FILED
June 4, 2025
Missouri Public
Service Commission

# Exhibit No. 6

Evergy – Exhibit 6
Testimony of Katy Onnen
Direct
File No. EA-2025-0075

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| Exhibit No.: | |
| Issue: | SPP Interconnection Procedures and Network Upgrades |
| Witness: | Katy Onnen |
| Type of Exhibit: | Direct Testimony |
| Sponsoring Party: | Evergy Missouri West |
| Case No.: | EA-2025-0075 |
| Date Testimony Prepared: | November 15, 2024 |

**MISSOURI PUBLIC SERVICE COMMISSION**

**CASE NO. EA-2025-0275**

# DIRECT TESTIMONY

# OF

# KATY ONNEN

# ON BEHALF OF

# EVERGY MISSOURI WEST

**Kansas City, Missouri**
**November 2024**

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**DIRECT TESTIMONY**

**OF**

**KATY ONNEN**

**CASE NO. EA-2025-0075**

**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 Missouri Metro ("Evergy Missouri Metro" or "EMM"), and Evergy Missouri West, Inc., d/b/a/ Evergy Missouri West ("Evergy Missouri West" or "EMW"). I serve in this same capacity for Evergy Kansas Central, Inc. and Evergy Kansas South, Inc., collectively d/b/a as Evergy Kansas Central ("Evergy Kansas Central"). They are the operating utilities of Evergy, Inc.

**Q: On whose behalf are you testifying?**

A: I am testifying on behalf of Evergy Missouri West and Evergy Missouri Metro (which are also referred to collectively here 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 Company 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 Missouri Public Service Commission ("PSC" or "Commission") or before any other utility regulatory agency?**

A: No.

**Q: What is the purpose of your testimony?**

A: The purpose of my testimony is to (1) describe Southwest Power Pool, Inc. ("SPP") and its Generator Interconnection Procedures that are used to identify Interconnection Facilities and Network Upgrades associated with the interconnection service that SPP will require the Company to pay in order to connect the two generation projects proposed in the Application to the transmission system ("the Projects"); (2) explain 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., an affiliate of Burns & McDonnell, is managing the variables in the SPP Generation Interconnection Procedures 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 an independent regional transmission organization ("RTO") recognized by the Federal Energy Regulation Commission ("FERC") responsible for reliably and efficiently operating and planning the power grids across much of the central United States. Evergy Metro, Inc., Evergy Missouri West, and Evergy Kansas Central are members of SPP. 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 Generation Interconnection Procedures, SPP identifies (a) 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 (b) 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 will likely identify and require Interconnection Facilities and Network Upgrades related to the Viola and Mullin Creek #1 generation plants described in the Application.

**Q: What is the process by which SPP identifies the Network Upgrades necessary to allow interconnection of a generator?**

A: The SPP Generator Interconnection Procedures specify 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: (1) Energy Resource Interconnection Service ("ERIS") and (2) 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. This 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 proceed to the next study phase. Decision Point One follows DISIS Phase 1 where an applicant can adjust the size of its request by up to 50% or reduce its request from NRIS down to ERIS. Decision Point Two follows DISIS Phase 2 where an applicant can adjust the size of its request by up to 10%.

Applicants must pay a financial security to advance through 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: What is 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 seams between SPP, the Midcontinent Independent System Operator, Inc. ("MISO") (the RTO to the east of SPP), 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 other systems is described in Section 9.4 of the Joint Operating Agreement between MISO and SPP ("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 determines whether its system is impacted and identifies Network Upgrades necessary to mitigate any impacts, which are communicated back to SPP and the interconnection customer. The impacted party and the interconnection customer are then required to enter into a Facilities Study agreement to ensure the 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 JOA between SPP and AECI.

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

[1] *See* FERC Docket No. ER24-2798.
[2] *See* FERC Docket No. ER24-2825.

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. FERC accepted the proposed changes effective November 14, 2024, subject to compliance filings required of both MISO and SPP.[3]

**Q: What is the status of the JTIQ Study portfolio?**

A: 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, although the U.S. Department of Energy has approved a $464 million grant to help partially fund the projects.[4] The remaining capital costs of this portfolio will be recovered through a charge from generator interconnection customers identified as an interconnection request in a study cluster that meets the criteria for having an impact on at least one JTIQ Study upgrade. The costs assigned to each generator interconnection customer will be 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 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.[5]

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[3] FERC Docket Nos. ER24-2797, ER24-2871, ER24-2798, and ER24-2825.
[4] https://www.energy.gov/sites/default/files/2023-10/DOE-GRIP-Minnesota-Department-of-Commerce.pdf
[5] https://spp.org/Documents/71215/CAWG%20030524%20Meeting%20Materials%20v5.zip

In addition to costs associated with the JTIQ projects, SPP will also monitor MISO facilities near the border during their DISIS process, which could identify additional upgrades required for interconnection. Due to its proximity to the seam between SPP and MISO, we believe identification of additional upgrades for Mullen Creek #1 SCGT is possible.

## II. Generation Interconnection Process for the Projects

**Q: What is the anticipated timeframe when the Network Upgrades for the Projects are expected to be required by SPP?**

A: The Company has recently submitted a GIR for the Viola and Mullin Creek #1 projects for inclusion in the SPP 2024-001 DISIS, as well as the McNew project which will be the subject of a subsequent filing in February 2025, as discussed in the direct testimony of Evergy witness Kevin Gunn. The POI for the Viola Generating Station is the Viola 345kV substation; the POI for the Mullin Creek 1 Generating Station is the Mullin Creek Station; 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 re-studies caused by 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 re-studies may push this date out to the second quarter of 2027.

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

A: Possibly. In October 2021, SPP filed a generator interconnection backlog clearing plan that was accepted by FERC.[6] 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 has resulted in the need to conduct numerous unplanned restudies, causing uncertainty in the study assumptions for later-queued clusters.

In August 2024, SPP filed a request with FERC asking it to approve a waiver of Attachment V of SPP's 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.[7] 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 will allow SPP greater certainty regarding upgrades assigned to prior queues, most likely resulting in fewer re-studies for later clusters. SPP claimed the request would not delay the ultimate completion of any future queue cluster or execution of final GIAs.

[6] *See* FERC Docket No. ER22-253.
[7] *See* FERC Docket No. ER24-2860.

SPP also requested, as part of its waiver filing, 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 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 that 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 approve a delay in closing the 2024 request window until March 1, 2025.[8]

**Q: What are the variables that affect any estimate of the expected costs of the SPP system Network Upgrades assigned to the projects?**

A: 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, system Network Upgrades, compared to Interconnection Facilities related to these Projects, can be very difficult to estimate.

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

However, in order to develop an estimate of the system Network Upgrade costs for the Commission to review in this filing, Evergy worked with 1898 & Co. to perform evaluations that 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: What approach did 1898 & Co. ("1898) use to estimate the system Interconnection Upgrades and the findings from its analysis?**

A: 1898 ran two separate indicative DISIS analyses on the three sites identified by Evergy. It studied the sites for the two CCGTs proposed to be located in Kansas (Viola and McNew) and a third site for two simple-cycle natural gas Mullin Creek units that Evergy Missouri West 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 to analyze 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 a 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 if 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.

**Q: What are the estimated interconnection costs that 1898 reported to Evergy?**

A: The cost estimates from the two studies are shown in Table 1 below.  Because the analysis was run for two units at the Mullin Creek POI, the total cost was divided in half to determine the costs attributable to only Mullin Creek #1 as each unit would share equally in the costs of any Network Upgrades. It is important to note that the costs in Table 1 are current best estimates and that the final Network Upgrade costs for the Projects will be determined by the SPP DISIS process for the 2024-001 cluster.

***Table 1: Network Upgrades Costs Attributable to Projects Based on Indicative Analysis***

| | 2023 DISIS Analysis | 2024 DISIS Analysis |
|---|---|---|
| Reno | $ - | $ 13,841,292 |
| Viola | $ - | $ 73,978,925 |
| Mullin Creek #1 | $ 3,223,248 | $ 45,262,747 |

**Q: Why do you say that the estimates provided by 1898 might not indicate 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, the vast majority of the SPP interconnection queue up to this point has consisted 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: What are the estimated Network Upgrade costs on non-SPP Transmission Providers' systems?**

A: The costs associated with the JTIQ portfolio and attributable to the natural gas resources in this filing are equivalent to $44.4 million for the site at Viola and $27.24 million for the site at Mullin Creek #1. This is not inclusive of any additional upgrades that may be identified by on the MISO or AECI systems.

## III. Evergy's Mitigation of Risk related to Network Upgrades

**Q: You discussed a number of variables inherent in the SPP process. How does the Company plan to manage and mitigate the risks related to these variables in the course of the construction process?**

A: The Company is using a number of tools and techniques to mitigate and manage these risks in order to assure that the Projects meet the reliability standards of SPP, while assuring that the project costs are reasonable and prudent. At the start of this process, the Company made prudent and appropriate siting decisions related to the location of the plants. Substantial consideration was given in the course of those siting decisions 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 undue risks and costs are discussed in more detail in the direct testimony of Evergy witness Kyle Olson.

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

A: It provides the Company with the best information available to help predict the potential magnitude of system Network Upgrade costs that will be related to the 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, while also assuring that the Company can make reasonable and prudent decisions about the Projects.

**Q: In what other ways is the Company managing the risks and uncertainties related to SPP mandated costs?**

A: The Company is also pursuing revisions to SPP processes to make them more efficient and accelerate finalization of the Projects' assigned system Network Upgrades and their associated costs. Evergy 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 leave the backlogged DISIS study process and its many studies, re-studies, and cascading issues. SPP is targeting finalization of this option in the second quarter of 2025.

Additionally, the Company is also working with SPP staff and other SPP-member electric utilities to reform SPP's 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, also referred to as Base Plan funding. Pursuant to this 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 a load ratio share basis, and thus reducing the amount allocated directly to the Company's retail customers.

**Q: When does the Company expect to know if and how much of the SPP system Network Upgrade costs can be recovered pursuant to Base Plan funding?**

A: The process for obtaining Base Plan funding for system 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 system Network Upgrades?**

A: Base Plan funding 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, which reduces the amount of costs borne by the Company's customers. Advocating for Base Plan funding treatment of these system Network Upgrades is an example of how the Company is using all the tools available to it to assure that the mandated SPP costs associated with the Projects are reasonable and in the public interest.

**Q: Why is the Company choosing to construct now 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 demand 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.

**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 and Evergy Metro, Inc. d/b/a Evergy Missouri Metro for Permission and Approval of a Certificate of Public Convenience and Necessity For Natural Gas Electrical Production Facilities | ) ) ) ) ) ) ) | Case No. EA-2025-0075 |

## AFFIDAVIT OF KATY ONNEN

**STATE OF MISSOURI )**
**) ss**
**COUNTY OF JACKSON )**

Kay Onnen, being first duly sworn on his oath, states:

1. My name is Katy Onnen. I work in Kansas City, Missouri and I am employed by Evergy Metro, Inc. as Director of Transmission and Distribution Planning.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Evergy Missouri Metro and Evergy Missouri West consisting of seventeen (17) 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.

Katy Onnen

Katy Onnen

Subscribed and sworn before me this 15th day of November 2024.

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