispatch would benefit ratepayers through displacing other higher cost sources of energy during peak demand hours. While the exact value of these additional savings will vary depending on wholesale power and fuel markets, a rough $78 per MWh valuation can be assigned based on the 2023 lambda prices, which coincided with modeled battery dispatch in my model. This implies additional annual system savings over **____ ** that would offset revenue requirements for the new capacity. This offset is shown in Figure 5 in red cross-hatched bars. Including these savings with the other differences in cost, the total net-revenue requirements in 2030 would be reduced by around **__** compared to Mullin Creek #1 on its own.



Q: What are the potential reliability trade-offs if BESS was substituted for a portion of the Mullin Creek's capacity?

A: A full study of reliability impacts would be necessary. However, several factors would suggest that reliability would not be harmed and may be improved by such a substitution. It is true that Mullin Creek #1 would no longer be able to commit its full 440 MW capacity to serving EMW. However, the combined Mullin Creek and BESS plant would represent up to 490 MW of committed capacity available during peak times. While the BESS portion of this would be time-limited, a 490 MW dispatch could be maintained for up to 4 hours. This increase in nameplate capacity would enhance system reliability during acute demand peaks. Once the BESS had fully dispatched, 340 MW of CT capacity would still be available to meet more sustained capacity needs. I contend that this would likely be sufficient to meet peak periods even under the harshest of conditions. For instance, during Winter Storm Uri, SPP reached a peak of 43.5 GW of load at 9:00 AM on February 15, 2021[63]. However, system load fell by 2.0 GW over the following four hours. By four hours after that, system load had fallen another 1.7 GW. The intraday load profile, even under emergency conditions, means that a well-managed BESS could contribute effectively to meeting load at the period of most acute need and recharge prior to the next peak. An additional reliability enhancement would be expected from the nearly instantaneous ramping capability, which exceeds even the most advanced natural gas plants.

Q: Has Evergy thoroughly considered BESS as an alternative to the proposed Mullin Creek plant?

A: As described earlier, Evergy has included BESS as a resource option in modeling capacity additions for EMW. However, there are several ways that those models may bias resource selection to exclude BESS in favor of gas. One of the most significant sources of bias is the assumption that EMW will own 100% of any new CT plant such as Mullin Creek #1. Evergy has objected to a discovery request meant to confirm that they have planned under this assumption.[64] Modeling inputs shared in response to a different discovery request would imply that resource models only considered CTs of a standard capacity and only considered 100% EMW ownership. Had Evergy considered alternative ownership

[63] Energy Information Administration, Hourly Electric Grid Monitor, Accessible at: https://www.eia.gov/electricity/gridmonitor/dashboard/custom/pending

[64] EMW Objection to Renew Missouri DR 4.

structures, it may have resulted in a lower net ownership of the Mullin Creek plant and the inclusion of alternatives such as BESS.

Q: How should the Commission interpret your analysis of these alternatives in determining whether Evergy's proposal is economically feasible and in the public interest?

A: To conclude my analysis of BESS, either of my alternative plans would aim to keep overall capacity additions slightly above Evergy's preferred portfolio while shifting a portion of the investment in the McNew CCGT plant or a portion of the investment in the Mullin Creek #1 CT plant toward a new BESS plant to be in-service by 2030. Based on my modeling, either alternative would result in lower revenue requirements. Therefore, such an alternative would be more economically feasible and better serve the public interest than the Company's current application.

Importantly, the reduction in fuel consumption would also reduce exposure to risks in commodity fuels markets, such as those illustrated in earlier sections of this testimony. Relatedly, an alternative with lower fuel requirements would also be better poised to hedge against risk and volatility wholesale power market, as demonstrated earlier in this testimony. On both counts, the public interest would be better served through an option which more effectively managed these risks and mitigated their effects on electric rates.

Of course, the public interest also requires maintaining electrical service with a high degree of reliability. By adding BESS capacity under my proposed alternatives, reliability would likely be maintained and potentially even be improved through diversifying EMW's fleet of dispatchable resources. I acknowledge that such a plan would require further vetting to determine that it is practical and advantageous to EMW ratepayers. The specific balance of BESS and natural gas capacity may have to be optimized for both cost and reliability through iterative modeling. With that said, I present two alternatives here not to conclusively assert that either is the optimal solution, but rather to show that Evergy has not demonstrated the benefits of its own proposal over realistic potential alternatives such as these.

VII. EVERGY SHOULD EVALUATE THE POTENTIAL FOR EXPANDED CUSTOMER SUBSCRIPTION PROGRAMS TO FUND INCREMENTAL RENEWABLE PROJECTS AS A RISK-MINIMIZING COMPLEMENT FOR NEW NATURAL GAS GENERATION

Q: Why have you cited customer-subscribed renewable capacity as another recommended alternative to the proposed plants?

A: With careful program design, customer subscription programs allow large customers to offset the cost of installing new renewable capacity. By leveraging these customers' particular preference for clean energy and their demand for these programs, utilities can potentially add capacity at a lower net-cost than other resources. While the addition of more renewable capacity does not eliminate the need for new dispatchable resources, it would reduce the call on thermal plants to generate and therefore directly reduce fuel costs and exposure to fuel market risk.

Q: What evidence is there that more demand exists for these types of programs?

A: **

______.**[65]_This sampling, coupled with the findings of broader market intelligence,[66] strongly suggests that demand exists for these types of programs.

Q: How can Evergy ensure that the potential of customer subscription programs is fully considered?

A: I advise that Evergy commit to engaging in a stakeholder process to consult with large customers and industry experts in designing a program or set of programs that would better leverage these customers' interest in renewable energy and willingness to underwrite associated costs. Dockets currently being considered on the topic of large-load tariffs,[67] which provide an opportunity to undertake this consultation and bring forward actionable options in the near term. With due consideration, Evergy can increase renewable resources in its preferred portfolio while reducing the exposure of general ratepayers to fuel costs and associated market risks.

VI. CONCLUSION

Q: What is your conclusion and recommendation to the Commission?

A: The ultimate cost of Evergy's proposed plants will heavily depend on the cost of natural gas – meaning that their cost to ratepayers will be subject to the risks of a notoriously volatile and unpredictable market. At the same time, alternative resource portfolios allow the opportunity to minimize the costs and risks associated with fuel procurement. Such an alternative could be pursued in a way that also reduces initial capital costs and potentially

[65] EMW Response to Renew Missouri DR 9.

[66] Wood Mackenzie, "Gridlock: the demand dilemma facing the US power industry." Accessible at: https://www.woodmac.com/horizons/gridlock-demand-dilemma-facing-us-power-industry/.

[67] In the Matter of the Application of Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Approval of New and Modified Tariffs for Service to Large Load Customers, File No. EO-2025-0154.

even improves reliability. The strongest and most affordable path forward is one that best diversifies Missouri's energy market.

To summarize my recommendations, I suggest that the Commission consider fuel costs associated with the proposed plants in determining their impact on ratepayers and whether they result in the plants not being economically feasible. Relatedly, I recommend that the Commission evaluate the impact on revenue requirements under a range of natural gas price scenarios to determine whether the public is exposed to undue fuel market risk. Thirdly, the Commission should consider Evergy's fuel supply plan to be inadequate for minimizing ratepayer exposure to fuel market risk. The Commission should reject Evergy's claim that the proposed plants will serve the public interest through lowering exposure to wholesale power market risk. The Commission should require that Evergy evaluate reducing its net ownership in the proposed plants and evaluate BESS and other alternatives as fractional substitutions to optimize the economic feasibility and better serve the public interest. The Commission should also consider requiring that Evergy evaluate the potential for expanded customer subscription programs to fund incremental renewable projects as a risk-minimizing complement for new natural gas generation, which would additionally further the public interest as customers have expressed in participating in customer subscription programs.

Q: Does this conclude your testimony?

A: Yes.