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Witness: Kayla Messamore
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Sponsoring Party: Evergy Missouri West
Case No.: EA-2023-0291
Date Testimony Prepared: November 8, 2023

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EA-2023-0291

DIRECT TESTIMONY

OF

KAYLA MESSAMORE

ON BEHALF OF

EVERGY MISSOURI WEST

Kansas City, Missouri
November 2023

CONTENTS

DIRECT TESTIMONY

OF

KAYLA MESSAMORE

Case No. EA-2023-0291

Q: Please state your name and business address.

A: My name is Kayla Messamore. My business address is 1200 Main, Kansas City, Missouri 64105.

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

A: I am employed by Evergy Metro, Inc. and serve as Vice President of Strategy and Long-Term Planning for Evergy Metro, Inc. d/b/a as Evergy Missouri Metro ("Evergy Missouri Metro"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("Evergy Kansas Metro"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a as Evergy Kansas Central ("Evergy Kansas Central"), the operating utilities of Evergy, Inc.

Q: Who are you testifying for?

A: I am testifying on behalf of Evergy Missouri West ("EMW" or "Company").

Q: What are your responsibilities?

A: My responsibilities include development of Evergy's corporate strategy and leadership of long-term planning activities, which include Energy Resource Management ("ERM"), Transmission Planning, Distribution Planning, Operations Compliance Engineering, and Operations Technology. Specifically related to this testimony, the activities of ERM include integrated resource planning, wholesale energy purchase and sales evaluations, and renewable energy standards compliance.

Q: Please describe your education, experience and employment history.

A: I hold a Bachelor of Business Administration from the University of Texas at Austin. I worked as a strategy consultant in the power and utilities industry beginning in 2014 and have worked in strategy and planning at Evergy since 2018.

Q: Have you previously testified in a proceeding at the Missouri Public Service Commission ("MPSC" or "Commission") or before any other utility regulatory agency?

A: Yes.

Q: What is the purpose of your direct testimony?

A: The purpose of my testimony is to describe the Integrated Resource Planning ("IRP") process and how it supports this application. I will also provide an overview of EMW's need for capacity and energy, and describe how the proposed purchase of a portion of the natural gas, combined cycle 668 MW Dogwood Energy Facility ("Facility", "Asset", or "Dogwood") meets these needs.

Q: Are you sponsoring any schedules with your testimony?

A: Yes. I am sponsoring the following schedules:

Confidential & Public Schedule KM-1 – IRP Sections 1, 3 & 6

Confidential Schedule KM-2 – Dogwood NPVRR Model

Q: What is the structure of your testimony?

A: My testimony is structured in three main sections:

I. Analysis of EMW Needs – explains the IRP process and results, and describes Evergy Missouri West's current and long-term needs.

II. Selection of Dogwood to Meet EMW Needs – describes the process by which Dogwood was selected to meet a significant portion of EMW needs in all IRP planning scenarios.

III. Benefits of Dogwood – explains why Dogwood is uniquely positioned and the best available resource to fit EMW's near and long-term needs.

Q: Please summarize the key points of your testimony.

A: EMW has near- and long-term needs for physical capacity, physical energy, and a hedge against the SPP energy market. Dogwood was selected in the 2023 IRP as part of the lowest-cost plan to meet EMW needs in every modeled scenario and produces $90 – 110 million in NPVRR savings in low and mid carbon restriction scenarios. Dogwood compares favorably to market capacity and new build alternatives and provides additional benefits: 1) efficient, low-cost energy production which can produce net SPP revenues to partially offset fixed costs; 2) eliminated construction risk because it is an operating asset; 3) favorable transmission location in EMW's service territory; 4) resilient natural gas supply from two pipelines; 5) additional dispatchable capacity to support reliability. While Dogwood does not meet all of EMW's needs for capacity, energy, or a market hedge, it is a valuable first step toward meeting those needs through a low-cost, reduced-risk operating asset.

I. ANALYSIS OF EMW NEEDS

Q: Please describe the IRP process in Missouri.

A: The IRP process is completed under the Commission's Electric Utility Resource Planning Rules found in 20 CSR 4240-22. The IRP process results in the selection of a Preferred Plan, which is the combination of supply-side and demand-side resources, that EMW will use to meet forecasted customer requirements for the next twenty years. Confidential Schedule KM-1 includes excerpts from EMW's 2023 IRP to provide more detail on the IRP process and outline updates to supply-side resources and the integrated resource plan analysis.

Q: What is Evergy's objective in the IRP process?

A: Evergy is guided by the Commission's Rule at 20 CSR 4240-22.010(2) which states: "The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies." To achieve this objective, the IRP is performed using minimization of net present value of revenue requirements ("NPVRR") as the primary objective function. The IRP also considers potential risks and uncertainties which could impact the economics of a resource plan ("critical uncertain factors"), and compares demand-side and supply-side resources on an equivalent basis.[1]

[1] *See* Confidential Schedule KM-1, Section 6: Integrated Resource Plan and Risk Analysis Update.

Q: Was the Request for Proposal ("RFP") process initiated in August 2022, which is described in detail by Company Witness Carlson, consistent with EMW's IRP at that time?

A: Yes. The 2022 Annual Update included the forecasted expiration of EMW's existing capacity contract with Evergy Metro prior to the summer of 2024 and the replacement of that contract with new market capacity. That need led to the release of an RFP to seek out replacement capacity options. While the focus was on market capacity, with or without corresponding energy, equity offers were also accepted. Dogwood was ultimately offered as an equity purchase option in response to that RFP. Dogwood, along with other RFP responses, were subsequently evaluated qualitatively, as described by Company Witness Carlson. All offers were also evaluated quantitatively using the 2022 IRP model to determine the most attractive candidates for more detailed negotiations. The combination of Dogwood and the **[redacted]** was selected by capacity expansion as the lowest-cost option. Those results, combined with the qualitative evaluation Company Witness Carlson describes, resulted in negotiations continuing with these two counterparties. However, the bulk of the quantitative evaluation of the Dogwood acquisition occurred in the 2023 IRP following more detailed due diligence and, as a result, I will focus most of my attention on that process.

Q: Were there any changes to the inputs for EMW's 2023 Annual Update compared to its 2022 Annual Update?

A: Yes. Since filing the 2022 Annual Update, changing conditions and major drivers were refreshed to reflect the latest information and forecasts available to determine if the Preferred Plan and associated Resource Acquisition Strategy identified in the 2022 Annual Update continue to be the Company's path forward. The information and forecasts that have been updated for the 2023 Annual Update[2], which was filed in No. EO-2023-0213 on June 15, 2023, include:

- Updated market pricing reflecting the latest Southwest Power Pool ("SPP") transmission planning model assumptions of future resource mix and potential transmission congestion;
- Updated fuel price forecasts, including high, mid, and low natural gas price scenarios;
- Carbon dioxide emissions limitations scenarios reflecting future environmental risks, including high, mid, and low (no) restrictions;
- Updated cost estimates and timing assumptions for resource additions based on request for proposal ("RFP") results;
- Modeling of battery storage and hybrid resources as supply-side options;
- Inclusion of incentives for new renewable and storage resources based on the 2022 Inflation Reduction Act;
- Updated load forecasts including large new customers, and considerations for future large customer growth based on existing economic development pipeline;
- Updated demand response potential study, including four Missouri program options;

[2] *See* Confidential Schedule KM-1, Section 1: Executive Summary.

- Included possible reductions in peak demand from the Commission-ordered mandatory time of use rates;
- Updated planning reserve margin requirements consistent with SPP rule changes adopted in 2022;
- Increased focus on planning for utility-level (as opposed to Evergy-level) resource needs to better identify each utility's future energy and capacity needs, reduced level of market reliance (for both capacity and energy) or reliance on other Evergy affiliates to meet customer needs;
- Expanded use of PLEXOS software for production cost modeling and capacity expansion, which was first implemented for the 2022 IRP Annual Update; and
- Annual refresh of data for existing EMW generators (Capital and Operations & Maintenance costs).

This 2023 IRP Annual Update also incorporated feedback received from MPSC Staff as part of the Persimmon Creek Certificate of Convenience and Necessity case in order to supplement and refine past IRP approaches:

- Use of updated SPP Transmission Planning models which include significantly higher level of negative SPP market prices;
- Updated dispatch assumptions for wind resources which ensure PTC-eligible wind realizes negative revenues when dispatched at negative prices;

- Full use of capacity expansion modeling to identify lowest-cost supply-side resource additions and no hard-coded resource additions; and
- A more fulsome explanation of the modeling approach and method of using capacity expansion modeling and software.

Q: Why is the IRP the appropriate mechanism to assess EMW's needs and what resource types / resources are most effective in meeting those needs?

A: The IRP is built with EMW's long-term load forecast as its foundation and starting point. This load forecast represents EMW customers' needs for energy over the next 20 years and the peak in each year establishes EMW's capacity requirement (i.e., the amount of accredited capacity required to meet SPP resource adequacy requirements). Within the IRP, every evaluated plan is built in order to meet these customer needs, meaning that every plan includes sufficient capacity and energy to meet EMW needs. From there, the IRP process determines which of those plans is lowest-cost on a risk-adjusted basis.

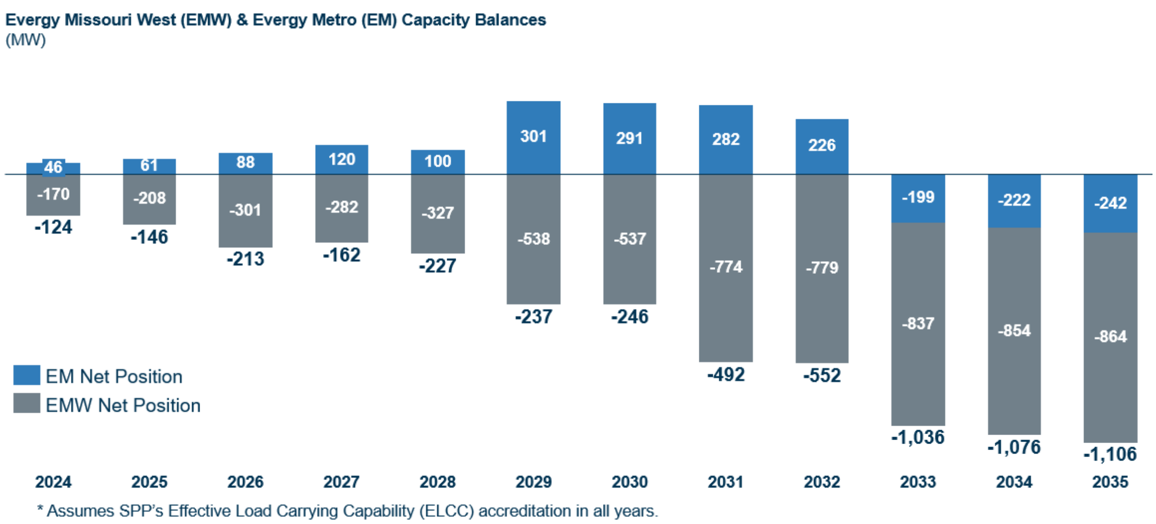
As a result, a Preferred Plan selected out of the IRP is the combination of resources which most effectively and economically meets EMW customer needs over the long-term, based on integrated risk analysis in a wide variety of potential scenarios. This integrated, long-term analysis is the appropriate way to assess customer needs and different resources because no resource decision can be made in a vacuum. Any decision made on a resource today (including a decision to *not* add a resource today) will impact the decisions that need to be made in the future.

The IRP assesses those trade-offs over time through the construction of lowest-cost resource plans over a 20-year period.

Q: Based on the 2023 IRP, does EMW have a capacity need?

A: Yes. As a result of SPP's increased resource adequacy requirements, even after procuring between 200 and 275 MW from Evergy Metro for the years 2024-2028, EMW still has a capacity need of over 300 MW in 2026. In this same year, Evergy Metro has only 88 MW of additional forecasted excess capacity. While these estimates do include a small amount of buffer to account for future large new loads and/or changes in accreditation, the total magnitude of these changes is expected to increase capacity needs compared to these positions. This means that additional market capacity from Evergy Metro will not be available to meet the remainder of Missouri West's need, as evidenced in Figure 1 below.

FIGURE 1



Beyond 2028, EMW's capacity needs steadily increase as plant retirements reduce the amount of owned capacity in its portfolio and capacity purchases ramp down. In parallel, Evergy Metro begins to see plant retirements (La Cygne 1 in

2032) which further reduce its available capacity. The small amount of buffer included in these capacity positions for EMW (100 MW beginning in 2027) is insufficient due to likely economic development activity in addition to expected future increases in SPP capacity requirements. SPP has indicated that further increases to the Planning Reserve Margin are likely, and potential Performance Based Accreditation scenarios evaluated in the 2023 IRP Update indicated that this new policy for thermal resource accreditation could create an increase in Evergy's capacity need of almost 200 MW in a "mid-case" scenario (which aligns fairly closely with the policy recently approved by the Regulatory State Committee).[3]

Due to uncertainty around how this new accreditation policy will ultimately be implemented and calculated for each of Evergy's utilities, this risk has not been directly factored into the capacity balance described above, but at this stage, it is likely to drive an incremental need of approximately 50 to 100 MW for EMW, specifically. In addition, a 2% increase in the reserve margin would equate to an increased need of approximately 40 MW for EMW. All of these factors combine to create a significant, near and long-term capacity need for EMW.

Q: Do these changing dynamics impact EMW's past practice of utilizing market capacity to meet a portion of its resource adequacy requirements?

A: Yes. While there can be benefits to wholesale market capacity, namely favorable economics at times and flexibility, there are inherent risks as well. Given the resource adequacy changes at SPP that I just explained, the Company expects a decrease in the availability of shorter-term wholesale market capacity.

[3] *See* Confidential Schedule KM-1, Section 3.2: Supply-side Technology Changes from the 2021 Triennial IRP, Discussion of Resource Options and Economics.

SPP's 2023 Resource Adequacy Report filed in June 2023 states: "The SPP Balancing Authority Area Planning Reserve Margin is 20.1% for the 2023 Summer Season and decreases to 9.7% by planning year 2028".[4] SPP's market-wide forecast aligns with my discussion earlier in this testimony which shows that going forward Evergy Metro's excess capacity will no longer support EMW's longer-term needs. For these reasons, EMW will be better positioned moving forward by procuring long-term dispatchable capacity (i.e., "steel in the ground") rather than utilizing shorter-term market capacity.

Wholesale capacity provides no long-term dispatchability to a buyer and the availability of surplus capacity is tied to variable market forces, whereas resources like Dogwood provide the certainty of steel-in-the-ground capacity that will be operating for years to come.

Q: Does EMW have an energy need?

A: Yes. Capacity is essentially the ability to produce energy when called upon. Therefore, any time a market participant is short on capacity it is also short on energy capability. As a result, the forecasted reserve balance in the 2023 IRP is an indication of a current and ongoing energy need for EMW customers. In addition, market capacity like the capacity EMW purchases from Evergy Metro only includes mutually agreed upon market energy (or no energy at all), which doesn't provide a long term energy hedge. As a result, the amount of capacity currently covered by these market capacity purchases (240 MW in 2026) represents an incremental need for energy available on the EMW system to meet customer needs. This need for

4 https://www.spp.org/documents/69529/2023%20spp%20june%20resource%20adequacy%20report.pdf

energy can, and has, been met by the wholesale energy market, but this dependence on the energy market can create risk if it is covering a large portion of customer needs for the long-term.

Q: In prior testimony, Staff implies that there is not a need for energy, but rather a need for a hedge against market energy prices.[5] **Do you agree with this perspective?**

A: No. These two needs are not mutually exclusive and EMW has a need for both. SPP's capacity requirements are in place to ensure that market participants have enough generation capability (physical energy) to meet their load in peak conditions. Therefore, since EMW is short on future capacity, they clearly have a physical energy need in times of higher customer demand.

As I described above, in the past, EMW has been able to use market capacity to meet its capacity needs and has relied on the wholesale market to provide sufficient physical energy. In today's tightening capacity market, that is no longer a viable long-term option because market capacity is simply less available. As Company Witness Reed describes in more detail, wholesale markets are not built to meet the future physical energy needs of EMW (or any other load-serving entity) because they are not designed to provide full cost recovery of participating generators (i.e., they do not incentivize the building of generation to meet customer needs). They are simply a mechanism to manage economic dispatch on a daily and hourly basis and ensure appropriate compensation for generators based on those operational decisions – compensation that is based on generators marginal, short-

[5] Docket No. EA-2022-0328, Eubanks Rebuttal, p. 7, lns.4-7.

run economics and not their all-in costs. This compensation provides an offset to generator costs, as Company Witness Reed describes, but assuming that this wholesale market will provide sufficient excess capacity and energy to also serve EMW's customers in the long-term leaves customers exposed to energy unavailability over which they have no control.

In addition, a strategy of relying on wholesale capacity and energy does not provide a hedge for EMW to mitigate its exposure to energy prices. As I will describe in more detail later in this testimony, a large portion of EMW capacity consists of inefficient, high heat rate natural gas turbines which operate very infrequently, as Company Witness Carlson explains. EMW leans on the more economic wholesale market to provide energy when these units aren't dispatched due to being "out of the money". Effectively, this results in EMW being a price taker any time the wholesale market is cheaper than the operating costs of its natural gas turbines, which is a significant portion of the time. For example, assuming a $3/mmbtu natural gas price, the marginal cost of the average EMW gas turbine would be around $50/MWh, which means they would not operate at prices lower than that and would not receive meaningful net revenues in excess of their fuel costs unless prices were significantly higher. In the same way, some of EMW's market capacity contracts also make it a price taker because those contracts do not include corresponding energy. The capacity contracts that do include an energy option are only set at mutually agreeable market prices at the time of transaction. That is the need for an energy hedge which Staff references and which is very real for EMW customers.

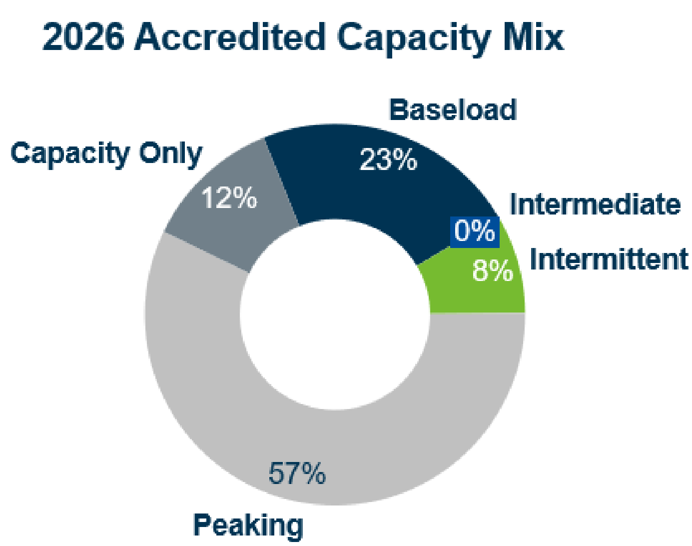
Q: What does it mean to need a hedge?

A: A need for a hedge simply means that you do not have sufficient control or certainty around your future outcomes, based on your specific risk tolerance, and so you want to find some way to improve that control / certainty. As Company Witness Reed describes, insurance is an example of a hedge in that it does come with a cost (insurance premium), but the purpose of it is to give you greater stability and security in your future costs. In general, if you do not end up using your health insurance (e.g., because you did not have any major medical issues), you are better off overall. Would it have been nice to know that you were not going to use the insurance so you could save yourself paying the premium cost? Yes. Would it have been possible for you to know that in advance? No. If something serious *had* happened, would you have been very glad you had insurance? Yes.

In the same way, an energy hedge provides you greater energy cost stability and security in an inherently uncertain future. At times, a hedge can be a specific financial or physical transaction to try and offset your future risk on a particular commodity. However, it can also simply be a strategy of "not putting all eggs in one basket" or, in more technical terms, maintaining a diverse fleet of resources so that you are not overly exposed to the price or availability of any single fuel / energy source. Figure 2 below shows that, while EMW does have a relatively diverse mix of fuels in its portfolio, approximately 70% of its forecasted capacity in 2026 is coming from market or peaking capacity. That means that EMW is essentially a price-taker for 70% of its energy and that is why it has a need for a hedge – a generator which will produce economic energy to offset EMW's exposure to the

SPP energy market, in addition to the needs for physical capacity and energy that it *also* has. Hedges should not be purchased "at any cost" (e.g. a coal plant can provide a hedge, but – depending on its fixed and variable costs – it could be too costly to justify its hedge value), but instead should be evaluated based on its all-in costs and the long-term benefits it provides in terms of physical capacity, energy, and hedge value.

FIGURE 2



Q: How has Evergy assessed this need for an energy hedge in the 2023 IRP?

A: For the 2023 IRP, Evergy developed resource plans targeting less market dependence for meeting energy and capacity needs, particularly in the second half of the 20-year IRP planning horizon. Specifically, there were hourly purchase and sale constraints inserted into the model to reduce EMW's exposure to market energy over time. As a result, the capacity expansion model was solving to meet EMW's physical capacity and energy needs, while also assessing the value of different resource plans as hedges against wholesale market exposure. These constraints did not force EMW to cover 100% of its load in all hours – in fact, EMW was still able to purchase approximately 15% of its average load from the market in any hour – but they did incentivize the capacity expansion model to select a more diverse portfolio of resources so that EMW's load could be met economically in the large variety of market scenarios tested.

Q: How did these needs and changes impact EMW's Preferred Plan selected through the 2023 IRP?

A: The combination of higher resource adequacy requirements, updated cost and in-service dates for new resources based on recent RFPs, and EMW's near-term need for capacity and energy resulted in the addition of Dogwood – an operating, low-cost, dispatchable source of capacity and energy – in all modeled capacity expansion scenarios and in the ultimately-selected Preferred Plan. In addition, the Preferred Plan now includes additional new natural gas capacity in 2027, solar additions in 2026 and 2028 (similar to 2022 Preferred Plan), and significant build-out of new wind between 2029 and 2035.

II. SELECTION OF DOGWOOD TO MEET EMW NEEDS

Q: What is EMW's 2023 Preferred Plan?

A: As presented on page 6 of the 2023 Annual Update filed with the Commission on June 15, 2023, Figure 3 represents EMW's Preferred Plan:

FIGURE 3

Gross New MWs In-Service								
EMW	2023	2024	2025	2026	2027	2028	2029	2030
Wind	-	-	-	-	-	-	150	150
Solar	-	-	-	150	-	150	-	-
Combined Cycle	-	143	-	-	260	-	-	-
Total	-	**143**	-	**150**	**260**	**150**	**150**	**150**

IRP modeling selected a mix of solar, wind, and natural gas resources to meet these needs. The increased amount of natural gas selected in this IRP was driven by increased SPP Resource Adequacy Requirements. This balanced portfolio of multiple resource types ensures that EMW is not overly exposed to one "fuel" source (i.e., natural gas, solar, or wind) and that it is prepared to mitigate market exposure in the long-term as continued baseload retirements are likely to create increased market price volatility.

Q: How do the 2023 IRP results support the Dogwood acquisition?

A: Dogwood was available as an input to the model at the purchase price of $62.7 million and used as a potential candidate resource option in capacity expansion modeling for the 2023 IRP. This means that any capacity expansion modeling scenarios could "choose" Dogwood if it resulted in the lowest-cost plan overall. This capacity expansion modeling was performed in Low-Low (low natural gas price, low carbon restriction), Mid-Mid, and High-High scenarios, with 4 different levels of Demand-Side Management programs, and with a variety of different retirement options. The capacity expansion model selected Dogwood as part of the lowest cost plan in every modeled scenario.[6] The only "hard-coded" adjustment to resource additions in the 2023 IRP was a scenario where Dogwood was removed

[6] *See* Confidential Schedule KM-1, Section 6.2.2: Overall Modeling Approach.

as a resource option in order to force the model to produce a plan which didn't select it, so that this plan could be used for comparison purposes (Plan ACAC below compared to Plan ACAA).

The 2023 IRP demonstrated that in both the Low and Mid carbon restriction scenarios, the addition of Dogwood reduced net present value of revenue requirements by approximately $90-110 million over the 20-year period. Using a straight comparison of the two plans in the High carbon restriction scenario (which assumed a very restrictive 95% reduction in CO_2 emissions over the 20-year period), the plan with Dogwood was higher cost by an estimated $350 million which results in a relatively small, expected value reduction of $8 million when all scenarios are combined. However, the reason the Dogwood plan is more expensive in that scenario is driven more by other resources being added later in the plan than it is by Dogwood itself (specifically, the "no Dogwood" plan is building an additional late-period Combined Cycle which is assumed to be non-emitting in the high carbon restriction scenario).

This is one challenge with capacity expansion modeling in that it makes it harder to do apples-to-apples comparisons of plan changes. What's more important to note than this one-off comparison is that when the capacity expansion model was *solving for* the high carbon restriction scenario (combined with a high gas price) in Plan ACAD, the model selected Dogwood, combined with additional wind and an additional late-period Combined Cycle, and this plan was lower-cost than the "no Dogwood" plan described above.

FIGURE 4: "Preferred Plan" Comparison Plan (base capacity expansion results)[7]

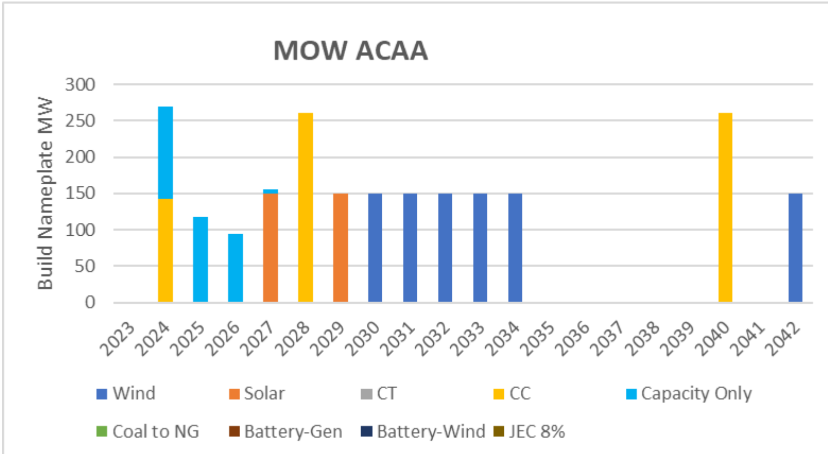
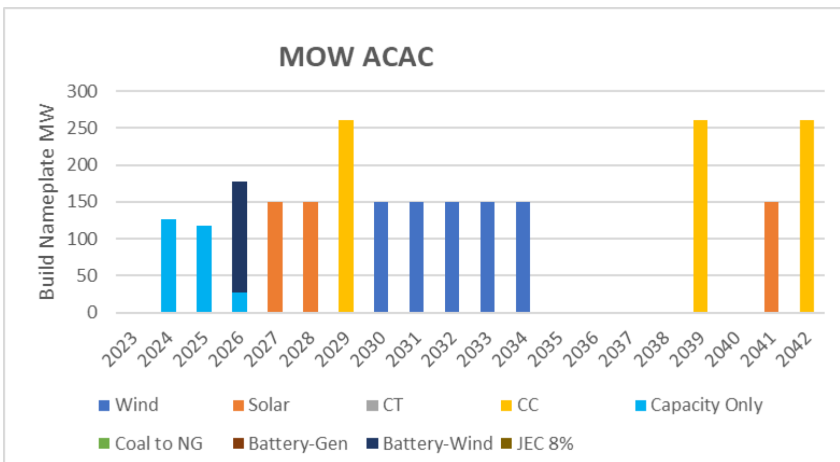
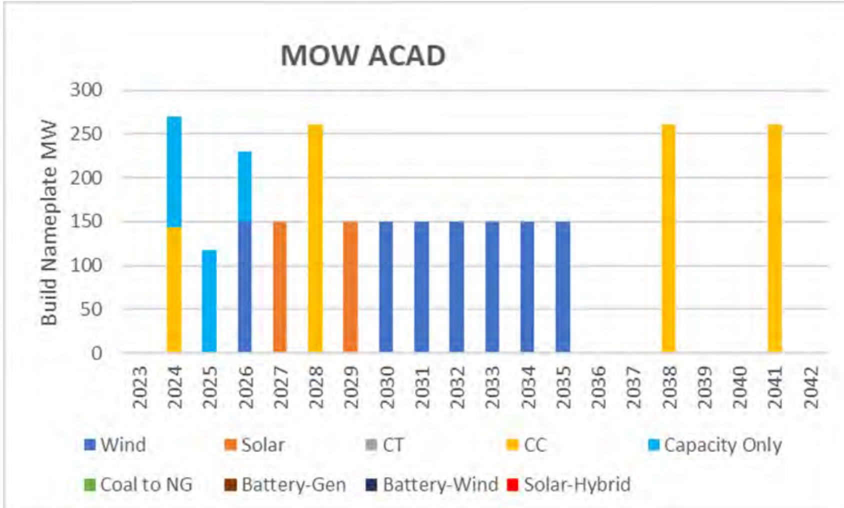


FIGURE 5: "No Dogwood" Capacity Expansion Results



[7] Plan ACAA is identical to the Preferred Plan (ECAA) with the exception of the selected level of Demand Side Management programs (RAP vs. RAP+). This change in DSM portfolios did not materially change build decisions and would have impacted the "no Dogwood" plan in the same way it impacted this comparison plan.

FIGURE 6: "High-High" Capacity Expansion Results



This comparison demonstrates that resource decisions cannot be evaluated in isolation because finding the lowest-cost resource mix means balancing both capacity and energy needs, as well as managing exposure to both carbon restrictions and natural gas prices. This is why an integrated analysis, like the one performed through the IRP process, is the best method of assessing potential resource additions.

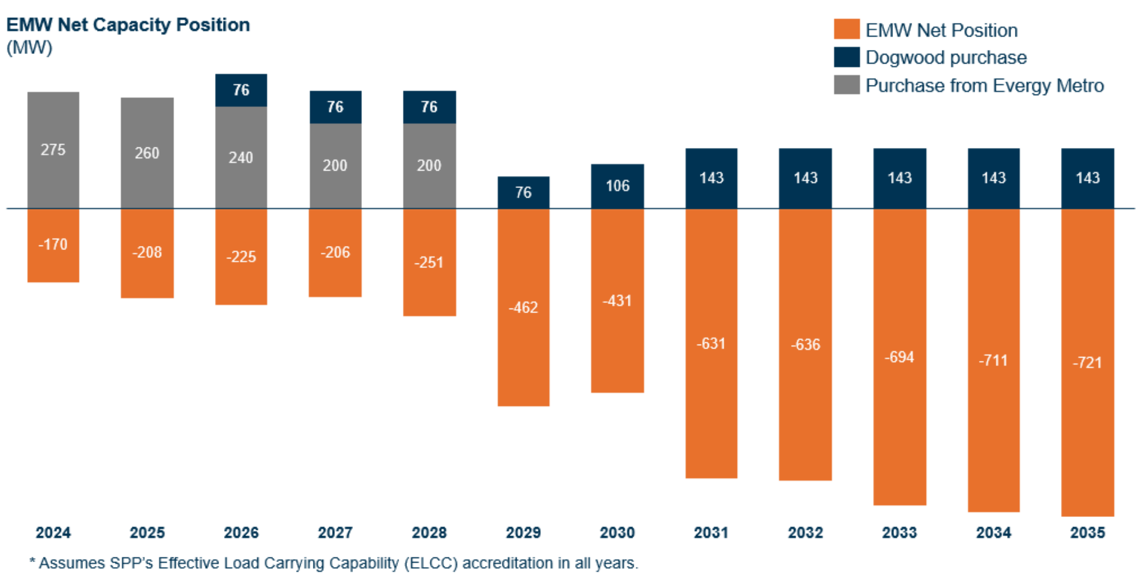
Q: What other alternative resource options were available to be selected in place of Dogwood in the IRP?

A: To provide the same accredited capacity as Dogwood, the IRP capacity expansion model could have selected additional near-term wind or solar, additional new natural gas in the late 2020s, up to 20 MW of market capacity each year starting in 2027 (with higher allowed purchases in earlier years prior to the expected implementation of resource adequacy requirement changes), and/or new battery energy storage. In addition, deploying Maximum Achievable Potential demand-side management programs could have been a lower-cost way to meet these needs.

Q: Does Dogwood fulfill all of EMW's capacity and energy needs?

A: No. As Figure 7 illustrates, even after including Dogwood, EMW is projected to be short both capacity and energy in the near-term and the long-term. Without considering any new resource additions beyond Dogwood, in 2024-2026 EMW is projected to be approximately 170 to 225 MW short and beginning in 2029, and for the next decade plus, EMW is projected to be short approximately 460 to 720 MW short.

FIGURE 7



Note: Net position values shown in orange above reflect EMW's net position after the inclusion of the Metro contract and Dogwood

In addition, while Dogwood will only make up a small portion of EMW's accredited capacity mix (~7% comparing the total 143 MW to EMW's projected

2026 accredited capacity), it is still a valuable addition to EMW's portfolio from a hedge perspective, as I will describe in more detail in the next section.

Q: Does the IRP assume that Dogwood operates differently than it has historically in order to meet EMW needs?

A: No. Over the last five years, Dogwood has operated at a net capacity factor of approximately 36%. In the IRP, the Preferred Plan is tested against different end points, which include varying levels of natural gas prices and carbon restriction assumptions. These different modeling assumptions drive a range of capacity factors and the weighted average capacity factor across the twenty-year planning period is approximately 37% – very comparable to Dogwood's recent operations.

III. BENEFITS OF DOGWOOD

Q: How does the cost of Dogwood compare to third-party capacity contracts?

A: Generally, third-party capacity contracts are offered as a shorter-term product, whereas Dogwood would be a dispatchable asset for years to come. As I've mentioned previously, given the expected thermal retirements and capacity requirement changes throughout SPP, Evergy expects market capacity, and in particular long-term capacity, to be less available over the next decade. There is a benefit to having the certainty of steel in the ground, rather than having exposure to the whims of the market and whether market capacity will be available.

**[redacted]

CONFIDENTIAL

[redacted]**

From a cost perspective, Dogwood is competitive with market capacity options. Assuming a remaining life of 20 years and the $62,700,000 purchase price of Dogwood, the net present value of revenue requirement equates to **[redacted]**[8]. The current short-term capacity-only market (typically less than five years; no energy included) has been trading in the **[redacted]**. Importantly, the Dogwood capacity comes with access to reliable, dispatchable, and economically competitive energy so it is expected to be priced at a premium to short-term capacity-only contracts. In EMW's 2022 request for proposals for capacity, EMW had one other comparable offer, which included a combined-cycle unit located within SPP, **[redacted]**. The main difference with this offer was that it was structured as a long-term tolling agreement, rather than equity ownership. The offer provided both a capacity and energy option, meaning it was offered at a premium to third-party capacity-only contracts. It included capacity rights for between 125 to 250 MWs starting at **[redacted]** and escalated by **[redacted]** annually over ten years, along with a call option for energy based on a gas price-index plus a small adder

[8] *See* Confidential Schedule KM-2.

(essentially purchasing energy "at cost"). In year ten the capacity contract would have cost **[redacted]** and the ten-year annual levelized cost would have been **[redacted]**, which is higher-cost than the Dogwood purchase. While similarly priced, it is also important to note that Dogwood is located in better proximity to EMW customer's load and has the added benefit of long-term ownership control.

Q: How does the cost of Dogwood compare the cost to build new natural gas capacity?

A: The Dogwood purchase price equates to $438/kW. Most public sources list current costs of simple cycle turbines in the $900-1,400/kW range depending on technology and combined cycle turbines in the $1,000-1,500/kW range. The U.S. Energy Information Administration's Southwest Power Pool/Central forecast from March 2023 estimates overnight costs for combustion turbine – industrial frame at $867/kW, combustion turbine – aeroderivative at $1,411/kW, and combined-cycle gas turbines in the range of $1,163 to $1,309/kW.[9] Across all of these technology types and sources, new build technologies are orders-of-magnitude greater than the purchase price of Dogwood. These new technologies will play an important role in EMW's portfolio in the future, but it is critical to take advantage of existing resources, which are available at a lower cost, for the benefit of customers when they are available.

[9] https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf.

Q: Is Dogwood the best available option to meet EMW's needs?

A: Yes. Dogwood was consistently selected in the IRP capacity expansion modeling due to the asset being the least cost resource available to serve EMW's near – and long-term capacity and energy needs. The 2023 IRP Annual Update shows that Dogwood reduces EMW's expected value of NPVRR by $8 million over the next 20 years, with approximately $100 million in NPVRR savings in the low and mid carbon restriction scenarios.

FIGURE 8: 2023 IRP PLAN COMPARISON

Table 37: Plan Comparison with and without Dogwood Addition
Evergy Missouri West Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR	Difference	Description
1	ACAA	10,858		RAP; Jeffrey 2 Retires 2030
2	ACAC	10,867	8	RAP; No Dogwood, Jeffrey 2 Retires 2030

Q: Why else is Dogwood a good option?

A: Dogwood provides access to an existing combined-cycle resource, which allows it to meet EMW's needs sooner, with costs below that of building a new unit. Not only is the purchase price of the Asset attractive, but the fact that steel is in the ground and the unit is operational means that siting, permitting, and construction risk is eliminated. Additionally, because it is located in Pleasant Hill, within EMW's Missouri service territory, Dogwood will benefit customers through its favorable transmission location, as evidenced by the historic correlation of market energy prices between the Dogwood and EMW load pricing nodes shown in Figure 9. The combination of cost, availability and location make Dogwood the best option to meet the needs identified in the 2023 IRP Update.

FIGURE 9

SPP Day Ahead Market Prices: January 1, 2020 – June 19, 2023		
Node	**Peak**	**Off Peak**
MPS_MPS (EMW Load)	$55.43	$33.04
Dogwood	$53.66	$31.64
Dogwood -vs- EMW Load	-3.2%	-4.2%

Q: Why does it make sense to add Dogwood now even though partial capacity isn't available until 2026 and full capacity in 2031?

A: First, with a tightening SPP capacity market, and the numerous challenges of interconnection, siting, and construction that are faced when building new generation, the Company believes that cost-effective, in-service resources, like Dogwood, will be sought after even more in the coming years. Simple economic theory would indicate that increasing demand paired with tightening supply will place higher future value on this asset. Even more directly for Dogwood, there are six existing owners of the plant – **[redacted]**. These co-owners are all facing the same increasing capacity requirements and tightening capacity market that Evergy is facing. As a result, it is probable that they will pursue the purchase of this portion of the asset if it becomes available, meaning that it will not be available to EMW in the future.

Second, as discussed in Company Witness Carlson's direct testimony, there is the added benefit of interim capacity contract revenues from 2024 to 2030 that will flow to customers via the Fuel Adjustment Clause until full capacity is available in 2031. These capacity revenues will serve to reduce the revenue requirement associated with Dogwood. Importantly, even though portions of

Dogwood's capacity have been contracted through 2030, one hundred percent of the energy will inure to the benefit of EMW customers on day one.

Assuming that EMW could simply wait until the current capacity contracts roll off to purchase this resource is simply depriving EMW customers of these near-term revenues and would likely result in missing the chance to purchase the asset altogether. Figure 10 shows how available Dogwood capacity aligns well and is complimentary to the schedule of EMW's current market capacity purchases.

FIGURE 10

Q: Will Dogwood be able to provide winter capacity to meet EMW winter needs once SPP formalizes those requirements?

A: Yes. Dogwood's advantaged position on two natural gas pipelines promotes strong winter availability which should result in a relatively high level of winter accreditation once those rules are finalized.

Q: What value does the Dogwood plant provide to meet Evergy Missouri West's need for an energy hedge?

A: EMW has historically been a net purchaser of about 3,000,000 MWh per year. With its 2020-2022 three-year average annual generation of approximately 427,000 MWh[10], Dogwood would fill approximately 14% of this 20-year average annual need. While there would still be a sizable gap even after adding Dogwood, it does provide a good start at solving this current need.

While Dogwood is still a natural gas-fired resource, like much of EMW's current fleet, it is a much more efficient asset, which allows it to provide diversity to EMW's fleet and mitigate EMW's energy market exposure. As stated in Company Witness Carlson's direct testimony, the average heat rate for EMW's combustion turbine fleet in 2022 was approximately 14,000 Btu/kWh. Dogwood's heat rate in 2021 and 2022 averaged **[redacted]**, nearly twice as efficient as EMW's existing combustion turbine fleet. Because the 143 MW of Dogwood is a more efficient combined-cycle technology, it will immediately benefit EMW customers by providing more economically competitive energy and fuel costs than the existing simple-cycle peaking units. This is depicted in the Figure 11 below and is described in more detail by Company Witness Reed.

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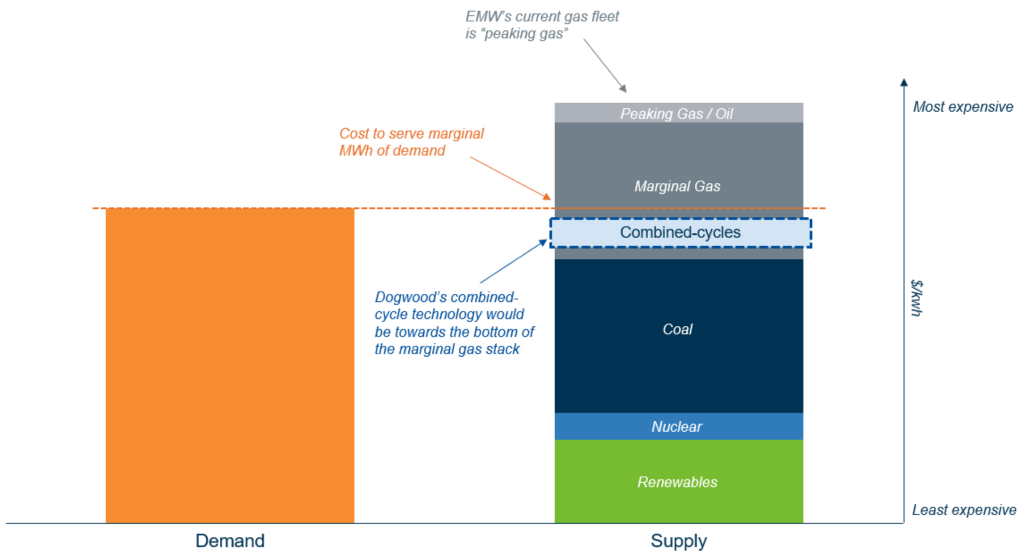
[10] Represents Evergy's 143MW share of Dogwood, which is ~22.2% of the total plant. The three-year average generation 2020-2022 was 1.92 million MWs for the full plant.

FIGURE 11



Q: What have stakeholders previously indicated regarding the benefits that an additional thermal resource would provide EMW?

A: In recent proceedings, members of MPSC Staff and the Office of the Public Counsel ("OPC") have acknowledged the merits of dispatchable resources. Staff witnesses have noted the benefits of a dispatchable resource's ability to dispatch based upon market and system conditions.[11] OPC has pointed out that purchasing capacity-only contracts with no energy leaves EMW customers exposed to market pricing during times of high demand. Specifically, in a recent evidentiary hearing in docket EA-2022-0328 OPC witness Lena Mantle said, "*The problem is Evergy West does not have dispatchable resources that can come online. …it's been a long time since they added resource. They're depending on Evergy Metro and the market. They need to start whittling away at some of that. If you have a hundred*

[11] Docket No. EA-2022-0328, Luebbert Rebuttal, p. 22, lns. 9-18.

million dollars to spend on plant, my opinion is it would be a much better use of the customers' money to do a dispatchable unit."[12]

While I disagree with Staff and OPC's expressed views that renewable resources do not *also* have value in meeting EMW's needs, I do agree with their articulation of the value of dispatchable resources.

Q: Please summarize your testimony.

A: EMW has near- and long-term needs for physical capacity, physical energy, and a hedge against the SPP market. A portion of Dogwood is being acquired as part of Evergy Missouri West's executing on the Preferred Plan identified in its IRP where it was shown to partially meet those needs and produce economic benefits for customers. The Project provides a valuable addition to EMW's portfolio because it is an existing asset with reduced risk, is located favorably to EMW's load, has access to reliable natural gas, is priced favorably to other available capacity, and provides long-term control of dispatchable energy. These unique characteristics are why Dogwood is the best currently available asset to meet EMW's near- and long-term needs.

Q: Does that conclude your testimony?

A: Yes, it does.

[12] https://www.efis.psc.mo.gov/Document/Display/26993; pages 281-283.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of)
Evergy Missouri West, Inc. d/b/a Evergy)
Missouri West for Permission and Approval of) Case No. EA-2023-0291
a Certificate of Public Convenience)

AFFIDAVIT OF KAYLA MESSAMORE

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Kayla Messamore, being first duly sworn on his oath, states:

1. My name is Kayla Messamore. I work in Kansas City, Missouri, and I am employed by Evergy Metro, Inc. as Vice President of Strategy and Long-Term Planning.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Evergy Missouri West consisting of thirty (30) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Kayla Messamore

Kayla Messamore

Subscribed and sworn before me this 8th day of November 2023.

Anthony R Westenkirchner

Notary Public

My commission expires: 4/26/2025

ANTHONY R. WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2025
PLATTE COUNTY
COMMISSION #17279952

EVERGY MISSOURI WEST

INTEGRATED RESOURCE PLAN

2023 ANNUAL UPDATE

JUNE 2023

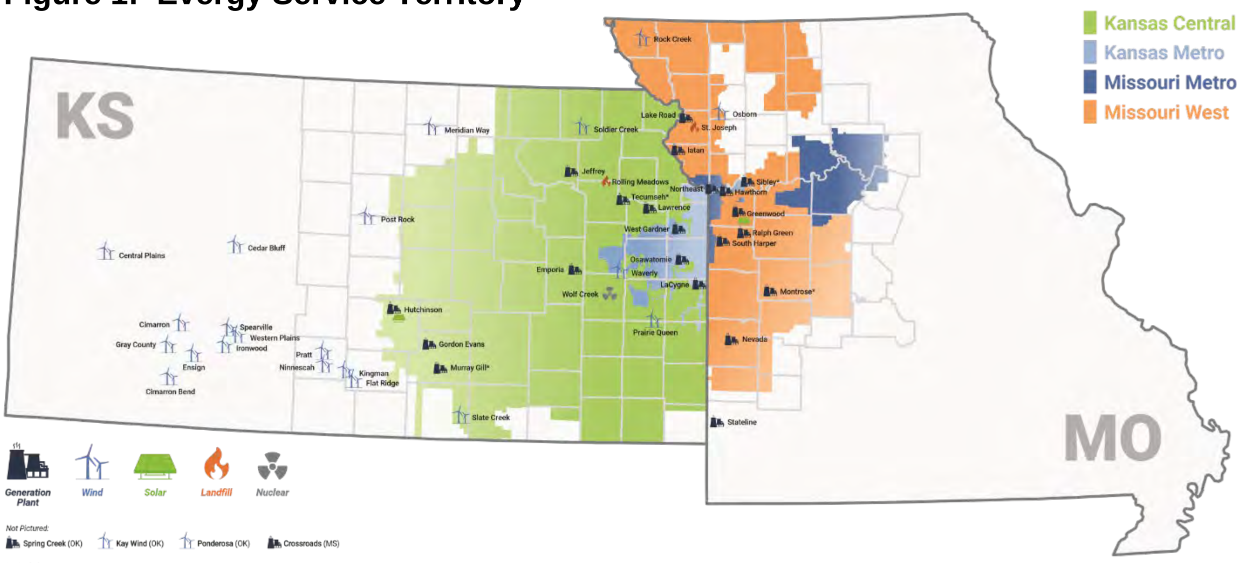
** CONFIDENTIAL **

SECTION 1: EXECUTIVE SUMMARY

1.1 UTILITY INTRODUCTION

Evergy Missouri West ("Missouri West" or "Company") is an integrated, mid-sized electric utility serving portions of Northwest Missouri including St. Joseph and several counties south and east of the Kansas City, Missouri metropolitan area. Missouri West also provides regulated steam service to certain customers in the St. Joseph, Missouri area. A map of the entire Evergy service territory which includes Missouri West is provided in Figure 1 below:

Figure 1: Evergy Service Territory



Missouri West is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Table 1 provides a snapshot of the number of customers served, retail sales and peak demand based upon 2022 data.

Table 1: Missouri West Customers, Retail Sales, and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Missouri West	340,298	8,666,707	1,923

Missouri West owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. Table 2, reflect Missouri West's generation assets operating in 2021.

Table 2: Missouri West Capacity and Energy By Resource Type

Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Evergy Missouri West	Coal	463	19.1%	1,770,534	33.1%
	Nat. Gas	1,069	44.1%	478,896	8.9%
	Oil	104	4.3%	20,443	0.4%
	Wind*	783	32.3%	3,068,274	57.3%
	LFG	2	0.1%	8,867	0.2%
	Solar	6	0.3%	4,110	0.1%
	Total	2,427	100.0%	5,351,124	100.0%

* Wind capacity is based upon nameplate

1.2 CHANGES FROM THE 2021 TRIENNIAL IRP AND 2022 ANNUAL UPDATE

Evergy Missouri West submitted its 2021 Triennial IRP filing on April 30, 2021, updated its resource plan on June 10, 2022, with its 2022 IRP Annual Update filing, and filed a Change in Plan Filing on September 26, 2022. This year's 2023 IRP Annual Update reflects updated information and forecasts based on market and policy changes and additional studies that have occurred in the past year.

Changes from the 2021 Triennial IRP, 2022 Annual Update, and 2022 Change in Plan filing:

- Updated market pricing reflecting latest SPP transmission planning model assumptions of future resource mix and potential transmission congestion
- Updated fuel price forecasts, including high, mid, and low natural gas price scenarios

- Carbon Dioxide emissions limitations scenarios reflecting future environmental risks, including high, mid, and low (no) restrictions
- Updated cost estimates and timing assumptions for resource additions based on First Quarter 2023 Request for Proposal (RFP) results
- Modeling of battery storage and hybrid resources as supply-side options
- Inclusion of incentives for new renewable and storage resources based on Inflation Reduction Act
- Updated load forecasts including large new customers in both Missouri and Kansas, and considerations for future large customer growth based on existing economic development pipeline
- Updated demand side management potential study, including four Missouri program options
- Included possible reductions in peak demand from Missouri Commission-ordered mandatory time of use rates
- Updated planning reserve margin consistent with SPP rule changes enacted in 2022
- Increased focus on planning for utility-level (as opposed to Evergy-level) resource needs to better identify each utility's specific energy and capacity needs in the future, reduced level of assumed market availability (for both capacity and energy) and reliance on other Evergy affiliates to meet long-term customer needs
- Removal of Persimmon Creek wind farm (due to the company not advancing the project further in the Missouri West jurisdiction)
- Expanded use of PLEXOS software for production cost modeling and capacity expansion, which was first implemented for 2022 IRP
- Annual refresh of data for existing generators (Capital and Operations & Maintenance costs)

1.3 2023 ANNUAL UPDATE PREFERRED PLAN

1.3.1 INTEGRATED RESOURCE PLAN OVERVIEW

Evergy's integrated resource planning experience spans many decades with its most recent Triennial Preferred Plans filed for both Evergy Metro and Evergy Missouri West in 2021 ("2021 IRP"). Between Triennial IRP filings, Commission regulations require annual updates reflect any material changes to the triennial filing and/or confirmation of the continued applicability of the originally filed Preferred Plan. This document includes the annual update filing for Evergy Missouri West for 2023 ("2023 Update") that, consistent with Commission regulations, outlines material changes to the 2021 IRP.

Due to the many changes in planning considerations over the past year, the Preferred Plan selected for Missouri West in this 2023 IRP Annual Update differs from the 2021 Triennial and 2022 IRP Preferred Plans. The 2023 Preferred Plan adds natural-gas resources to the Missouri West fleet earlier in the planning horizon. It increases the total amount of wind additions but postpones them until 2029. More solar is selected in the first few years of the plan, but there are less solar additions in the later half of the 20-year horizon.

Additionally, the refresh of the demand response potential study shows value in choosing the "Realistically Achievable Potential Plus (RAP+)" level of demand response programs over the Realistically Achievable Potential (RAP) level selected in the 2022 Annual Update. Notably, the new study shows much lower demand response potential than was forecasted in the last study, so the level of capacity and energy reductions which can be achieved from all programs are smaller.

Finally, in the 2022 Annual Update, Evergy identified the potential for an additional accelerated retirement which could be economically replaced, but at that time chose not to identify a specific unit for retirement as part of the Preferred Plan due to the uncertainty around which specific unit would ultimately be the best candidate for retirement. In this Annual Update, Jeffrey Unit 2 has been identified for 2030 retirement as part of the Preferred Plan. There is still significant uncertainty around different environmental regulations which could drive the retirement of Jeffrey Unit 2 or a different Evergy coal unit and thus Jeffrey Unit 2 still remains a "placeholder" for an accelerated retirement. However, given recent regulation released by the Environmental Protection Agency (EPA), it seems more probable that all units would need to install Best Available Control Technology in order to continue operating beyond the early 2030s. Given Jeffrey Units 2 and 3 are the only large units in Evergy's fleet without Selective Catalytic Reduction (SCR) systems, the capital forecasts used in this IRP (and prior IRPs) assume that SCRs would need to be added if the units do not retire by 2031. This large capital cost to continue operations makes these units the most attractive options for early retirement. Evergy will continue to monitor environmental regulations and make adjustments to retirement plans as needed if conditions change, but at this time believes it is prudent to plan around a medium-term retirement of both Jeffrey Units 2 and 3 in order to avoid a situation where retirements are forced by environmental regulation and replacement capacity has not been procured proactively. Further discussion of environmental regulations is provided in Sections 3.4 and 7.2. Because Missouri West is a minority owner in the Jeffrey Units, these retirements are included in Missouri West's Preferred Plan. It is important to note that, as an 8% owner, Missouri West does not have ultimate control of this retirement decision, but the lowest-cost resource additions for Missouri West are the same with and without the additional Jeffrey Unit 2 2030 retirement.

Table 3: Evergy Missouri West Preferred Plan Comparison

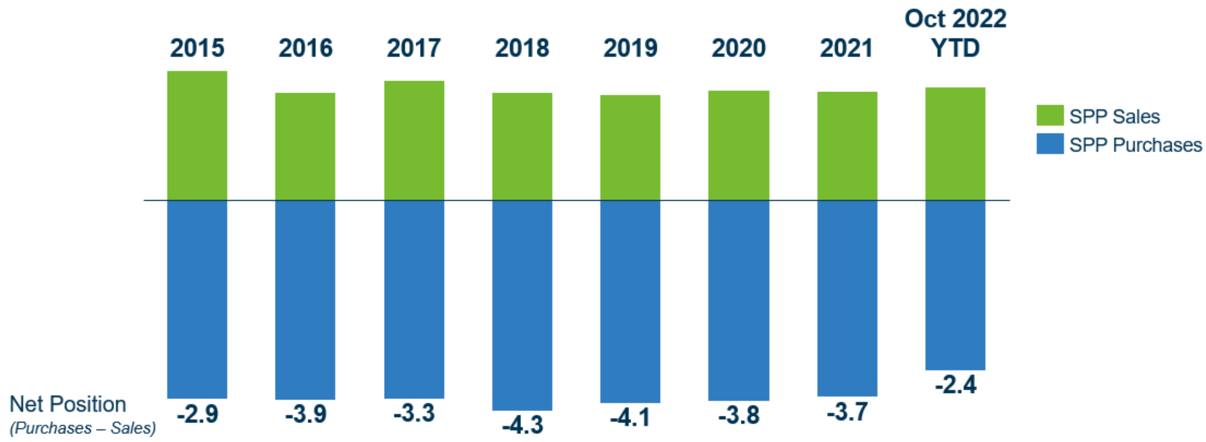
Note: All dates shown in this summary are end-of-year unless otherwise noted. Capacity balance views shown elsewhere in this document represent summer capacity impacts which means that additions are typically shown in the following year (the year in which they will be available for summer capacity)

	2021 Triennial IRP	2022 IRP Annual Update	2023 IRP Annual Update
Retirements	Lake Road 4/6 in 2024 Jeffrey 3 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039	Lake Road 4/6 in 2030 Jeffrey 3 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039	Lake Road 4/6 in 2030 Jeffrey 3 in 2030 Jeffrey 2 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039
Wind Additions	80 MW in 2025 80 MW in 2026	150 MW in 2024 72 MW in 2026	150 MW in 2029 150 MW in 2030 150 MW in 2031 150 MW in 2032 150 MW in 2033
Solar Additions	120 MW in 2024 80 MW in 2028 80 MW in 2029 80 MW in 2030 80 MW in 2031 80 MW in 2032	48 MW in 2028 72 MW in 2029 72 MW in 2030 72 MW in 2031 72 MW in 2032 72 MW in 2033 72 MW in 2034 72 MW in 2035	150 MW in 2026 150 MW in 2028 150 MW in 2041
Battery Additions			
Hybrid Additions			
Thermal Additions	233 MW CT in 2033 233 MW CT in 2039 233 MW CT in 2040	237 MW CT in 2036 237 MW CT in 2040	143 MW Dogwood CC in 5/2024 260 MW CC in 2027 260 MW CC in 2039
New DSM Programs	RAP	RAP	RAP+

Missouri West has historically been short energy and capacity, fulfilling its load obligations through market purchases from SPP and bilateral capacity contracts (net energy position since 2015 shown in Figure 4). The 2023 IRP Annual Update plan transitions Missouri West to greater self-sufficiency over time. In the 2021 Triennial IRP, stand-alone plans for Missouri West selected early combustion turbine (CT) builds to meet capacity needs, however, joint planning postponed the need for natural-gas capacity as affiliates had enough excess capacity that ensured there would be market capacity available for Missouri West. Similar assumptions were used in the 2022 IRP. Joint planning demonstrated that thermal additions could be postponed and Missouri

West's Preferred Plan included heavy reliance on future capacity deals to meet reserve margin requirements.

Figure 2: Missouri West Net Energy Position (GWh)



For the 2023 IRP, Evergy developed resource plans targeting less market dependence for meeting energy and capacity needs, particularly in the second half of the 20-year IRP planning horizon. The increasing prevalence of low- and negative-energy market prices in SPP, combined with increasing resource adequacy requirements mean that it is unlikely that significant excess capacity will persist in SPP in the long-term. Additionally, as the resource mix transitions and environmental regulations continue to drive baseload retirements, Missouri West must ensure it has energy to serve its load at a stable price, without simply assuming that other Pool members continue to build out sufficient energy resources to meet Missouri West customer energy needs at low prices. Given low wholesale market prices which are generally insufficient to cover all-in costs of new resources, Missouri West does not expect other utilities or merchant generators to build excess resources that are dispatchable or aligned to the load profile of Missouri West's customers as baseload coal resources retire and renewables are added. Notably, the amount of excess energy available from two of Missouri West's closest neighbors, Evergy Kansas Central and Evergy Metro, is expected to decline over time as those utilities are also planning to dedicate proportionately more of their resources to meet *their* respective utility customers' capacity and energy needs.

The 2023 IRP Preferred Plan continues to follow Evergy's strategy of adding to its resource portfolio ratably over time to meet increasing customer needs and transition out aging resources. This strategy considers annual capital spend limits to maintain balance sheet strength and customer rate stability. Spreading investment over time diversifies risk and allows time for robust selection processes to add the best projects available to its fleet. The 2023 Preferred Plan was developed considering a wider variety of options for adding new resources, updated cost assumptions, and new government incentives.

This 2023 IRP also incorporates feedback received from MPSC Staff as part of the Persimmon Creek Certificate of Convenience and Necessity case (outlined below). Evergy Missouri West looks forward to working further with Staff and other stakeholders in the development of the 2024 Triennial in order to implement further modeling improvements and/or assumption adjustments.

- Use of updated SPP Transmission Planning models which include significantly higher level of negative prices
- Updated dispatch assumptions for wind resources which ensure PTC-eligible wind realizes negative revenues when dispatched at negative prices
- Full use of capacity expansion modeling to identify lowest-cost supply-side resource additions; no hard-coded resource additions
- More fulsome explanation of modeling approach and method of using capacity expansion (provided in Section 6.2)

In summary, this 2023 Update is consistent with the Commission's integrated resource planning regulations and highlights changes to the Preferred Plan filed in our 2022 IRP. The changes to Missouri West's Preferred Plan compared to the 2022 IRP are driven by:

- Increased SPP Resource Adequacy requirements and increased load expectation driven by economic development activity
- Updated resource cost assumptions based on recent Requests for Proposal and new incentives under the Inflation Reduction Act

- New Potential Study results for Demand-Side Management programs

For reference, a summary of the Evergy-level Preferred Plan (based on a combination of the Preferred Plans of Missouri West, Evergy Metro, and Evergy Kansas Central) is provided below.

Table 4: Evergy-Level Preferred Plan Comparison

Note: All dates shown in this summary are end-of-year unless otherwise noted. Capacity balance views shown elsewhere in this document represent summer capacity impacts which means that additions are typically shown in the following year (the year in which they will be available for summer capacity)

	2021 Triennial IRP	2022 IRP Annual Update	2023 IRP Annual Update
Retirements	Lawrence 4 in 2023 Lawrence 5 in 2023 Lake Road 4/6 in 2024 Jeffrey 3 in 2030 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039 Iatan 1 in 2039	Lawrence 4 in 2024 Lawrence 5 in 2024 (Coal) Jeffrey 3 in 2030 Lake Road 4/6 in 2030 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039 Iatan 1 in 2039	Lawrence 4 in 2028 Lawrence 5 in 2028 (Coal) Jeffrey 3 in 2030 Jeffrey 2 in 2030 *(Placeholder for add'l accelerated retirement)* Lake Road 4/6 in 2030 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039 Iatan 1 in 2039
Wind Additions	500 MW in 2025, 2026	300 MW in 2024 500 MW in 2025 450 MW in 2026 450 MW in 2041	199 MW in 5/2023 200 MW in 2024 150 MW in 2029, 2030 300 MW in 2031 450 MW in 2032 300 MW in 2033 150 MW in 2040, 2041
Solar Additions	350 MW in 2023, 2024 500 MW in 2028, 2029, 2030, 2031, 2032, 2033, 2034, 2035	190 MW in 2024 300 MW in 2028 450 MW in 2029, 2030, 2031, 2032, 2033, 2034, 2035 150 MW in 2036	300 MW in 2026 150 MW in 2027 300 MW in 2028, 2029, 2030, 2031 150 MW in 2033, 2034, 2040 450 MW in 2041
Thermal Additions		338 MW Lawrence 5 to NG in 2024	176 MW in 2023 143 MW in 5/2024 781 MW in 2027 338 MW Lawrence 5 to NG in 2028 521 MW in 2028 238 MW in 2032
"Firm Dispatchable"[1]	233MW in 2036, 2037, 2039 2,796MW in 2040	237 MW in 2036 418 MW in 2038 836 MW in 2039 948 MW in 2040	238 MW in 2035 260 MW in 2037 780 MW in 2038 1,278 MW in 2039
New DSM Programs	RAP MO/ RAP - KS	RAP MO/ RAP- KS	RAP+ MO/ Low KS

1) Similar to past IRPs, thermal additions beginning in 2035 are assumed to be non-emitting “firm, dispatchable resources”

SECTION 3: SUPPLY-SIDE RESOURCE ANALYSIS UPDATE

3.1 MARKET CONDITIONS AND FUTURE OUTLOOK

Evergy considers current and future market conditions in developing its 20-year forward looking forecasts for the IRP. Starting with the 2022 IRP Annual Update, Evergy contracted with 1898&Co. to produce 20-year market price forecasts using SPP's transmission planning models as a baseline.

SPP conducts the integrated transmission planning process (ITP) on an annual basis, to assess reliability and economic transmission needs up to 10 years in the future. Every five years, SPP also performs a 20-year assessment. To perform these transmission assessments, SPP develops different future resource mix scenarios based on stakeholder feedback, including utility IRP plans. These resource mix assumptions, which include retirements or continued operation of existing resources and additions of new resources, enable the models to predict future economic dispatch of the system, transmission congestion, and resulting price differentials between load and resources.

For the 2023 IRP Annual Update, 1898&Co. used the most recent ITP models to produce market prices using Evergy's load and fuel price assumptions, including high, mid, and low natural gas price scenarios. The most recent ITP included forecasting models for years 2, 5, 10 and 20.

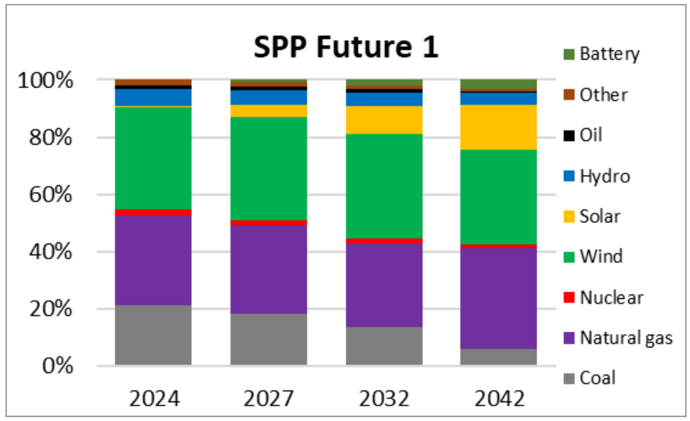
3.1.1 OVERVIEW OF SPP ITP FUTURES

The SPP Future 1 case represents a "business as usual" case with longer retention of existing resources, assuming by 2042 coal resources 56 years and older as well as natural gas and oil generators 50 years and older will retire. The 2024 planning model reflects near-term transmission upgrades and resource additions and is the same for all Futures described.

Figure 5: SPP Future 1 Overview

SPP Future 1				
Resource	2024	2027	2032	2042
Coal	21%	18%	14%	6%
Natural gas	31%	31%	29%	35%
Nuclear	2%	2%	2%	1%
Wind	35%	36%	36%	33%
Solar	1%	4%	10%	16%
Hydro	6%	5%	5%	4%
Oil	2%	1%	1%	0%
Other	2%	1%	1%	1%
Battery	0%	1%	2%	3%

Source: 1898&Co.

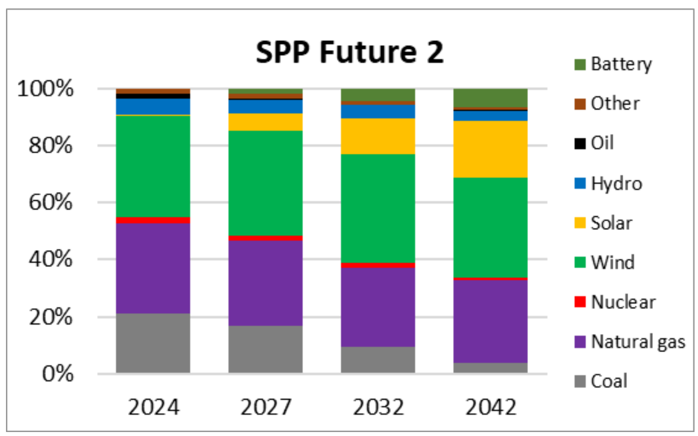


The SPP Future 2 case is an emerging technologies scenario, incorporating growth of electric vehicles and distributed generation as well as higher penetration of renewables and earlier retirement of existing generation. The ages for retirements are reduced to 52 years for coal units and 48 years for natural gas and oil units. Solar and battery resources account for a larger portion of 2042 capacity.

Figure 6: SPP Future 2 Overview

SPP Future 2				
Resource	2024	2027	2032	2042
Coal	21%	17%	9%	4%
Natural gas	31%	30%	28%	29%
Nuclear	2%	2%	2%	1%
Wind	35%	36%	38%	35%
Solar	1%	6%	13%	20%
Hydro	6%	5%	4%	4%
Oil	2%	0%	0%	0%
Other	2%	1%	1%	1%
Battery	0%	2%	4%	7%

Source: 1898&Co.

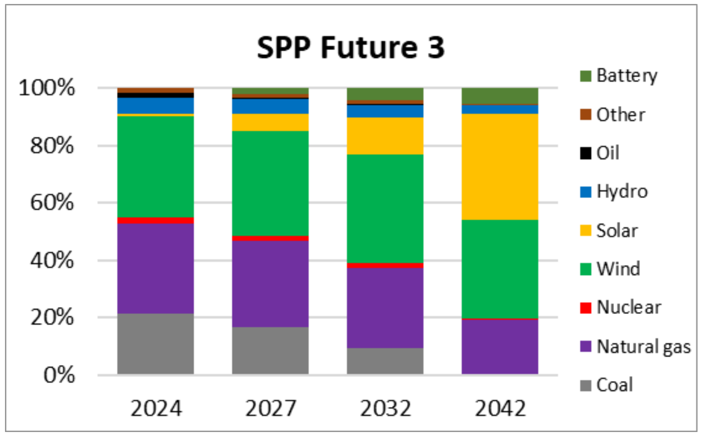


The SPP Future 3 case models accelerated decarbonization. All coal and oil resources are retired by 2042 and new resource build is driven by targeted emissions reductions of approximately95% from 2017 by 2042, leading to much higher reliance on solar. Future 3 is only modeled for 2042, so years 5 and 10 (2027 and 2032) reflect Future 2 models.

Figure 7: SPP Future 3 Overview

SPP Future 3				
Resource	2024	2027	2032	2042
Coal	21%	17%	9%	0%
Natural gas	31%	30%	28%	19%
Nuclear	2%	2%	2%	1%
Wind	35%	36%	38%	34%
Solar	1%	6%	13%	37%
Hydro	6%	5%	4%	3%
Oil	2%	0%	0%	0%
Other	2%	1%	1%	1%
Battery	0%	2%	4%	5%

Source: 1898&Co.



The Evergy market price forecasts for the 2023 IRP use a combination of the SPP Futures models. Evergy believes that Future 2 is the most representative forecast considering the recent pace of resource additions in SPP, interconnection queue activity and utility resource plans. However, the IRP also uses market prices from Future 3 to forecast a potential future with more stringent carbon regulation. Evergy believes this Future 3 scenario is particularly informative given the EPA's recently proposed Greenhouse Gas rules, which would drive a similarly aggressive pace of decarbonization.

3.1.2 <u>PRICING ENDPOINTS</u>

Consistent with the 2021 Triennial IRP, Evergy identified natural gas prices and carbon emissions policy as the critical factors to include in its market price forecasts. Nine price series were developed using combinations of high, mid, low natural gas price forecasts and high, mid, and low (no) carbon restriction scenarios. The natural gas forecasts and carbon emissions policy forecasts were updated as explained in later sections. Evergy did not change the 2023 IRP probabilities for each natural gas – carbon emissions policy scenario from the 2021 and 2022 IRPs.

Table 6: Market Pricing Endpoints and Probabilities

Endpoint	NG Price Forecast	Future	Carbon Restriction	Probability
H3C	High	Future 3	Future 3	3%
H2C	High	Future 2	H2C Model	9%
H2N	High	Future 2	None	3%
M3C	Mid	Future 3	Future 3	10%
M2C	Mid	Future 2	M2C Model	30%
M2N	Mid	Future 2	None	10%
L3C	Low	Future 3	Future 3	7%
L2C	Low	Future 2	L2C Model	21%
L2N	Low	Future 2	None	7%

Evergy also did not change the 2023 IRP probabilities for load forecast endpoints compared to the 2022 Annual Update. As a result, the overall endpoint probabilities used for Integrated Analysis are the same as those used in the 2022 Annual Update:

Table 7: Critical Uncertain Factor Probability Distribution

	Low	Mid	High
Load Growth	35%	50%	15%
Natural Gas	35%	50%	15%
CO_2 Restrictions	20%	60%	20%

Table 8: Scenario Weighted Endpoint Probabilities

Endpoint	Load Growth	Natural Gas	CO_2	Endpoint Probability
1	High	High	High	0.5%
2	High	High	Mid	1.4%
3	High	High	Low	0.5%
4	High	Mid	High	1.5%
5	High	Mid	Mid	4.5%
6	High	Mid	Low	1.5%
7	High	Low	High	1.1%
8	High	Low	Mid	3.2%
9	High	Low	Low	1.1%
10	Mid	High	High	1.5%
11	Mid	High	Mid	4.5%
12	Mid	High	Low	1.5%
13	Mid	Mid	High	5.0%
14	Mid	Mid	Mid	15.0%
15	Mid	Mid	Low	5.0%
16	Mid	Low	High	3.5%
17	Mid	Low	Mid	10.5%
18	Mid	Low	Low	3.5%
19	Low	High	High	1.1%
20	Low	High	Mid	3.2%
21	Low	High	Low	1.1%
22	Low	Mid	High	3.5%
23	Low	Mid	Mid	10.5%
24	Low	Mid	Low	3.5%
25	Low	Low	High	2.5%
26	Low	Low	Mid	7.4%
27	Low	Low	Low	2.5%

3.1.3 NATURAL GAS PRICES

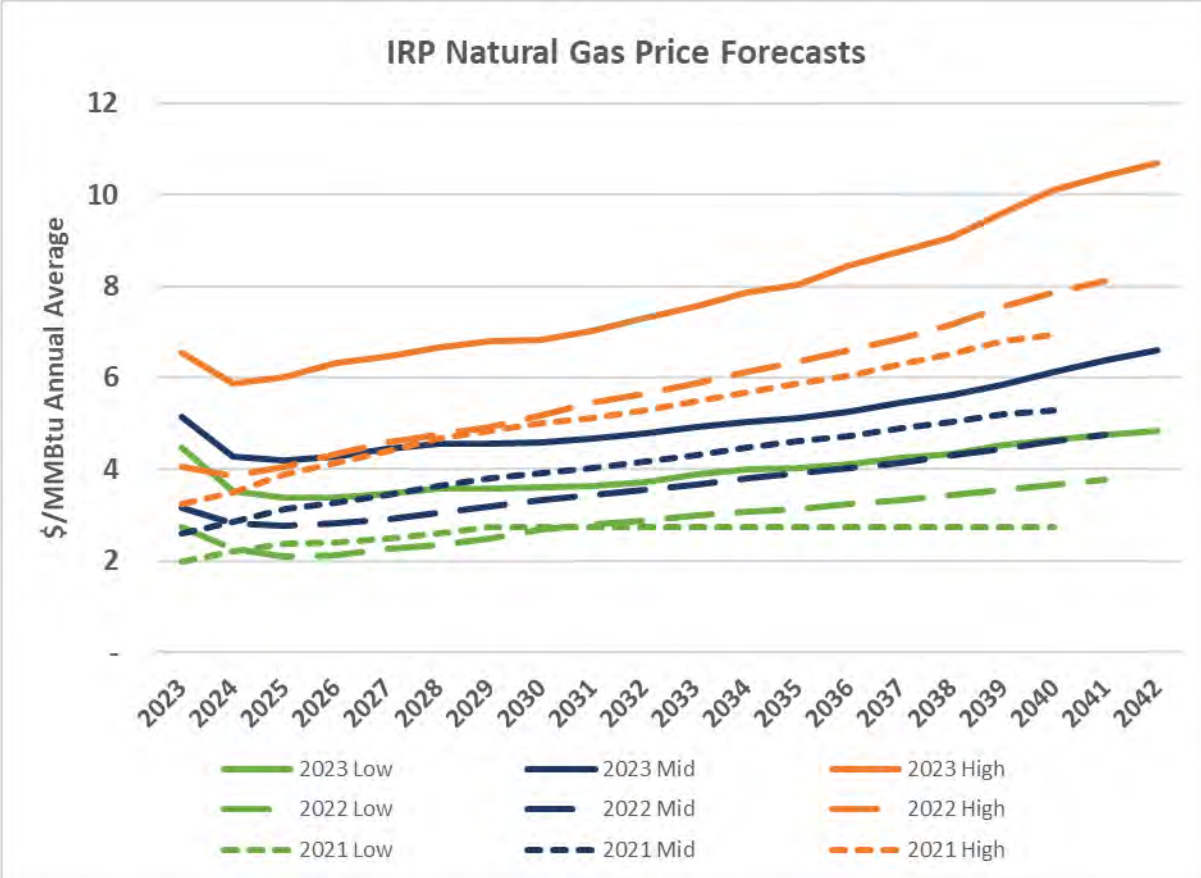
Natural gas forecast prices increased for the 2023 IRP in comparison with previous forecasts.

Evergy updates the IRP natural gas forecast annually based on the forecast used for internal budgeting, which is developed from vendor forecasts and forward markets. Last year, in response to Evergy's 2022 IRP filings, stakeholders noted a disconnect between the volatile and higher natural gas prices seen in the markets in late 2021 and early 2022 and the lower long term forecast prices in the IRP. The 2023 forecast reflects higher natural gas prices. Natural gas prices have been affected by the Ukraine War, supply chain pressures, global demand, and inflation. While future natural gas prices are uncertain, there are fundamental factors supporting the higher forecast including higher breakeven production costs, producer discipline, and increased global demand despite current lower natural gas prices compared to last year.

The high and low forecasts were developed by using the mid forecast and scaling it based on the fundamental supply and demand forecasts in the EIA Annual Energy Outlook model. The EIA builds its forecasts considering a variety of factors, including current laws and regulations, current assessments of economic and demographic trends, technology improvements, compounded annual economic growth, oil and natural gas supply and demand, and renewable energy cost cases. Key drivers for US natural gas production volumes include EIA's outlook on international prices and US LNG exports, as well as technology assumptions. Evergy used the "High Oil and Gas Supply" to calculate the low natural gas price forecast, and the "Low Oil and Gas Supply" for the high natural gas price forecast.

This method was used beginning in the 2022 IRP to derive a wider range of prices based on changes in fundamental assumptions. For the 2021 IRP, the high and low forecasts were derived statistically from the range of vendor forecasts, with the low forecast capped at the five-year historical average.

Figure 8: IRP Natural Gas Price Forecast Comparison



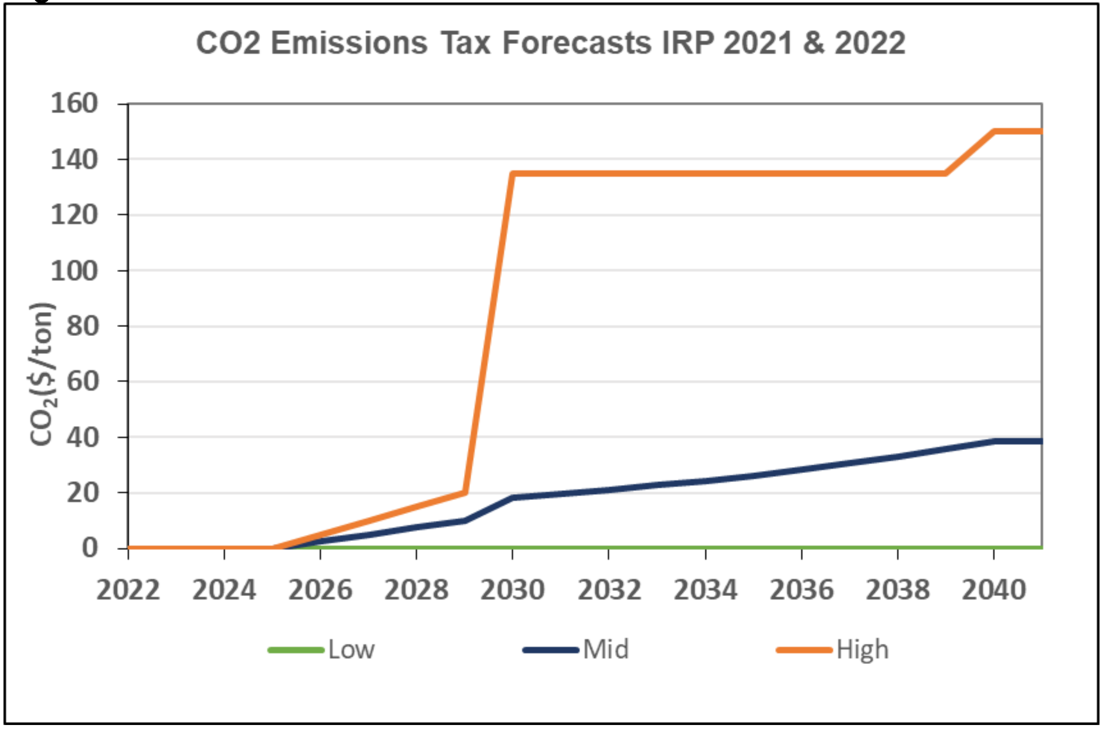
The 2023 IRP natural gas forecasts reflected in the above charts are based on forecasts provided by these third-party sources:

- IHS Markit
- Energy Information Administration
- S&P Global Platts
- Energy Ventures Analysis
- CME Futures
- ICE

3.1.4 CARBON RESTRICTIONS

Since the 2021 Triennial IRP, Evergy has modeled three levels of potential future carbon emissions policies. For the 2021 and 2022 IRPs, the policies were modeled as a carbon emission tax, while for the 2023 IRP they were modeled with both restrictions on carbon emissions production and carbon emissions taxes.

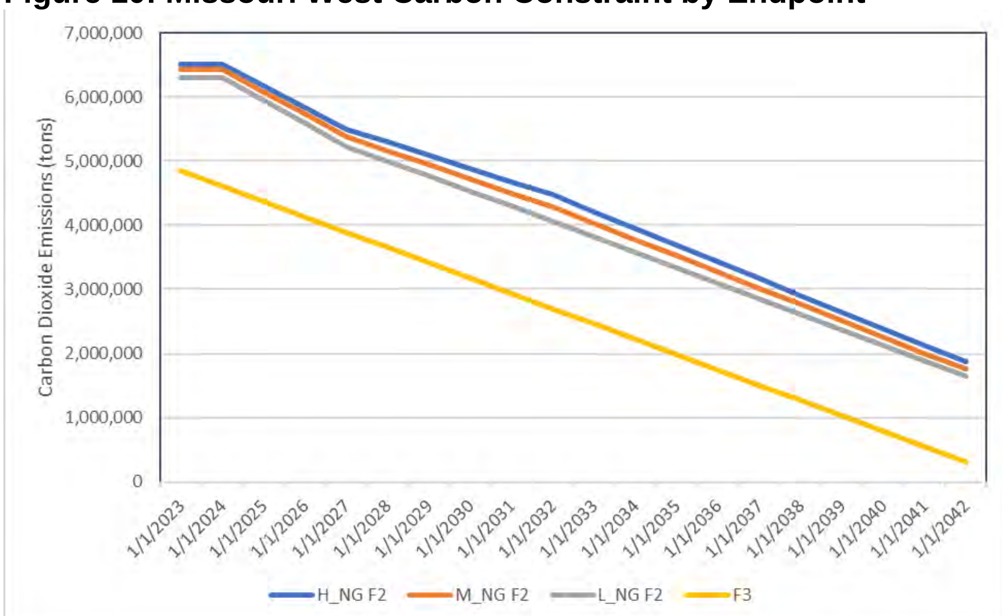
Figure 9: Carbon Tax Forecasts IRP 2021 and 2022



For the 2023 IRP, Evergy modeled carbon restrictions using assumptions built into the SPP futures models, aligning emissions reduction scenarios with market forecast expectations. Evergy discontinued using vendor carbon tax forecasts. Vendor forecasts were no longer available or were outdated considering the current administration and recent policy actions. In addition, Evergy currently expects future carbon policies to be in the form of incentives (such as those in the IRA), or requirements for physical emissions reductions, rather than carbon taxes.

The low forecast for the 2023 IRP has no emissions restrictions with market prices developed using the Future 2 pricing model. The mid forecast uses the same market price forecast but employs a carbon emissions restriction consistent with the dispatch solution of the pricing model. The CO_2 production constraint mirrors Evergy's anticipated emission levels within the SPP market (e.g., if the dispatch in the pricing model produced a 70% reduction in Missouri West's carbon emissions in 2042, the carbon restriction applied in the IRP dispatch model for 2042 is 70%). The high forecast is consistent with the assumptions in the SPP Future 3 model which was engineered with an explicit carbon reduction goal of an approximately 95% reduction in CO_2 production from 2017 levels. Evergy used the same logic to ratably restrict emissions from historic 2017 CO_2 production levels to culminate in 2042 with a 95% reduction. The high forecast also incorporates a carbon tax which ramps to $25/ton by the end of the twenty-year horizon, consistent with Future 3.

Figure 10: Missouri West Carbon Constraint by Endpoint[1]



[1] H_NG F2: High Natural Gas, Mid Carbon restriction; M_NG F2: Mid Nat Gas, Mid Carbon; L_NG F2: Low Nat Gas, Mid Carbon; F3: High Carbon Restriction (applies in all gas price scenarios)

Table 9: Future 3 Carbon Tax ($/ton)

	Price
2023	**0**
2024	0
2025	0
2026	0
2027	0
2028	0
2029	0
2030	0
2031	0
2032	0
2033	2.5
2034	5
2035	7.5
2036	10
2037	12.5
2038	15
2039	17.5
2040	20
2041	22.5
2042	25

In order to achieve SPP Future 3 emissions goals, breakthroughs would be needed in dispatchable carbon-emissions-free technology. Newer combined cycles and combustion turbines are engineered to burn cleaner fuels including hydrogen or ammonia blends. However, refining and transport of these fuels is still cost prohibitive. Improvements in carbon capture and sequestration technologies are another option for reducing or eliminating emissions. US government subsidies are encouraging innovation in these areas. Because achieving Future 3 would be unlikely based on current technology, new combined cycles and combustion turbines were assumed to have zero emissions beginning in 2036 for Future 3 models, representing the necessary technological breakthroughs. Additionally, carbon-free energy was assumed to be available in all models for $300/MWh in case the fleet was unable to generate enough energy, or carbon-free energy to serve load. This price point is based on the current typical price of fuel oil-fired peaking units which, although clearly not representative of actual carbon-free energy, provides a “scarcity price” proxy for the cases when Evergy is unable to meet its own load.

3.1.5 CONGESTION AND NODAL PRICES

Since the 2022 IRP Annual Update, Evergy has incorporated transmission congestion in its modeling by using market prices at different nodes/zones within the SPP system. The 2021 Triennial IRP used a single market clearing price for all load and resources but included some dispatch adjustments to align resource capacity factors with historical averages.

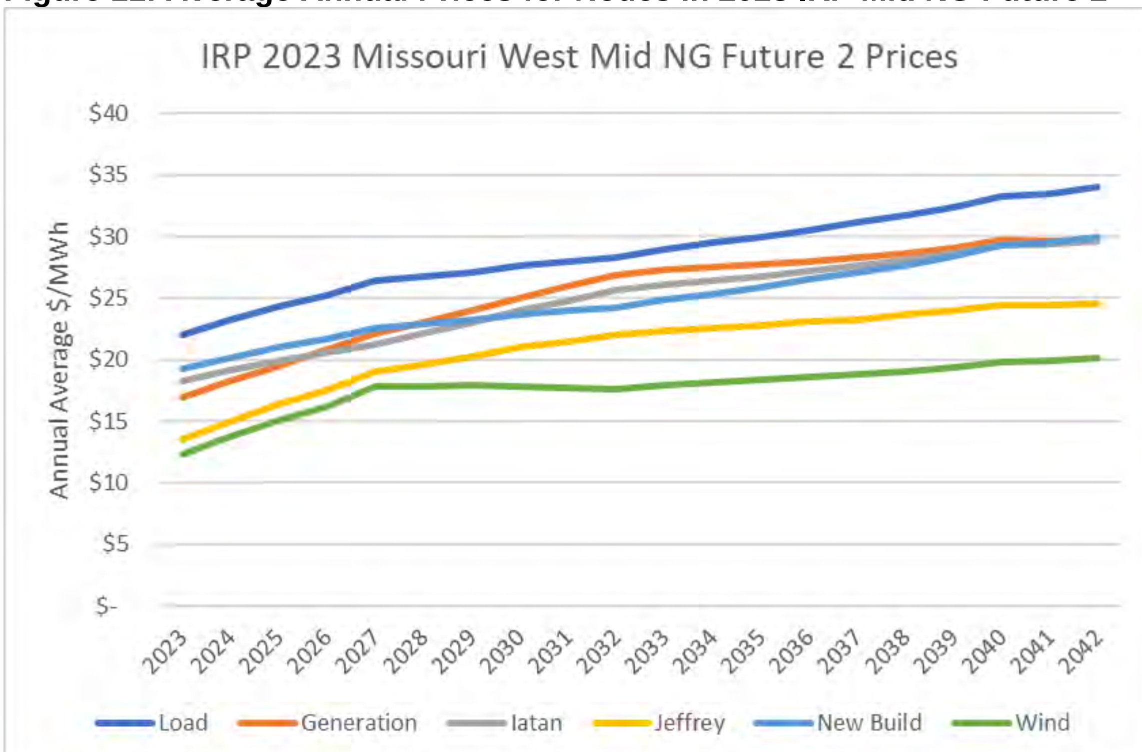
The 2023 IRP pricing models, based on the SPP ITP models, reflect current transmission topology and near-term transmission upgrades. The models use economic dispatch, considering transmission limits, to calculate nodal pricing. The 2022 and 2023 IRP both used pricing at the following locations:

- Load zones for each utility: used for load and DSM
- Coal resource locations for each coal site
- Wind location: used for all new and existing wind and wind PPAs
- Generation zones for each utility: used for existing generators; Metro location used for new solar, batteries, hybrids

Because these models are used to identify future transmission needs, congestion tends to increase in future model years as new resources are assumed without corresponding transmission upgrades that might improve their economic deliverability to load. The base models are likely to overestimate future congestion, however future transmission upgrades are uncertain. The long-term transmission planning processes attempt to identify and select beneficial transmission projects that can reduce the total costs to serve load. Development of new resources may exacerbate congestion, but it can take time for potential savings to reach a tipping point where transmission becomes cost effective. Lags in planning and uncertainty around the timing and viability of new resource additions can also delay new transmission investment. Given the significant build-out of renewable resources between 2032 and 2042, which is not accompanied by enabling transmission investment and thus results in a significant increase in congestion in the "base" SPP model, Evergy assumes congestion is held constant over this second decade of the planning horizon.

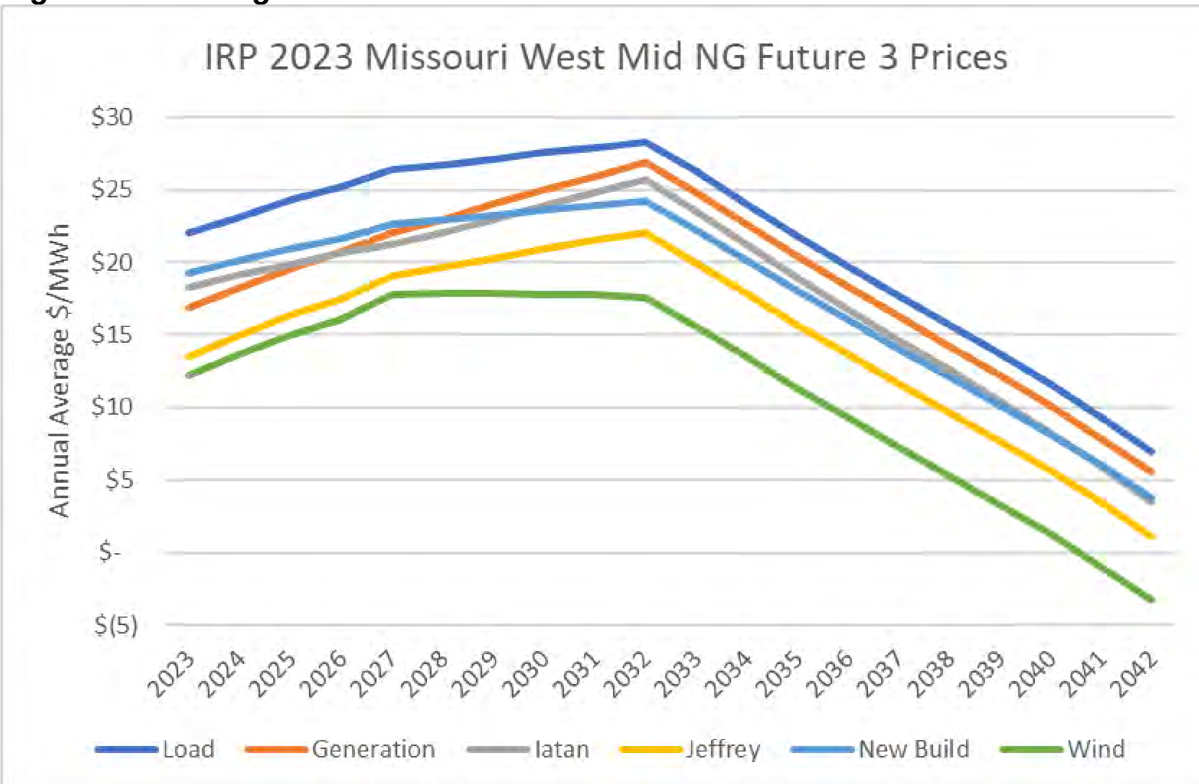
The new SPP ITP models, used for the 2023 IRP pricing, reflect increased congestion, particularly in the western part of Evergy's footprint.

Figure 11: Average Annual Prices for Nodes in 2023 IRP Mid NG Future 2



Future 3, used for the high carbon restriction scenarios in IRP 2023 predicts a decreasing price future, as resource additions continue to have fixed costs, but no production costs. Market prices are driven down by a high penetration of zero cost renewable resources, that may also have production tax credits, making their marginal production cost negative.

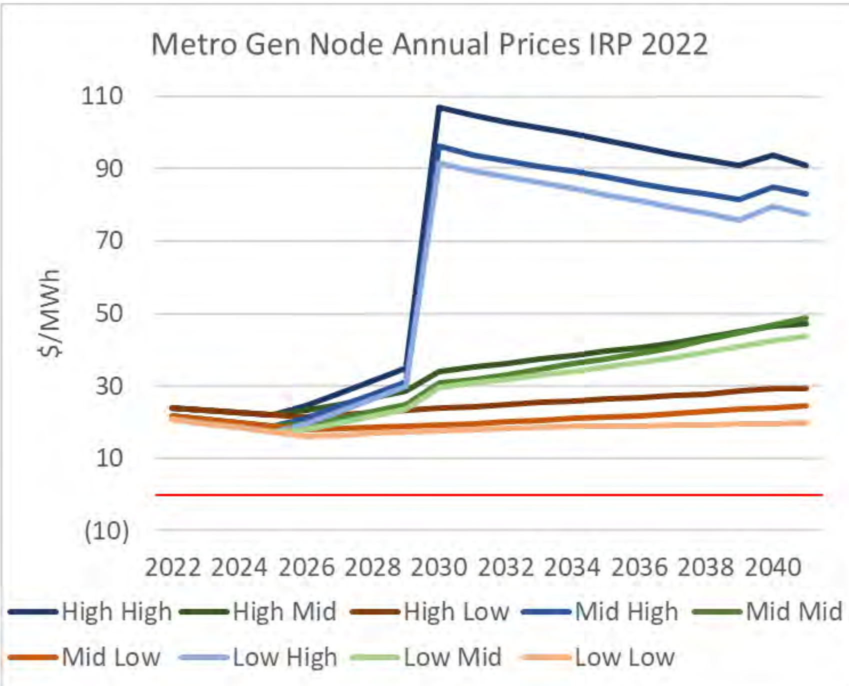
Figure 12: Average Annual Prices for Nodes in 2023 IRP Mid NG Future 3

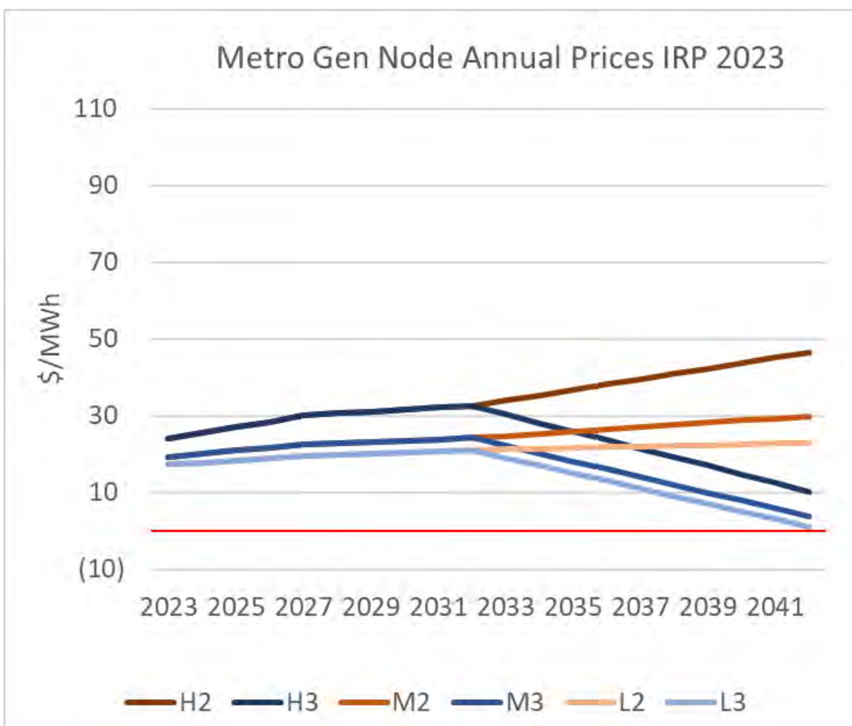


Prices are also generally lower than prices in the 2021 and 2022 IRPs due to higher expected renewable penetration in the future resource mix. Prices in the 2021 and 2022 IRPs also reflected explicit carbon emissions taxes for the mid and high carbon scenarios which resulted in higher production costs and higher market prices. The change in planning assumption to a carbon restriction results in lower prices as the tax no longer impacts production costs.

Figure 13: 2022 IRP and 2023 IRP Market Price Comparison

Note: Evergy Metro Generation Node is used in the graphs below for comparison purposes as a relatively "average" pricing node

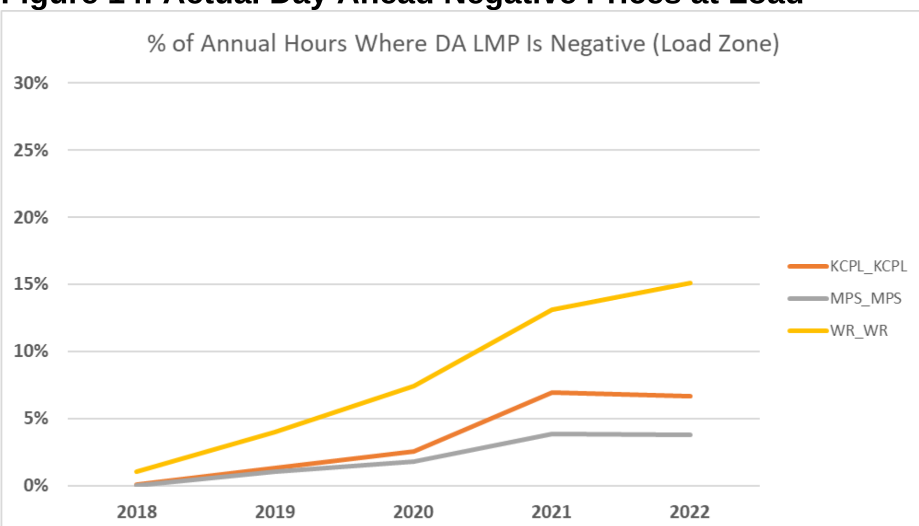




3.1.6 NEGATIVE PRICES

The 2023 market price forecasts reflect the negative pricing that has been observed in SPP and predict that the number of negative-priced hours in SPP will continue to grow. When Evergy began using SPP ITP models for its pricing forecast in the 2022 IRP, it also introduced negative pricing into the IRP analysis. The previous software, used for the 2021 Triennial IRP and prior IRPs did not calculate negative prices. The 2022 IRP price forecasts had a small percentage of negative prices, which was consistent with the modeling assumptions in the most current version of the SPP ITP model available, which had slightly dated assumptions given the pace of change in SPP resource additions. The 2023 market price forecasts have the most up-to-date planning assumptions and align more closely with recent SPP experience.

Figure 14: Actual Day Ahead Negative Prices at Load



KCPL_KCPL: Metro
MPS_MPS: Missouri West
WR_WR: Kansas Central

Figure 15: 2023 IRP Modeled Negative Prices at Load

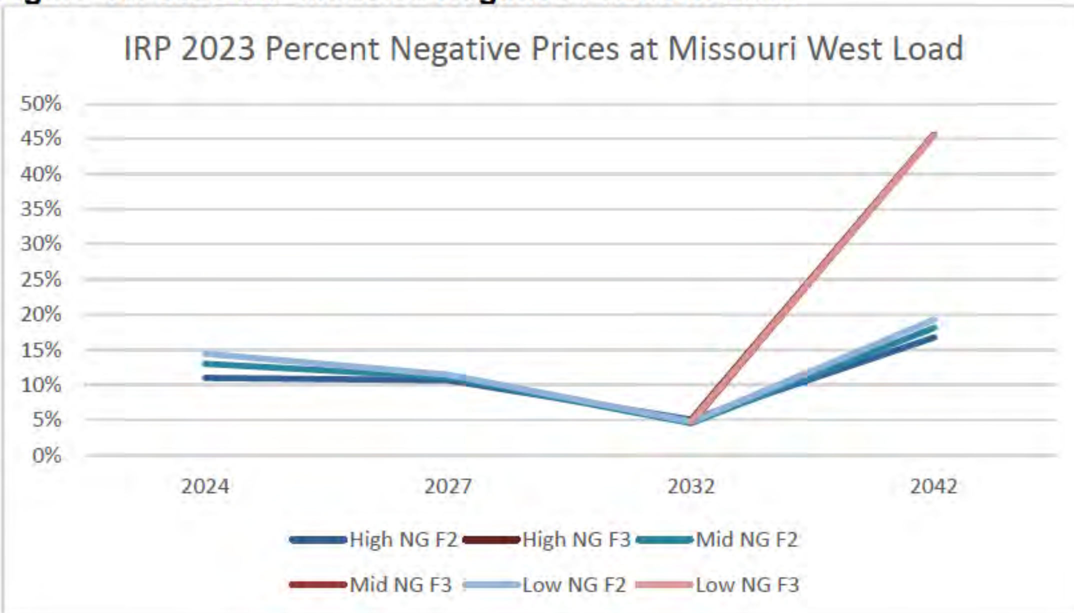


Figure 16: Actual Day Ahead Negative Prices at Generator Nodes

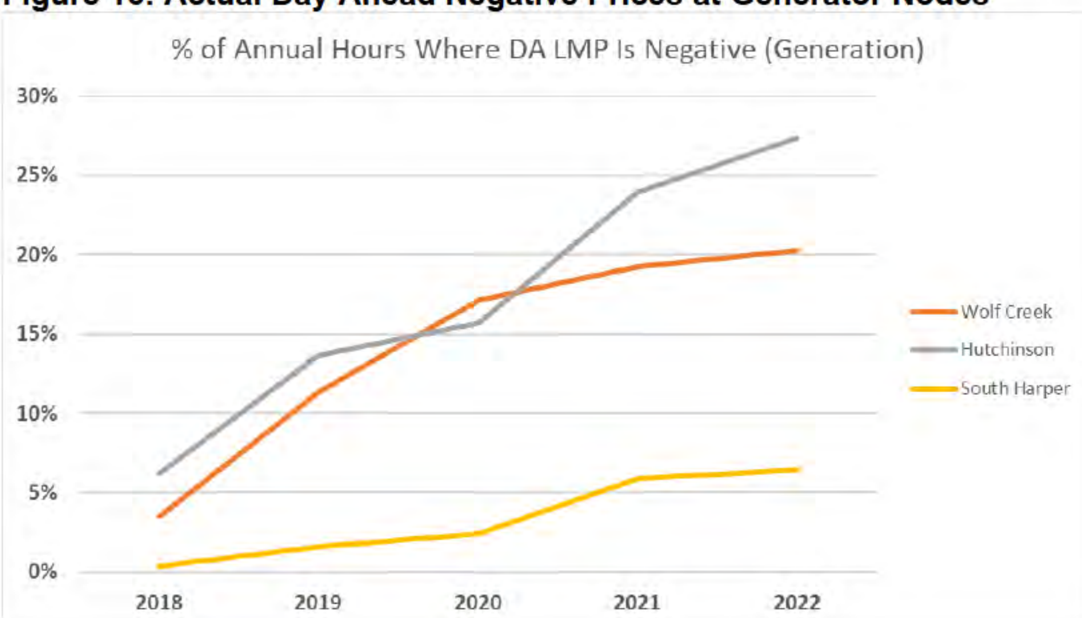


Figure 17: 2023 IRP Modeled Negative Prices at Generator Nodes

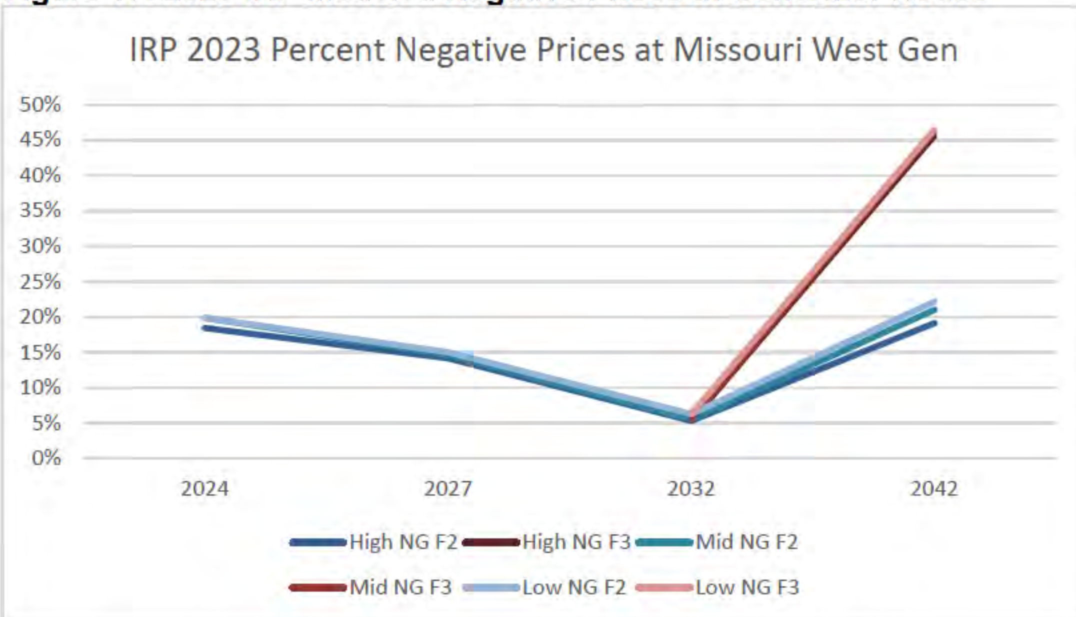


Figure 18: Actual Day Ahead Negative Prices at Wind Nodes

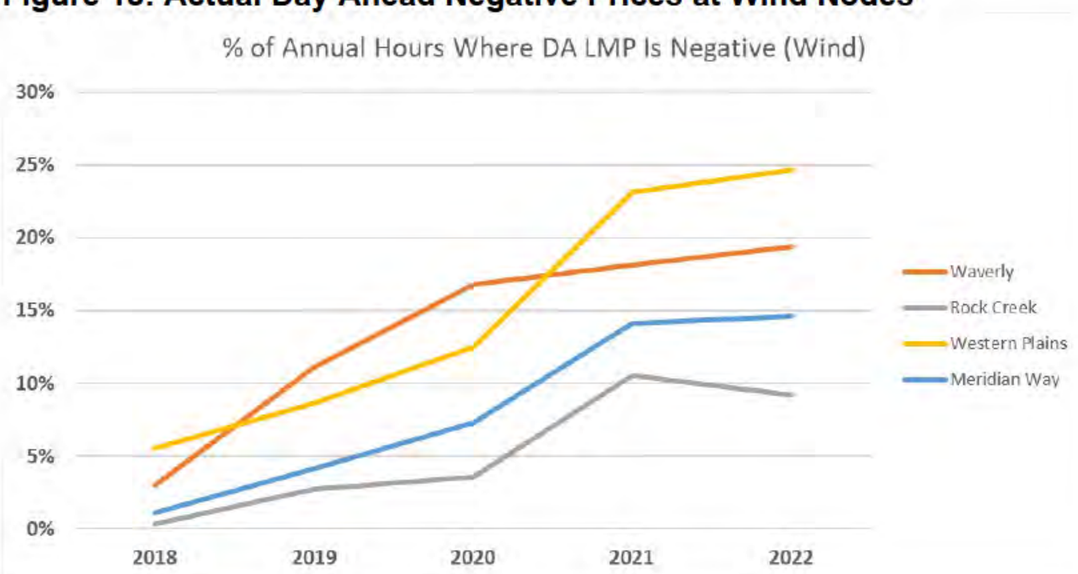
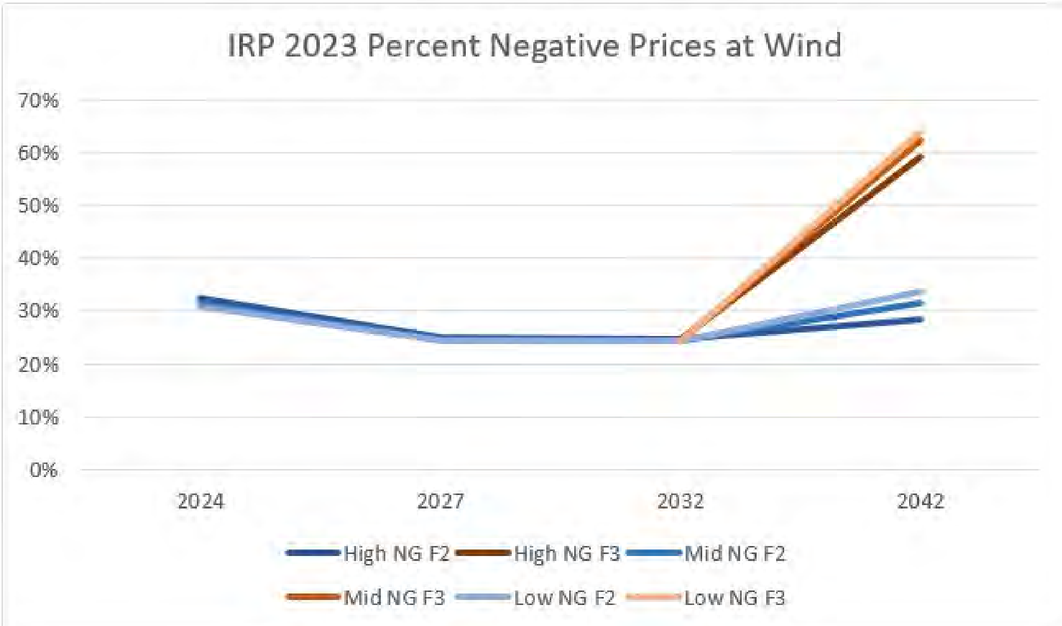


Figure 19: 2023 IRP Modeled Negative Prices at Wind Nodes



3.2 SUPPLY-SIDE TECHNOLOGY CHANGES FROM THE 2021 TRIENNIAL IRP

For the 2023 Annual Update, Evergy considered more options for resource additions, based on stakeholder feedback and solicitation of offers for resources.

2023 Request for Proposal (RFP)

In January 2023, Evergy issued a request for proposals for new resources. In March 2023, Evergy received offers for wind, solar, solar-hybrid, and battery storage resources from various suppliers, with different contract structures, locations, and technologies offered. Evergy used the information from the RFP to estimate the near-term availability of resources, expected costs, and operating characteristics. Evergy received offers for both Build-Transfer (i.e., owned resources) and Power Purchase Agreements (PPA) through this RFP, however, all resources evaluated in this IRP are assumed to be owned, consistent with the approach used in past IRPs. This consistency of assumptions enables better comparison of “generic” resource options and leaves the evaluation of different ownership structures (e.g., PPA) to more detailed analysis during the resource procurement process.

Natural Gas Resources

Evergy is currently conducting a study to determine optimal locations to build new natural gas resources in the future. While the study is not complete in time for this IRP filing, resource specifications and costs were updated in the IRP modeling analysis. Evergy has determined that due to interconnection queue times and siting needs, the earliest operational year for a new natural gas resource is 2028. Simple and combined cycle technology is rapidly evolving towards hydrogen blending capable, emissions-controlled combustors. Evergy anticipates that whatever technology is ultimately selected will be hydrogen combustion capable at a 30% blend or higher.

Other Resources

Evergy considered the purchase of ownership shares of Dogwood Energy Center for Missouri West based on the results of a late 2022 capacity Request for Proposal. If purchased, this resource would be available to Missouri West in 2024.

Evergy also considered the addition of Persimmon Creek Wind and the currently-merchant 8% share of Jeffrey Energy Center for Kansas Central.

Discussion of Resource Options and Economics

Key changes in market conditions in the past few years have driven changes to expected availability and installed costs of new resources. Last year, Evergy noted high inflation and supply chain pressures increasing the cost of materials and limiting their availability. Uncertainty around US government trade policies and tariffs also contributed to solar panel scarcity.

The Inflation Reduction Act, which was passed after the 2022 IRP filing, extended and created new incentives for zero-carbon-emitting resources. Currently US agencies are formalizing regulations which will clarify how resources will qualify and account for these incentives. Despite some uncertainties about the final rules, The Inflation Reduction Act may be spurring demand for qualifying projects, as intended by lawmakers.

The SPP interconnection queue continues to be highly backlogged, slowing the ability of new projects to assess their economic viability considering transmission upgrade costs, and increasing their lag time to achieve commercial operation.

While the addition of new resources is likely to be slowed, the need for new resources is forecasted to increase. As part of its electric reliability planning, SPP ensures that it has the resources to meet demand at all times. SPP requires Evergy and all load-serving entities to own or contract for enough capacity to meet this objective. SPP uses updated weather and system operational data as well as lessons learned from events such as Winter Storm Uri to perform reliability studies. Recently, SPP raised the summer reserve margin from 12% to 15% of peak load beginning in summer 2023. This means that load-serving entities must maintain more capacity as a percent of load. SPP Stakeholders continue to work through future rule changes affecting capacity needs, including winter reserve margin requirements, which are currently voluntary. SPP is also considering changes to how much credit it gives to each resource to meet capacity needs, termed capacity accreditation. This summer, SPP planned to implement Effective Load Carrying Capability (ELCC), which aligns capacity accreditation with resource contribution at peak times for resources that are limited by weather (Wind, Solar) or duration (Batteries), effectively decreasing the credit these resources receive, however it was postponed by a FERC decision. Evergy expects ELCC, or a similar capacity accreditation method to be implemented in the future, as well as a new method that will decrease capacity accreditation for other non-fuel-limited resources based on operational performance, specifically forced outage history (performance-based accreditation).

Refreshed capital cost assumptions for new resources are shown in Table 17 below. Capital cost assumptions for the same resources are shown for the 2021 Triennial IRP and the 2022 Annual Update for comparison. "First Year" represents the first year in which the resource option was assumed to be available based on RFP results and/or expected construction timeline. "Capacity" shown in the table below represents the assumed size of one "project" of that resource type, which was an input into capacity expansion modeling (described further in 6.2)

Table 10: Supply-Side Technology Options ** Confidential **

[redacted]

Installed capital costs for zero-emitting technologies rose substantially and longer lead times to commercial operation were observed based on the 2023 RFP offers.

The capital cost increases may be mitigated by the increased incentive values provided by the Inflation Reduction Act. Evergy incorporated expected Inflation Reduction Act incentives in the modeling of new resource economics, including a 10-year production tax credit (PTC) for wind and solar, which are valued as reducing revenue requirements by 100% of the pre-tax value for every MWh of output. Wind and Solar resources were assumed to be dispatchable, offering into the market at the negative value of the credit to enable production and receipt of the credits, if economic. Batteries were expected to receive an investment tax credit (ITC) of 30% of installed cost upon commercial operation. The Inflation Reduction Act phases out incentives as US targets are achieved. Both PTC and ITC credit eligibility for new resources was assumed to reduce to 75% in 2034, 50% in 2035, and end in 2036.

Table 11: Inflation Reduction Act Incentives Modeled for New Resources

Resource	Incentive Modeled	Max Capacity Factor	Max Incentive (2023 $/kW)
Wind	PTC, 10 Years	48%	1,421
Solar	PTC, 10 Years	26%	756
Battery	ITC Upfront	17%	489
Solar-Hybrid	PTC, 10 Years Solar; ITC Upfront Battery	42%	639

Note: Currently operating resources were modeled based on years of remaining PTC eligibility. ITC incentive based on installed cost.

Installed cost estimates decreased for Combustion Turbine and Combined Cycle technologies. These cost decreases may be due to better information as opposed to actual technological improvements. Past costs were based on publicly available information, and likely did not reflect regional differences. Costs this year reflect engineering firm estimates particular to Evergy.

Last year, Evergy planned to wait on Combined Cycle and Combustion Turbine additions until technological improvements made non-emitting, dispatchable resources attainable as an alternative – assumed to be after 2035. Evergy did not model additions of these resources before 2036, reasoning that existing non-emitting resources could economically replace retiring coal and meet load growth until that time. This year, based on Evergy's forecasted need for more capacity earlier due to SPP requirements as well as potential load growth, Evergy will consider building hydrogen-capable natural gas-fired resources sooner. Evergy assumes that these resources will procure firm natural gas transportation to ensure energy production is available when needed and capacity will be accredited by SPP and includes these costs in modeling. These resources, while not zero-emitting, still offer considerable carbon emissions reductions compared to coal resources. For Evergy's Future 3 modeling (High carbon restriction scenario), new natural gas (CT or CC) is assumed to become carbon-free in years beyond 2035, consistent with the expected technological innovation that would need to occur to achieve minimal emissions system-wide.

Costs modeled for all new resources in future years reflect the expectation of continued technology improvements over time, based on publicly available capital cost forecasts from the Energy Information Administration (EIA) and the National Renewable Energy Laboratory (NREL). The cost curves available in these forecasts were averaged and applied to the near-term capital costs.

3.3 CAPITAL PLAN UPDATE FROM THE 2021 TRIENNIAL IRP

Evergy continues to utilize a combination of condition-based planning, operating estimates, and industry expertise when formulating a 20-year capital plan for each unit in the generation fleet. Near term budgeting is based on equipment condition based on advanced pattern recognition (APR) models along with routine predictive maintenance and visual inspections. Long term budgeting is dictated by historical condition of the units along with industry and original equipment manufacturer (OEM) guidance.   When possible, individual unit outages are spread out to avoid the risk of a generation capacity deficiency and some maintenance cycles may be altered by up to a year.

3.4 ENVIRONMENTAL REGULATION CHANGES FROM THE 2021 TRIENNIAL IRP

Material changes from 2022 are shown in italics.

3.4.1 AIR EMISSION IMPACTS

3.4.1.1 National Ambient Air Quality Standards

The Clean Air Act (CAA) requires the Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) for six air pollutants which are considered harmful to public health and the environment. These pollutants include particulate matter (PM), ozone, sulfur dioxides (SO_2), nitrogen dioxide (NO_x), carbon monoxide (CO) and Lead (Pb). Following is a brief description and current state of each NAAQS.

3.4.1.2 Particulate Matter

In 2012, the EPA strengthened the PM standard and maintained the same requirements in a 2020 final action. The Kansas City area is currently in attainment of the PM NAAQS. No additional emission control equipment is currently needed to comply with this standard. It is not known whether the Kansas City area will remain in attainment of a future revision of the standard. *In January 2023, the EPA proposed strengthening the primary annual PM2.5 (particulate matter less than 2.5 microns in diameter) NAAQS. The EPA is proposing to lower the primary annual PM2.5 NAAQS from 12.0 µg/m3 (micrograms per cubic meter) to a level that would be between 9.0 and 10.0 µg/m3. The EPA is proposing to retain the other PM NAAQS at their current levels*. Future non-attainment of revised standards could require additional reduction technologies, emission limits, or both on fossil-fueled units.

3.4.1.3 Ozone

In 2015, the EPA strengthened the NAAQS for ozone and maintained the same requirement in a 2020 final action. The Kansas City area is currently in attainment of the ozone NAAQS. No additional emission control equipment is currently needed to comply with this standard. *In March 2023, the EPA released a revised draft Policy Assessment for Reconsideration of the Ozone NAAQS recommending the EPA retain the current 2015 Ozone NAAQS. EPA anticipates issuing a proposed decision in the reconsideration of the ozone NAAQS in 2024.* Future non-attainment of revised standards could result in regulations requiring additional nitrogen oxides (NOx) reduction technologies, emission limits or both on fossil-fueled units. NOx is considered a precursor pollutant for ozone formation.

3.4.1.4 <u>Sulfur Dioxide</u>

In 2010, the EPA strengthened the NAAQS for SO_2 and maintained the same requirement in a 2019 final action. The Kansas City area is currently in attainment of the SO_2 NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional SO_2 reduction technologies, emission limits or both on fossil-fueled units.

3.4.1.5 <u>Carbon Monoxide</u>

In 2011, the EPA maintained the existing 1971 NAAQS for CO. The Kansas City area is currently in attainment of the CO NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional CO reduction technologies, emission limits or both on fossil-fueled units.

3.4.1.6 <u>Lead</u>

In 2016, the EPA maintained the existing 2008 NAAQS for Lead (Pb). The Kansas City area is currently in attainment of the Pb NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional Pb reduction technologies, emission limits or both on fossil-fueled units.

3.4.1.7 <u>Cross-State Air Pollution Rule</u>

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR), requiring eastern and central states to significantly reduce power plant emissions that cross state lines and contribute to ozone and fine particle pollution in downwind states. The CSAPR Update Rule took effect in 2017 with more stringent ozone-season NO_x emission budgets for electric generating units (EGUs) in many states to address significant contribution to modeling nonattainment and maintenance areas in downwind states with respect to the 2008 ozone NAAQS. In 2021 EPA published the final Revised CSAPR Update rule which found that nine states including Kansas, Missouri, and Oklahoma have insignificant impact on downwind states' nonattainment and/or maintenance areas. As a result, no additional reductions in these states' allowances were required.

When EPA lowered the Ozone NAAQS in 2015, impacted states were required to submit Interstate Transport State Implementation Plans (ITSIPs) to address the "Good Neighbor" obligations in the Clean Air Act. These ITSIPs were due to EPA in 2018. The EPA did not act on these submissions and was challenged in a court filing in May 2021 to address them. In February 2022, the EPA published proposed disapprovals of ITSIPs for nineteen states including Missouri while in April 2022, EPA issued final approval of the Kansas ITSIP.

In April 2022, the EPA published in the Federal Register a proposed Federal Implementation Plan (FIP) to resolve the outstanding "Good Neighbor" obligations with respect to the 2015 Ozone NAAQS for 26 states including Missouri and Oklahoma. This FIP would establish a revised CSAPR ozone season NOx emissions trading program for electric generating units, a new daily backstop NOx limit for applicable coal-fired units larger than 100MW, and unit-specific NOx emission rate limits for certain industrial emissions units. The proposed FIP includes reductions to the state ozone season NOx allowance allocations for Missouri and Oklahoma beginning in 2023 *with additional reductions in future years. In March 2023, the EPA issued the final ITFIPs for twenty-three states, including Missouri and Oklahoma*. The Company currently complies with the existing CSAPR regulations through a combination of trading allowances within or outside its system in addition to changes in operations as necessary. Future, strengthened ozone, PM, or SO_2 standards could result in additional CSAPR updates requiring additional procurement of allowances, emission reduction technologies or reduced generation on fossil-fueled units.

3.4.1.8 Regional Haze

In June 2005, the EPA finalized amendments to the July 1999 Regional Haze Rule. These amendments apply to the provisions of the Regional Haze Rule that require emission controls for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. The pollutants that reduce visibility include $PM_{2.5}$, and compounds which contribute to $PM_{2.5}$ formation, such as NO_x, and SO_2.

Under the 1999 Regional Haze Rule, states are required to set periodic goals for improving visibility in natural areas. As states work to reach these goals, they must periodically develop regional haze implementation plans that contain enforceable measures and strategies for reducing visibility-impairing pollution. The Regional Haze Rule directs state air quality agencies to identify whether visibility-reducing emissions from affected sources are below limits set by the state or whether retrofit measures are needed to reduce emissions.

States must submit revisions to their Regional Haze Rule SIPs every ten years and the first round was due in 2007. For the second ten-year implementation period, the EPA issued a final rule revision in 2017 that allowed states to submit their SIP revisions by July 31, 2021. Evergy worked with the Kansas Department of Health and Environmental (KDHE) and the Missouri Department of Natural Resources (MDNR) as they worked to draft their SIP revisions. *MDNR submitted the Missouri SIP revision to the EPA in August 2022, however, they failed to do so by the EPA's revised submittal deadline of August 15, 2022. As a result, on August 30, 2022, the EPA published "finding of failure" with respect to Missouri and fourteen other states for failing to submit their Regional Haze SIP revisions* *by the applicable deadline. This finding of failure established a two-year deadline for the EPA to issue a Regional Haze federal implementation plan (FIP) for each state unless the state submits and the EPA approves a revised SIP that meets all applicable requirements before the EPA issues the FIP.* MDNR shared a draft of this SIP revision in March 2022 which does not require any additional reductions from the Evergy generating units in the state. The Kansas SIP revision was placed on public notice in June 2021 and requested no additional emission reductions by electric utilities based on the significant reductions that were achieved during the first implementation period. KDHE submitted the Kansas SIP revision in July 2021. EPA is waiting for additional states to submit their SIP revisions before they review and either approve or disapprove these SIP revisions. *In March 2023, several environmental organizations notified the EPA of their intent to sue for failure of the EPA to timely approve or disapprove of the SIP revisions submitted by Kansas and seven other states.*

Evergy Missouri West's existing emission controls at its Jeffrey and Iatan Generating Stations maintain compliance with these requirements. Future visibility progress goals will likely result in additional SO_2, NO_x and PM controls or reduction technologies on fossil-fired units. This assumption led to the inclusion of selective catalytic reduction (SCR) systems in the future capital plan for Jeffrey unit 2 and unit 3. Jeffrey unit 1 already has an SCR installed and in service. The timeline selected for these projects is based on EPA's next Regional Haze planning period which will occur in 2028. It is assumed that a compliance timeline would be agreed upon at that time which would allow the SCRs to be online by the end of 2032 for one unit and 2033 for the other.

3.4.1.9 Greenhouse Gases

In May 2023, the EPA proposed CO2 emission limits and guidelines for fossil fuel fired electric generating units. The proposal regulations would impose CO_2 emission limitations for existing coal, oil and natural gas-fired boilers, existing large natural gas fired combined cycle combustion turbines and new natural gas fired simple and combined cycle combustion turbines. EPA established these *proposed emission limitations based on utilizing such technologies as hydrogen co-firing with natural gas, and carbon capture and sequestration (CCS). It is highly likely this proposed regulation will face administrative and legal challenges prior to finalization. However, this regulation* could require *hydrogen co-firing with natural gas*, *natural gas co-firing with coal, reduced generation, carbon capture and sequestration, alternate generation, or demand reduction technologies.*

3.4.1.10 Mercury and Air Toxics Standards

In April 2023, the EPA released a proposal to tighten certain aspects of the mercury and air toxics standards (*MATS) rule. The EPA is proposing to lower the emission limit for particulate matter (PM), require the use of PM continuous emissions monitors (CEMS) and lower the mercury emission limit for lignite coal-fired electric generating units (EGUs). The EPA is also soliciting comment on further strengthening of the PM emission limitation beyond the proposal*. *When implemented in 2016*, these mercury and air toxics standards (MATS) for power plants reduced emissions from new and existing coal and oil-fired electric generating units (EGUs). Control equipment was installed to comply with this rule. No additional emission control equipment is currently needed to comply with the current *or proposed* standards. *However, further strengthening of the PM emission limitation could require* Evergy Missouri West to *consider additional PM controls* at the Jeffrey Energy Center.

3.4.2 WATER EMISSION IMPACTS

3.4.2.1 Effluent Limitation Guidelines (ELG)

In 2015, EPA established the effluent limitations guidelines (ELG) and standards for wastewater discharges, including limits on the amount of toxic metals and other pollutants that can be discharged. Implementation timelines for this 2015 rule varied from 2018 to 2023. In April 2019, the U.S. Court of Appeals for the 5th Circuit (5th Circuit) issued a ruling that vacated and remanded portions of the original ELG rule.

In October 2020, the EPA published the final ELG Reconsideration Rule. This rule adjusts numeric limits for flue gas desulfurization (FGD) wastewater and adds a 10% volumetric purge limit for bottom ash transport water. The timeline for final FGD wastewater compliance is now as soon as possible on or after one year following publication of the final rule in the federal register but no later than December 31, 2025. *On July 26, 2021, EPA initiated a supplemental rulemaking to strengthen certain discharge limits in the ELG regulation. EPA proposed this supplemental rulemaking on March 29, 2023. In the 2023 proposal EPA removes the 10% volumetric purge allowance on bottom ash wastewater and proposes zero liquid discharge for both FGD wastewater and bottom ash wastewater. In addition, the proposal established new discharge limitations for coal combustion residual (CCR) leachate. Compliance with these new limitations must be as soon as feasible no later than December 31, 2029.* Evergy is currently in compliance with this regulation, and intends any required upgrades to be in place prior to the 2029 deadline.

3.4.2.2 Clean Water Act Section 316(A)

Evergy's river plants comply with the calculated limits defined in the current permits. *Hawthorn and Iatan Generating Stations' water discharge permits issued February 1, 2022 and April 1, 2023, respectively, contain future thermal discharge limits that become effective no later than February 1, 2032. The compliance period will be utilized by Evergy to study both discharge conditions and conditions of the receiving river to finalize compliance plans.* Application of these future limitations or future regulations that could be issued that restrict the thermal discharges may require alternative cooling technologies to be installed at coal-fired units using once through cooling, a reduction or shutdown of certain plants during periods of high river water temperature, or application of a thermal variance process.

3.4.2.3 Clean Water Act Section 316(B)

In May 2014, the EPA finalized standards to reduce the injury and death of fish and other aquatic life caused by cooling water intake structures at power plants and factories. The rule could require modifications to cooling water inlet screens and fish return systems.

3.4.2.4 Zebra Mussel Infestation

Evergy monitors for zebra mussels at generation facilities, and a significant infestation could cause operational changes to the stations.

3.4.2.5 Total Maximum Daily Loads

A Total Maximum Daily Load (TMDL) is a calculation of the maximum amount of a given pollutant that a body of water can absorb before its quality is impacted. A stream is considered impaired if it fails to meet Water Quality Standards established by the Clean Water Commission. Future TMDL standards could restrict discharges and require equipment to be installed to minimize or control the discharge.

3.4.3 WASTE MATERIAL IMPACTS

3.4.3.1 Coal Combustion Residuals (CCR’s)

In April 2015, the EPA finalized regulations to regulate CCRs under the Resource Conservation and Recovery Act (RCRA) subtitle D to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The rule requires periodic assessments; groundwater monitoring; location restrictions; design and operating requirements; recordkeeping and notifications; and closure, among other requirements, for CCR units.

In March 2019, the D.C. Circuit issued a ruling to grant the EPA's request to remand the Phase I, Part I CCR rule in response to a prior court ruling requiring the EPA to address un-lined surface impoundment closure requirements. In August 2020, the EPA published the Part A CCR Rule. This rule reclassified clay-lined surface impoundments from "lined" to "un-lined" and established a deadline of April 11, 2021 to initiate closure. In November 2020, the EPA published the final Part B CCR Rule. This rule includes a process to allow unlined impoundments to continue to operate if a demonstration is made to prove that the unlined impoundments are not adversely impacting groundwater, human health, or the environment. Evergy Missouri West is in compliance with the Part A CCR rule which included initiating closure of all unlined impoundments by the deadline of April 11, 2021.

In January 2022, EPA published proposed determinations for facilities that filed closure extensions for unlined or clay lined CCR units. These proposed determinations include various interpretations of the CCR regulations and compliance expectations that may impact all owners of CCR units. These interpretations could require modified compliance plans such as different methods of CCR unit closure. Additionally, it includes more stringent remediation requirements for units that are in corrective action or forced to go into corrective action. Future rule modifications could require additional monitoring or remediation of current or closed impoundments and landfills along with additional requirements related to design and construction of future units to more stringent standards.

In May 2023, EPA released a proposed rulemaking on legacy CCR units. This regulation, if finalized, will expand the number of CCR units subject to regulation under the Federal CCR rule. Future rule modifications could require additional monitoring or remediation of current or closed impoundments and landfills along with additional requirements related to design and construction of future units to more stringent standards.

SECTION 6: INTEGRATED RESOURCE PLAN AND RISK ANALYSIS UPDATE

6.1 CHANGES FROM THE 2021 TRIENNIAL IRP

Evergy Missouri West submitted its 2021 Triennial IRP filing on April 30, 2021, updated its resource plan on June 10, 2022, with its 2022 IRP Annual Update filing, and filed a Change in Plan Filing on September 26, 2022. This year's 2023 IRP Annual Update reflects updated information and forecasts based on market and policy changes and additional studies that have occurred in the past year.

Changes from the 2021 Triennial IRP, 2022 Annual Update, and 2022 Change in Plan filing:

- Updated market pricing reflecting latest SPP transmission planning model assumptions of future resource mix and potential transmission congestion
- Updated fuel price forecasts, including high, mid, and low natural gas price scenarios
- Carbon Dioxide emissions limitations scenarios reflecting future environmental risks, including high, mid, and low (no) restrictions
- Updated cost estimates and timing assumptions for resource additions based on First Quarter 2023 Request for Proposal (RFP) results
- Modeling of battery storage and hybrid resources as supply-side options
- Inclusion of incentives for new renewable and storage resources based on Inflation Reduction Act
- Updated load forecasts including large new customers in both Missouri and Kansas, and considerations for future large customer growth based on existing economic development pipeline
- Updated demand response potential study, including four Missouri program options
- Included possible reductions in peak demand from Missouri Commission-ordered mandatory time of use rates

- Updated planning reserve margin consistent with SPP rule changes enacted in 2022
- Increased focus on planning for utility-level (as opposed to Evergy-level) resource needs to better identify each utility's specific energy and capacity needs in the future, reduced level of assumed market availability (for both capacity and energy) and reliance on other Evergy affiliates to meet long-term customer needs
- Removal of Persimmon Creek wind farm due to not executing under the Commission ordered Certificate of Convenience and Necessity with conditions
- Expanded use of PLEXOS software for production cost modeling and capacity expansion, which was first implemented for 2022 IRP
- Annual refresh of data for existing generators (Capital and Operations & Maintenance costs)

6.2 ALTERNATIVE RESOURCE PLAN DEVELOPMENT

6.2.1 CAPACITY EXPANSION PLANNING

Capacity expansion planning involves using a long-term wholesale market simulation model (Missouri West utilizes PLEXOS) which is designed to generate the lowest-cost resource plan given a set of resource options, a given market scenario (e.g., natural gas prices, wholesale energy prices, emissions constraints), and a forecasted capacity requirement (i.e., forecasted load plus planning reserve margin). Missouri West's goal in this Annual Update was to use Capacity Expansion to the fullest extent practical in selecting the lowest-cost resource additions. To that end, no supply-side resource additions were "hard-coded" into pre-made resource plans for the purpose of arriving at Missouri West's Preferred Plan. The only portion of the Alternative Resource Plans used in this filing which were manually tested were plant retirements and demand-side management portfolio additions. This makes it easier to compare different options side-by-side to see what trade-offs may exist between decisions. Even in testing these decisions, however, Capacity Expansion was still used to develop the lowest-cost portfolio of supply-side resources (e.g., if a higher level of DSM was assumed, then Capacity Expansion would build less resources as part of the optimized resource plan). This approach makes comparison somewhat more complicated than the past approach where plans could be compared on a truly apples-to-apples basis (i.e., because only one item in the whole plan changed and thus the difference in cost between the two plans is driven specifically by that one item), but it also more accurately depicts the integrated nature of resource planning, where every decision has an impact on future decisions and a portfolio should be viewed holistically as opposed to looking at an individual decision in a vacuum.

Unless otherwise noted in the description of the Modeling Approach below, capacity expansion modeling was performed using the “Mid-Mid-Mid” endpoint, based on the Mid natural gas price forecast, Mid load forecast, and Mid level of carbon restrictions (based on SPP Future 2 model as described in 3.1.4). This was, again to provide easier comparisons between resource plans because a capacity expansion model will often generate different resource plans in different market scenarios. Evergy believes this approach provides a viable assessment of our current “base” expectations and that using these capacity expansion results, with revenue requirements for these Alternative Resource Plans calculated across all 27 endpoints, enables a robust analysis of these “base-case” Alternative Resource Plans across a wide variety of potential future scenarios.

For this year’s Annual Update, the supply-side options available for selection by Missouri West in each year are outlined below. In each year, the model could select up to the number of megawatts listed in the table below by selecting “projects” of that resource type. The capacity and cost of each resource type are included in Table 9. In any given year, resource additions were constrained to only one “project” per year based on Missouri West’s assumed ability to finance these additions. This assumption also ensures that resources are added ratably over time as opposed to being stacked in one year, to drive more stable rate impacts over time. As an example, in 2027, capacity expansion could select *either* 150 MW of wind, 150 MW of battery storage, 150 MW of solar-storage hybrid, *or* 150 MW of solar. In 2028, it could select any of those options *or* a 260 MW combined cycle (based on an assumed ½ combined cycle project, on the assumption that CC builds can likely be shared across jurisdictions to drive economies of scale) *or* a 238 MW combustion turbine. The phased in availability of options in the table below is based on Request for Proposal responses (e.g., no solar projects received in the RFP had in-service dates before end-of-year 2026 and thus solar was not available for capacity expansion until 2027) or expected construction timeline (i.e., five years is currently the expected shortest time required to build new natural gas resources given SPP interconnection queue delays and permitting / construction timelines).

Table 21: Missouri West Builds Available (MW)

Resource	2024	2025	2026	2027	2028	2034	2039
Wind			150	150	150	150	150
Solar			150	150	150	150	150
Battery			150	150	150	150	150
Solar Hybrid						267	
Combined Cycle					260	260	260
Combustion Turbine					476	476	476
Dogwood CC	143						

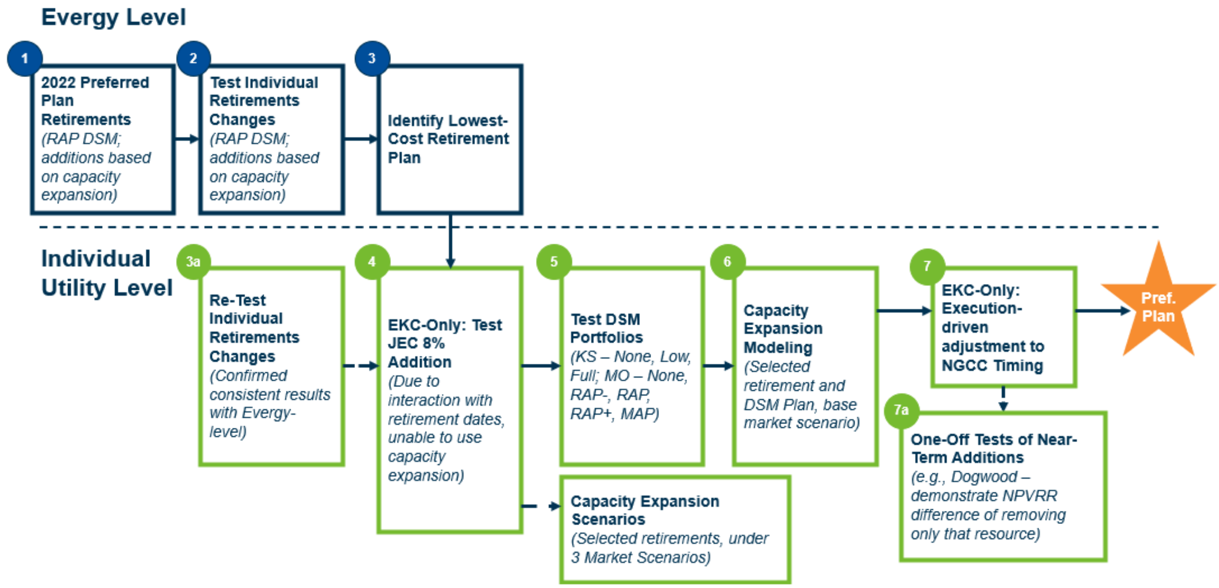
Note: Each year shown represents the MW available by resource type in that year and following years until the next year shown in the table, which represents updated constraints

6.2.2 OVERALL MODELING APPROACH

As described previously, the updated modeling approach for the 2023 Annual Update focused primarily on performing capacity expansion planning at the individual utility level (as opposed to the Evergy level) to ensure a targeted assessment of each utility's customers' energy and capacity needs. However, due to the large number of co-owned coal units in Evergy's portfolio, potential plant retirement options were tested at the Evergy level first before moving to the individual utility level. From there, these retirements were re-tested at the individual utility level, different demand-side management portfolios were compared, capacity expansion was performed in a "High" scenario (high natural gas prices, high carbon restriction) and "Low" scenario (low natural gas prices, no carbon restriction), and ultimately a Preferred Plan was generated using the selected plant retirement plan, selected DSM portfolio, and with capacity expansion-generated supply-side resource additions. In order to ease comparison of resource plans, particularly as it relates to near-term decisions (e.g., addition of a share of the Dogwood Combined Cycle plan), additional plans were created where that resource addition was removed as a capacity expansion option and a new lowest-cost plan was generated. As a result, the Preferred Plan can then be compared to this new plan to show the cost savings created by that specific decision.

Given this process is very different from the process used in past IRPs, and in order to make the process more transparent, the results outlined below will be described in the various stages outlined in the graphic below.

Figure 20: High-Level Modeling Approach



6.3 EVERGY-LEVEL RETIREMENT ANALYSIS

As described above, Evergy-level modeling was used to determine whether changing the coal retirements from the 2022 Preferred Plan could result in lower NPVRR. This analysis was performed primarily at the Evergy level (as opposed to the Missouri West level) due to the number of jointly-owned units in Evergy's portfolio. However, additional testing was performed at the individual utility level to ensure any change in retirements at the Evergy level was also beneficial or approximately neutral for the individual utilities (results described below).

Table 22: Evergy Joint Planning Alternative Resource Plan Naming Convention

Demand-Side Management Potential	Early Retirements	Coal to NG	Other
B. RAP MO, No DSM KS	A. None (2021/22 Preferred Plan)	A. Lawrence 5 to NG 2024	A. None
J. MAP MO, Full DSM KS	B. Extend Lawrence 4 & 5 to 2028	B. Lawrence 5 to NG 2029	D. High/High
	C. Jeffrey 2 Retires 2030	C. Hawthorn 5 to NG 2027	E. Low/Low
	D. Iatan 1 Retires 2030	D. Jeffrey 3 to NG 2030	F. Only Renewable/Storage Build
	E. Hawthorn 5 Retires 2027	E. Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039	N. No Major Environmental Costs
	F. LaCygne 2 Retires 2032		
	G. Jeffrey 1 & 2 Retire 2030		
	H. Extend Lawrence 4 & 5 to 2028, Extend all others past 2042		
	I. Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030		
	J. All Earliest Retirements		
	K. Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039		
	L. Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039, Iatan 1 Retires 2030, LaCygne 2 Retires 2032		

Note: Letters which are excluded from naming convention above (e.g., "A" Demand Response Potential) were used in IRP development for one or more utilities but not used at the Evergy Joint Planning level.

Table 23: Overview of Joint-Planning Resource Plans

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy BAAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2034 150 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2031 300 MW Solar 2033 150 MW Solar 2041		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CT (238 MW) in 2039 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BACA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 K Hawthorn5: Dec 31, 2026 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 150 MW Wind 2035 450 MW Wind 2041 450 MW Wind 2042	150 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2031		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Coal to NG (375 MW) in 2027 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CT (238 MW) in 2039 2 CC (1041 MW) in 2039 3 CC (1,562 MW) in 2040
Evergy BADA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2029 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 450 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2035 450 MW Wind 2042	150 MW Solar 2028 450 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2031 150 MW Solar 2035 300 MW Solar 2041		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Jeffrey 3 NG (727 MW) in 2030 1 CC (521 MW) in 2037 1 CC (521 MW) in 2038 1 CC (521 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BAEA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: December 31, 2029 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 2: December 31, 2038 Iatan 1: Dec 31, 2039 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2041 450 MW Wind 2042	150 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2031 450 MW Solar 2035		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Jeffrey 3 NG (727 MW) in 2030 1 CC (521 MW) in 2037 1 CC (521 MW) in 2038 1 CC (521 MW) in 2039 Jeffrey 2 NG (730 MW) in 2039 2 CC (1041 MW) in 2040

Table 24: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy BBBA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2034 150 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2031 300 MW Solar 2033 150 MW Solar 2041		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CT (238 MW) in 2039 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BCAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 2&3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 450 MW Wind 2041 450 MW Wind 2042	450 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2031 150 MW Solar 2040		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 2 CC (1041 MW) in 2039 2 CC (1041 MW) in 2040
Evergy BDAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Iatan 1: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1&2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2031 150 MW Solar 2035		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CT (238 MW) in 2036 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BEAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Hawthorn 5: December 31, 2027 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1&2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 450 MW Wind 2034 150 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	150 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2031 150 MW Solar 2041	150 MW Hybrid-Solar 2033 117 MW Hybrid-Battery 2033	Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2028 1 CC (521 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2038 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BFAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2031 150 MW Wind 2032 450 MW Wind 2034 300 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2032 150 MW Solar 2035		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 1 CT (238 MW) in 2032 2 CC (1041 MW) in 2033 1 CT (238 MW) in 2036 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040

Table 25: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy BGAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 1, 2, & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2035 450 MW Wind 2041 450 MW Wind 2042	600 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2032 150 MW Solar 2040		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 3 CT (714 MW) in 2031 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CC (521 MW) in 2039 2 CC (1041 MW) in 2040
Evergy BHAA	RAP MO, No DSM KS;	Lawrence 4: Dec 31, 2028 Lawrence 5 Coal: Dec 31, 2028 Lake Road 4/6: Dec 31, 2030	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2029 450 MW Wind 2030 450 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2042	150 MW Solar 2029 600 MW Solar 2035 750 MW Solar 2041		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2037 2 CC (1041 MW) in 2039 1 CC (521 MW) in 2040 1 CC (521 MW) in 2042
Evergy BIBA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 450 MW Wind 2041 450 MW Wind 2042	450 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2031 150 MW Solar 2040		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2031 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 2 CC (1041 MW) in 2039 2 CC (1041 MW) in 2040
Evergy BIBD	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2026 450 MW Wind 2030 450 MW Wind 2032 450 MW Wind 2034 450 MW Wind 2035	600 MW Solar 2027 600 MW Solar 2028 600 MW Solar 2029 300 MW Solar 2031	150 MW Hybrid-Solar 2033 117 MW Hybrid-Battery 2033	Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2031 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CC (521 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BIBE	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1 & 2: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039		150 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2032 300 MW Solar 2033 150 MW Solar 2034		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2031 2 CT (476 MW) in 2031 1 CC (521 MW) in 2033 1 CT (238 MW) in 2036 1 CT (238 MW) in 2037 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040

Table 26: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy JEAF	MAP MO, Full DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Hawthorn 5: Dec 31, 2027 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2032 3000 MW Wind 2032	1200 MW Solar 2028 750 MW Solar 2031 150 MW Solar 2033 150 MW Solar 2040	1200 MW Hybrid-Solar 2033 936 MW Hybrid-Battery 2033 750 MW Battery-Gen 2039 1500 MW Battery-Wind 2039 900 MW Battery-Gen 2040	Lawrence 5 NG (338 MW) in 2024
Evergy JJAF	MAP MO, Full DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Hawthorn 5: Dec 31, 2025 Jeffrey 1, 2, & 3: Dec 31, 2030 LaCygne 1 & 2: Dec 31, 2030 Iatan 1 & 2: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030	199 MW Persimmon Wind 2023 200 MW Wind 2025 2250 MW Wind 2026 2400 MW Wind 2033	150 MW Solar 2026 1800 MW Solar 2031	150 MW Battery-Gen 2026 150 MW Battery-Wind 2026 150 MW Battery-Wind 2028 1200 MW Battery-Gen 2030 1500 MW Battery Wind 2030 1500 MW Hybrid-Solar 2030 1170 MW Hybrid-Battery 2030 150 MW Hybrid-Solar 2032 117 MW Hybrid-Battery 2032 150 MW Hybrid-Solar 2033 117 MW Hybrid-Battery 2033	Lawrence 5 NG (338 MW) in 2024

Note: For these modeled resource plans, Dogwood and Jeffrey 8% were assumed to be in place in all plans with capacity expansion used to solve for all other resource additions. Because this modeling is being used only to assess which retirement changes reduce costs, these decisions around builds are not critical (as long as the approach used for all retirements is consistent). The evaluation of resource additions for the ultimate Preferred Plan occurred at the individual utility level and did not include any hardcoded resource additions (Section 6.6).

6.4 REVENUE REQUIREMENT – EVERGY-LEVEL RETIREMENT ANALYSIS

For each of the Alternative Resource Plans developed, integrated analysis yielded an expected value of the Net Present Value of Revenue Requirement shown in Table 26 below.

These results, along with the by-scenario results in Section 6.5, indicate that an earlier retirement of Jeffrey Unit 2 in 2030, as well as a delay of the Lawrence Unit 4 retirement and Lawrence Unit 5 transition to natural gas, is more economic than the 2022 Preferred Plan. Based on this, and supported by Missouri West-level modeling below, the 2023 Preferred Plan for Missouri West includes the retirement of its portion of Jeffrey Unit 2 in 2030. There is still significant uncertainty around different environmental regulations which could drive the retirement of Jeffrey Unit 2 or a different Evergy coal unit and thus Jeffrey Unit 2 still remains a “placeholder” for an accelerated retirement. However, given recent regulation released by the Environmental Protection Agency (EPA), it seems more probable that all units would need to install Best Available Control Technology in order to continue operating beyond the early 2030s. Given Jeffrey Units 2 and 3 are the only large units in Evergy’s fleet without Selective Catalytic Reduction (SCR) systems, the capital forecasts used in this IRP (and prior IRPs) assume that SCRs would need to be added if the units do not retire by 2031. This large capital cost to continue operations make these units the most attractive options for early retirement.

Table 27: Joint-Planning Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBA	62,248		Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
2	BCAA	62,295	47	Jeffrey 2 Retires 2030
3	BBBA	62,382	135	Extend Lawrence 4 & 5 to 2028
4	BAAA	62,430	182	2021/22 Preferred Plan
5	BIBD	62,449	201	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High
6	BDAA	62,604	356	Iatan 1 Retires 2030
7	BGAA	62,608	360	Jeffrey 1 & 2 Retire 2030
**8	[redacted]	[redacted]	[redacted]	[redacted]**
9	BADA	62,707	459	Jeffrey 3 to NG 2030
10	BACA	62,742	494	Hawthorn 5 to NG 2027
11	BAEA	62,753	505	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
12	BEAA	62,757	510	Hawthorn 5 Retires 2027
13	BHAA	62,778	531	Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
14	BIBE	64,405	2,157	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low

6.5 BY-SCENARIO RESULTS – EVERGY-LEVEL RETIREMENT ANALYSIS

Table 27, Table 28, and Table 29 show the expected value of NPVRR for the joint plans assuming high, mid, and low CO_2 restrictions.

Table 28: Joint Plan Results - High CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBD	62,747		Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High
2	BIBA	62,917	170	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
3	BCAA	62,942	196	Jeffrey 2 Retires 2030
4	BGAA	63,236	490	Jeffrey 1 & 2 Retire 2030
5	BBBA	63,580	833	Extend Lawrence 4 & 5 to 2028
6	BDAA	63,595	848	Iatan 1 Retires 2030
7	BAAA	63,605	859	2021/22 Preferred Plan
** [redacted]		[redacted]	[redacted]	[redacted] **
9	BACA	63,819	1,073	Hawthorn 5 to NG 2027
10	BEAA	63,946	1,199	Hawthorn 5 Retires 2027
11	BADA	64,455	1,709	Jeffrey 3 to NG 2030
12	BAEA	64,601	1,855	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
13	BHAA	65,208	2,462	Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
14	BIBE	66,941	4,195	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low

Table 29: Joint Plan Results - Mid-CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBA	62,174		Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
2	BBBA	62,184	10	Extend Lawrence 4 & 5 to 2028
3	BCAA	62,226	52	Jeffrey 2 Retires 2030
4	BAAA	62,236	62	2021/22 Preferred Plan
5	BADA	62,366	192	Jeffrey 3 to NG 2030
6	BHAA	62,368	194	Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
7	BAEA	62,384	210	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
8	BIBD	62,417	243	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High
9	BDAA	62,445	271	Iatan 1 Retires 2030
** [redacted]		[redacted]	[redacted]	[redacted] **
11	BGAA	62,522	348	Jeffrey 1 & 2 Retire 2030
12	BEAA	62,534	361	Hawthorn 5 Retires 2027
13	BACA	62,553	379	Hawthorn 5 to NG 2027
14	BIBE	64,500	2,327	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low

Table 30: Joint Plan Results - No CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BHAA	61,580		Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
2	BIBE	61,583	3	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low
3	BBBA	61,781	201	Extend Lawrence 4 & 5 to 2028
4	BIBA	61,800	220	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
5	BAAA	61,835	255	2021/22 Preferred Plan
6	BCAA	61,854	274	Jeffrey 2 Retires 2030
7	BADA	61,982	402	Jeffrey 3 to NG 2030
8	BAEA	62,011	431	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
9	BDAA	62,090	510	Iatan 1 Retires 2030
** [redacted]		[redacted]	[redacted]	[redacted] *
11	BACA	62,233	653	Hawthorn 5 to NG 2027
12	BGAA	62,237	657	Jeffrey 1 & 2 Retire 2030
13	BEAA	62,238	658	Hawthorn 5 Retires 2027
14	BIBD	62,247	667	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High

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6.6 EVERGY MISSOURI WEST RESOURCE PLANS

To make results clearer given the increased use of capacity expansion modeling in this IRP, Missouri West analysis will be divided into 5 sections, which ultimately culminate in the creation of 18 Alternative Resource Plans.

- Testing retirement options to ensure alignment with Evergy-level analysis
- Evaluation of Capacity Expansion sensitivities (perform capacity expansion under different market price scenarios to supplement "Base" modeling)
- Testing DSM portfolio levels to identify lowest-cost option
- Preferred Plan development using Capacity Expansion modeling
- Incremental tests of near-term decisions (e.g., Dogwood addition) to assess robustness across scenarios and impact on NPVRR

Supply-side resource additions were not an input into any of these Alternative Resource Plans. All additions were selected using capacity expansion modeling subject to the constraints denoted by the "Other" column above.

Table 31: Evergy Missouri West Alternative Resource Plan Naming Convention

Demand-Side Management Potential	Early Retirements	Coal to NG	Other
A. RAP	A. None (2021/22 Preferred Plan)	A. None	A. None
C. MAP	C. Jeffrey 2 Retires 2030		B. No Wind
E. RAP+	D. Iatan 1 Retires 2030		C. No Dogwood
G. RAP-	G. Jeffrey 1 & 2 Retire 2030		D. High/High
M. No DSM			E. Low/Low
			O. No New Renewable/Storage Builds

Table 32: Evergy Missouri West Alternative Resource Plan Overview

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Missouri West AAAA	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2027 150 MW Solar 2029		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2040
Missouri West AAAB	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039		150 MW Solar 2027 150 MW Solar 2029 150 MW Solar 2030 150 MW Solar 2031 150 MW Solar 2032 150 MW Solar 2033 150 MW Solar 2034 150 MW Solar 2035 150 MW Solar 2041 150 MW Solar 2042		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040
Missouri West AAAC	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2028 150 MW Solar 2035 150 MW Solar 2041 150 MW Solar 2042	150 MW Battery-Wind 2026	1/2 CC (260 MW) in 2029 1/2 CC (260 MW) in 2039
Missouri West ACAA	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2027 150 MW Solar 2029		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2040
Missouri West ACAC	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2027 150 MW Solar 2028 150 MW Solar 2041	150 MW Battery-Wind 2026	1/2 CC (260 MW) in 2029 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2042
Missouri West ACAD	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2026 150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2035	150 MW Solar 2027 150 MW Solar 2029		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2041

Table 33: Evergy Missouri West Alternative Resource Plan Overview (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Missouri West ACAE	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033	150 MW Solar 2027 150 MW Solar 2031		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2039
Missouri West ADAA	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2030	150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2026 150 MW Solar 2027 150 MW Solar 2041		1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2030 1/2 CC (260 MW) in 2040
Missouri West AGAA	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 1, 2 & 3: Dec 31, 2030 Iatan 1: Dec 31, 2039	150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2026 150 MW Solar 2027 150 MW Solar 2041		1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2030 1/2 CC (260 MW) in 2040
Missouri West CAAA	MAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2028		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2029 1/2 CC (260 MW) in 2040
Missouri West CCAA	MAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2028		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2029 1/2 CC (260 MW) in 2040
Missouri West EAAA	RAP+	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2027 150 MW Solar 2029 150 MW Solar 2042		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2040

Table 34: Evergy Missouri West Alternative Resource Plan Overview (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Missouri West ECAA	RAP+	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2027 150 MW Solar 2029 150 MW Solar 2042		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2040
Missouri West ECAO	RAP+	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039				Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2031 1/2 CC (260 MW) in 2036 1/2 CC (260 MW) in 2037
Missouri West GAAA	RAP-	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2026 150 MW Solar 2029 150 MW Solar 2040 150 MW Solar 2041		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2039
Missouri West GCAA	RAP-	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2028 150 MW Solar 2041	150 MW Battery-Wind 2026	Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2029 1/2 CC (260 MW) in 2039
Missouri West MAAA	No DSM	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2041	150 MW Solar 2027 150 MW Solar 2029 150 MW Solar 2042	150 MW Battery-Wind 2026 150 MW Battery-Wind 2033	Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2039
Missouri West MCAA	No DSM	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2029 150 MW Wind 2030 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2027 150 MW Solar 2041	150 MW Battery-Wind 2026	Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2031 1/2 CC (260 MW) in 2040

Refer to Appendix B, Capacity Balance Spreadsheets, for tables which provide the Missouri West forecast of capacity balance over the twenty-year planning period for each of the Alternative Resource Plans outlined above. These capacity forecasts include renewable and generation additions. The capacity for existing and new renewable facilities is based on expected accreditation under the Effective Load Carrying Capability methodology.

6.7 REVENUE REQUIREMENT – EVERGY MISSOURI WEST

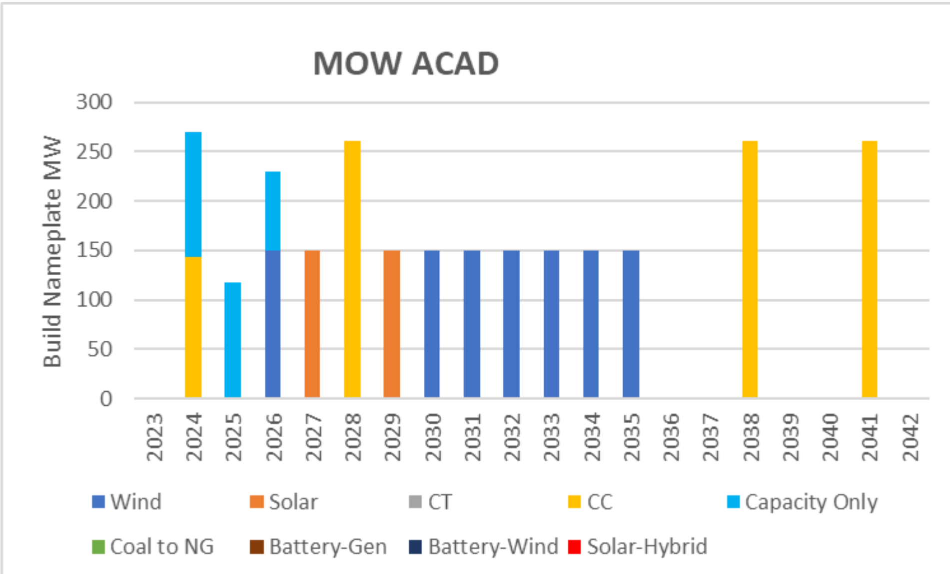
Table 35: Retirement Re-Testing
Evergy Missouri West Twenty-Year Net Present Value Revenue Requirement

Missouri West Retirement Rankings

Rank	Plan	NPVRR ($M)	Difference	Description
1	AGAA	10,858		RAP; Jeffrey 1 & 2 Retire 2030
2	ACAA	10,858	0	RAP; Jeffrey 2 Retires 2030
3	AAAA	10,954	96	RAP; 2021/2022 Preferred Plan
4	ADAA	11,004	146	RAP; Iatan 1 Retires 2030

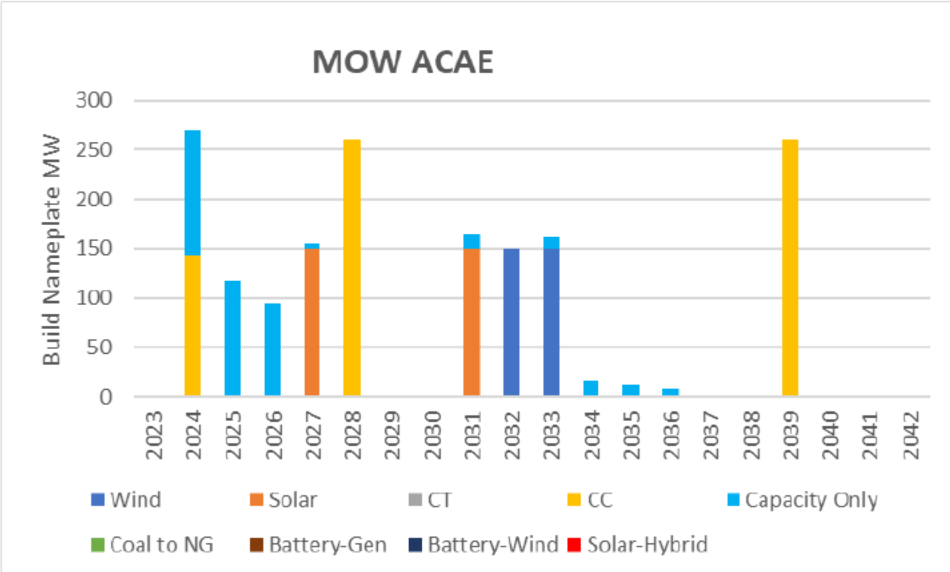
At the Missouri West level, retiring Jeffrey 2 reduces NPVRR by $96 million compared to the 2021/2022 Preferred Plan retirements. This plan is the same cost as the plan which also retires Jeffrey 1 (meaning that Missouri West's 8% share of Jeffrey 1, 2, and 3 would all be retired in 2030 given Jeffrey 3 is retiring in 2030 in the 2021/2022 Preferred Plan). The additional retirement of Jeffrey 1 is not economic at the Evergy level or for Evergy Kansas Central. Given Missouri West is a minority unit of Jeffrey Energy Center, the Jeffrey 1 retirement is not included in Missouri West's Preferred Plan at this time.

Figure 21: Capacity Expansion "High" Scenario Supply-Side Additions



Capacity expansion modeling performed specifically in the High Gas – High Carbon Restriction ("High/High" or "High") scenario shows an increased level of wind builds compared to the Preferred Plan given the increased value of zero-carbon energy in a heavily carbon-restricted market. Despite high gas prices and carbon restrictions, capacity expansion also selects Dogwood in 2024 and builds additional Combined Cycle plants in 2028, 2038, and 2041 as part of the lowest-cost plan. In this scenario, new Combined Cycle resources (excludes Dogwood) are assumed to transition to non-emitting operations beyond 2035. Dogwood is assumed to emit carbon based on current parameters throughout the timeframe.

Figure 22: Capacity Expansion "Low" Scenario Supply-Side Additions



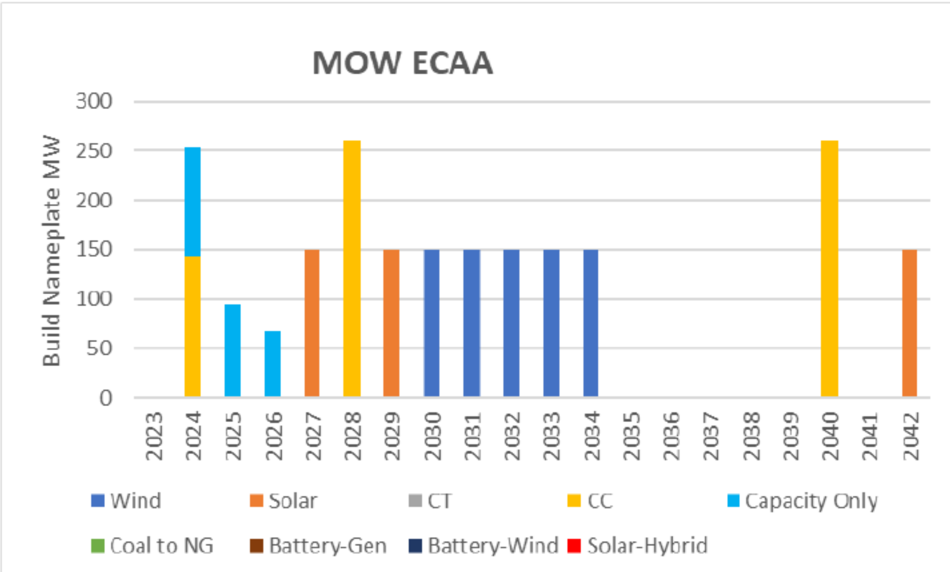
Capacity expansion modeling performed specifically in the Low Gas – Low Carbon Restriction ("Low/Low" or "Low") scenario shows a reduced level of wind and solar builds compared to the Preferred Plan given the reduced value of zero-carbon energy without the imposition of carbon restrictions. Similar to the Preferred Plan, capacity expansion selects Dogwood in 2024 and builds additional Combined Cycle plants in 2028 and 2039 as part of the lowest-cost plan.

Table 36: DSM Portfolio Comparison
Evergy Missouri West Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	ECAA	10,838		RAP+; Jeffrey 2 Retires 2030
2	ACAA	10,858	20	RAP; Jeffrey 2 Retires 2030
3	GCAA	10,878	39	RAP-; Jeffrey 2 Retires 2030
4	MCAA	10,975	137	No DSM; Jeffrey 2 Retires 2030
5	CCAA	11,018	180	MAP; Jeffrey 2 Retires 2030

Holding the retirement plan constant across all Plans and allowing capacity expansion to solve for the lowest-cost portfolio of supply-side resources, RAP+ is the lowest cost DSM portfolio for Missouri West. RAP+ reduces costs by $20M compared to RAP, which is the assumed level of DSM in the 2021/2022 Preferred Plan. Additionally, deploying no new DSM and deploying the Maximum Achievable Potential (MAP) level of DSM are both significantly higher cost than RAP+.

Figure 23: Preferred Plan Supply-Side Additions (Capacity Expansion-Generated)



Utilizing the lowest-cost retirement (2021/2022 Preferred Plan plus acceleration of Jeffrey-2 retirement to 2030) and DSM (RAP+) options, based on a Mid/Mid (mid natural gas price, mid carbon restriction) scenario, capacity expansion generates the resource addition portfolio above as the lowest-cost plan. This plan (ECAA) is the plan ultimately selected as Missouri West's Preferred Plan.

Table 37: Plan Comparison with and without Dogwood Addition
Evergy Missouri West Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR	Difference	Description
1	ACAA	10,858		RAP; Jeffrey 2 Retires 2030
2	ACAC	10,867	8	RAP; No Dogwood, Jeffrey 2 Retires 2030

To supplement these analyses, ACAC was generated using capacity expansion with Dogwood removed as a candidate supply-side resource option. This analysis was done to show the impact of Dogwood on the costs of the resource plan, while retaining use of capacity expansion to generate the lowest-cost resource plan.

Table 38: All Alternative Resource Plans
Evergy Missouri West Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR($M)	Difference	Description
1	ECAA	10,838		RAP+; Jeffrey 2 Retires 2030
2	ACAD	10,851	12	RAP; Jeffrey 2 Retires 2030; High/High
3	AGAA	10,858	20	RAP; Jeffrey 1 & 2 Retire 2030
4	ACAA	10,858	20	RAP; Jeffrey 2 Retires 2030
5	ACAC	10,867	28	RAP; No Dogwood, Jeffrey 2 Retires 2030
6	GCAA	10,878	39	RAP-; Jeffrey 2 Retires 2030
7	EAAA	10,943	105	RAP+
8	AAAA	10,954	115	RAP
9	GAAA	10,958	120	RAP-
10	AAAC	10,966	128	RAP; No Dogwood
11	MCAA	10,975	137	No DSM; Jeffrey 2 Retires 2030
12	ADAA	11,004	166	RAP; Iatan 1 Retires 2030
13	CCAA	11,018	180	MAP; Jeffrey 2 Retires 2030
14	AAAB	11,100	262	RAP; No Wind
15	CAAA	11,113	275	MAP
16	MAAA	11,184	346	No DSM
17	ACAE	11,383	545	RAP; Jeffrey 2 Retires 2030; Low/Low
18	ECAO	11,487	649	RAP+; Jeffrey 2 Retires 2030; No New Renewable/Storage Builds

6.8 BY-SCENARIO RESULTS – EVERGY MISSOURI WEST

Table 32, Table 33, and Table 34 show the expected value of NPVRR for Missouri West alternative resource plans assuming high, mid, and low CO_2 restrictions.

Table 39: Evergy Missouri West Plan Results – High CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	ACAD	10,846		RAP; Jeffrey 2 Retires 2030; High/High
2	ACAC	10,961	115	RAP; No Dogwood, Jeffrey 2 Retires 2030
3	GCAA	11,005	158	RAP-; Jeffrey 2 Retires 2030
4	AGAA	11,007	160	RAP; Jeffrey 1 & 2 Retire 2030
5	AAAC	11,103	257	RAP; No Dogwood
6	MCA A	11,127	281	No DSM; Jeffrey 2 Retires 2030
7	ADAA	11,150	304	RAP; Iatan 1 Retires 2030
8	CCAA	11,166	320	MAP; Jeffrey 2 Retires 2030
9	ECAA	11,254	407	RAP+; Jeffrey 2 Retires 2030
10	CAAA	11,270	424	MAP
11	ACAA	11,306	460	RAP; Jeffrey 2 Retires 2030
12	GAAA	11,362	516	RAP-
13	EAAA	11,368	522	RAP+
14	AAAA	11,411	565	RAP
15	AAAB	11,466	620	RAP; No Wind
16	MAAA	11,677	831	No DSM
17	ECAO	11,751	905	RAP+; Jeffrey 2 Retires 2030; No New Renewable/Storage Builds
18	ACAE	12,383	1,536	RAP; Jeffrey 2 Retires 2030; Low/Low

Table 40: Evergy Missouri West Plan Results – Mid CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	ECAA	10,743		RAP+; Jeffrey 2 Retires 2030
2	ACAA	10,757	14	RAP; Jeffrey 2 Retires 2030
3	AGAA	10,834	91	RAP; Jeffrey 1 & 2 Retire 2030
4	EAAA	10,846	103	RAP+
5	AAAA	10,850	108	RAP
6	ACAC	10,852	109	RAP; No Dogwood, Jeffrey 2 Retires 2030
7	ACAD	10,852	110	RAP; Jeffrey 2 Retires 2030; High/High
8	GCAA	10,860	117	RAP-; Jeffrey 2 Retires 2030
9	GAAA	10,866	123	RAP-
10	AAAC	10,943	200	RAP; No Dogwood
11	MCAA	10,951	208	No DSM; Jeffrey 2 Retires 2030
12	ADAA	10,980	238	RAP; Iatan 1 Retires 2030
13	CCAA	10,994	251	MAP; Jeffrey 2 Retires 2030
14	AAAB	11,034	291	RAP; No Wind
15	MAAA	11,077	334	No DSM
16	CAAA	11,087	344	MAP
17	ACAE	11,282	539	RAP; Jeffrey 2 Retires 2030; Low/Low
18	ECAO	11,633	890	RAP+; Jeffrey 2 Retires 2030; No New Renewable/Storage Builds

Table 41: Evergy Missouri West – No CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	ACAE	10,687		RAP; Jeffrey 2 Retires 2030; Low/Low
2	ECAA	10,708	21	RAP+; Jeffrey 2 Retires 2030
3	ACAA	10,715	28	RAP; Jeffrey 2 Retires 2030
4	AGAA	10,782	95	RAP; Jeffrey 1 & 2 Retire 2030
5	ECAO	10,786	99	RAP+; Jeffrey 2 Retires 2030; No New Renewable/Storage Builds
6	GCAA	10,803	116	RAP-; Jeffrey 2 Retires 2030
7	AAAA	10,805	118	RAP
8	EAAA	10,808	121	RAP+
9	ACAC	10,817	130	RAP; No Dogwood, Jeffrey 2 Retires 2030
10	GAAA	10,830	143	RAP-
11	ACAD	10,849	162	RAP; Jeffrey 2 Retires 2030; High/High
12	MCAA	10,895	208	No DSM; Jeffrey 2 Retires 2030
13	AAAC	10,900	213	RAP; No Dogwood
14	ADAA	10,929	242	RAP; Iatan 1 Retires 2030
15	AAAB	10,930	243	RAP; No Wind
16	CCAA	10,942	255	MAP; Jeffrey 2 Retires 2030
17	MAAA	11,014	327	No DSM
18	CAAA	11,031	344	MAP

6.9 SUMMARY AND EVALUATION

The lowest-cost plan for Evergy Missouri West includes the early retirement of Jeffrey Unit 2 in 2030 in addition to the retirements included in the 2022 Preferred Plan, the RAP+ portfolio of DSM, and the resource additions selected by capacity expansion and shown in Figure 24. This retirement plan aligned with the Joint Planning conducted at the Evergy level and includes an optimized mix of new resource additions selected based on Missouri West customers' specific energy and capacity needs. By-scenario results also show that the retirement of Jeffrey 2 (in addition to retirements already identified in the 2022 Preferred Plan) is part of the lowest-cost plan regardless of carbon restriction level. In addition, the lowest-cost plan for each of the three levels of carbon restrictions includes the addition of Dogwood in 2024, solar in 2027, and a new Combined Cycle resource in 2028. As a result, this plan – denoted as ECAA – has been selected as the new Missouri West Preferred Plan.

SCHEDULE KM-2
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