PUBLIC VERSION

**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

DIRECT TESTIMONY OF

KAYLA D. MESSAMORE

ON BEHALF OF EVERGY METRO, INC., EVERGY KANSAS CENTRAL, INC. AND EVERGY KANSAS SOUTH, INC.

IN THE MATTER OF THE APPLICATION OF EVERGY KANSAS METRO, INC., EVERGY KANSAS SOUTH, INC. AND EVERGY KANSAS CENTRAL, INC. TO MAKE CERTAIN CHANGES IN THEIR CHARGES FOR ELECTRIC SERVICE PURSUANT TO K.S.A. 66-117.

Docket No. 23-EKCE-775-RTS

April 25, 2023

I. INTRODUCTION AND SUMMARY OF TESTIMONY

Q: Please state your name and business address.

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

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

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

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of EKC ("the Company"). I will refer to EKC and EKM together as "Evergy".

Q: What are your responsibilities?

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

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

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

Q: Have you previously testified in a proceeding before the Kansas Corporation Commission ("Commission" or "KCC") or before any other utility regulatory agency?

A: Yes. I have provided testimony before the KCC and before the Missouri Public Service Commission ("MPSC").

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to discuss EKC's resource adequacy position, the resource planning challenges EKC faces in the coming years, and the proposals we are making in this docket to help address some of those challenges as well as the associated customer benefits that will be produced.

Q: Please provide a summary of your testimony.

A: EKC relies upon a robust Integrated Resource Planning ("IRP") process to plan for its forecasted resource adequacy requirements. The IRP is updated annually and considers a wide range of dynamic market conditions and scenarios. The pace of market changes has accelerated and EKC is now experiencing tremendous market changes even between annual filings – for example, beyond those contemplated in its preferred portfolio in the IRP Annual Update filed in June 2022. EKC's need for capacity is expected to increase significantly over the next several years due to two primary factors. The first is the addition of a new plant Panasonic is building in EKC's service territory that is forecasted to be twice as large as EKC's current largest customer. The second pertains to changes that have been made / proposed by SPP to its tariff and planning criteria which will increase EKC's generation capacity reserve margin requirements, as well as change its calculation of accredited generation capacity. EKC's ongoing IRP modeling efforts for the 2023 Annual Update and ongoing SPP stakeholder processes will ultimately inform the full quantification of these resource adequacy impacts. However, preliminary evaluations demonstrate that EKC will need to add substantial capacity before 2026 to meet these obligations.

The Company has three specific resources that each are currently operational and economically beneficial for customers to satisfy a portion of this resource adequacy need that we propose to reflect in rates in this proceeding: (1) EKC's ownership of 8% of the Jeffrey Energy Center that is not in rate base and is not being used to meet EKC's resource adequacy requirements, (2) the Persimmon Creek Wind Farm – upon which EKC intends to close its purchase on or before April 28, 2023; and (3) postponement of the retirement of the Lawrence Energy Center ("LEC") Unit 4.

II. EVERGY'S RESOURCE ADEQUACY POSITION AND CHALLENGES

Q: In your testimony summary, you state that Evergy's last IRP was filed with the KCC in June of 2022. Have there been any significant changes since that time affecting Evergy's near-term generation adequacy?

A: Yes, there have been two major changes:

(i) Economic development is driving the need for more near-term capacity. Most specifically and urgently, Panasonic is building a large, new plant in EKC's service territory.

(ii) SPP is changing its generation reserve margin requirements and modifying the way it calculates accredited generation capacity.

Q: Please describe the challenges presented by Panasonic's new plant.

A: It has been announced that Panasonic is building a new facility to be located in Johnson County, Kansas, which is in EKC's service territory. The new plant is scheduled to be operational in 2024. In addition, with anticipated attendant support facilities from other companies and housing for new employees, there will be increased load from new residential and commercial construction that will occur in the area as people move near the plant to work there. All of this economic development is great for EKC's growth and the growth of its communities, but it does create near-term challenges from a resource adequacy perspective. The estimated increase in load plus SPP reserve requirement from the Panasonic facility, not including any incremental attendant load activity, is estimated to be approximately **[redacted]** MWs by 2026, with an expected load factor of approximately **[redacted]**%. The expected Panasonic load alone will be roughly double the size of EKC's current largest customer. Further, adding Panasonic will increase EKC's current peak load (5,571MW) and total annual energy demand (25,064,533 MWh in 2022), by approximately **[redacted]**, respectively.

Q. Are there other challenges presented by Panasonic's new plant?

A: Yes. Beyond the sheer magnitude of load and load factor, Panasonic's construction schedule, and, in turn, its energy needs, are being planned on a very aggressive schedule. With energy needs starting to ramp in 2024 and full load requirements by 2026, there is urgency to procure capacity and energy to fulfill the expected energy usage schedule. Under normal operating conditions this timeline would present a significant challenge.

Given the supply chain constrained conditions of the current market, it is nearly impossible to design, develop, construct and commercialize a resource to fulfill Panasonics needs within their required timeline. Utilizing existing resources will be key to successfully meeting Panasonic's demand requirements over the next few years.

Q. Is Panasonic the only large load being evaluated or added in the EKC territory?

A: No. EKC continues to receive inquiries related to data centers, new manufacturing, and hydrogen production across its territory. While not all of these projects will ultimately materialize, they represent hundreds of MWs of potential loads which EKC's current / currently planned resource mix are not sufficient to serve. While these prospective loads are not explicitly quantified in this testimony and the resources proposed here are not sufficient to serve these other loads in addition to Panasonic, the existence of incremental economic development potential highlights the importance of leveraging all available and currently operational resources to meet customer needs *first* prior to having to rely on new generation builds which could introduce schedule and pricing uncertainty for potential new customers.

Q. What changes is SPP making that will impact the adequacy of Evergy's generation resources?

A: First, SPP has increased its generation reserve margin requirement for its members from 12% to 15%, effective for summer 2023 reserve margin planning. One of the main functions of our IRP process is to ensure that there is sufficient accredited capacity to meet our expected load over the next 20 years plus the minimum SPP reserve margin requirement. By increasing the reserve margin requirement to 15%, it increases Evergy's generation capacity needs and ultimately decreases any potential capacity surplus position.

For example, if EKC were to apply the 15% reserve margin requirement to the EKC load forecast used in the 2022 IRP Annual Update, it would result in roughly 150 MW of additional required capacity above the then-current 12% reserve margin requirement. This means EKC would be required to build or otherwise obtain additional capacity of approximately 150 MWs to maintain the net capacity position from the 2022 IRP filing. Failure to meet capacity obligations would result in deficiency or sufficiency payments to be assessed by SPP. These payments are based on SPP's Cost of New Entry "CONE", which approximates the cost of new generation in SPP.

Second, SPP is modifying the way it calculates generation capacity for *accreditation* purposes. Resource accreditation is the process that determines how much of a resource's capacity can be claimed for meeting SPP's reserve margin requirement. Renewable resources, for example, get much lower capacity credit than firm, dispatchable resources like coal, nuclear or natural gas generation because they are intermittent and less predictable in terms of how much they will produce during a peak time and thus how much we can count on them to serve our customers' needs. In addition to traditional capacity testing, SPP's proposed capacity accreditation methodology for dispatchable resources will take into account actual reliability performance metrics. This new accreditation methodology is currently expected to be phased in from 2025 through 2028. As these rules are finalized and phased-in, EKC's thermal resources are expected to receive decreases to capacity accreditation, although it is difficult to forecast exactly what the impact will be given the new approach will be based on generators' relative reliability performance compared to the SPP overall. For renewable resources, SPP has also proposed accreditation changes that were set to take effect in 2023. These accreditation changes would result in lower accredited capacity for EKC's existing wind resources compared to SPP's prior method. In August 2022, FERC approved the renewable accreditation methodology changes, but in March 2023 decided its initial decision was wrong and that it would require SPP to further define aspects of the tariff. Ultimately, Evergy expects SPP's proposed changes to be enacted in the next few years – likely in parallel with the changes to thermal accreditation. Similar to the increased reserve margin requirements, these changes to capacity accreditation mean EKC must acquire other resources to make up for the loss in its historic accredited capacity of its existing generation portfolio.

III. PROPOSALS TO ADDRESS RESOURCE ADEQUACY ISSUES

Q: How does EKC propose to address resource adequacy challenges you discussed above?

A: We are proposing to meet these challenges with (1) the 8% of Jeffrey Energy Center ("JEC 8%") that is not currently in rate base, (2) the Persimmon Creek Wind Farm, and (3) delaying the retirement of LEC Unit 4. I address each of these resources in detail in the following sections of my testimony.

a. JEC 8%

Q: What is EKC's proposal as regards its Jeffrey Energy Center generation resource?

A: Presently, EKC's ownership of 8% of the Jeffrey Energy Center is not in rate base and is not being used to meet EKC's resource adequacy requirements. In this application, EKC is requesting Commission approval to place the JEC 8% into EKC's rate base and flow power sales revenues from the JEC 8% through EKC's Retail Energy Cost Adjustment ("RECA") for the benefit of customers.

Ms. Linda Nunn discusses the adjustment made to move the purchase price and NFOM costs for the JEC 8% into base rates and the changes we are proposing to EKC's Retail Energy Cost Adjustment ("RECA") tariff that will allow the revenues associated with capacity sales from the JEC 8% (and other capacity sales) to flow through the RECA and benefit customers.

There is significant history around the ownership of the JEC 8% that has been discussed in several dockets before the Commission. I won't repeat that history here but would refer the Commission and parties to Docket Nos. 18-WSEE-328-RTS, 19-MPCE-064-COC, and 19-WSEE-355-TAR for additional details.

Q: How much generation capacity does the JEC 8% represent?

A: The 8% undivided interest in the JEC represents 174 MW of generating capacity. Based upon the purchase price of $3.7 million, Westar obtained the resource at a cost of $21/kW.

Q: What was the most recent Commission decision regarding the JEC 8%?

A: In March 2019, Westar filed an application in Docket No. 19-WSEE-355-TAR ("19-355-Docket") seeking recovery through its RECA of the lease expense and NFOM associated with the 7-month lease and subsequent ownership of the 8% JEC interest. Westar indicated that capital costs incurred during the 7-month lease period would be recorded to leasehold improvements and, after the purchase was completed, such capital costs (including the $3.7 million purchase price) would be recorded to plant accounts – in each instance to be recovered in Westar's next general rate case.

Q: Did KCC Staff object to Westar's proposal?

A: No, Staff said:

> Staff views both of Westar's decision to extend the JEC lease and purchase the 8% portion of JEC to be prudent given Staff's NPV analysis projects it will create $1.13 million in benefits for customers.[1]
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> . . .
>
> In order to evaluate the prudency of Westar's decision to extend the JEC lease and then purchase 8% undivided interest in JEC, Staff performed an incremental NPV analysis based on the incremental costs and incremental revenues associated with the decision. The incremental costs included in the analysis are $4.83 million in lease expenses that customers would pay in 2019, return on and return of the $3.7 million purchase price beginning in 2024, fuel expense associated with running the 8% portion, variable NFOM expenses associated with running the 8% portion, then projected out through 2035. The result of the analysis is a $1.13 million benefit for Westar customers.[2]

Q: What did the Commission decide?

A: In its September 12, 2019 Order, the KCC denied Westar's request, finding that it should not be allowed to recover the lease expenses or NFOM costs, future capital expenditures or fuel costs for the 8% interest. The Order provided that Westar would be permitted to retain any wholesale sales directly attributable to the 8% portion of JEC at issue.

Q: Why did the Commission reject Staff's recommendation and deny EKC's application?

A: The Order said that Westar had not established the prudency of the short-term lease and purchase agreements, and that Westar had "declined the option" to negotiate a zero-cost transfer of ownership of the 8% interest.[3] These findings of the Commission were disappointing since Westar did not have the unilateral authority to dictate the negotiating

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[1] Post-Hearing Brief of Commission Staff filed July 31, 2019, in the 19-355 Docket, p. 10.
[2] *Id*, at p. 13.
[3] Order Denying Westar's Petition For Reconsideration Or Clarification, issued on October 24, 2019, in the 19-355 Docket.

decisions of Midwest Power ("MWP") and considering the very favorable price at which Westar obtained this generation resource. As stated above, the $3.7 million purchase price for 174 MW of generating capacity is approximately $21/kW. By contrast, according to the US Energy Information Administration, the construction cost for other types of generation per kW in 2019 were: Solar $1,796; Gas $948 (combined cycle); and Wind from $1,252 to 1,615 depending on the size of a wind farm.

Q: What reasons did the Commission give for denying Westar's application?

A: The Commission was critical of Westar's efforts to address the lease expiration, but the overriding reason the Commission gave for denial was that Westar could satisfy its current service and capacity needs without the 8% interest in JEC and, therefore, the new lease and purchase agreement would unjustifiably increase retail rates.[4]

In finding that Westar would have no need for the 8% interest capacity to serve retail load, the KCC referenced the 2019 Electric Supply and Demand Annual Report.[5] The Commission dismissed the significance of future unknown operational variables, such as weather or changes in SPP capacity determinations that might create a need for the 8% interest.[6]

Q. How is the JEC 8% currently treated by EKC for capacity and energy sales and for costs?

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[4] Order Denying Westar's Petition for Reconsideration or Clarification, p. 4.

[5] Order On Westar's Application To Recover Certain Costs Through Its R.E.C.A Related To The 8% Portion Of Jeffrey Energy Center, issued September 12, 2019, in the 19-355 Docket, p. 17.

[6] *Id*, at pp.17-18. In its subsequent Petition for Reconsideration or Clarification, Westar committed that it would not seek recovery of the $3.7 million purchase price or the lease payments made during the 7-month period if the KCC were to deem such action equivalent to a zero-cost transfer and thereby allow Westar to qualify for automatic recovery of the fuel and NFOM costs related to the 8% JEC interest. This offer was not accepted by the Commission.

A: NFOM and fuel costs for the 8% interest are recorded below the line. EKC currently bids the entire available energy from JEC into the SPP market and can enter into bilateral capacity or energy sales with other entities. There is no distinction between production and capacity from the 8% interest at issue and the balance of the plant. So, when sales occur in the SPP market, 8% of the total revenues received are attributed to KCC-designated merchant interest. EKC retains the wholesale revenue attributable to the merchant 8% portion of JEC.

Q. What is EKC requesting in this case for the JEC 8%?

A: The Commission's finding that EKC does not need this generation to satisfy its current service and capacity needs is no longer accurate and the 2019 Electric Supply and Demand Annual Report relied on by the KCC no longer presents valid data. EKC now needs this additional capacity to reliably serve its customers and meet its SPP reserve margin requirements, as I will outline in more detail below. Thus, we are requesting approval to place the $27.6M in rate base, inclusive of the $3.7M purchase price, and all other on-going cost-of-service items (depreciation expense, taxes other than income taxes, and NFOM) into rates based on changes in circumstances since 2019. The inclusion in rates of these items would result in an estimated annual revenue requirement impact of $9.2M, with $2.4M of that attributable to the revenue requirement on rate base and $6.8M from total cost of service items. We would also flow the fuel expense associated with the 8% interest through the RECA.

The amount requested to be recovered in rates tied to the JEC 8% equates to approximately ~$4.40/kW-month, and includes the associated economic and dispatchable energy of a baseload generating source, compared to the current capacity market trading in the range of **[redacted]** for capacity-only transactions for the next three to five years, which do not include the value of an economically competitive energy call option. Additionally, SPP's CONE for new generation is currently $85.61/kW-year, which equates to $7.13/kW-month. In short, the capacity cost of the JEC 8% was, and still is, favorable to market and new build capacity options, as well as the Cost of New Entry for generators in the SPP. It is now clear that the decision to obtain the JEC 8% generation at the very low price of $21/kW was a prudent decision – what was found to be imprudent under the facts of 2019 is now prudent under the facts of 2023.

Q: Are there other considerations that establish the prudency of the JEC 8% purchase?

A: Yes, the February 2021 Uri weather event produced both service challenges and extraordinary run-ups in natural gas prices. While natural gas prices had been low for many years at the time the KCC considered the JEC 8% in 2019, those prices increased from an average closing price of $2.56 in 2019 to $6.45 in 2022.[7] More recently, SPP set a record for winter electric use on December 22, 2022, of more than 47,000 MW, surpassing the previous record of 43,661 set on February 15, 2021. These weather events underscore the value of having coal generation in EKC's diverse generation resource portfolio which can provide relatively fixed-cost, firm fuel supply during extreme winter events.

Q: What about the other findings the Commission made in the 2019 Order?

A: As stated above, EKC believes the Commission's rejection of its application in 2019 was based primarily upon its conclusion that the purchase was imprudent because the generation was not needed. This reason is not accurate in light of the changed circumstances of today. With due respect to the Commission, the other reasons given in

[7] Henry Hub natural gas annual spot prices sourced from U.S. Energy Information Administration.

the Order – such as Westar's handling of the lease expiration and its purchase negotiations with Wilmington Trust Company ("WTC") - are not really supported by the record in the 19-355 Docket. Hopefully, the Commission will reconsider these findings considering that Staff recommended approval in 2019 and circumstances have only become more supportive of approval today.

Q: How does EKC's most recent IRP support the request in this case on the JEC 8%?

A: Evergy develops resource plans at the overall Evergy level (which includes all operating companies across both Kansas and Missouri) and at the individual utility (e.g., EKC) level. Modeling at the overall Evergy level allows for a more optimal portfolio to be selected by taking advantage of the economies of scale available to Evergy as a combined company and allows for more holistic evaluation of units which are jointly-owned by multiple Evergy utilities. However, the IRP also includes individual utility-level resource plans to test whether there are any potential differences between what is preferred at the individual utility level and what is preferred at the overall Evergy level.

Q. How does the resource plan developed only for EKC support inclusion of the JEC 8% in rate base now?

A: The capacity associated with the JEC 8% (174 MWs) is not currently benefiting EKC's retail customer base. The resource adequacy changes referenced above will impact each of Evergy's individual utilities, so there is need to add capacity now in order to meet the requirements of Evergy's retail customers in the coming years. The specific addition of Panasonic for EKC increases and accelerates this need. Table 1 below displays the annual resource position that EKC is facing. The table starts with EKC's resource position at the time of the Annual IRP Update filed in June 2022 and factors in the market changes that are impacting EKC's forecasted position. The Preferred Portfolio also included forecasted new resource additions, but these are excluded below because the only forecasted addition before 2025 was the 190 MW of solar in 2024 and this addition is no longer expected to be executed due to the lack of mature solar projects available on the market. The Preferred Portfolio also included forecasted Demand Side Management programs which are excluded below due to uncertainty around scale and timing of implementation driven by the pending Kansas Energy Efficiency and Investment Act ("KEEIA") case. These types of new resources (both supply- and demand-side) will be a valuable part of EKC's long-term resource plan which will be assessed in future IRPs as many other factors (including performance-based accreditation for thermal resources and additional economic development, as mentioned above) continue to drive up capacity requirements. However, they are not available today, without construction/implementation cost or schedule risk, to meet EKC's near-term need in the same way as JEC 8% and the other operating resources being proposed in this case.

Table 1 – **

[redacted]

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The benefits of including JEC 8% in EKC's rate base will be further supported and quantified in the upcoming 2023 IRP filing, which will be submitted in June 2023, before the true-up date in this proceeding and before Staff and intervenors file their testimony. The 2023 IRP filing will take an all-encompassing view of EKC's long-term capacity and energy needs in light of many market changes, including updates in total retail load forecasts, changes in existing curtailable loads, new demand-side response projections, changes in new-build generation costs, among other market factors. Including the JEC 8% in retail rate base in this rate case will help fill the very near-term capacity need that EKC is facing.

Q. Why is EKC proposing to include JEC 8% in rate base now when capacity is not needed until 2025?

A: Locking in the JEC 8% now gives EKC the ability to make future decisions based on retail customer needs and benefits only. Given JEC 8% is operating as a merchant asset today, EKC has an obligation to manage the asset in a way which maximizes returns for its shareholders – which could include continuing to sell energy or capacity off of the resource to non-Evergy entities if market conditions dictated it. Once JEC 8% is included in rate base as a retail asset, EKC can prioritize its retail customers' needs and potential future risks first. In addition, bringing the asset into rate base now allows EKC customers to benefit from existing capacity and energy sales of the JEC 8% which are quantified below and which are sufficient to cover the forecasted costs of the resource up until the time it is needed to meet capacity requirements for EKC retail customers.

Q. What is the financial value to EKC's customers of including the JEC 8% in rate base now?

A: Table 2 projects the annual customer financial impact, which is driven by the revenue requirement associated with placing the plant balance into rate base, the total on-going cost of service, and the capacity revenue and energy margin associated with existing capacity and energy transactions.

Table 2

Projected JEC 8% Customer Valuation	2024	2025	2026
Revenue Requirement on Rate Base	$2,440,650	$2,440,650	$2,440,650
Total Cost of Service	$6,751,056	$6,751,056	$6,751,056
Capacity Revenue	($6,378,500)	($9,238,260)	($3,918,400)
Energy Margin	($3,095,057)	$0	$0
Total Customer Financial Impact	**($281,851)**	**($46,553)**	**$5,273,307**

NOTE: Capacity revenue assumes expected June 2024-May 2025 capacity sale is extended to May 2026. This extension will only take place if the capacity is not needed by EKC in Summer 2025.

Q. How have you calculated the cost component of including the JEC8% in rate base?

A: The revenue requirement on rate base is calculated using a total rate base of $27,619,165, inclusive of the $3.7 million purchase price, as of the test-year ending September 30, 2022, and will be trued-up at June 30,2023 the true-up date in this rate case. The total cost of service is primarily driven by test-year costs associated with depreciation expense, operating and maintenance expense, taxes other than income tax.

Q. Please explain the nature and timing of the capacity revenues and energy margin included in the calculation.

A: There are existing capacity and energy transactions that lock-in value and reduce the total cost impact for customers until the capacity is needed for EKC's retail needs. The first transaction is currently in place for 75 MW of capacity through May 2024 and 85 MW of fixed price, around-the-clock energy through March 2024. The energy margin in 2024 is quantified by reducing the projected energy revenue by the average production cost used for similar JEC 8% wholesale energy transactions over the period June 2022 through February of 2023, which we feel is a reasonable proxy for future production costs.

Beyond this approach of quantifying energy margins, there is upside to the potential customer financial impact in times when the energy associated with this transaction can be fulfilled by wholesale locational marginal prices. This is possible when the unit is not dispatched due to market economics, essentially allowing EKC to purchase the energy beneath the JEC 8% margin production cost.

Additionally, a second 158 MW capacity and energy deal is expected to start in June 2024 and run through May 2025, with an option to extend to May 2026. **[redacted].** Similarly for this transaction, the capacity price is fixed allowing for quantification of capacity revenue, but the deal terms for energy allow the party to schedule energy on an as-needed basis subject to certain parameters. Given that the energy schedule is unknown at this time, we are unable to provide a reasonable quantification of the expected energy margin associated with this transaction, but it will provide on-going customer value incremental to Table 2 above.

Additionally, we expect there to be incremental energy margins from SPP wholesale market activity 2024 through 2026 given there is incremental energy production potential of the JEC 8% beyond the committed energy transactions I just referenced. None of these incremental energy margins are included in Table 2 above but would flow through the RECA to EKC customers. Even with these very conservative estimates around potential energy value, the existing transactions are sufficient to offset the cost of bringing the JEC 8% into rate base up until the time it is needed to meet capacity requirements. This is an indication of how well-priced this asset is given short-run market revenues are not typically sufficient to offset all-in fixed costs.

Q. What is the total overall impact of the JEC 8% request with the RECA factored in?

A: Our conservative estimate shows that customers will see a net benefit of $281,851 in 2024 and $46,553 in 2025, before ultimately needing the capacity in service in 2026. Again, we expect there to be customer benefits above these amounts driven by incremental energy margins in these periods.

Q. How does EKC propose to integrate the JEC 8% into rates if its request is approved by the Commission?

A: EKC proposes that the JEC 8% go into EKC rates as part of the revenue requirement requested in this proceeding. Thereafter, revenues from the asset will flow through to customers via the RECA. EKC customers would receive revenue from the existing capacity and energy deal from January 1, 2024, through the end of the contract, which is May 31, 2024. ** [redacted] ** Starting in either June 2025 or 2026 at the expiration of that sale, the JEC 8% capacity would be used to help cover the Panasonic load and any other resource adequacy shortfalls resulting from SPP rule changes.

Including capacity revenues from this expected future deal is dependent on the change to the RECA tariff which is described by Witness Nunn. It is important that those tariff changes are implemented so that these revenues can be passed on to customers once the deal begins in June 2024. In addition to these specific capacity revenues, the proposed changes would also allow EKC to include other short-term capacity sales and purchases in the RECA going forward. Given the capacity market in SPP continues to tighten and resource adequacy requirements are becoming much more fluid, it will be important to be able to manage EKC's short-term capacity position actively in the context of the RECA as opposed to holding capacity deals static between rate cases.

b. Persimmon Creek Wind Farm

Q: What is the Persimmon Creek project?

A: Persimmon Creek Wind Farm ("Persimmon Creek") is a 199 MW wind generating facility located in western Oklahoma. It was built in 2018 by Scout Clean Energy, a Colorado based renewable energy develop-owner-operator. It consists of 80 General Electric turbines stretching across 17,000 acres in Dewy, Ellis and Woodward counties in Oklahoma. In August 2022, Evergy entered into an agreement with Scout to purchase Persimmon Creek for $250 million. That agreement is subject to meeting all closing conditions, including necessary regulatory approvals.

Q: What is EKC requesting in this case concerning the Persimmon Creek Wind Farm?

A: The Company is asking the Commission to approve, upon close of the transaction, inclusion of the cost of this generation resource into EKC's rates to meet changing circumstances occurring over the next few years as to our need for additional resources to meet customer needs in Kansas.

Company witness, Jason Humphrey, explains in his direct testimony the project selection details, request for proposal process and the transaction structure and price. John

Grace discusses the benefits of purchasing the asset as opposed to entering into a purchase power agreement and explains the levelized rate proposed by EKC to be included in the revenue requirement calculation at true-up. I am addressing how this asset fits within EKC's resource generation plan for Kansas.

Q: Does EKC need this generation to serve its Kansas customers?

A: Yes, we will need additional generation for Kansas within the next few years, likely starting in 2025 as shown in Table 1 above. At this point, EKC has not completed a full analysis on its Kansas resource adequacy with the inclusion of Persimmon Creek in the equation since the use of the asset was only contracted for in 2022 and it was not fully known whether it would be used for Missouri load, Kansas load, or a mixture of both.

Q: What do you mean?

A: The initial intent was to dedicate Persimmon Creek to serving Evergy's load in Missouri because additional generation was needed there before it was expected to be needed in Kansas. Because the need is more imminent and significant in Missouri, Evergy requested a Certificate of Convenience and Necessity ("CCN") for Persimmon Creek from the MPSC in a case filed last year and, assuming the MPSC granted that request, it was anticipated that we would seek different additional resources to meet our increased needs in Kansas (including JEC 8%). However, on April 6, 2023, the MPSC issued its order finding that Persimmon would only be certificated with conditions not reasonable or acceptable to Evergy. This allowed Evergy to shift the use of Persimmon Creek to serve Kansas customers and seek other ways of serving the need in Missouri, such as through purchasing power from the market.

Q: Why is Evergy planning to go forward with purchasing the asset even though the MPSC order included unacceptable conditions?

A: Because the terms of the transaction are very favorable for our customers, and we will need this additional resource in the near future to serve our customers in Kansas.

Q: If you haven't performed a full analysis for Kansas that includes Persimmon as a resource, how do you intend to support your request for approval in this docket?

A: EKC's preliminary analyses indicate there is a clear need for the Persimmon Creek generation for EKC as early as 2025. Similar to the JEC8% discussed above and the delay of the retirement of LEC Unit 4 addressed below, the preliminary view of the June 2023 IRP is showing that EKC will need Persimmon in the short-term and these are the only generation assets available in the short term to meet that need.

From the long-term perspective, we have done a high-level analysis where we included Persimmon Creek in the EKC preferred plan using the 2022 IRP model and determined that the net present value revenue requirement ("NPVRR") impact of the addition of Persimmon Creek is approximately $70 million lower than that of the wind included in the Preferred Plan. Adding these savings to those identified in the 2021 Triennial IRP when wind was first added in 2025 and 2026 (approximately $80 million), this equates to total savings from the addition of Persimmon Creek (compared to no new wind additions) of approximately $150 million.[8] This demonstrates that the addition of the resource to EKC's portfolio will be beneficial for customers over the long-term. This value comes not only from meeting EKC's capacity needs, but also from providing low-cost energy and a hedge against future carbon restrictions or commodity price increases. As I

[8] 2021 Savings based on 199 MW share of expected value net present value revenue requirement delta between Plans CLJBU and CLJBV (600 MW wind addition).

indicated above, we will be submitting our next annual IRP update in June 2023 – prior to the true-up date for this proceeding and prior to the deadline for Staff and intervenors to submit testimony – and we intend to use this analysis to further evaluate and document the benefits associated with the addition of Persimmon Creek for EKC.

Q: Does EKC need the Persimmon Creek generation even if the Commission approves its request on the JEC 8%?

A: Yes, the addition of Panasonic load, SPP increasing reserve margin requirements, and SPP amending its capacity accreditation rules all will unfavorably impact EKC's capacity position. As seen in Table 1, the Panasonic load and the reserve margin changes could cause EKC to need to procure up to 400 MWs in the coming years. The 174 MWs of JEC 8% will not be sufficient to cover the expected resource adequacy shortfall. With the 199 MWs from Persimmon Creek expected to add at a minimum around 20 MW of accredited capacity, EKC will still be roughly 200 MWs short. In addition to capacity, Persimmon Creek also offers a lower-cost energy source for EKC to complement JEC 8%'s higher capacity accreditation.

Q. Has EKC recently surveyed the market for resource development projects that could contribute to addressing its capacity and energy needs?

A: Yes, in January 2023 Evergy announced a Request for Proposals ("RFP") to purchase or contract up to 1,240 MW of energy resources to be in service by 2026. While this RFP is intended to advance resource additions contemplated in our 2022 Annual Update IRP and to inform updated modeling for the 2023 Annual Update, it provides a timely market resource check for the Panasonic and SPP requirements. While the RFP responses are preliminary and confidential, directionally the responses validate EKC's short term analysis that it will be nearly impossible to meet Panasonic's schedule of load ramping in 2024 and full load requirements by 2026 with projects that are currently under development. This further supports EKC's request to include Persimmon Creek to meet EKC customer needs in upcoming years.

c. Lawrence Energy Center Unit 4

Q. Does EKC own any other existing resources that could be used to meet these changing resource adequacy issues?

A. Yes. Even before we were aware of the Panasonic load and the SPP changes, EKC's latest IRP Annual Update filed in 2022 postponed the retirement of LEC Unit 4 by one year and included the transition of LEC Unit 5 to natural gas (instead of retirement) because of the expected future increases in the need for generation caused by SPP's responses to extreme events.

Q: Please explain how retirement of the LEC has evolved and the challenge its retirement presents to EKC.

A: As described above, the initial plan in early 2021 was to retire both LEC Unit 4 and 5 in late 2023 or early 2024. As a result of lessons learned and expected changes to resource adequacy due to Winter Storm Uri, the plan was adjusted to reflect a delay in the LEC Unit 4 retirement and a transition to gas-only operations at LEC Unit 5 in place of its retirement. At this stage, given the remaining shortfall to serve Panasonic and EKC's other capacity requirements, it is expected that the retirement of LEC Unit 4 will be delayed further in order to bridge EKC's capacity position until new resources can be built. There is also the potential that the transition of LEC 5 to natural gas-only operations will be delayed given this transition results in a small capacity derate to the unit. Both of these potential changes will be evaluated in the 2023 Annual Update to determine updated retirement plans, but it is extremely likely that Lawrence will be an important part of serving Panasonic's loads in the near-term.

Q: Please summarize how the three resources you described above help to meet EKC's forecasted capacity needs.

A: As shown in Table 3, the capacity from the JEC 8%, Persimmon Creek, and LEC 4 will help fill the projected shortfall starting in 2025. These three resources add up to roughly 342 MW of capacity, but still don't return EKC to its 2022 IRP net position or provide adequate length to cover other potential load growth fluctuations over the next few years. Even with these additions EKC will likely still need to acquire incremental capacity. To cover the remaining expected shortfall, EKC will lean on the 2023 IRP Update Filing to ultimately determine how much capacity to secure over the next few years and then leverage our ongoing RFP to select projects that best fit customer needs.

Table 3 **

[redacted]

**

Q: Does this conclude your testimony?

A: Yes, it does.

STATE OF KANSAS)
) ss:
COUNTY OF SHAWNEE)

VERIFICATION

Kayla Messamore, being duly sworn upon his oath deposes and states that she is the VP Strategy & LT Planning, for Evergy, Inc. that she has read and is familiar with the foregoing Direct Testimony, and attests that the statements contained therein are true and correct to the best of her knowledge, information and belief.

Kayla Messamore

Kayla Messamore

Subscribed and sworn to before me this 24 day of April, 2023.

Leslie R. Wines

Notary Public

My Appointment Expires: May 30, 2026

NOTARY PUBLIC - State of Kansas
LESLIE R. WINES
MY APPT. EXPIRES 5/30/2026