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

DIRECT TESTIMONY OF

KATY ONNEN

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

IN THE MATTER OF THE PETITION OF EVERGY KANSAS CENTRAL, INC., EVERGY KANSAS SOUTH, INC., AND EVERGY METRO, INC. FOR DETERMINATION OF THE RATEMAKING PRINCIPLES AND TREATMENT THAT WILL APPLY TO THE RECOVERY IN RATES OF THE COST TO BE INCURRED FOR CERTAIN ELECTRIC GENERATION FACILITIES UNDER K.S.A. 66-117.

Docket No. 25-EKCE-207-PRE

November 6, 2024

DIRECT TESTIMONY

OF

KATY ONNEN

Q: Please state your name and business address.

A: My name is Katy Onnen. 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 Director of Transmission and Distribution Planning for Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("Evergy Kansas Metro"), and Evergy Kansas Central, Inc. and Evergy Kansas South, Inc., collectively d/b/a as Evergy Kansas Central ("Evergy Kansas Central") the operating utilities of Evergy, Inc., as well as Evergy Missouri Metro ("Evergy Missouri Metro"), and Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West").

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Evergy Kansas Metro and Evergy Kansas Central (combined as "Evergy" or "the Company").

Q: What are your responsibilities as the Director of Transmission & Distribution Planning?

A: My responsibilities include supervision of the Company's long-term transmission and distribution planning departments. The departments ensure the continued ability to serve our customers under various system conditions by completing annual studies and identifying necessary capital expenditures. We are also required to maintain accurate models of our system, prove continued compliance with various governmental and regulatory requirements, and provide technical input to regulatory filings.

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

A: I graduated from Kansas State University in 2003 with a Bachelor of Science in Electrical Engineering. I received my Master of Business Administration degree from the University of Missouri-Kansas City in 2023. I am a licensed Professional Engineer in the state of Kansas. From 2004 to 2012, I worked in various roles in operations and regulatory at Southwest Power Pool, Inc. I was first employed by Kansas City Power & Light in 2012 and held positions of progressive responsibility in Transmission Planning and was named Senior Manager of Transmission and Distribution Planning in 2019. I have held my current position as Director of Transmission and Distribution Planning since January 2023.

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

A: No.

Q: What is the purpose of your testimony?

A: The purposes of my testimony are (1) to discuss and describe Southwest Power Pool, Inc. (SPP) and its Generator Interconnection Procedures (GIP), which are used to identify Interconnection Facilities and Network Upgrades associated with the interconnection service that SPP will require the Company to pay for in order to connect the two generation projects proposed in this Application to the transmission system ("the Projects"), (2) explain and discuss when those Network Upgrades are likely expected to cause the Company to incur additional costs related to the Projects, and (3) explain how the Company, with the assistance of consultant 1898 & Co. ("1898"), is managing the variables in the SPP GIP to account for foreseeable risks and quantify likely costs related to the SPP Network Upgrades associated with the Projects.

I. OVERVIEW OF SPP GENERATION INTERCONNECTION PROCESS

Q: What is SPP, and what does it control and mandate as it relates to the Projects at issue in this docket?

A: SPP is a regional transmission organization, which controls various issues with respect to the transmission grid in this region, including safety and reliability. Among other aspects of operation on the transmission system, SPP controls the process by which generators are granted access to interconnect to the transmission system pursuant to Attachment V of the SPP Open Access Transmission Tariff (OATT). Under Attachment V's GIP, SPP identifies Interconnection Facilities, which are comprised of the equipment necessary to physically and electrically interconnect the new generation assets to the transmission system, as well as Network Upgrades, which include transmission upgrades required to maintain reliability on the interconnected system as a result of the injection of power from the interconnection of new generation assets. SPP likely would identify and require Interconnection Facilities and Network Upgrades related to the generation plants at issue in this docket.

Q: Describe the process by which SPP identifies the Network Upgrades necessary to allow interconnection of a generator.

A: The SPP GIP specifies that Generator Interconnection Requests (GIRs) to the SPP transmission system will be evaluated using the SPP Definitive Interconnection System Impact Study (DISIS) process, which involves a series of evaluations to assess the effects of proposed generation projects on the SPP transmission system based on the Point of Interconnection (POI) of each GIR. This process identifies the Interconnection Facilities and Network Upgrades necessary for these projects based on the level of service requested. SPP has two interconnection service products, Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). ERIS is an interconnection service product that allows a generator to inject its energy into the SPP transmission system on an as available basis. In contrast, NRIS is an interconnection service product that ensures the generator's output is deliverable to all load in its local area. Upon designation as a Network Resource by a Load Responsible Entity (such as Evergy), Evergy would be able to claim the Network Resource to meet SPP's firm capacity and resource adequacy requirements. SPP examines both ERIS and NRIS projects in "clusters," which include all generation interconnect proposals submitted within a specific timeframe. For instance, nearly all projects submitted in 2024 will be reviewed together in one cluster.

The DISIS process is divided into three phases:

- Phase 1: Steady-state analysis and short-circuit ratio calculation.
- Phase 2: Steady-state analysis, dynamic stability analysis, and short-circuit analysis.
- Phase 3, also called Interconnection Facilities Study: Steady-state analysis, dynamic stability analysis, and short-circuit analysis.

Each phase of the DISIS is followed by a Decision Point, which is a period of fifteen business days during which the interconnection customer may review the study results, including required system Network Upgrades and their costs from the previous phase, ask questions, and decide whether to withdraw its request or process to the next study phase. Decision Point One follows DISIS Phase One where an applicant can adjust the size of their request by up to 50% or reduce their request from NRIS down to ERIS. Decision

Point Two follows DISIS Phase Two where an applicant can adjust the size of their request by up to 10%. Applicants must pay a financial security to advance each of the phases, leading some to withdraw once fees are determined. This withdrawal impacts the required system Network Upgrades and the distribution of costs within the cluster, which are reassessed in the following phase. Before proceeding to Phase 3, generators must provide a financial security deposit equal to 20% of their assigned Network Upgrade costs. The final system and interconnection Network Upgrades and costs for each generator are determined at the end of Phase 3. Once the DISIS is complete, the proposed generator, the transmission owner, and SPP will execute a Generator Interconnection Agreement (GIA).

Q: Describe the process for identifying costs associated with Network Upgrades on non-SPP Transmission Providers' systems that will be assigned to the Projects.

A: Due to the seam between SPP, the Midcontinent Independent System Operator, Inc. (MISO) and Associated Electric Cooperative, Inc. (AECI), generators seeking to interconnect to one of the Transmission Providers' systems must go through the affected system study process to identify impacts necessitating upgrades to the other Transmission Providers' systems. The process for coordinating to determine impacts of an interconnection request on the others' system is described in Section 9.4 of the Joint Operating Agreement between the Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc. (MISO-SPP JOA). When the request is made to connect to SPP's system, SPP is responsible for identifying potential impacts on MISO's system and communicating those impacts to MISO. MISO then makes a final determination on if their system is impacted and identifies Network Upgrades necessary to mitigate any impacts, which would be communicated back to SPP and the interconnection customer. The impacted party and the interconnection customer would then be required to enter into a Facilities Study agreement to ensure completion of the upgrades required to allow interconnection.

The process between SPP and AECI is similar to that of SPP and MISO and is described in Section 7.3.3 of the Joint Operating Agreement Among and Between Southwest Power Pool, Inc. and Associated Electric Cooperative, Inc.

In August 2024, SPP and MISO both filed with FERC proposed changes to the MISO-SPP JOA[1] and OATT[2] to implement changes to their affected system study process. In mid-2020, SPP and MISO, recognizing that the transmission system along the SPP-MISO seam was at capacity and the next iteration of Network Upgrades that were identified were typically too costly for generation interconnection projects to proceed, began working together to perform a joint targeted interconnection queue Study (JTIQ Study). This study identified key projects to enable generator interconnections at the seams and evaluated the economic and reliability benefits these projects could provide to customers within both Transmission Providers.

Ultimately, the first JTIQ Study portfolio identified a seven-project portfolio with a planning level estimate of $1.7 billion at the time of SPP's filing. If the filing is accepted by FERC, the capital costs of this portfolio will be recovered through a charge from generator interconnection customers identified as an interconnection request in a study cluster following approval of the JTIQ Study portfolio that meets the criteria for having an impact on at least one JTIQ Study upgrade. The costs assigned to each generator interconnection customer is determined by multiplying the total megawatts of interconnection service granted to the customer by a JTIQ Generator Rate. The JTIQ Generator Rate is equivalent to the

[1] *See* FERC Docket No. ER24-2798.
[2] *See* FERC Docket No. ER24-2425.

capital costs of the JTIQ Upgrades applicable to the generation interconnection customers divided by 85% of the total megawatts identified as having been enabled to interconnect due to the JTIQ projects. According to a presentation given by SPP to a stakeholder group on August 7, 2024, the JTIQ Generator Rate is estimated to be approximately $60 per kilowatt[3].

In addition to costs associated with the JTIQ projects, SPP will also monitor MISO facilities near the border and could identify additional upgrades required for interconnection.

II. GENERATION INTERCONNECTION PROCESS

Q: When does the Company anticipate SPP will require the Network Upgrades related to the Projects?

A: The Company has recently submitted GIRs for the Projects for inclusion in the SPP 2024-001 DISIS. The POI for the Viola Generating Station is the Viola 345kV substation and the POI for the McNew Generating Station is the Reno 345kV substation. The timing for the finalization of the SPP 2024 DISIS report, which will include the total number of Network Upgrades and costs assigned to the Projects, is uncertain. Due to the number and size of the GIRs submitted to SPP for evaluation over the past several years as well as the number of restudies due to late-stage GIR project withdrawals, SPP currently has a substantial backlog of interconnection requests to its transmission system. As of October 1, 2024, SPP is still in the process of evaluating requests submitted in 2018. If SPP continues along the current path, Evergy's GIR for its Projects would not be scheduled to receive a GIA until the first quarter of 2026. However, based on the history of unplanned withdrawals following GIA execution, unplanned restudies may push this date out to the second quarter of 2027.

[3] https://spp.org/Documents/71215/CAWG%20030524%20Meeting%20Materials%20v5.zip

Q: Are there ways in which the backlog can be relieved and the SPP process expedited?

A: Possibly. In October 2021, SPP filed a generator interconnection backlog clearing plan that was accepted by the Federal Energy Regulatory Commission (FERC).[4] This plan included reforms to improve the SPP GIP by (1) reducing restudies through development milestones, (2) increasing financial commitments, and (3) simplifying and reducing study timelines. The simplification and reduction of study timelines was to be achieved by conducting backlogged studies in parallel instead of sequentially. However, the number of late-stage withdrawals in earlier queued clusters have resulted in the need to conduct numerous unplanned restudies, causing uncertainty in the study assumptions for later-queued clusters and delayed timelines for delivering results.

In August 2024, SPP filed a request with FERC asking them to approve a waiver of Attachment V of their OATT to postpone processing of the DISIS 2024-001 GIRs or the acceptance of new GIRs until greater certainty can be achieved regarding studies in progress and anticipated re-studies of the 2018-001 through 2023-001 clusters.[5] SPP proposed to modify the start of Phase 1 of the 2024-001 DISIS cluster to begin at the completion of the first planned Phase 2 restudy of the 2023-001 DISIS. This waiver allows SPP greater certainty regarding upgrades assigned to prior queues, most likely resulting in less restudies for later clusters. SPP claimed the request would not delay the ultimate completion of any future queue cluster or execution of final GIAs. SPP also requested, as part of the waiver, to defer closing the 2024-001 DISIS queue cluster window, which was scheduled to close October 31, 2024, until March 1, 2025, and to defer opening the next DISIS queue cluster window until the earlier of (i) April 1, 2026, or (ii) the completion of

[4] *See* FERC Docket No. ER22-253.
[5] *See* FERC Docket No. ER24-2860.

Decision Point Two for the 2024-001 cluster. Evergy expects that, under the waiver process, the Projects could receive a generator interconnection agreement by the fourth quarter of 2026. On October 30, 2024, FERC granted SPP's waiver request.

In a separate but related filing, SPP also requested FERC approve a waiver to allow requests for interim service without a pending DISIS request until the opening of the subsequent DISIS queue cluster window and for a delay in closing the 2024 request window until March 1, 2025.[6]

Q: Are you able to provide an estimate quantifying the expected costs of the SPP Network Upgrades assigned to the Projects?

A: Company witness Kyle Olson provides a cost estimate of the interconnection Network Upgrades that will be required for the Projects. With respect to the system Network Upgrades, as previously discussed, the backlog and late-stage withdrawals of higher queued GIRs in SPP's generator interconnection process can cause system Network Upgrades identified to support those GIRs to change and/or cascade down to lower queued GIRs that were relying on those Network Upgrades to support their interconnection service. Additionally, other GIRs that will be submitted in the DISIS 2024-001 will impact the availability of interconnection service to the Projects and, subsequently, its assigned system Network Upgrades. For this reason, compared to interconnection Network Upgrades, system Network Upgrades related to these Projects can be very difficult to estimate. However, in order to develop an estimate of the system Network Upgrade costs for the Commission to review in this filing, we worked with 1898 to perform evaluations that

[6] *See* FERC Docket No. ER-24-2863.

could simulate the SPP generator interconnection process and identify potential system Network Upgrades that may be all or partially cost assigned to the Evergy Projects.

Q: Please summarize the approach 1898 used to estimate Network Upgrades and the findings from 1898's analysis.

A: 1898 ran two separate, indicative DISIS analyses on the three sites identified by Evergy. 1898 studied the sites for the two CCGTs proposed to be located in and a third site for a simple cycle natural gas plant Evergy Missouri West, Inc. plans to construct in Missouri. The initial indicative analysis used the 2023 DISIS Phase 1 model set, which included the Network Upgrades identified and attributed to the previous clusters, as the base case for analysis for a cluster containing only Evergy's Projects. Additionally, 1898 performed a sensitivity analysis to identify Contingent Facilities, which are unbuilt Interconnection Facilities and Network Upgrades upon which the Projects costs, timing, and study findings are dependent and, if delayed or not built, could cause the need for restudies of the Projects. If the Projects met the screening criteria, they were cross-checked with previous DISIS study results to identify if there was as Network Upgrade assigned in a previous DISIS cycle. If so, the Network Upgrade was backed out of the model and the DISIS analysis was rerun to evaluate whether the Network Upgrade was necessary to resolve issues caused by the Projects. If it was deemed necessary, the cost of the Network Upgrade(s) was attributed to the Projects. This first analysis produced the 2023 DISIS Analysis costs included in Table 1 below.

To provide an additional view of the Network Upgrades that may be identified and attributed to the Projects within a larger cluster size, 1898 performed another analysis with the Projects included as if they were part of the 2023-001 cluster. Before running the study, all upgrades assigned to 2023 were reverted back to their previous state. This allowed the study to identify which Network Upgrades were still needed to reliably serve the 2023 cluster with the Projects included. 1898 then identified the Network Upgrades necessitated by the cluster and the subset of those upgrades for which the Projects would be assigned costs. The identified Network Upgrades were categorized into four risk categories based on the likelihood and total cost allocation to the project, and the highest two risk categories were included in the 2024 DISIS Analysis costs included in Table 1, below.

The cost estimates from the two studies are shown in Table 1; however, it is important to note that these estimates may not be indicative of the final costs determined for the Projects by SPP through tits DISIS process for the 2024-001 cluster.

Table 1: Network Upgrades Costs Attributable to Project POIs Based on Indicative Analysis

	2023 DISIS Analysis	2024 DISIS Analysis
Reno (KS)	$ -	$ 13,841,292
Viola (KS)	$ -	$ 73,978,925

Q: Why do you say the estimates provided by 1898 might not be indicative of the final costs determined by SPP?

A: While the study process performed by 1898 is similar to SPP's generator interconnection study process, there are several assumptions that could impact the upgrades attributed to the Projects. First, the cumulative impacts caused by a cluster of three projects is not likely to accurately replicate the upgrades identified due to a cluster the size that 2024 will likely be, especially considering the 2024 DISIS queue cluster window will remain open until March 1, 2025. Moreover, a vast majority of the SPP interconnection queue up to this point has been comprised of variable energy resources, with minimal conventional generators. It is expected that more conventional generators will be submitted into the 2024 cluster, which will likely have an impact on identified Network Upgrades. Additionally, as previously discussed, it is unlikely that all Network Upgrades currently assigned to previous clusters and included in the base model for evaluation of the Projects will move forward due to late-stage withdrawals of higher queued GIRs. The 1898 analysis attempted to identify costs associated with the most likely system Network Upgrades to be assigned to the Projects. Finally, because the 2024-001 cluster is still open, it is not possible to know what other requests within the Projects' cluster could impact the system and drive additional system Network Upgrades.

Q: Are you able to provide an estimate quantifying the expected costs of the Network Upgrades assigned to the Projects?

A: The costs associated with the JTIQ portfolio and attributable to the natural gas resources in this EKC predetermination filing is equivalent to $44.4 million for sites at Reno (McNew Generating Station) and Viola (Viola Generating Station) in Kansas. Due to their distance from the seam between SPP, MISO, and AECI, Evergy does not believe additional Network Upgrades on neighboring Transmission Providers' systems are likely to be identified for either of the CCGTs proposed to be located in Kansas.

Q: Has the Company evaluated and estimated the rate impacts from these Network Upgrades?

A: Under the SPP rules as they exist today, the system Network Upgrade costs will be directly assigned to Evergy as the generation owner and included in rates as a component of the total project cost. Mr. Olson provides the Company's estimate of total project costs in his Direct Testimony and Mr. Klote discusses the rate impact for customers based on total cost estimate.

III. EVERGY'S MITIGATION OF RISKS RELATED TO NETWORK UPGRADES

Q: You discussed a number of variables inherent in the SPP process. How is the Company planning for, managing and mitigating the risks related to these variables in estimating its predetermination costs and in the course of the construction process?

A: The Company is using a number of tools and techniques to mitigate and manage these risks to ensure the Projects meet SPP reliability standards, all while ensuring project costs are reasonable and prudent.

Q: Please describe the techniques and tools the Company is using to manage these risks?

A: First, the Company manages risk by making prudent and appropriate project siting decisions. In this case, substantial consideration was given in the course the siting process to identify locations for the plants where fewer and less costly Network Upgrades were expected. The Company's siting analysis and the decisions made in that process to minimize risk and costs are discussed in greater detail in the direct testimony of Mr. Olson.

Q: How does 1898's analysis help the Company manage the risks and uncertainties related to SPP's Network Upgrades assigned to the Projects?

A: It provides the Company with the best information available to help predict a possible magnitude of system Network Upgrade costs that will be related to these Projects. Although the Company cannot be certain about those upgrades and the costs resulting from those upgrades, the Company's engagement of 1898 helps with project optimization and estimation of the SPP Network Upgrades that will be assigned to the Projects, while also assuring that the Company can make reasonable and prudent decisions about the Projects.

Q: Are there other ways the Company is managing the risks and uncertainties related to SPP-mandated costs?

A: Yes. The Company is also pursuing revisions to SPP processes to make them more efficient and to accelerate finalization of the Projects' assigned system Network Upgrades and their associated costs. Specifically, the Company is working with SPP staff and other SPP-member electric utilities to provide an option for GIRs submitted in the DISIS 2024-001 cluster to have their interconnection service studied and granted using SPP's 2026 Integrated Transmission Planning (ITP) regional study. If implemented by SPP, this option would provide an opportunity for these GIRs to get out of the backlogged DISIS study process and its many studies, restudies, and cascading issues if they opt in. SPP is targeting finalization of this option in Q2, 2025.

Additionally, the Company is working with SPP staff and other SPP-member electric utilities to reform its process to provide a path for system Network Upgrades associated with NRIS to be placed in transmission rates and cost shared sub-regionally or regionally across SPP (referred to as Base Plan funding). Pursuant to the SPP Base Plan funding approach, up to $180,000/MW of the costs related to required upgrades would be assigned sub-regionally or regionally to SPP transmission customers, as opposed to directly assigning all of those costs to the Company. These Base Plan funded costs would be allocated in transmission rates and spread across the SPP region and/or sub-region on load ratio share basis and thus reducing the amount allocated directly to the Company's retail customers. SPP already provides a separate study process and path for Load Responsible Entities to designate an existing generator as a Network Resource and receive Base Plan funding treatment for up to $180,000/MW of the system Network Upgrades identified in that study process. So, the proposed reform would effectively just be to extend the existing SPP policy to system Network Upgrades associated with new NRIS resources that are trying to come online as quickly and efficiently as possible to meet SPP capacity and resource adequacy requirements. All SPP Base Plan funded costs are ultimately recovered from retail customers through the FERC-approved transmission formula rate.

Q: How does the process for obtaining Base Plan funding work with SPP, and when does the Company expect to know if and how much of the SPP Network Upgrade can be recovered pursuant to Base Plan funding?

A: The process for obtaining Base Plan funding for Network Upgrades associated with the deliverability of the Projects to the Company's retail customers is still under development. The Company is working closely with SPP staff, other SPP-member electric utilities, and members of the SPP Regional State Committee and its Cost Allocation Working Group to develop, approve, and implement these revisions to the SPP study processes with a target date for implementation by the end of 2025, although implementation by this date is not guaranteed.

Q: How does Base Plan funding help the Company manage and minimize costs related to SPP Network Upgrades?

A: It permits the Company to spread some of these costs, which are necessary to ensure the deliverability of this generation, across a broader set of ratepayers, not just among the Company's own retail customers, and therefore reduces the amount of costs borne by the Company's retail rate payers. Advocating for Base Plan funding treatment of these system Network Upgrades, therefore, is an example of how the Company is using all the tools available to ensure the mandated SPP costs associated with the Projects are reasonable and that the Company makes prudent decisions about how those costs are recovered through its rates.

Q: Why is the Company choosing to construct now and utilize predetermination, as opposed to waiting for these mandates to be issued by SPP and waiting for these costs to become more certain?

A: Because of the lengthy backlog at SPP, the Company expects substantial delays before the Network Upgrades and attendant costs are finalized by SPP. The Company has determined that it cannot wait that long to begin construction for a number of reasons, but most notably because it must timely meet its customers' immediate capacity and energy needs, as discussed by Mr. Humphrey and Mr. VandeVelde in their Direct Testimony. Simply stated, SPP's expected timeline is well beyond the timeframe needed to meet the Company's demand requirements.

Q: Does that conclude your testimony?

A: Yes, it does.

STATE OF KANSAS)
) ss:
COUNTY OF SHAWNEE)

VERIFICATION

Katy Onnen, being duly sworn upon her oath deposes and states that she is the Director Transmission and Distribution Planning, for Evergy, Inc., that she has read and is familiar with the foregoing Testimony, and attests that the statements contained therein are true and correct to the best of her knowledge, information and belief.

Katy Onnen

Katy Onnen

Subscribed and sworn to before me this 6th day of November 2024.

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