Exhibit No. 9

Evergy West – Exhibit 9
Kayla Messamore
Surrebuttal Testimony
File No. EA-2022-0328

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Issue:	General Overview; IRP
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NOS.: EA-2022-0328

SURREBUTTAL TESTIMONY

OF

KAYLA MESSAMORE

ON BEHALF OF

EVERGY MISSOURI WEST

Kansas City, Missouri
January 2023

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SURREBUTTAL TESTIMONY

OF

KAYLA MESSAMORE

Case No. EA-2022-0328

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: Are you the same Kayla Messamore who previously submitted Direct and Supplemental Direct Testimony in this case on behalf of Evergy Missouri West, Inc. ("EMW" or "Company")?

A: Yes, I am.

Q: What is the purpose of your Surrebuttal Testimony?

A: The purpose of my testimony is to respond to issues raised in the testimonies of Staff witnesses J Luebbert, Claire Eubanks, and Brad Fortson related generally to EMW's need for Persimmon Creek, economic analysis utilized in supporting this application, and the use of the Commission's Integrated Resource Planning ("IRP") process, 20 C.S.R. 4240-22.010-.080, in support of resource acquisition decisions. As I have outlined in my Direct and Supplemental Direct testimony, EMW has a need for both energy and capacity, the current IRP has identified wind – and specifically Persimmon Creek – as an economic step towards meeting those needs as part of an integrated long-term plan, and nothing Staff has identified changes either of those facts.

Q: Please summarize your response to Staff's recommendation.

A: Staff's recommendation hinges on a variety of impossible and illogical "standards" by which to determine need, public interest, and prudence and thus should be rejected. The Staff's approach is founded on the implied premise that the only prudent path available to an electric utility is to add resources only when its hand is forced by regulatory mandates or other external forces. This is an incredibly risky approach for EMW's customers, particularly in today's environment where the need to transition our generating fleet to lower- / no-carbon sources responsibly over time is recognized by essentially all parties.

Staff's arguments purportedly address only this project – Persimmon Creek. However, Staff's implied premise creates a serious obstacle to the addition of <u>any</u> renewable resources that are not being specifically utilized for Renewable Energy Standard ("RES") compliance and, to a lesser extent, new resources of any fuel type. If Staff's position is adopted for Persimmon Creek or as a guiding principle for other resource procurements, there will be no realistic options available to meet EMW's current and increasing future needs, leaving EMW's customers exposed to rely only on the wholesale market to meet these needs for the long-term. Such an outcome would likely increase both the cost and volatility of customers' electricity bills which would not be in the public interest.

Q: Please describe the structure of your testimony.

A: I will address each of these topics in the following sections:

- **Section 1 - Definition of "Need":** Staff witnesses Luebbert and Eubanks rely on an overly narrow conception of "need" to support their arguments which imply that EMW may only add resources when it is at imminent risk of non-compliance with Southwest Power Pool ("SPP") Resource Adequacy Requirements or at imminent risk of not having sufficient electrons to physically provide power to its customers. I will again reinforce EMW's very real need for capacity and energy (Messamore Supplemental Direct, pp. 10-13) and provide projections of that need going forward from EMW's IRP.

- **Section 2 - Long-Term Needs and Risks:** As an extension of Staff's narrow definition of "need," Mr. Luebbert appears to argue that if EMW has a need, the only acceptable option to meet that need is a resource which meets it in its entirety. Staff extends this argument to state that because Persimmon Creek does not fully meet EMW's needs or may not be the optimal resource to meet its entire need, EMW has not demonstrated that the project is needed. Stating that something is not needed simply because it does not completely fulfill the full need is illogical. Persimmon Creek is simply a step in executing the long-term plan necessary to responsibly transition from the use of fossil fuels to low- or non-emitting resources over time. Staff's assertion that EMW should not make this step because Persimmon Creek does not fully satisfy the full need essentially guarantees that EMW's only option is to do nothing. Adding new generation capacity in increments has been a long-standing accepted approach in Missouri, as well as in the electric utility industry generally.

While Staff witness Fortson mentions the risk analysis provided with the 2022 IRP Annual Update in response to Staff's concern of adding renewable resources when not required to meet federal, state, or regional transmission organization ("RTO") requirements, he finds fault because it uses words like "expected," "likely," and "potential" (Fortson Rebuttal, p. 15). When assessing the long-term risks associated with resource planning, the idea that near certainty about future events is required for an analysis to be valid is contrary to the entire idea of risk analysis which is intended to assess the impact of uncertainty on a plan.

- **Section 3 - Assessment of Project Economics:** Mr. Luebbert asserts that because Persimmon Creek is being added to meet a need for economic energy, and because the forecasted energy revenues from the project may not outweigh the revenue requirements associated with the project (i.e., it may not generate net profits from the wholesale market and tax credits), Commission approval of the CCN should effectively be conditioned to hold shareholders responsible for any differences. This assertion ignores the need this resource will meet and would establish a standard that very few new or existing resources – renewable or otherwise – would be likely to meet on a standalone basis, other than in an extreme event. EMW will not proceed with the Persimmon Creek acquisition if any such condition is imposed on the CCN approval.
- **Section 4 - Use of the IRP to Support Resource Decisions:** Mr. Fortson refers to the IRP process as simply a "modeling exercise" (Forston

Rebuttal, p. 19, lines 11-13) and suggests that it has almost no value in informing actual resource decisions because the Preferred Plan it identifies may change over time. This total disregard for the IRP as a planning process is baffling, given the Commission's historical use of the IRP to support resource decisions. The framework outlined in the Commission's IRP Rule requires the IRP be used to support and be consistent with a utility's business planning. Additionally, Staff's suggestion that the IRP process raises concerns because it produces different results as input assumptions and market conditions change over time is illogical. What would be much more concerning is if an IRP never changed over time as external markets are moving. This Staff position seems to say that any plan which may be adjusted over time is inherently suspect. Under this view, given that *conditions will always be dynamic*, the only acceptable action is inaction. Such inaction would assuredly be to the detriment of our customers over the long-term.

Mr. Luebbert essentially asserts that because he disagrees with some of the modeling assumptions made in the IRP analysis used to support this application, it should not be used to justify the Persimmon Creek acquisition. This sets an impossible and short-sighted standard where only modeling which is perfect (or, as he states at pages 13 and 47, "aligns" with recent history, adjusted only for the future expected expiration of tax credits) is acceptable to justify a project. The modeling critiques that Staff has offered do nothing to change the fact that resources like Persimmon Creek were identified as an economic way to meet a portion of EMW customers' long-term energy and capacity needs as part of an overall integrated resource plan.

- **Section 5 - Comparison to Power Purchase Agreements (PPAs): Mr.** Fortson points to past testimony related to benefits and costs of EMW's existing wind PPAs as a basis for concern about modeling supporting the acquisition of Persimmon Creek. However, past PPAs are not relevant to assess the need for or economic feasibility of Persimmon Creek. Market revenues are only one part of the value a resource provides to customers. The fact that a resource may not receive market revenues in excess of its total costs does not prove any decision to enter the PPA was imprudent.
- **Section 6 - Risk of Delaying Resource Additions:** As a general response to Staff's recommendation to reject this application and as a closing summary of my testimony, I will outline the risks such a decision would create for EMW's customers.

Section 1 - Staff's Definition of Need

Q: How does Staff define a "Need" which would justify the addition of a resource?

A: Although Staff offers no clear definition, it seems to rely on these principles in defining whether a need exists:

- "[EMW] should be able to clearly articulate and demonstrate the *physical needs* of the ratepayers to be fulfilled through the purchase of the

Persimmon Creek wind project...” (Luebbert Rebuttal, p. 8, emphasis added)

- “Mitigation of market energy costs is not equivalent to a *physical need* for energy production. If a given resource is not necessary to meet a *physical need*, ratepayers run the risk that the resource is ultimately uneconomic without the opportunity to realize physical benefits.” (Luebbert Rebuttal, p. 13, emphasis added)
- Capacity needs are based on the difference between SPP resource adequacy requirements and EMW’s existing capacity portfolio, net of the amount EMW could procure from Evergy Metro (Eubanks Rebuttal, p. 3-4)
- Energy needs are defined as a need for physical electrons produced at the time EMW needs them (Eubanks Rebuttal, p. 7)

Q: In light of this testimony, what is Staff’s position?

A: Staff implies that EMW must be expected to fall short of SPP’s resource adequacy requirements in the near-term, having exhausted available purchases from Evergy Metro, to be able to claim that it has a capacity need. On the energy side, Staff implies that a physical shortage of electrons to serve customers is required to prove an “energy need” which could only be shown by either a historical or expected forced load-shedding event needed to maintain system balance.

Q: Do you agree with a definition of "need" that reflects this view?

A: No, I think it is far too narrow and risky for customers. It jeopardizes EMW's ability to effectively meet its obligation to serve and is beyond historical Commission decisions on the addition of supply resources, inconsistent with the focus of the IRP, and generally misaligned with the current articulated policy of the Commission and the State of Missouri in regard to the transition of supply resources utilizing renewable resources.

Q: Does EMW have a need based on Staff's view of capacity and energy needs?

A: EMW does have a capacity need that aligns with this view, yes. Staff's assertion is that EMW can continue to rely on purchases from Evergy Metro to meet its capacity needs and cites a chart from EMW's 2022 Annual Update as support (Eubanks Rebuttal, p. 4, lines 6 and 7). First, Staff's read of the chart is incorrect as the chart includes EMW, Evergy Metro, and Evergy Kansas Central's combined capacity position (referenced by Staff as a chart of EMW and Evergy Metro's combined position).

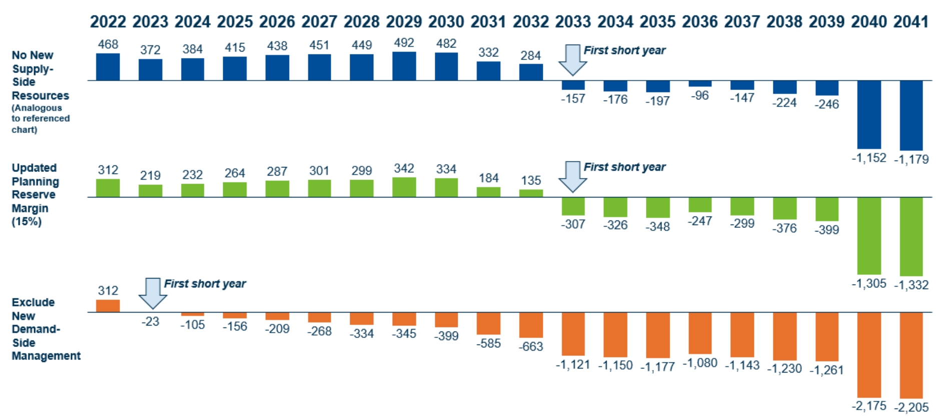
Second, although Staff references the change later in testimony (Eubanks Rebuttal, p. 6), the change to the SPP reserve margin is not incorporated into Staff's assessment of Evergy's combined capacity position (including Evergy Kansas Central).

Third, the chart includes forecasted new demand-side management ("DSM") implemented at a Realistically Achievable Potential ("RAP") level across all three jurisdictions. While this DSM was identified as part of EMW's and Evergy Metro's Preferred Plans, it is "masking" the combined entities' capacity "need" given it is assumed to be in place in this chart.

To demonstrate the combined entities true "capacity need" (which can be met by either supply- or demand-side resources), the chart below was developed based on the Preferred Plan capacity balance spreadsheets provided with the 2022 Annual Update, adjusting for the three items listed above.

Evergy Metro and Evergy Missouri West Combined Position

2022 IRP Annual Update Preferred Plan; MW long (+) or short (-)



This chart highlights not only the criticality of Evergy's forecasted DSM programs in meeting future customer capacity needs, but also demonstrates that EMW has a current need for capacity even based on Staff's overly narrow definition of "need" (i.e., assuming EMW continues purchasing capacity from Evergy Metro).

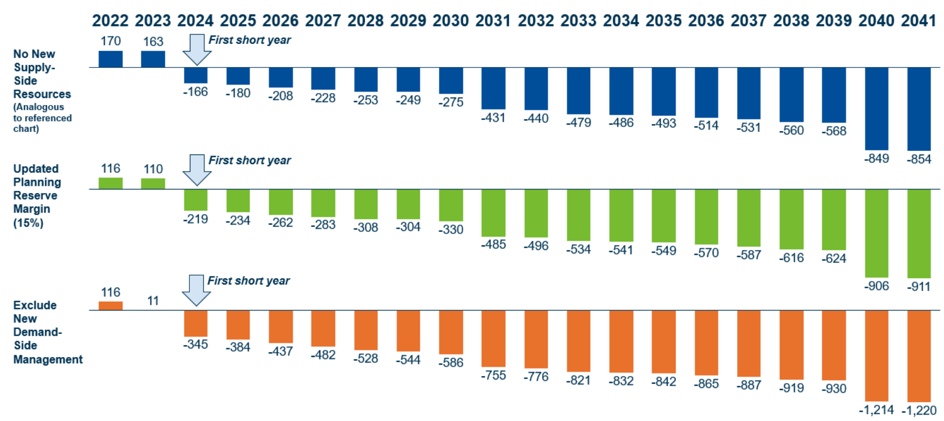
It is also important to recognize that Staff's implied assertion that EMW should essentially be guaranteed the available surplus from Evergy Metro could result in Metro customers directly subsidizing EMW customers. Both Metro's capacity sales and EMW's capacity purchases have been managed through competitive RFP processes to ensure no such subsidization occurs. As a result, available Evergy Metro capacity could ultimately be sold to customers other than EMW.

Q: As a standalone utility, what is EMW's forecasted capacity position?

A: In the chart below the existing capacity sale of approximately 325 MW from Evergy Metro to EMW is factored into the position shown for 2022 and 2023, but no new supply-side resource additions are included. This chart demonstrates EMW's imminent and long-term capacity need.

Evergy Missouri West Capacity Position

2022 IRP Annual Update Preferred Plan; MW long (+) or short (-)



Q: Does EMW have a need for energy based on Staff's definition?

A: No. In today's world of the SPP Integrated Marketplace, it is unlikely that EMW, <u>on a standalone basis</u>, would be able to demonstrate a shortage of physical electrons to serve its customers. If such a shortage occurred, it would be driven either by (1) transmission constraints which prevented EMW from importing sufficient energy to serve its load, or (2) SPP pool-wide energy shortages. Winter Storms Elliot and Uri demonstrated both types of shortages. During Winter Storm Elliot in December 2022, SPP implemented short-term, localized load shed in the southwest Missouri area because, in general terms, transmission constraints prevented sufficient external supply from reaching the area. This resulted in a localized supply-demand imbalance which, in turn, created voltage sags that threatened system balance overall.

During Winter Storm Uri in February 2021, SPP implemented pool-wide mandatory load shed due to insufficient energy supply across the footprint, which impacted EMW along with all other load-serving entities.

However, neither of these scenarios would seem to qualify as an energy need based on Staff's definition, given they would not be EMW-specific issues.

Q: What elements of EMW's "need" does Staff exclude in its analysis of capacity needs?

A: In setting the threshold for "need" at the current SPP Resource Adequacy Requirement, three key sources of uncertainty are ignored. First, SPP is implementing performance-based accreditation for thermal resources, which is expected to reduce the capacity accreditation of those resources in the future and thus increase EMW's capacity need, all else being equal.

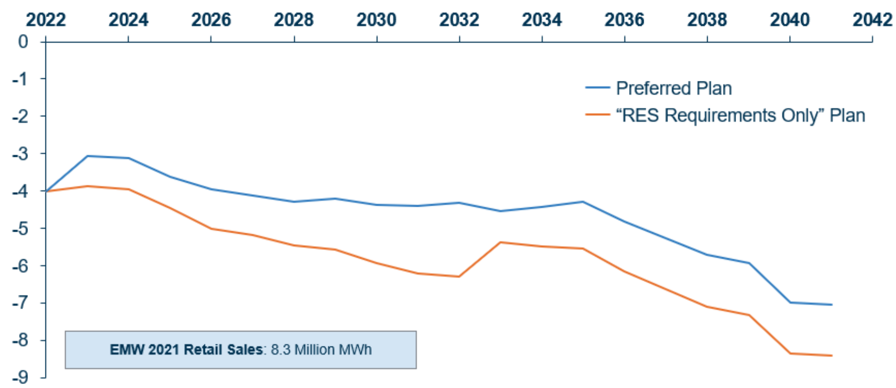
Second, SPP has indicated that it anticipates future increases to the Planning Reserve Margin (beyond the recent increase to 15%) as the resource mix continues to change and we see more extreme weather events. This will also increase EMW's capacity need and the risk of staying near the minimum Planning Reserve Margin as there are likely to be more increases.

Third, Staff's stay-the-course, "do nothing" approach ignores the possibility that plant retirements may have to be accelerated and thus capacity must be replaced. EMW and the other Evergy utilities (which are majority owners in the large coal units EMW owns) currently forecast a very moderate pace of coal retirements compared to many utility peers. This is largely to mitigate the reliability risks already mentioned and to allow time for new non-emitting, firm dispatchable technologies to develop. However, there remains risk that one or more of these coal retirements may have to be accelerated if environmental regulations change or an unexpected equipment failure makes continued operation no longer feasible or economic.

Q: What elements of EMW's "need" does Staff exclude in its analysis of energy needs?

A: Staff implies that a financial need for energy is not a legitimate need, given its focus on physical needs for energy. This perspective essentially dictates that EMW remain a net energy purchaser from the market (regardless of the cost) as long as physical electrons are still available. Looking forward, EMW's net energy purchases are expected to increase as aged coal plants retire and existing wind PPAs begin to roll off toward the end of the 2030s. The chart below compares EMW's net annual energy position in its 2022 Preferred Plan ("generic" wind additions only, not Persimmon Creek) to the "RES Requirements Only" plan modeled to support the Staff-requested risk analysis (which compared the Preferred Plan to adding renewables only when required for RES compliance).

EMW Net Energy Position (Million MWh, No CO_2 Price, Mid Gas Price)



This chart shows that EMW customers currently consume approximately 4 million MWh of energy per year more than is produced by EMW generation. This clearly demonstrates the Company's need for additional generation now. Even with the expected additions in the Preferred Plan (including the wind site which is now identified as Persimmon Creek), EMW is forecasted to remain a significant net purchaser of energy. Without these additions, EMW's net purchases in 2041 are near the level of total 2021 EMW retail sales and represent a risky level of market reliance under this "RES Requirements Only" plan.

With its annual generation of approximately 875,000 MWh, Persimmon Creek would reduce EMW's typical net short position of near 3.9 million MWh by approximately 23%. Even using Staff's adjusted capacity factor which assumes Persimmon Creek is curtailed at all negative prices (i.e., a proxy for when it is no longer PTC-eligible in the future), it would still reduce this net short position by approximately 15%.

Section 2 – Long-Term Needs and Risks

Q: Why do you believe Staff states that a resource must fully satisfy a need in order to qualify as "meeting a need"?

A: I believe this because Staff has stated:

- "Persimmon Creek will not resolve Evergy Missouri West's alleged capacity need..." (Luebbert Rebuttal, p. 9)
- "...Persimmon Creek is not particularly well-suited to provide such mitigation [of market purchased power costs] in the time periods when market prices and Evergy Missouri West's load are highest" (Luebbert Rebuttal, p. 9)

Q: Why do you believe these standards are unreasonable?

A: Regarding the first point, stating that something is not needed simply because it does not resolve or fulfill the entire need is short-sighted and illogical. Regarding the second point, stating that something is not needed simply by implying it is not the ideal solution at a particular time ignores all the other benefits it is likely to provide over time. Given EMW's known need for capacity and for a hedge against energy market exposure, the Company should assess what available alternatives most effectively meet that known need. Comparing an option to an "ideal" alternative that fulfills the need completely makes sense only when such an alternative exists. In the case of today's electric utility resource planning, such an ideal alternative does not exist and, tellingly, Staff has not put one forward. It has simply stated that Persimmon Creek is not the "ideal" alternative and thus should be rejected.

Q: Do you agree with Staff's statements regarding Persimmon Creek's ability to meet EMW's need?

A: No. Although I agree that Persimmon Creek does not resolve EMW's entire capacity need and does not provide a consistent energy hedge during peak hours, it does resolve some of EMW's capacity need and provides an energy hedge in general that EMW does not currently have. That is why it is part of an overall portfolio of resources, identified through the IRP, to meet EMW customers' long-term needs. Satisfying these long-term needs is not and will never be a "one-and-done" resource decision.

Q: Mr. Fortson noted a Staff concern regarding risks related to additional generation resources from the 2021 IRP which was ultimately included as a Special Contemporary Issue in the 2022 Annual Update in his Rebuttal Testimony at pages 13-14. What was EMW directed to prepare regarding Staff's request in that Special Contemporary Issue?

A: The Commission directed EMW to provide detailed analysis in its next annual update filing comparing ratepayer risks and shareholder risks for additional generation resources that are not required to meet federal, state, or RTO requirements. This analysis was provided with the 2022 Annual Update and is attached as **Schedule KM-**3.

Q: Is Mr. Fortson correct in view that this risk analysis "mostly reiterated discussions from its [EMW's] 2021 triennial compliance filing and attempted to further support its preferred plan from its 2022 IRP annual update and the risks of not implementing that plan"? (Fortson Rebuttal, p. 14)

A: No. EMW performed a new analysis which compared the Preferred Plan to an "RES Requirements Only" plan across all modeled scenarios. This analysis was performed to assess the customer risks of adding the resources included in the Preferred Plan, as compared to a plan where capacity was only added when required for SPP resource adequacy requirements and when renewables were only added to meet RES requirements. This modeling was performed at the Evergy level given most risks are consistent across its utilities, other than the net energy position mentioned previously which adds additional risk for EMW customers.

Q: What were the results of this analysis?

A: The analysis showed

> [T]hat the RES Requirements plan is more expensive than the Preferred Plan in 15 out of 27 modeled endpoints, particularly those which include medium or high carbon prices. In addition, in 6 of the 12 scenarios where the RES plan is lower cost than the Preferred Plan, it is higher cost than plan CCBAA which is identical to the Preferred Plan in the Implementation Period [first 3 years of the plan] and only varies in the medium- and long-term. The remaining 6 plans where the RES Requirements plan is lower cost than both the Preferred Plan and CCBAA all include no carbon restriction and either low or medium gas prices.[1]

On an expected value basis, the "RES Requirements" plan was $450 million more expensive than the Preferred Plan. It also had the highest standard deviation of all plans across modeled scenarios which indicated a high level of

[1]EMW Integrated Resource Plan 2022 Annual Update, EO-2022-0202, June 10, 2022, p. 100.

risk from potential market changes, particularly high gas prices and the imposition of carbon restrictions.

The intent of this analysis was to provide additional data and risk considerations in response to Staff's concerns. Staff failed to provide any feedback on this analysis as part of its comments filed in response to the 2022 Annual Update.

Q: Mr. Fortson highlighted concerns with the analysis given it was called a "point-in-time summary of [EMW's] current understanding" and used words such as "expected," "likely," and "potential." (Fortson Rebuttal Testimony at pages 14-15). Does EMW's use of these words invalidate the finding of the analysis?

A: Not at all. A risk analysis will always be a point-in-time estimate based on current expectations which are being stress-tested. Implying that these words somehow make the analysis invalid completely misses the point of a risk analysis which is to gauge the sensitivity of a plan to different future scenarios, given inherent future uncertainty.

Q: How does this risk analysis support the need for Persimmon Creek?

A: While this analysis was not performed with Persimmon Creek in mind, the overall comparison of the "RES Requirements Only" plan and the Preferred Plan shows the risk in taking the approach Staff suggests by opposing EMW's application to be granted an Operating CCN for Persimmon Creek. The long-term need for new resources, given the expectation of coal plant retirements and the need to transition the fleet responsibly over time, means that only adding renewable resources when they are required to meet RES requirements would likely add significant costs for EMW's customers.

Section 3 - Assessment of Project Economics

Q: Mr. Luebbert states that "market revenues and ratepayer realized benefits of the production tax credits will need to exceed the overall cost over the asset's life in order to ultimately be economic from a ratepayer perspective" (Luebbert, p. 19). Do you agree with this assertion?

A: No.

Q: As an extension of this same point, Staff recommends that if the Commission approves the CCN that it be conditioned on EMW holding ratepayers harmless "if the costs of Persimmon Creek exceed the market revenues and ratepayer realized tax benefits" (Luebbert Rebuttal, p. 58, lines 1-3). Is this a reasonable condition?

A: No.

Q: Why would requiring such a condition be unreasonable?

A: There are a variety of reasons why such an unprecedented condition is both unreasonable and unjust.

First and foremost, EMW will not be able to proceed with the Persimmon Creek acquisition if such a condition is imposed on the CCN approval. This condition would break the longstanding regulatory compact where the balance between providing a utility the opportunity to earn a reasonable return is exchanged for its obligation to serve. Under Staff's recommended condition, EMW's return could be determined by SPP wholesale energy market conditions that are outside of the Company's control. If SPP wholesale energy revenues in combination with the Persimmon Creek tax credits were below what was needed to recover all costs (including capital related costs), EMW shareholders would be required to absorb the difference under Staff's recommended condition. This would be both unreasonable and confiscatory.

The SPP wholesale energy market was not designed to recover all retail costs related to generating electricity. The SPP market was designed to dispatch available generators reliably and efficiently across its 14-state footprint on a real-time basis. Dispatch is generally based on short-run marginal costs. Offering a generation resource into the SPP market such that all fixed costs (e.g., return of capital) are recovered is not permitted under market rules. The table below demonstrates this phenomenon for EMW's existing resources using 2020 as an example.

****Net Costs of Existing EMW Assets[2]**
($ Million, 2020)

[redacted] **

This does not mean that these current resources are not meeting a need for EMW. If taken to its logical conclusion, Staff's argument would indicate that

[2] Persimmon Creek values calculated based on actual 2020 revenues versus year-1 revenue requirement included in LCOE calculation.

many of EMW's existing resources should not be a part of its fleet and EMW should simply procure all of its energy from the SPP market for EMW customers, accepting the pricing and reliability risk that come with that decision. Presumably, this is not Staff's intention, particularly given that Mr. Luebbert states that energy prices are "likely to become more volatile over time" at page 25, line 15 of his Rebuttal Testimony.

Q: Does Staff's analysis of "net benefits" from Persimmon Creek factor in all benefits of the project?

A: No. Not all generation resource benefits are reflected in market revenues and tax credits. As Mr. Humphrey's Supplemental Direct Testimony on page 26 explains, Persimmon Creek is in service, operating efficiently, and does not present construction, procurement, transmission interconnection, and other risks. Having largely addressed these typical risks, Persimmon Creek will clearly provide benefits to EMW customers.

Similarly, there are no capacity benefits included in Staff's analysis to reflect the fact that EMW would have to buy additional capacity if Persimmon Creek is not part of the Company's portfolio. While the accredited capacity value of Persimmon Creek is low (assumed to be 10%), it is not zero and is thus a real benefit.

Because Persimmon Creek would provide both capacity and an energy market cost hedge, the benefits of this hedge or "insurance policy" are also not directly reflected in the energy market revenues. Stating that a hedge is only valid when it generates net profits in a single scenario built on recent history completely misses the value of a hedge. There is no such thing as a free hedge or a hedge that is guaranteed to be profitable. Hedges are insurance policies which mitigate the impact of negative events, namely customer bill volatility. In the case of Persimmon Creek, adding this energy resource helps to mitigate the price volatility (that directly impacts customer bills) which Staff acknowledges is likely to increase over time.

Q: Mr. Luebbert stated that Persimmon Creek is likely not an effective energy hedge because its energy production is not "highest when nodal market prices and ratepayer demand are high" (Luebbert Rebuttal, p. 47, 50, 55). What is your view of his point?

A: It is a narrow view of energy price hedging and fails to reflect the benefit that Persimmon Creek does provide. The fact that wind production is not typically highest when load and market prices are highest is factored into the IRP analysis of potential revenues and thus the economic benefits of this project.

More critically, the fact that wind is not a perfect hedge does not mean it is not an effective hedge. Based on similar logic, while solar is generally more available during peak hours in the summer than wind, its availability during winter peaks is often negligible. While a natural gas resource may be dispatched only during peak times, it does essentially nothing to mitigate commodity price exposure given that natural gas will need to be purchased to operate the unit.

This doesn't mean that these options are ineffective hedges. It means that all of these resource types play a role in managing risk for customers as part of an overall integrated generating portfolio called for by the Commission's IRP process.

Section 4 - Use of the IRP to Support Resource Decisions and Staff's Concerns

Q: Staff witness Fortson claims that the results of EMW's IRP should not be construed as justification for EMW's purchase of Persimmon Creek. (Fortson Rebuttal, p. 19, lines 9-11). What is the basis for this argument?

A: There appear to be at least four reasons provided for this position:

- Future IRPs could render the decision wrong (Fortson Rebuttal, p. 13, line 2)
- The IRP is a "modeling exercise" (Fortson Rebuttal, p. 19, line 11-13)
- IRP plans change frequently (Fortson Rebuttal, p. 15, lines 6-11)
- Renewable resource additions have a real cost to ratepayers while the benefits are uncertain (Fortson Rebuttal, p. 15, lines 18-22)

Q: Do you agree with these reasons?

A: No. Finding any of his points to be credible would certainly call into question why the Commission's IRP Rule exists and why Missouri utilities spend so much time to prepare and complete these comprehensive plans, and other parties analyze and evaluate them.

Q: Why do you believe Mr. Fortson's reasoning is wrong?

A: Regarding Mr. Fortson's first point, from a decision-making standpoint, a resource decision is either right (i.e., prudent) or "wrong" at the time the decision is made. Subsequent IRP analysis and results have absolutely nothing to do with rendering a prior decision right or wrong. There is longstanding Commission precedent for determining prudence at the time the decision is made, contrary to what Mr. Fortson's first point suggests. The hindsight review of resource decisions violates the prudence standard and is inappropriate, as the Commission has consistently found.

Second, Mr. Fortson refers to the IRP as simply a "modeling exercise" and seems to assert that the IRP process has almost no value in informing actual resource decisions because a utility's Preferred Plan may change over time. This direct disregard for the IRP as a planning process is baffling, given the Commission's historical use of the IRP in supporting decision-making and the framework outlined within the IRP rules which requires the IRP be used to support, and be consistent with, company business planning.

Mr. Fortson claims support for this position by pointing to the IRP rules where it states: "Compliance with these rules shall not be construed to result in commission approval of the utility's resource plans, resource acquisition strategies, or investment decisions."[3] The fact that the IRP rules state that compliance shall not be construed as commission approval in no way negates the use of IRP analysis as the support for a resource investment such as Persimmon Creek. The rule simply makes it clear that rule compliance does not equal Commission approval of utility resource decisions.

Third, saying that the IRP process cannot be relied on to make resource decisions, in part because it produces different results as input assumptions and market conditions change over time, is illogical. The IRP provides the fundamental basis for utility resource planning and, as such, provides the basis for

[3] 4 CSR 4240-22.010(1)

utility resource decisions. Given the complex nature of utility planning and the significant uncertainty under which resource decisions need to be made, resource planning has become a continual process. As current and projected assumptions change, the appropriateness of resource plans can change as well.

Such changes are explicitly recognized and accounted for in the IRP rules. Beyond its requirements for assessing the risk of assumption changes in the triennial IRP analysis, there are also requirements to monitor for changes between filings and to re-evaluate plans as needed. When the original IRP rules went into effect in the early 1990's, there were no requirements for an annual update process. Given how assumptions can and do change significantly between triennial IRP filings, the original IRP rules were subsequently modified in 2011 to require an annual update process per Section 22.080(3).

What would be much more concerning is if an IRP never changed over time even as external markets moved. Staff's position seems to say that any plan which may be adjusted over time is inherently invalid and so are all steps within that plan. Under this supposition, given *conditions will always be dynamic*, the only acceptable action under Staff's analysis is inaction.

Fourth, as I noted above, Mr. Fortson raises a concern that EMW uses words such as "expected," "likely" and "potential" in its IRP related filings[4] (Fortson Rebuttal, p. 15 lines 12-14). Essentially, Staff is concerned that while the cost of additional renewable resources are real, customer benefits are uncertain (Fortson Rebuttal, p. 15, lines 17-22). While generally true, this is no

[4] The Commission's IRP Rule at 20 CSR 4240-22 the words "expected," "likely" and "potential" are mentioned a total of 145 times.

reason to reject the IRP results as support for resource decisions. The uncertainty of benefits from long-term resource decisions are a fact of life. No analysis is going to change this fact. Given that the IRP's fundamental objective, as stated in Section 22.010(2), is "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," it provides the foundation for evaluating the appropriateness of resource additions.

Q: Staff expressed concern over EMW's manual adjustments to the first three years of the 2022 IRP annual update and that these types of adjustments could continue indefinitely (Fortson Rebuttal, p. 13, lines 10-14). Is this a valid concern?

A: No. As described earlier in my Supplemental Direct testimony, these adjustments were made to reflect current market knowledge and were therefore appropriate and supportable. These adjustments were documented and supported in the Annual Update filing (EMW 2022 Annual Update pages 34, 65) and any such adjustments in future IRPs will also be described and supported, consistent with the IRP Rule's requirements for an electric utility to update its filings and data. It is pure speculation by Staff that such changes will be made by EMW in every IRP analysis.

Q: Staff expressed a concern that the IRP does not account for negative revenues that will occur during negative pricing intervals (Luebbert Rebuttal, p. 34, lines 9-10). Please respond.

A: It is true that the IRP assumed Persimmon Creek was not dispatched below prices of $0/MWh, given constraints in available modeling parameters. However, as the model provided to Staff in data request response 0051S2 demonstrated, the minor impact of this assumption was revenue being over-stated by **[redacted]** over the first 5 years of assumed operations (the variance between the farm operating based purely on its historical capacity factor – regardless of market price – and the farm being curtailed below $0/MWh). Once Persimmon Creek is no longer PTC-eligible, it would not be expected to incur negative revenues given it would be offered at ~$0/MWh variable cost (as opposed to approximately negative $30/MWh) and would not be dispatched by SPP at negative prices.

Q: Staff expressed a concern that the IRP assumed a Persimmon Creek capacity factor near the historical average and that once the PTCs expire, this overestimated the Persimmon Creek generation (Luebbert Rebuttal p. 36, lines 4-12). Please respond.

A: This concern is misplaced as the IRP model dispatch is based on hourly market prices and generation was curtailed when market prices are negative, as mentioned previously. While capacity factor was used to estimate the potential generation, market prices (which vary by IRP scenario) drive the generation output levels in the IRP evaluation. As described below, the long-term expectations around negative prices and resulting curtailments are based on SPP's long-term economic transmission model.

Q: Staff expressed a concern that the IRP includes a lower number of negative pricing hours than what has occurred at Persimmon Creek in recent years. (Luebbert Rebuttal, p. 33-34) What is your response?

A: In the near term, curtailments driven by negative market prices are already baked into the Persimmon Creek capacity factor (given it is a historical capacity factor). As a result, creating additional "price-driven" curtailments in the IRP model would double-count the impacts on the site's production. As mentioned previously, negative revenues from cases where the farm is dispatching at a negative price greater than its offer price are not included in the model. Even if negative prices continued at the level seen over the farm's history throughout Persimmon Creek's remaining PTC eligibility, this would only be a reduction in revenue of approximately **[redacted]** per year through the PTC expiration in 2028 (**[redacted]** on a net present value basis), which pales in comparison to the $130 million in savings (on a net present value basis) identified through past IRP analysis.

Rather than simply utilizing this type of recent history to develop long-term market scenarios for risk analysis in the IRP, however, the pricing model utilized in the IRP is based on SPP's economic transmission model, driven by SPP's assumptions around transmission and resource build-out for the pool overall, and Evergy's commodity and carbon price scenarios. As a result, the decline in negative price hours over time is predicated on SPP's assumptions around transmission buildout which help mitigate transmission congestion which (in turn) can cause negative prices. These pricing models also reflect a changing resource mix over time as varying combinations of commodity prices and carbon restrictions (depending on the scenario), combined with pool-wide retirements and additions, impact the supply/demand balance overall and drive changes in prices.

Q: Staff expresses concern that the IRP analysis overestimated the Persimmon Creek capacity factor because it "does not account for the likely reduction in capacity factor upon Evergy Missouri West's acquisition of the asset due to potential prudence disallowances for generating at a loss in excess of the PTC value." (Luebbert Rebuttal, p. 38, lines 10-12). Please respond.

A: This is another misplaced concern. First, it implies that capacity factor is an input into the IRP model, which it is not. A wind profile built on Persimmon Creek's historical capacity factor is an input into the model which is then dispatched (curtailed) as dictated by market prices. More importantly, this concern implies that EMW's market offer strategy will be markedly different than the current owner's strategy, which is highly unlikely given that would mean the current owner is allowing Persimmon Creek to be dispatched at a loss.

Market offers for PTC-eligible wind are based upon the short-run marginal cost of the resource which factors in the value of the PTC as a "negative cost." Given that wind is generally a $0 variable cost resource, this means that a typical offer for a PTC-eligible wind farm is around –negative $33/MWh to –negative 34/MWh, (which is the PTC value grossed up for taxes). Generation is then dispatched by SPP based on these negative price offers, and the result is that Persimmon Creek would not be dispatched unless the market price exceeds its offer i.e., the value of the PTC. This allows the wind farm to continue generating energy in order to collect the value of the PTC even though the market price for energy is negative resulting in the wind farm paying SPP to continue to generate.

Staff's concern assumes that Persimmon Creek's current owner is generating energy when negative market prices are in excess of the PTC value (e.g., market energy price is -negative $40/MWh while the PTC value is $33 to $34). Staff essentially suggests that the owner is setting its offer price below its short-run marginal cost. Because this would result in financial losses for the current owner, this assumption is very suspect.

Regarding Staff's "adjusted capacity factor" which attempts to adjust Persimmon Creek's historical production for curtailments at prices below negative $26/MWh (Luebbert Rebuttal, pp. 37-38), the analysis is misleading. A wind offer price will be based on a PTC value grossed up for taxes, which is closer to $33 or 34/MWh, depending on the tax rate, as I mentioned above, and not the $26/MWh assumed by Staff. This is done to account for the all-in value of the PTC which will ultimately be realized. As a result, all hours with prices higher than –negative $33/MWh should not be excluded. This has been corrected in the table below. When adjusted for this change, the resulting capacity factors shown below align very closely with Persimmon Creek's actual capacity factors. This demonstrates that the current offer strategy for the wind farm is what I described above and is in line with what EMW's would be.

Persimmon Creek Capacity Factor (%) [5]

[redacted]

**

Note that Staff's actual capacity factors for Persimmon Creek included in Mr. Luebbert's Rebuttal Testimony on page 36 appear to be incorrect for 2020 and 2022, and do not reflect the data provided by the Company in response to Staff Data Request 0049 (See **Confidential Schedule KM-4**). The "Actual Values" column provided above is calculated based on EMW's DR Response, with the adjustment noted above applied for the "Adjusted Values" column.

[5] 2022 values shown are through December 1, 2022, consistent with data provided in response to DR 0049

Q: Mr. Luebbert references your Supplemental Direct testimony at page 16 where you describe the conditions under which a Preferred Plan may be reevaluated and he states that, on the basis of Staff's concerns over the capacity factor assumed for Persimmon Creek, the addition of the resource should be delayed and reevaluated. (Luebbert Rebuttal, p. 39-40) Please respond.

A: The conditions I described where a Preferred Plan may be reevaluated were higher actual project costs or worse project performance than what was assumed in IRP modeling of "generic resources". As discussed earlier in this testimony, the concerns Staff has identified with Persimmon Creek's assumed capacity factor and negative market revenues are either unfounded or not material compared to the savings identified in the IRP modeling and, in total, do nothing to change the fact that Persimmon Creek's cost and performance were *better* than what was assumed for the "generic" wind modeled in the IRP. As a result, there is no need for delay in this case.

Section 5 - Comparison to Power Purchase Agreements

Q: Staff witness Fortson points to past testimony related to benefits and costs of EMW's existing wind PPAs and uses this as support for concern about modeling supporting the acquisition of Persimmon Creek (Fortson Rebuttal, p. 21, starting at line 7). How is this information relevant to this CCN case?

A: It is not relevant. This general discussion of past PPAs has nothing to do with assessing the need or economic feasibility of Persimmon Creek and the Company's request for an Operating CCN.

However, as discussed in this testimony, market revenues are only one part of the value a resource provides to customers. The fact that a resource may not receive market revenues in excess of its total costs does not prove any decision to enter the PPA was imprudent. For example, the Commission specifically found that the Company's decisions to acquire the Rock Creek and Osborn wind PPAs were not imprudent, even though their market revenues were below their costs. See Report & Order at 15-18, 26, In re Eighth Prudence Review of Costs subject to the Fuel Adjustment Clause of KCP&L Greater Mo. Operations Co., Case No. EO-2019-0067 (Nov. 6, 2019).

Section 6 – Risk of Delaying Resource Additions

Q: Given Staff's current opposition to the Company's Operating CCN application and its failure to recognize the clear need for EMW to add capacity and energy resources now, what risks would EMW customers face if EMW is unable to add new resources?

A: There are many risks that EMW and its customers face if there is a delay in adding additional resources to the Company's resource portfolio.

Energy market exposure risk – EMW has a clear need for energy now. As shown through the IRP process, Persimmon Creek can economically fill a significant portion of that need. If EMW is not allowed to acquire this generation, that portion of EMW customer load will continue to be fully exposed to SPP energy market prices. As existing resources in SPP continue to be retired, market energy prices and market volatility are likely to increase.

Capacity risk – EMW has a clear need for capacity now. While Persimmon Creek is estimated to fulfill only a 20 MW share of EMW's capacity need, it is capacity that will have to be filled from other sources should the application for an Operating CCN be denied.

As SPP generating resources are being retired and SPP reserve margin requirements increase, surplus capacity in the region is shrinking. The Company has seen significant increases in capacity prices in the SPP region's bilateral capacity market. Short-term summer capacity that could have been purchased for $4-$8 per kW/season 3 to 4 years ago is now priced in the range of $16-$18 per kW/season. The days of a large surplus capacity in the SPP footprint are likely gone.

Future renewable resource addition cost risk – As described in Mr. Humphrey's Supplemental Direct Testimony, renewable resources have experienced significant cost pressures. This should be no surprise, given national supply chain, logistical, and permitting and siting issues, as well as and general economic inflation.

As utilities across the country continue their transition to cleaner generation fleets, the demand for renewable energy resources will undoubtably remain strong. Given the sustained demand for renewables, it can be expected that, at a minimum, any near-term renewable resource additions to EMW's resource portfolio will cost EMW customers more than Persimmon Creek.

Transmission interconnection risk – In order to place a new generating resource in operation, the project developer must get approval from SPP to interconnect with the transmission system. The complex studies needed to evaluate the transmission system impacts and potential system upgrades required to reliably interconnect new generation take time. This complexity, combined with the large number of interconnection requests in the SPP study queue, has resulted in long lead times in getting interconnection requests approved. It is currently estimated that a new interconnection request could take 3 to 5 years to get SPP approval. After approval is granted, transmission facilities must be constructed before a new resource can be placed in service. Persimmon Creek is connected to the grid and is operational today.

Lost opportunity risk – There are limited opportunities to add a fully developed and operating generating facility to EMW's supply portfolio. If EMW is unable to complete this transaction and acquire Persimmon Creek wind farm, it will have missed an opportunity to own and operate a highly efficient and productive renewable resource at a competitive price that will help meet its customers' current and long-term energy needs and serve the public interest.

Q: Does this conclude your testimony?

A: Yes.

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 a Certificate of Convenience and Necessity Authorizing It to Operate, Manage, Maintain and Control an Existing Wind Generation Facility in Oklahoma	)))))))	Case No. EA-2022-0328

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 Strategy and Long-Term Planning.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Evergy Missouri West consisting of thirty-four (34) 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 31st day of January 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

9.2 COMPARISON OF RATEPAYER AND SHAREHOLDER RISK

Provide detailed analysis in its next annual update filing comparing ratepayer risks and shareholder risks for additional generation resources that are not required to meet federal, state, or RTO requirements.

Response:

BACKGROUND

The Policy Objectives outlined in the Chapter 22 rules for the Integrated Resource Plan ("IRP") specify that a key purpose of the IRP process is for the utility to:

…describe and document the process and rationale used by decision-makers to assess the tradeoffs and determine the appropriate balance between minimization of expected utility costs and these other considerations in selecting the preferred resource plan and developing the resource acquisition strategy. These considerations shall include, but are not necessarily limited to, mitigation of:

1. Risks associated with critical uncertain factors that ***will affect the actual costs*** associated with alternative resource plans;
2. Risks associated with ***new or more stringent legal mandates that may be imposed*** at some point within the planning horizon; and
3. Rate increases associated with alternative resource plans. (20 CSR 4240-22.010(2)(C), emphasis added)

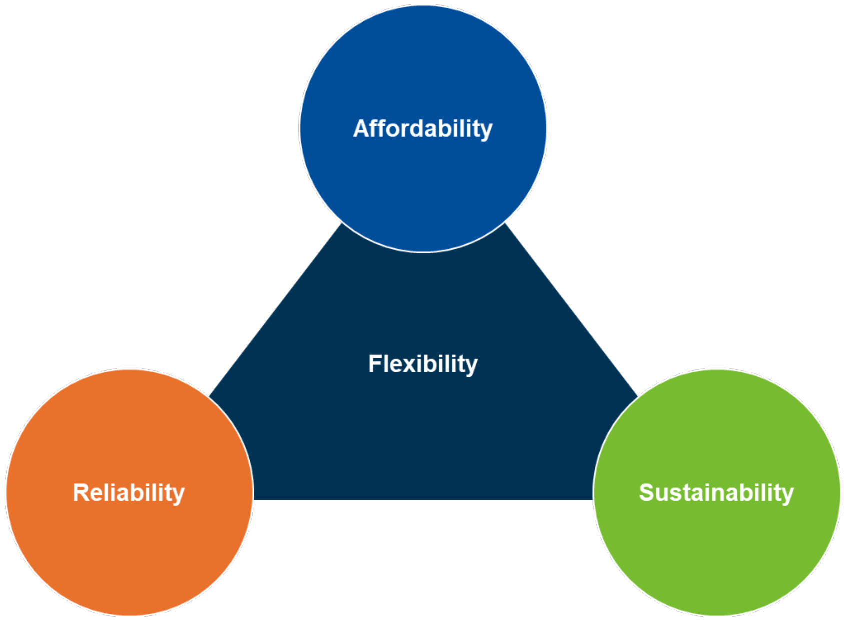
Based on this policy objective, it is clear that the purpose of the IRP is to include an analysis of risks associated with certain alternative resource plans, in addition to the expected costs associated with these resource plans. Balancing and managing risks to customers is a fundamental element of minimizing expected utility costs given an inherently uncertain future. As a result, much of the discussion associated with this Special Contemporary Issue will point to analysis performed within the existing framework of the IRP. Additional detail has been added to the IRP's risk analysis methodology, in particular to focus on shareholder risks, which are not explicitly included in the IRP rules given its focus on minimizing costs to customers. However, as will be discussed in more detail below, the primary reason for a focus on managing shareholder risk – in addition to and alongside managing customer risk – is that perceived or actual risk to shareholders directly or indirectly translates into increased customer costs / risks as these shareholder risks impact the ability of the utility to secure competitively-priced financing and insurance, which in turn influences the cost of service the utility provides to its customers.

In addition, while this Special Contemporary Issue is focused on "ratepayer risks and shareholder risks for additional generation resources which are not required to meet federal, state, or RTO requirements", a key consideration in any risk analysis – as noted by the Chapter 22 IRP rules quoted above – is the risk of <u>new or more stringent</u> legal mandates which could ultimately impact customer costs. For this reason, the risk analysis outlined below will focus on resource additions which are not required to meet *current* federal, state, or RTO requirements, but it will also include discussion of potential future changes to these requirements, which are a key driver of risks to Evergy's customers in the future.

Finally, while this Special Contemporary Issue, as ordered, is focused on generator *additions*, our response – and the IRP more broadly – will focus on an integrated view of both retirements and additions, as key components of an overall resource plan which seeks to manage customer risks and minimize long-term utility costs.

GUIDING PRINCIPLES

In implementing the fundamental objective of the resource planning process (20 CSR 4240-22.010(2)), Evergy's seeks to balance four key guiding principles, depicted below.



- **Affordability:** As outlined in the Chapter 22 rules, minimizing the present worth of long-run utility costs (as measured by the net present value of revenue requirements – NPVRR) is the primary selection criteria in selecting a preferred resource plan. However, this assessment of value and affordability should also include an assessment of other potential risks which could impact the cost of a resource plan or its ability to comply with future legal mandates. This assessment is done through the IRP process – as outlined in detail in Evergy's IRP filing and summarized below – through the use of Critical Uncertain Factors to assess the cost of a resource plan under various future macroeconomic or policy "futures".
- **Reliability:** In parallel with an assessment of risks which may impact the affordability of a given resource plan, it is also critical to assess the ability of the resource plan to continue to provide reliable service throughout the planning period. Evergy's IRP assesses this risk utilizing reliability standards for resource adequacy and resource accreditation which are established by the Southwest Power Pool (SPP); however, as the resource mix continues to change quickly across the SPP and the grid overall, there will continue to need to be refinements of how reliability risk is managed and how reliable service can be maintained as aged fossil plants are retired and replaced with

renewable and other new technologies. Evergy's approach to managing reliability risks for its customers is described in more detail below.

- **Sustainability:** Evergy has been working to transition its generating fleet to more sustainable technologies for many years. Looking forward, continuing this transition is critical not only in order to manage customer and shareholder risks, as described below, but also to continue to enhance our stewardship of the environmental resources impacted by our operations, for the benefit of our customers and communities.
- **Flexibility:** In achieving all of these objectives through the development of a preferred resource plan, maintaining flexibility in the execution and refinement of the plan is also vitally important as the policy, economic, and technology environment that we operate in continues to be more and more dynamic. In the discussion below, we will also describe how maintaining flexibility by conducting a measured and balanced transition is a key part of Evergy's resource plan, for the purpose of managing customer risk created by an ever-changing operating environment.

POLICY REQUIREMENTS

<u>Current:</u>

For the purpose of this analysis, Evergy considered the following current policy requirements:

- **Federal:** Existing Environmental Protection Agency (EPA) regulations are factored into resource cost assumptions in the IRP, but no current federal policy requirements were directly included in this analysis.
- **State:**
    - Missouri Renewable Energy Standard (RES): Evergy Missouri Metro and Evergy Missouri West are required to comply annually with the Missouri Public Service Commission's Renewable Energy Standard Rule 4 CSR 240-20.100 – Electric Utility Renewable Energy Standard Requirements. For 2022 and beyond, each utility must retire qualifying Renewable Energy Credits (RECs) equal to no less than to 15% of retail

sales. Within this, qualifying solar-generated RECs equal to no less than 0.3% of retail sales must be retired.

- **Regional Transmission Organization (RTO):**
  - SPP Resource Adequacy Requirements**:** The current SPP Resource Adequacy requirements include a reserve margin of 12% or greater - requiring that Evergy maintain a level of accredited capacity greater than or equal to 112% of its forecasted peak load for a season. Currently SPP has summer and winter resource adequacy requirements. SPP resource adequacy requirements also include rules for the accreditation of capacity which determines the extent to which a given resource can be counted toward meeting a load-serving entities resource adequacy requirement.

<u>Future:</u>

In addition to the current requirements outlined above, a variety of potential future requirements have also been considered in this analysis given the uncertainty of changes in future policies which is a factor in determining the overall customer or shareholder risk associated with Evergy's plans.

- **Federal:**
  - Future Environmental Protection Agency (EPA) regulations: In the future, it is likely that the EPA will continue to increase the stringency of environmental regulations which impact the viability of Evergy's existing fossil fleet. For example, the EPA has recently published a proposed Interstate Transport Federal Implementation Plan for the 2015 ozone National Ambient Air Quality Standards (NAAQS). This plan lowers nitrogen oxide emission allowances starting in 2023. While this plan is still in early stages, it, or similar changes in regulations, could have future impacts on Evergy's fossil plants which could ultimately require less frequent operations (due to emissions limits), increased capital investment, or, ultimately, retirement prior to Evergy's current planned retirement date for certain units. These changes would impact the economics and operations of Evergy's fleet and could also ultimately

impact its position relative to SPP Resource Adequacy requirements if capacity position is sufficiently changed.

  - Federal Carbon Tax or Similar CO_2 Restriction: One of the critical uncertain factors in Evergy's IRP (described in more detail below) is the imposition of a price on carbon emissions. While this is modeled as a "tax" in the IRP, it could take the form of any federal restriction on carbon emissions (e.g. emission limit or cap and trade). Although this type of policy has not yet been implemented, the ongoing push toward decarbonization among policymakers makes it a continued topic of discussion and a future policy which could have a very large impact on the economics of Evergy's fleet and, in turn, its resource decisions and capacity position.

- **State:**
  - Missouri Renewable Energy Standard: In recent legislative sessions, there have been multiple attempts to increase the RES requirements. The potential for this increase to occur in the future is a consideration in this analysis, although this policy change is perhaps less likely than changes at the Federal and RTO level.
- **Regional Transmission Organization (RTO):**

SPP Resource Adequacy Requirements**:** SPP continues to evaluate changes to resource adequacy requirements given recent extreme events and ongoing changes to the resource mix. These changes could materialize in the form of changes to capacity accreditation for traditional (non-renewable) resources, increases in required reserve margin, or the imposition of four- (or more) season resource adequacy requirements. All of these potential changes would have an impact on Evergy's ability to comply with these requirements and would thus impact its planning decisions related to retirements and additions.

OVERALL CONCLUSIONS AND EVERGY'S PREFERRED RESOURCE PLAN

Figure 6 includes Evergy's combined company capacity position given its current retirement plan, as outlined in the 2022 Preferred Plan. As shown in Figure 6, Evergy has a large capacity need (~4,000 MW) over the twenty-year period and thus all resource additions which were included in Evergy's overall Preferred Plan are ultimately required to meet SPP Resource Adequacy requirements (shown in Figure 7 which includes resource additions from the Preferred Plan). However, for the purpose of this risk analysis, Evergy will compare this Preferred Plan to a new Alternative Resource Plan which adds renewables only when needed to meet Missouri RES requirements (based on renewable forecasts for MO Metro and MO West) and capacity (of any type) only when needed to meet Resource Adequacy requirements as its benchmark for adding resources only when "required" ("RES Requirements Plan", Figure 8).

This comparison will demonstrate the risk-weighted economic benefits of Evergy's current Preferred Plan compared to the "RES Requirements" plan. In addition to this pure financial comparison, Evergy will describe below the way various types of customer and shareholder risks were factored into the decision-making which ultimately resulted in the Preferred Plan.

Figure 6: Capacity Balance based on 2022 Preferred Plan – No Additions

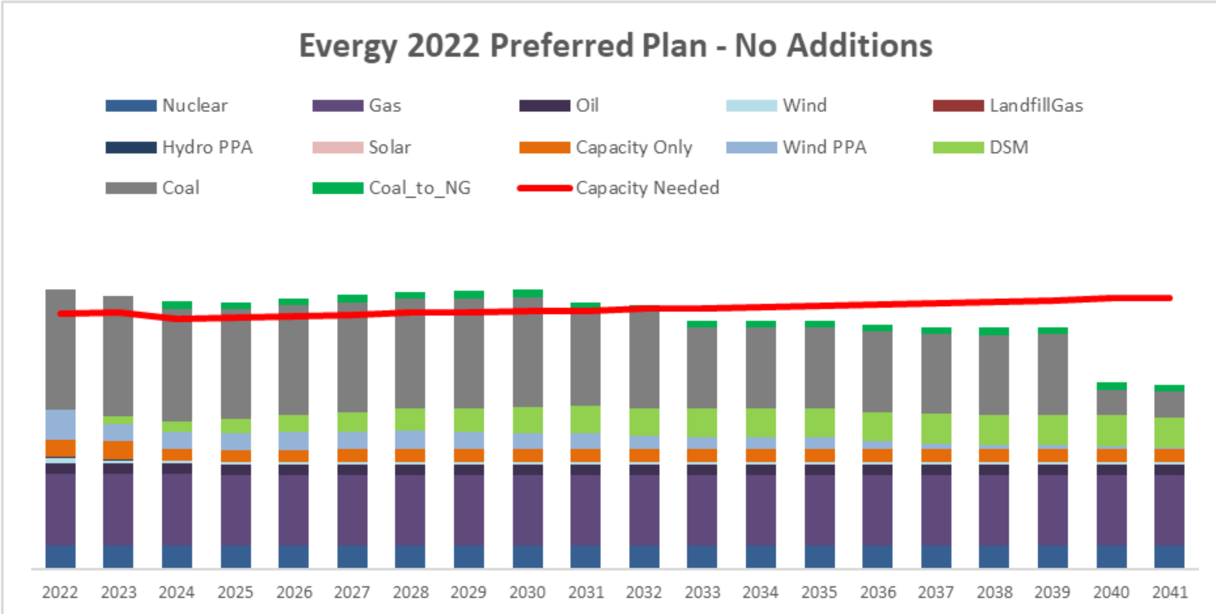


Figure 7: Capacity Balance based on 2022 Preferred Plan – Including Additions

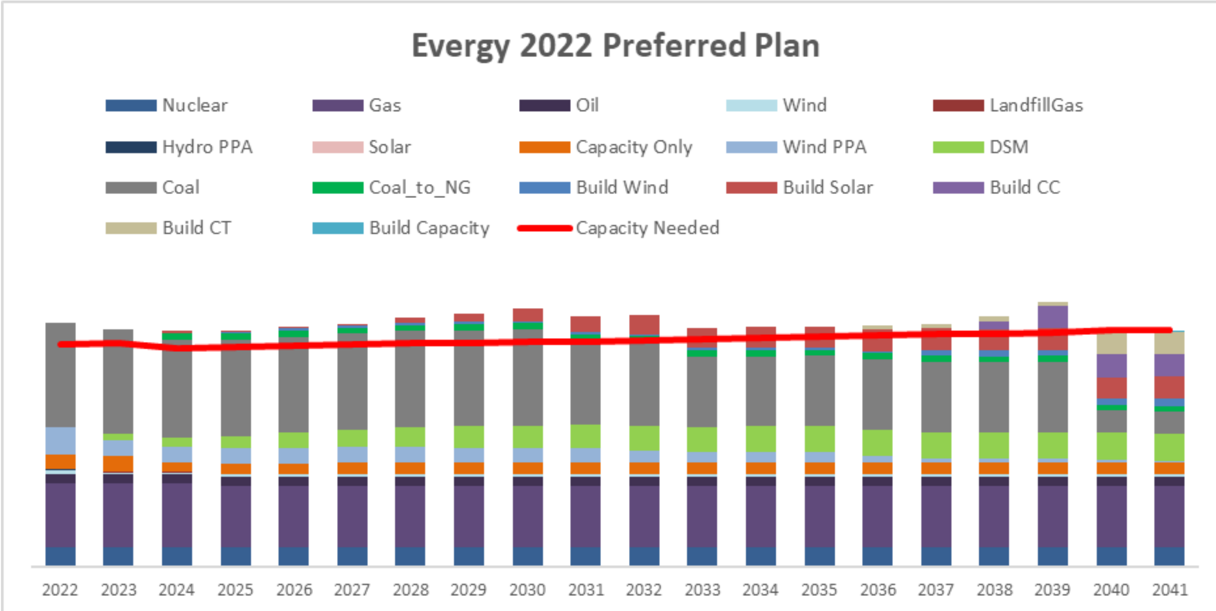
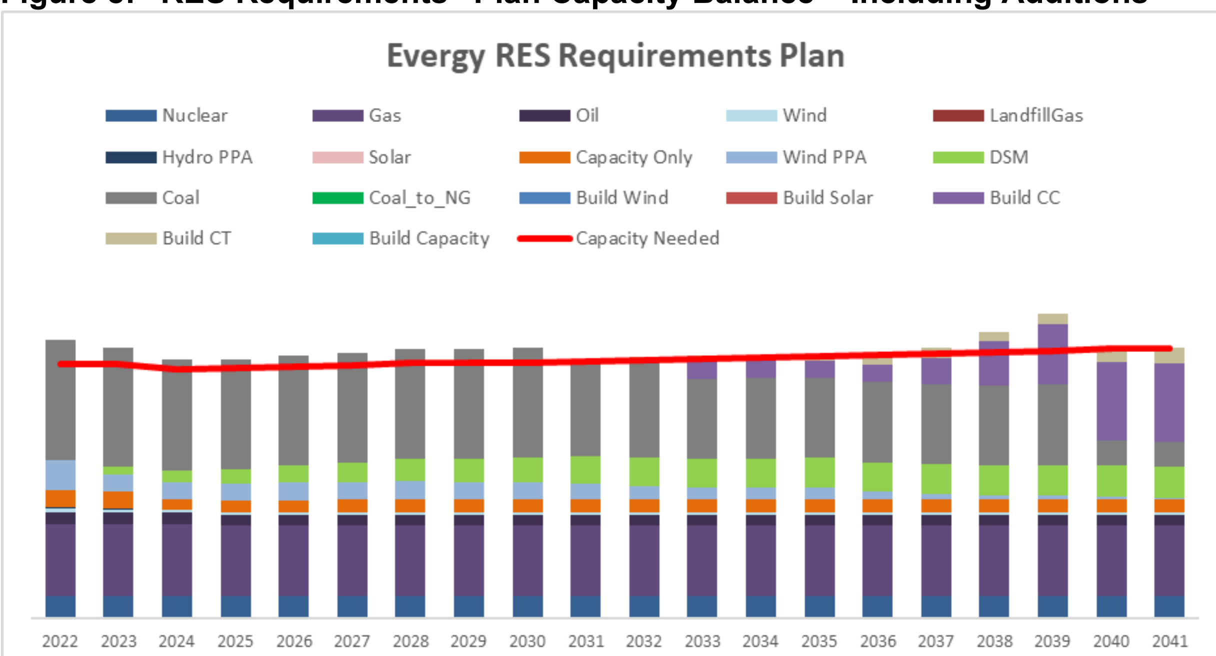


Figure 8: "RES Requirements" Plan Capacity Balance – Including Additions



Ultimately, Evergy's Preferred Plan (and the Preferred Plans of Evergy Missouri West and Evergy Metro which are aligned to Evergy's Preferred Plan), includes a measured pace of plant retirements in order to manage reliability risk and the risk of changes in resource adequacy requirements. The pace of retirements is paired with ratable renewable additions which allow the company to capitalize on current tax credits and the availability of high-quality renewable sites with more favorable locations on the transmission system for the benefit of our customers, while also mitigating the risk of future acceleration of plant retirements, continued pressure on financing and insurance costs, execution risk associated with large just-in-time execution of capacity replacements, and future increases in wholesale market prices due to carbon restrictions.

RISK ANALYSIS APPROACH

In assessing customer and shareholder risks associated with the preferred resource plan, Evergy has identified a variety of types of risks which can be analyzed – either quantitatively or qualitatively. Later sections will contain the results of these analyses.

Customer Risk:

Risk Analysis in the IRP

The IRP Rules include a robust risk analysis framework which has been utilized to conduct much of the Customer Risk Analysis supporting this evaluation. The results of this analysis will include a discussion of the following risk factors:

- Changes to Federal, State or RTO Policy
  - Change in EPA Requirements
  - Carbon Tax / Carbon Restrictions
  - Increase in RES Requirements
  - Changes to Resource Adequacy Requirements
- Commodity / Market Prices
- Resource Costs
  - Capital Costs and Technology Improvements
  - Tax Credits
  - Availability of High-Quality Sites
- Phasing and Executability

Additional Customer Risk Analysis in the IRP

To supplement to those factors explicitly considered in the IRP framework, additional customer risk factors have also been included in this analysis.

- Reliability
- Financing Costs
    - Capital Markets
    - Environmental, Social and Governance ("ESG") / Fossil Exposure
- Insurance Costs
- Customer Preferences

Shareholder Risk

As the IRP is focused primarily on customer risks, an additional shareholder risk analysis has been conducted which factors in the items listed below.

- Execution Risk
- Regulatory Risk

Customer Risk Analysis

RISK ANALYSIS IN THE IRP

The IRP process primarily utilizes scenario analysis to assess the risk of various resource plans in ultimately informing the selection of a Preferred Plan. In addition to this, the input assumptions which are utilized in the IRP can also be informed by risk analysis and can incorporate expectations around certain risks / uncertainties into the analysis, with the goal of selecting a plan which is ultimately robust across a variety of potential customer risks. Both scenario analysis and risk-informed input assumptions will be discussed below.

Scenario Analysis & Input Assumptions

As outlined in the Chapter 22 IRP rules, the IRP utilizes a combination of “Critical Uncertain Factors” to create scenarios across which the economics of various resource plans are subsequently evaluated. In Evergy’s 2022 Annual Update, this included three critical uncertain factors (natural gas prices, CO_2 prices, and load growth), each with three different potential levels (high, mid, low) – ultimately resulting in 27 different scenarios. Evergy then modeled 10 different joint planning (Evergy level) resource plans, with an additional RES Requirements plan modeled for this analysis across these 27 different scenarios, calculated NPVRR for each plan in each of the 27 scenarios, and then calculated an “Expected Value” for NPVRR, which is, essentially, a risk adjusted NPVRR. In the results section below, both the individual scenario results and the expected value will be discussed.

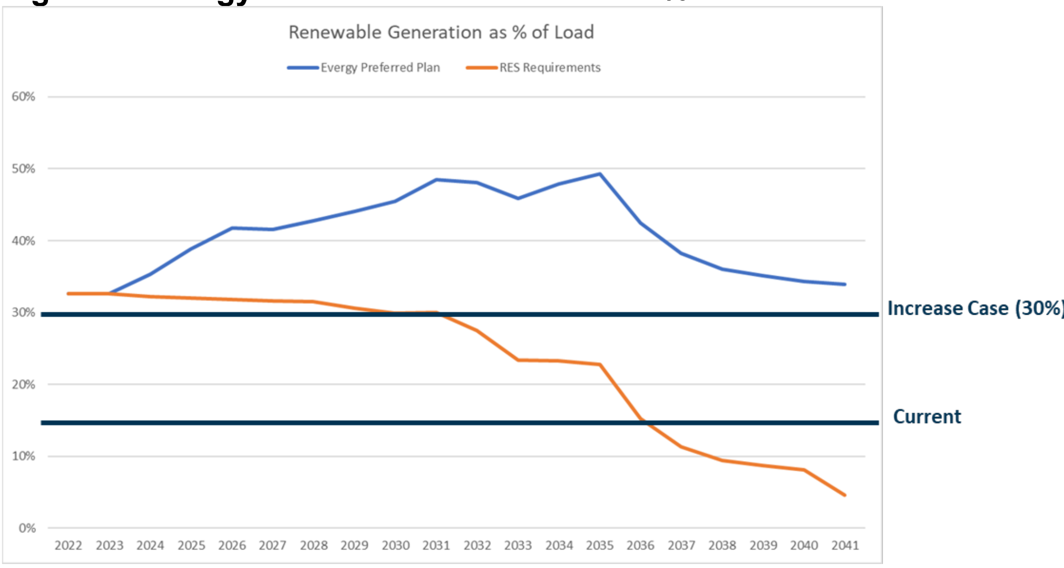
In addition to scenario analysis, risk and uncertainty is also incorporated into many of the input assumptions within Evergy’s IRP.

Through the combination of Critical Uncertain Factors, Alternative Resource Plans (scenario analysis), and Input Assumptions, Evergy has incorporated the customer risk factors discussed below into its analysis:

- Change in Federal Policy
    - Future EPA Regulations: Evergy utilized a mix of resource plans to assess the potential impact of changes to EPA regulations on its resource decisions. The capital plans included in the 2022 Annual Update all assume that Evergy’s resources comply with current EPA regulations. The majority also assume that all units have Best Available Control Technology (including selective catalytic reduction – SCR – and baghouses) before the end of the planning period. This represents an assumption that EPA regulations will continue to become more stringent over the next 10-20 years and, ultimately, these technologies will be required on all coal units. In addition to these base assumptions, two sensitivities were also used to evaluate uncertainty around future EPA regulations.

        - CDDAG and CDDAH: Sensitivity which demonstrates the impact of removing assumed cost of SCRs and baghouses for Jeffrey Energy Center units. This represents a case where relevant EPA regulations do not change in the next twenty years and thus these technologies are not required. Given the small Missouri West ownership percentage in Jeffrey, this sensitivity is included in the IRP filing, but will not be discussed in detail in this analysis.
        - Accelerated (2030) Retirements: Several plans were evaluated which represent accelerated retirement of one of Evergy's large coal units compared to the Preferred Plan from both the 2021 and 2022 IRP. While this retirement could ultimately be accelerated due to economics, assuming suitable replacement technology is available (discussed in more detail in Section 6 and Section 7:), it is perhaps even more likely that this acceleration could be driven by changes in policy requirements. While Jeffrey Unit 2 was identified as the most economic retirement option at the Evergy level, given the focus of this analysis on Missouri West and Metro, the Iatan 1 early retirement plan will be utilized here for illustration purposes.
    - Carbon Tax / Carbon Restrictions: In the 2022 Annual Update, three different levels (high, mid, low) of carbon tax were utilized to assess the impact of a carbon tax / carbon restriction of some sort on the impact of Evergy's resources. The results of this analysis are included in the IRP Results section below.
- Change in State Policy
    - Increase in RES Requirements: While an assessment of different RES Requirements was not directly factored into the 2022 Annual Update, a summary of Evergy's position under various RES Requirements – for both the Preferred Plan and the "RES Requirements" Plan – is included below. This view demonstrates that if, for example, the RES requirement was increased to 30%, it would likely accelerate the need for new renewables into the late 2020s or early 2030s.

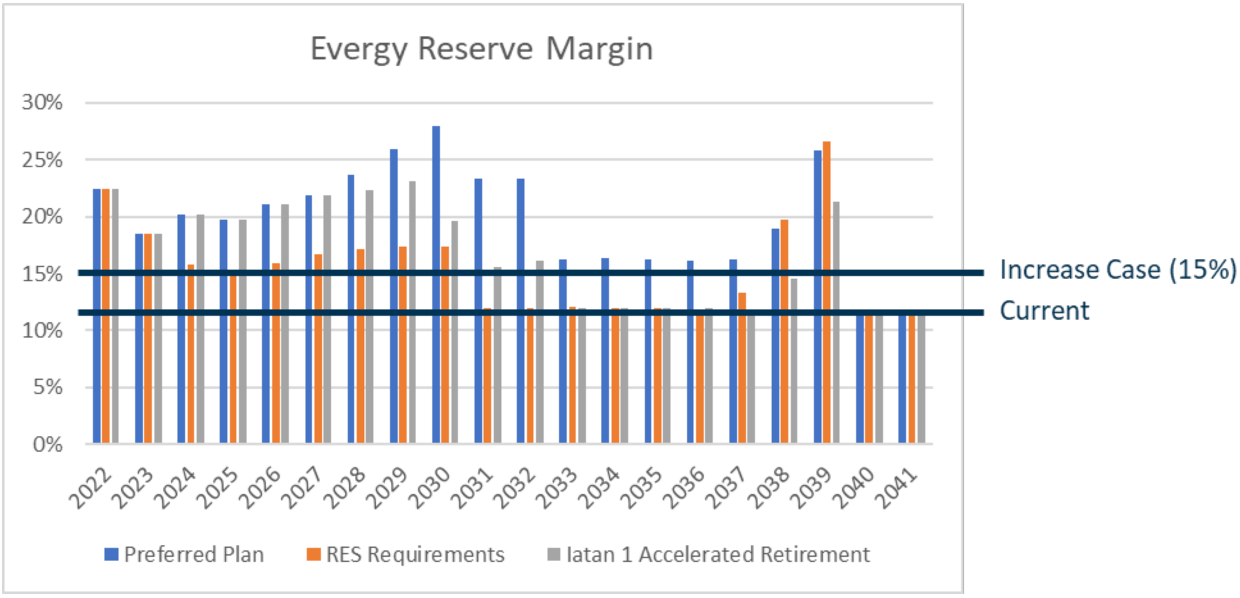
Figure 9: Evergy Renewable Generation as % of Load



Note: Forecast indicates Evergy Missouri West and Evergy Metro would have sufficient banked RECs to comply in later years of period (2037-2041) without additional renewables in RES Requirements plan

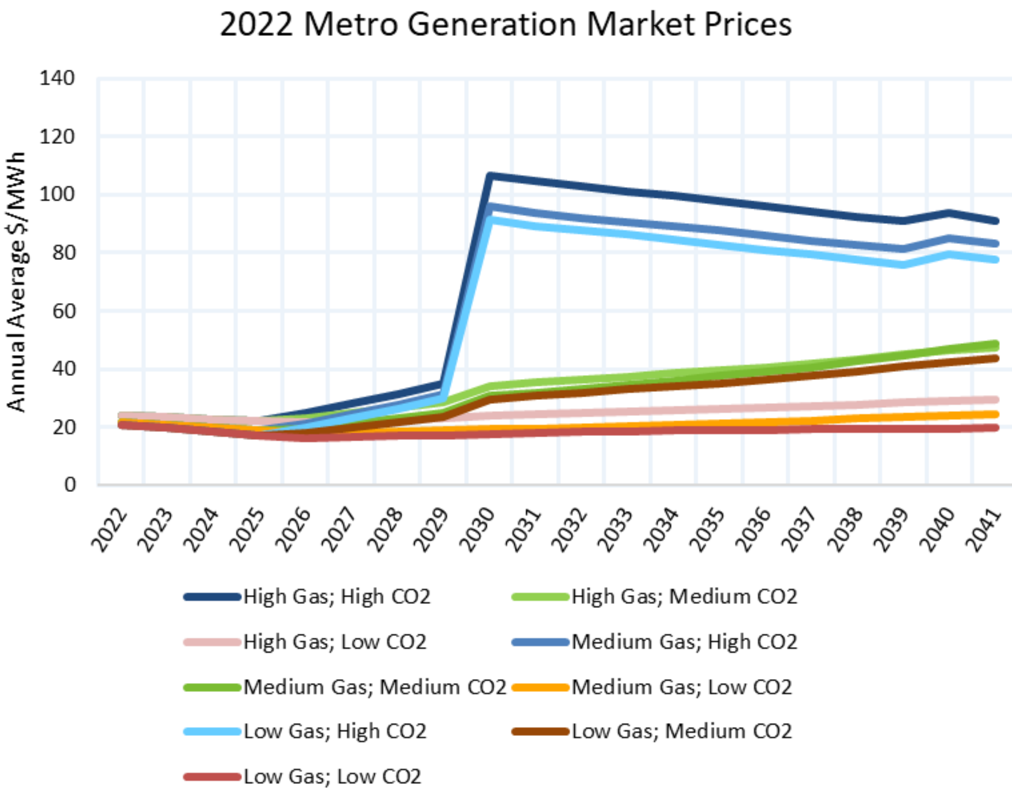
- Change in RTO Policy
  - Changes to Resource Adequacy Requirements: Given the uncertainty around changes to SPP's Resource Adequacy requirements, an assessment of different requirements was not directly factored into the 2022 Annual Update. However, reserve margin results are shown below for the Preferred Plan, the "RES Requirements" Plan, and the "Accelerated Retirement" sensitivity below. These results indicate that under the RES Requirements Plan, if SPP increased its minimum reserve margin requirement to 15%, for example, Evergy (collectively) would be short in the early 2030s after Jeffrey 3 and La Cygne 1 retire. If the retirement of Iatan 1 were accelerated to 2030 ("Accelerated Retirement" case), the combined entity would fall below a 15% reserve margin around the same time (although slightly later), even with consistent renewable additions between now and 2030.

Figure 10: Evergy Combined Reserve Margin



- Commodity / Market Prices: The Critical Uncertain Factors described above incorporate a range of commodity price assumptions into the IRP risk analysis and are, in turn, used to generate a variety of wholesale market price assumptions. This range of wholesale market prices ensures that future variability of commodity and market prices is incorporated into NPVRR calculations for various resource plans. The market prices used in the 2022 Annual Update are shown below.

Figure 11: 2022 Annual Update Market Prices (based on average Metro Generation Node)



- Resource Costs
  - Capital Costs and Technology Improvements: Renewable capital costs have generally declined over time and are expected to continue to decline going forward as technology continues to improve. However, recent supply chain challenges have caused costs to increase in the short-term. In order to incorporate these pricing dynamics into IRP input assumptions, Evergy has utilized recent RFP responses to inform near-term renewable build costs and has applied a third-party cost curve (average of NREL and EEI forecasts) to future builds. This assumption is built into all plans in order to incorporate expected cost changes into the company's risk analysis. While technology-driven cost declines are currently expected to continue, there is an additional risk – which is not included in current IRP assumptions – that future policy regarding renewable supply chains, at either the state or federal level, could increase requirements for domestic manufacturing. This type of policy change could apply upward pricing on supply chains and materials needed for renewable resources in the medium- and long-term depending on when / if these changes are implemented.
  - Tax Credits: Renewable Tax Credits (Investment Tax Credits and Production Tax Credits) can have a large impact on the economics of renewables. Although these tax credits have been extended many times in the past and there are discussions of changes to these credits

which could result in even more favorable economics for renewables, Evergy utilizes tax credit assumptions which are consistent with current Internal Revenue Service (IRS) rules as opposed to speculating about future changes to these rules. This assumption is built into all plans in order to assess the economics of plans under today's tax environment – if changes are made to IRS rules in the future, these changes will be incorporated in future IRPs.
    - Availability of High-Quality Sites: While this is not factored directly into the IRP risk analysis, a key consideration in determining whether to install renewables now or wait until they are absolutely required is the availability of attractive sites for renewable development. There are currently more than 80 GW of wind, solar, battery, and hybrid projects in the SPP interconnection queue. As developers have identified sites for these queue requests, they have first focused on the identification of the most attractive sites in terms of renewable resource, land availability, congestion / curtailment risk, and general executability. If Evergy chose to delay the investment in renewables until they are absolutely required, we would ultimately be limited to the less attractive development sites which would be available at that time.
- Phasing and Executability
    - A key risk to consider when it comes to installing new capacity of any type is executability and ensuring that construction and interconnection can be completed in a timely manner. Particularly given the current backlog in the SPP Interconnection Queue, Evergy believes it is critical to maintain a measured pace of new additions, without requiring sizeable additions all installed within a short one-to-three-year time period, for example. Measured, ratable additions allow Evergy to stay up to date on market conditions, maintain a consistent internal development / procurement organization, and mitigate the risk of delays caused by the Interconnection Queue. In order to capture these risk mitigation benefits, Evergy's capacity expansion model was constrained to allow a maximum number of builds per year, which varied by technology type (Combustion Turbine vs. Combined Cycle vs. Renewable). For renewable resources, this constraint was set at 450 MW per year (3-150 MW projects) based on Evergy's experience executing renewable projects to-date. As conditions change in the renewable supply chain and the SPP Interconnection Queue, it's possible this constraint could be eased, but based on market knowledge today, Evergy believes this constraint is reasonable and allows execution risk to be appropriately considered in the IRP risk analysis.

RESULTS OF IRP CUSTOMER RISK ANALYSIS

As shown below, the RES Requirements plan has a significantly higher expected value NPVRR than the Preferred Plan and was the most costly plan modeled at the Evergy level on an expected value basis. In addition, Figure 12 shows that the RES Requirements plan is also the highest risk plan, as measured by the standard deviation of NPVRR across all 27 endpoints. Standard deviation is used as a statistical measure of risk in this case because it demonstrates variability in resource plan cost across different modeled scenarios. Finally, Figure 13 shows a comparison of the Preferred Plan and the RES Requirements plan in each of the 27 modeled scenarios. This shows that the RES Requirements plan is more expensive than the Preferred Plan in 15 out of 27 modeled endpoints, particularly those which include medium or high carbon prices. In addition, in 6 of the 12 scenarios where the RES plan is lower cost than the Preferred Plan, it is higher cost than plan CCBAA which is identical to the Preferred Plan in the Implementation Period and only varies in the medium- and long-term. The remaining 6 plans where the RES Requirements plan is lower cost than both the Preferred Plan and CCBAA all include no carbon restriction and either low or medium gas prices. Given today's policy and commodity price environment (high gas prices) in particular, selecting the RES Requirements plan as opposed to either CCBAA or Preferred Plan – which include the same near-term actions – would be a poor way to manage future customer risks; particularly given the difference in expected value NPVRR and overall variation in NPVRR across scenarios.

Table 42: Expected Value NPVRR Results

Plan Name	Expected Value NPVRR ($M)	Delta From Preferred Plan ($M)
Preferred Plan (Ratable Renewable Additions)	$57,541	-
RES Requirements	$57,991	$450

Figure 12: Standard Deviation across 27 Endpoints

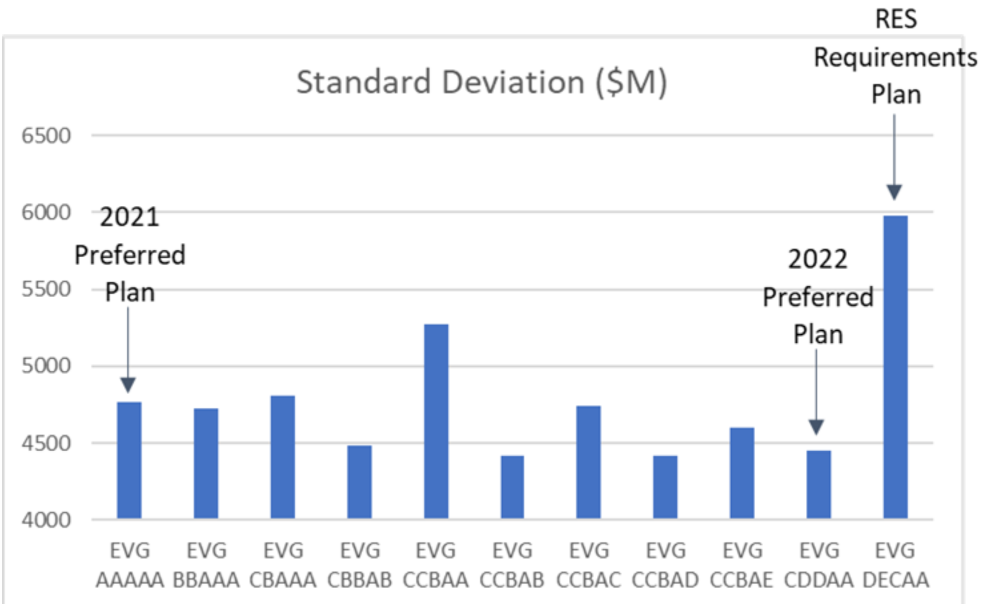
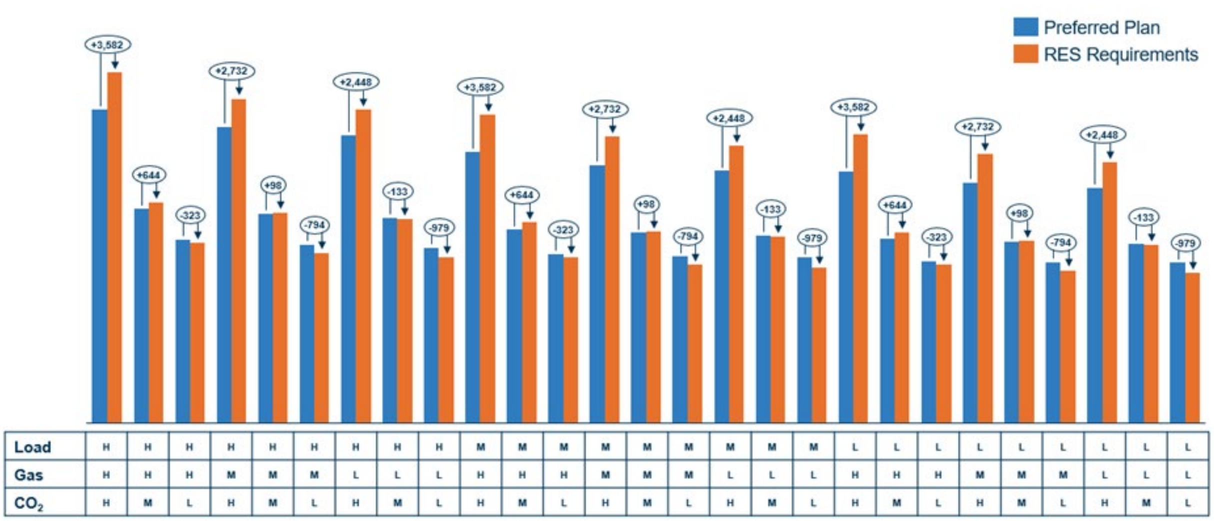


Figure 13: NPVRR Comparison by Endpoint ($M)



ADDITIONAL CUSTOMER RISK ANALYSIS – RELIABILITY

As demonstrated above and in Section 6 of the IRP, if an additional coal retirement is accelerated to the 2030 timeframe, it would reduce costs on an expected value basis compared to the current Preferred Plan and (as shown in Figure 10), the renewable additions included in the Preferred Plan would then be required to meet

SPP Resource Adequacy requirements shortly after the retirement (meaning they would no longer qualify as “additional generation resources that are not required to meet federal, state, or RTO requirements”). However, as outlined in Section 6, Evergy has chosen not to commit to an additional accelerated retirement at this point due to uncertainty in being able to maintain reliability when retiring ~2,500 MW of firm, dispatchable capacity in the next 10 years (through 2032) and relying solely on renewable replacement capacity, even when current SPP Resource Adequacy Requirements can be met using only renewables. The current Preferred Plan includes ratable renewable additions to provide valuable future capacity and energy to Evergy’s customers, managing risk of future policy and market changes, while also maintaining flexibility in coal retirements to allow time for low- or non-emitting technology to develop which can “back up” these renewable resource additions in the medium and long-term.

ADDITIONAL CUSTOMER RISK ANALYSIS – FINANCING COSTS

As part of complying with the Chapter 22 IRP rules, the Company quantitively evaluated financing costs (interest rates, specifically) as a potential critical uncertain factor in the 2021 Triennial IRP and this factor was not identified as critical (i.e., it did not have a material impact on the ranking of plans).

The Company also qualitatively assessed and considered the various levels of financing risk when selecting preferred resource plans. Timing of going to market with a transaction, the size or quantity of capital to be raised, the type of capital to be raised whether debt or equity, the types of projects the capital is going to finance (e.g. renewables, pollution control equipment, or coal generation maintenance), the Company’s regulatory calendar or timing of rate reviews, impacts to credit quality, as well as the current market cost of capital are all factors that need to be considered when assessing financing risk. Customers and shareholders are both subject to financing cost risk due to ever-changing market dynamics, credit risk, management’s track record of plan execution, the Company’s perceived regulatory construct, and world events, to name a few. In addition, investors are becoming more sensitive to environmental, social, and governance issues (“ESG”), also referred to as “sustainable investing.”

Evergy's current owned generating capacity is heavily dependent on fossil fuels, specifically coal. Any resource plan that delays or avoids transitioning the generation fleet to more sustainable sources will be viewed negatively by the growing investor base and investment banks that have ESG investment requirements or coal exposure limiting criteria. The criteria and metrics used by different investors and banks vary when evaluating ESG requirements, but generally, 30% of revenue or 30% of energy generated by coal is a common limit for coal exposure currently seen in the finance space, which most likely will tighten further over time. Currently, about 50% of Evergy's energy, whether generated or from purchased power agreements, comes from fossil fuel sources. Fundamental economic principals would indicate that reduced demand via fewer investors or lower exposure limits will increase the cost to raise future debt and equity capital which is ultimately borne by customers. These increased financing costs, not only impact the financing of maintaining current generation or transitioning the generating fleet but also impact the financing costs of investing in modernizing the transmission and distribution grids.

The possibility of correctly predicting the magnitude of the increase in debt borrowing cost and the future cost of equity returns that is commensurate with companies sharing similar risk is virtually nil. However, the assumption that financing costs will increase due to transitioning the current generating fleet too slowly should be expected. In addition, customers have received the benefit of the Company steadily reducing the weighted cost of its long-term debt portfolio over the last decade by taking advantage of historically low long-term debt rates. Customers have also received the benefit of historically low short-term interest rates, which manifests in the form of lower AFUDC and lower capital project costs. The recent historically low interest rate environment that we've experienced won't last forever, as the Federal Open Market Committee has raised the federal funds interest rates twice this year and has communicated the plan to raise the federal funds interest rate a total of 7 times during 2022 -- another sign that financing costs should be expected to increase in the future. In addition, the 10-year Treasury has moved from 1.63% on Jan 3, 2022 to a high of 3.12% on May 6, 2022 and the 30-year Treasury has moved from 2.01% on Jan 3, 2022 to a high of 3.23% on May 6, 2022. These rates represent a significant upward move in the cost of debt and the federal reserve has indicated continuing monetary policy.

Since the Company can't predict the rise of capital costs directly due to transitioning the generating fleet too slowly, or what is perceived by the investment community as too slowly, we've quantified a sensitivity for both debt and equity costs that would ultimately be paid by customers. A 100-basis point (bps) increase in current debt costs to finance the capital portion of the preferred resource plan (assuming ~50% of the plan is financed with long-term debt) would increase the 20-year NPVRR by $632 million. A 50-bps increase in the cost of equity to finance the capital portion of the preferred resource plan (assuming ~50% of the plan is financed with equity) would increase the 20-year NPVRR $413 million.

ADDITIONAL CUSTOMER RISK ANALYSIS – INSURANCE COSTS

Many commercial insurance markets have announced ESG targets limiting or completely excluding them, now or in the future, from insuring entities that have coal generation. Evergy anticipates that additional commercial insurance markets will announce carbon restrictions in the future. There are two primary results associated with commercial markets carbon restrictions and the Company's continued use of carbon emitting generation sources, these are:

1. Inability to complete our insurance programs and adequately transfer risk due to lack of capacity
2. Higher annual premium expense resulting from reduction of available capacity

Approximately 40% of Evergy's largest insurance lines, excluding nuclear insurance, are exposed to commercial markets. Evergy has already had commercial markets exit our program because of their carbon restrictions; additionally, there are current participants on our program who have announced carbon targets but are able to remain on our program at this time. The Company has qualitatively assessed these risks and determined a delay in transitioning our generating fleet would likely lead to a combination of the two items outlined above.

ADDITIONAL CUSTOMER RISK ANALYSIS – CUSTOMER PREFERENCES

While this has not been assessed quantitatively, a key consideration in Evergy's future fleet transition is customers' and communities' continued preference for more renewable energy and less dependence on fossil fuels. As an example, many of Evergy's commercial / industrial customers and municipalities have very aggressive carbon reduction goals. While Evergy's primary goal in its planning processes is to minimize expected customer costs (NPVRR), it is important to consider the risk – in terms of lost economic development opportunity, for example – of not transitioning away from fossil fuels. Evergy believes its current Preferred Plan contains an appropriate pace of transition that balances affordability, reliability and sustainability effectively given current technology, but a plan similar to the "RES Requirements" plan, by contrast, would severely hamper Evergy's ability to support the ESG goals of its customers and communities.

SHAREHOLDER RISK ANALYSIS

The IRP required risk analysis in selecting a preferred resource plan is centered around minimizing the present worth of long-run utility costs, as measured by the NPVRR. Investor risk, specifically shareholder risk, is a direct input into the cost and affordability of the resource plan for customers, therefore shareholder risks also need to be considered when selecting the preferred resource plan.

Shareholders provide capital to the Company to invest on their behalf with an expectation to be afforded the opportunity to earn a return on their investment that takes into consideration the risks to which their investment is exposed. Shareholders bear risks before customers begin to pay for the use of an asset that shareholders fund, and often, customers receive the benefits of the asset while shareholders continue to bear the entire cost. The risk shareholders are exposed to over the life of their investment can be summarized into the following broad categories:

- **Execution Risk:**
  Execution risk is the risk that management fails to deliver results consistent with operational and financial plans, or in other words, the Company's business plans are not successful when put into action.

The executability of the preferred resource plan and the flexibility the plan affords is a consideration in the selection. The Company considers and weighs the probability of successfully executing on the Preferred Plan to deliver operational and financial results consistent with shareholder expectations, while leaving enough room to adapt to the changing environment we operate within. This is the primary reason why the preferred resource plan must take a measured approach to transitioning the fossil-fuel generating fleet as opposed to making single large-scale changes that put shareholders at greater risk than necessary, which ultimately customers pay for when new rates are established. If the Company were to wait until the last moment to retire and replace the fossil-fuel generating fleet, optimal project site selection could be limited, the ability to negotiate the best terms for those projects is severely limited, and if the market knows the Company needs to raise significant capital at a given point in time, the expectation would be paying a premium to issue bonds and additional equity being issued at potentially steep discounts, all which increase the cost of capital.

Mitigating execution risk includes effectively managing individual project execution as it relates to the Preferred Plan, since relatively large sums of capital are tied to individual generation projects. Project execution involves mitigating pricing exposure to unknowns such as transmission interconnection and network upgrades, navigating supply chain interruptions, mitigating contractor risk, ensuring construction quality, and keeping entire project costs within budget and completed on time to avoid any questions or concerns surrounding prudency issues.

- **Regulatory Risk:**

  Regulatory risk is the risk shareholders are disallowed a return on or of their investment or lose out on opportunities to earn the Company's authorized return due to regulatory lag, or the time between investors deploying their capital and the time that capital is reflected in customer rates. Regulatory risk that shareholders also consider is the overall regulatory construct that an electric utility operates within, with a focus around authorized return on equity, capital structure, and mechanisms to mitigate regulatory lag. As electric utilities continue to transition their generation fleets to more sustainable forms of generation, investors will also consider the availability (or unavailability) of regulatory mechanisms which can facilitate the transition of the generation fleet. Predetermination, accelerated depreciation, and securitization are all examples of these types of mechanisms.

Managing execution and regulatory risk is vital in keeping the cost of equity capital competitive with our peer utilities that we compete with for capital. Managing these same risks is equally important to maintaining credit quality. If shareholders determine they are not being compensated or afforded the opportunity to be compensated for the level of risk they undertook, they will sell their investment, which will drive up the cost of equity capital. In the same vein, if the Company isn't managing execution and regulatory risk, credit rating agencies would view this negatively, which would increase the cost to raise debt capital. Ultimately, the higher cost of equity and debt capital will increase customer costs.

An estimate of the risk shareholders are exposed to over the life of their investment can be quantified by computing what a 100 – 200 bps under-earning of the allowed ROE would be over the 20-year preferred resource plan. Shareholders are exposed to additional risks that are outside just the capital investment of the resource plan. Shareholders are not compensated until all other parties exposed to the Company are paid, but in order to keep the relative risk comparable to the customer risk, the 100 – 200 bps under-earning range is only computed on the capital investment in the preferred resource plan. The present value of the generation related capital investment of the Preferred Plan is $6.2 billion. Assuming the investment is funded with 50% equity, a 100 – 200 bps under-earning of ROE is $31 million - $62 million.

CONCLUSION

The assessment of risk included in this document represents a point-in-time summary of the current understanding of the risk mitigation benefits associated with completing the fleet transition identified in Evergy's Preferred Plan as opposed to waiting to invest in renewables when they are required under the current regulatory and policy framework. The planning environment which Evergy operates within is continuing to become more dynamic so it is likely that our understanding of the drivers outlined in this document will evolve over time, as will the regulatory and policy framework. To that end, the key in selecting a Preferred Plan is ensuring that the near-term actions (Implementation Period) associated with the Preferred Plan are robust across a variety of future scenarios and that the Preferred Plan in total gives the Company sufficient flexibility to adjust over time as technology, market, and policy dynamics change – allowing it to manage risk for customers and shareholders effectively on an ongoing basis. Evergy's current Preferred Plan maintains a measured pace of fossil retirements, which continues to reduce our dependence on fossil fuels over time, but also maintains firm, dispatchable capacity from coal units until later in the planning horizon when it is expected that new / improved technologies will be available which can provide non-emitting, firm, dispatchable capacity to provide the same reliability benefits which coal plants have provided for the last century. In parallel with this pace of retirements, the Preferred Plan includes ratable, consistent renewable additions throughout the first 15 years of the planning horizon. This consistency of investment allows Evergy to manage execution risk for both customers and shareholders, capitalize on the highest-value renewable sites available, and continue to transition to a more renewable energy mix even as coal capacity is retained for reliability purposes. Additionally, this consistent investment in new capacity allows Evergy to be prepared if policy drivers of the fleet transition (e.g., carbon restrictions or EPA regulations) accelerate and force earlier retirement of more of its coal fleet. Through years 5-15 of the Preferred Plan, Evergy is hopeful to see the implementation of economic energy storage capacity as well to supplement / replace some of the planned renewable investments (as well as potentially delay the need for new firm, dispatchable technology). This potential will be evaluated in more detail in Evergy's 2023 Annual Update.

In summary, Evergy believes that the current Preferred Plan represents an effective balance of both customer and shareholder risks as they are understood at this time, while maintaining flexibility for future adjustments as conditions change.

Note: This SCI responds to the 2021 Evergy Missouri West 2021 Triennial Joint Filing "Staff's Concern B".

SCHEDULE KM-4

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