Exhibit No.: _____
Issue(s): Fuel Adjustment Base Factor, Non-FAC Fuel & Purchased Power Costs
Witness: Todd W. Tarter
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Sponsoring Party: The Empire District Electric Company d/b/a Liberty
Case No.: ER-2024-0261
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Before the Public Service Commission
of the State of Missouri

Rebuttal Testimony

of

Todd W. Tarter

on behalf of

The Empire District Electric Company d/b/a Liberty

August 18, 2025

Liberty™

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THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Todd W. Tarter. My business address is 602 South Joplin Avenue, Joplin, Missouri.

Q. Are you the same Todd W. Tarter who provided direct testimony in this matter on behalf of The Empire District Electric Company d/b/a Liberty ("Liberty" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony in this proceeding before the Missouri Public Service Commission ("Commission")?

A. In my rebuttal testimony, I address the Commission Staff's ("Staff") position on the fuel and purchased power ("FPP") expense level for setting the base FPP cost, as proposed in the direct testimony of Staff witness Brooke Mastrogiannis. I also respond jointly to Staff witnesses Antonija Nieto and Justin Tevie related to their inputs to the production cost model that Staff used to develop its fuel adjustment clause ("FAC") base factor in its direct filing. Finally, I respond to Office of the Public Counsel ("OPC") witness Angela Schaben regarding the amount of Transmission Congestion Rights ("TCR") revenue to be include in the FAC base, and to OPC witness Jordan Seaver concerning comments made in direct testimony about resource planning.

Q. Are there other Company witnesses that address FAC issues in their rebuttal testimony?

A. Yes. For additional information on FAC issues, please see the rebuttal testimonies of Company witnesses Aaron J. Doll (transmission expense and Staff request for information between rate cases) and John J. Reed (transmission expense and FAC sharing provisions).

II. RESPONSE TO STAFF WITNESS BROOKE MASTROGIANNIS

Q. Please summarize Staff's position on energy cost recovery in this case based on Staff's direct filing.

A. Consistent with the Company, Staff is recommending the continuation of the FAC and has proposed to update the FAC base factor based on a computer production cost model. The Staff's FAC base factor proposal, like the Company's, is higher than the current FAC base factor.

Q. Briefly summarize any major differences in Staff's FAC proposal and the Company's FAC proposal at this point in the proceeding.

A. When examining the details of all the FAC components, there are many differences between the Company and Staff FAC proposals, but the following is a summary of what I would describe as the "major" differences:

- The Company proposed an FAC base factor of $16.59/MWh and the Staff proposed $18.27/MWh[1]. However, these values are not directly comparable due to differing percentages of recoverable transmission expense in the proposals and other factors.
- The Company used a weighted average natural gas price of $1.88/MMBtu in its model run. Several months later, Staff used $3.43/MMBtu.

[1] The Company was notified that Staff had an error in its workpaper used to calculate its FAC base factor and the correct FAC base should have been $15.35 not $18.27, and the correction will be addressed in Staff's rebuttal testimony.

- With regard to the revenues from the Southwest Power Pool's ("SPP") congestion hedging instruments known as Auction Revenue Rights and Transmission Congestion Rights ("ARR/TCR"), which serves as an offset to the customer native load charges, the Company proposed an ARR/TCR offset of $23,533,318 in its FAC base factor calculation, while Staff used $40,317,269.
- Concerning the renewable energy credits ("RECs") revenues utilized in the FAC base factor calculation, the Company used $3,759,926 while Staff used $7,557,793.
- The Company proposed to flow all of the SPP transmission expense through the FAC, while Staff proposed a lower amount. The Company had $21,005,101 in the FAC base factor calculation for transmission expense and Staff proposed $6,818,953 (with the remaining portion in base rates).
- The Company supports 100% recovery of prudently incurred costs eligible for the FAC and Staff supports the current 95%/5% sharing mechanism.

Q. Does the Company agree with Staff's net ARR/TCR offset in the calculation of the FAC base factor?

A. No. The Company supports the ARR/TCR offset level of $23,533,318 that was proposed in the Company's direct filing. For more information on this subject, please see my response to OPC witness Angela Schaben below .

Q. Does the Company agree with Staff's Renewable Energy Certificate (REC) revenue level in the calculation of the FAC base factor?

A. No. The Company supports the REC revenue level of $3,759,926 that was proposed in the Company's direct filing. This amount is used as an offset to the customers' fuel costs in the FAC base factor proposal.

Q. What is a REC?

A. A REC, also known as a renewable energy certificate, is a tradable certificate that represents the environmental benefits of one megawatt-hour ("MWh") of electricity generated from a renewable energy source. A REC can be used to meet regulatory requirements for compliance with a renewable portfolio standard ("RPS") or can be sold on the open market.

Q. How did the Company calculate REC revenue?

A. In the Company's calculation of net REC revenue, a base rate $/REC was established based on history and the current market. Broker fees and agreements with the Empire Wind Holdings Company were also considered. This rate was applied to the normalized and annualized number of RECs that was assumed to be available for sale. It is important to note that not all RECs generated by the Company renewable resources can be sold. Some of the Company RECs are needed to meet RPS requirements and some are associated with capacity and energy sales. The remaining number of RECs that can be sold is based on market demand. At this stage in the proceeding, the Company continues to support its originally filed number. However, if new evidence or updated calculations are presented that warrant a revision, the Company will reevaluate this and all related figures accordingly.

Q. Are there any other concerns you have at this time related to Staff witness Mastrogiannis' direct testimony?

A. Yes. When reviewing the fuel model prepared by Staff witness Mastrogiannis in comparison to the normalization workpapers of Staff witness Nieto, a discrepancy was identified in the total purchased power expenses. Specifically, it appears that Staff witness Mastrogiannis is combining the total contracted purchases for Elk River, Meridian Way and Plum Point, similar to the Company's calculation but then added "net market purchases". In contrast, Staff witness Nieto is relying solely on the total contract purchases. I believe these figures should reconcile but would like to get a better understanding from Staff as to why they would be different.

Q. Do you have any potential concerns with Staff's model and the calculation of the market revenue?

A. Yes. When reviewing the hourly data in Staff's workpapers, some negative market prices were observed. It appears that Staff's model may have the Company's resources generating energy during hours when prices are negative, even at a level where Company resources would be curtailed. The Company's model addresses this curtailment issue, but it is unclear if Staff's model does so as well. This is concerning, as showing units operating during times when they would not actually operate would have an unfavorable impact on market revenues.

Q. Would you like to make any clarifications in response to Staff witness Mastrogiannis' direct testimony?

A. Yes. Page 10 on Staff witness Mastrogiannis' direct testimony, includes Table 2 titled "FAC BASE FACTOR CALCULATION." I would like to make a minor clarification to one of the line items in this table. The line titled "Plum Point O&M Cost-Variable" shows a difference of negative 81.4% from the current FAC base and the Company's proposed FAC base. This is due to the Company changing the reporting of some of these costs since the last rate case. In order to be comparable, the last case would have a value of $2,514,193 (as presented), and the same value for the Company's proposed FAC base would be $2,596,784 or a 2.2% increase. Further, the Company and Staff are using the same value for this cost component in their direct filed FAC base factor proposals.

III. RESPONSE TO STAFF WITNESSES ANTONIJA NIETO AND JUSTIN TEVIE

Q. Do you have any issues with the natural gas prices and market prices utilized as inputs in Staff's production cost model that produced Staff's FAC base factor proposal in this case?

A. My primary concern is not with Staff's natural gas price. It is well known that natural gas prices are subject to change. At the time of this writing, the actual natural gas price is somewhere between the Company and the Staff natural gas price proposals, and Staff's natural gas price proposal is close to 2026 futures (2026 futures are subject to change, of course). Therefore, the natural gas price used by Staff seems reasonable. Rather, my concern is that Staff's natural gas prices and market prices were developed independently and did not use a consistent methodology or a consistent set of data. Both natural gas prices and market prices are important inputs to the production cost model, and it is important that they are correlated.

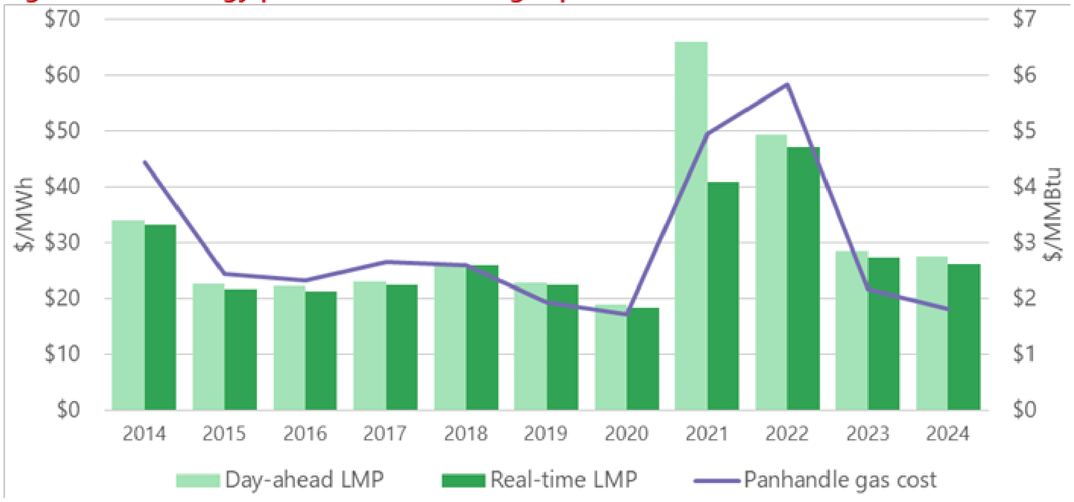
Q. Please explain how the correlation between natural gas prices and market prices is missing from Staff's analysis.

A. I conducted a high-level review of Staff's production cost model run, as I do not have full access to the underlying model or data development process. Based on the direct testimony, it appears that Staff witness Nieto developed the natural gas prices, while Staff witness Tevie developed the market prices. According to Staff witness Nieto

(Direct Testimony, page 7, lines 17-20), the non-hedged portion of natural gas prices was calculated using a twelve-month weighted average of the Company's actual spot market purchases ending September 30, 2024. The hedged portion was similarly based on actual data from that same period. This approach relies on actual purchases made during a specific year and does not account for broader market conditions or prices during periods when the Company did not purchase gas. As a result, the model lacks normalization and may not accurately reflect natural gas requirements under typical operating conditions, which can vary due to outages, weather, or SPP commitments.

In contrast, Staff witness Tevie (Direct Testimony, page 4, lines 22-24, and page 5, line 1) developed market prices using a three-year dataset ending September 30, 2024, and calculated monthly peak and off-peak adjustment factors. Notably, 2022 data was excluded due to perceived abnormal pricing. This creates a disconnect between the natural gas and market price assumptions, as they are based on different timeframes and methodologies. Below is a comparison that speaks to the correlation between natural gas prices and market prices (including both day-ahead and real-time) from the SPP Market Monitoring Unit ("MMU") 2024 Annual State of the Market Report.

Figure 4–1 Energy price versus natural gas price, annual



Historically, electric market prices have followed the cost of natural gas. The average gas cost at the Panhandle hub decreased by 16% from $2.16/MMBtu for 2023 to $1.81/MMBtu for 2024.[2]

Q. How did the Company approach this issue?

A. The Company engaged Horizons Energy, to develop both fuel and market prices using a consistent and integrated approach for fuel modeling. Horizons Energy specializes in modeling energy markets and provides hourly locational marginal prices ("LMPs") that reflect congestion, transmission losses, and other market dynamics. Their data is benchmarked, calendar-accurate, and formatted for use in the Encompass production cost model. This ensures that natural gas prices and market prices are internally consistent and aligned with the operational realities of the SPP nodal market. And are consistent with past rate cases and with the Company's internal budget process. In summary, Staff's approach lacks the necessary coordination between fuel and market price assumptions, which is critical for accurately simulating unit dispatch and market compensation. The Company's methodology, supported by Horizons Energy, provides a more robust and realistic representation of market behavior.

[2] 2024 MMU Annual State of the Market Report. Page 14. https://www.spp.org/documents/73953/2024_annual_state_of_the_market_report.pdf

Q. While not an FAC item, do you agree with Staff witness Nieto's calculation for natural gas transportation costs?

A. No. Staff's calculation relies on rates from contracts that expire in May 2025. However, new contracts have taken effect as of June 2025, and those updated rates are known and measurable and have been such since they were executed in May 2024. Therefore, they should be used when determining the annual level of natural gas transportation costs. I continue to support the total amount of $14,088,261 presented in my direct testimony, as it reflects the most current contracted pricing.

IV. RESPONSE TO OPC WITNESS ANGELA SCHABEN

Q. Please briefly describe the TCR revenue and how it is used in the FAC base factor proposal for this case.

A. In the SPP integrated marketplace, Transmission Congestion Rights or TCRs are financial instruments that entitle the holder to receive revenue or incur charges based on the difference in hourly Day-Ahead marginal congestion costs between the designated source and sink locations. In essence, TCRs serve as a hedge against transmission congestion costs. The revenue generated from TCRs reflects the value of congestion on the transmission system and is credited to the holders of these rights. For the Company, net TCR revenues are flowed through the Fuel Adjustment Clause (FAC) where they act as an offset to energy costs. This mechanism helps reduce the overall costs of energy for customers and is incorporated into the FAC base factor proposal to ensure those benefits are reflected in rates.

Q. What level of TCR revenue did OPC witness Schaben propose in direct testimony?

A. The OPC witness proposed a significantly higher level of TCR revenue than what the Company included in its filing. According to Ms. Schaben's direct testimony, the OPC proposal is based on using an average of TCR revenues, over the past five years, since the period 2021 through 2025 has been consistently higher than the period 2014 through 2020. The OPC witness continues by stating that, utilizing a 5-year average captures and normalizes a range of actual TCR revenues and delivers a more realistic estimation.

Q. Do you agree this this approach?

A. No. OPC witness Schaben's analysis is overly simplistic and fails to reflect the complexity of transmission congestion in the electricity markets. Relying on a straight 5-year average – especially with 2025 data incomplete- ignores the dynamic, non-linear, and often unpredictable nature of transmission congestion, particularly for market participants like Liberty that operate on SPP's eastern seam or in frequently constrained areas. This methodology does not account for critical factors such as changes in grid topology, shifts in generation mix, evolving market conditions, or operational realities like outages or weather events – all of which significantly influence congestion patterns. By contrast, the Company's approach involves estimating congestion under "normalized" conditions, while actively monitoring historical trends and anticipating future system changes that could affect congestion and hedging strategies. In short, Ms. Schaben's method lacks the nuance and rigor necessary to produce a reliable forecast and does not align with how congestion risk is actually managed in practice.

Q. Have there been any recent FERC filings made by SPP that will impact congestion hedging?

A. Yes. In FERC Docket No. ER24-1775, submitted April 17, 2024, SPP proposed revisions to its Open Access Transmission Tariff, specifically targeting "Congestion Hedging Improvements" through updates to Attachment AE. These changes address the allocation and mechanics of Auction Revenue Rights ("ARRs") and TCRs, which are key financial tools used to hedge congestion costs in the SPP Integrated Marketplace. FERC accepted SPP's proposed tariff revision in an order issued on July 25, 2024, and directed SPP to submit an informational filing to confirm the effective date of implementation. The goal of these revisions is to enhance the efficiency, transparency, and fairness of congestion hedging mechanisms for market participants. Importantly, these approved changes are not reflected in OPC's simplistic five-year average of historical TCR revenues. In contrast, the Company's TCR proposal accounts for anticipated reductions in ARR awards, a lower annual closeout payment, and the expected impact of system upgrades designed to reduce day-ahead congestion. This forward-looking approach better aligns with current market developments and provides a more accurate representation of future congestion hedging outcomes.

Q. Have there been any recent system upgrades that could impact the level of congestion the Company experiences, potentially invalidating OPC's witnesses' methodology?

A. Yes. The OPC witness proposes using a simple arithmetic average of TCR revenues from 2021 through 2025 to estimate future congestion costs. However, this approach does not account for significant system changes that materially affect congestion levels. For example, day-ahead congestion and TCR revenues were unusually high in 2022, which disproportionately skews OPC's average. This spike was largely driven by the Neosho-Riverton 161 kV flowgate, located within the Company's service territory.

According to the SPP Market Monitoring Unit's ("MMU") 2022 *Annual State of the Market* ("ASOM") report, this flowgate had the highest congestion-related payments from MISO to SPP and ranked among the top ten flowgates on shadow price. Importantly, the ASOM report noted that the Neosho-Riverton 161 kV upgrade was expected to alleviate congestion in the area. That upgrade was energized in January 2023. As a result, the congestion conditions that drove the elevated TCR revenues in 2022 are dramatically reduced, making OPC's backward-looking average an unreliable predictor of future congestion costs.

The Company's methodology accounts for these upgrades and reflects a more accurate, forward-looking view of congestion risk. OPC's approach, by contrast, ignores key structural changes and relies on outdated conditions that no longer reflect the realities of the transmission system.

Q. To summarize, is it reasonable to use a net TCR revenue offset in the calculation of the FAC base factor based on a simple arithmetic average of TCR revenues that includes 2022 with no adjustments?

A. No. A simple arithmetic average that includes 2022 without adjustment does not produce a reliable estimate of future congestion-related revenues. Additional analysis is necessary to develop a value that reflects day-ahead congestion under conditions consistent with the period being evaluated. OPC's proposal overlooks key developments that materially affect congestion and TCR revenues. For example, it does not account for the impact of the Riverton-Neosho 161 kV/69kV transmission upgrade, which was energized in early 2023 and has significantly reduced congestion in the Company's service territory. Nor does it consider the implications of FERC Docket No. ER24-1775, in which SPP proposed – and FERC approved – tariff revisions aimed at improving congestion hedging mechanisms. Moreover, it is important to recognize that increased congestion does not automatically translate into increased TCR revenues. TCRs are financial instruments subject to market conditions, allocation rules, and availability. Their value depends on how effectively they hedge congestion, not simply on the presence of congestion itself. In short, OPC's methodology fails to reflect current system conditions and market dynamics and therefore does not provide a reasonable basis for inclusion in setting the FAC base factor.

V. <u>RESPONSE TO OPC WITNESS JORDAN SEAVER</u>

Q. In his direct testimony, OPC witness Seaver references changes to the Company's preferred resource plan in the most recent Integrated Resource Plan ("IRP") as compared to earlier IRPs. How do you respond?

A. IRP planning is an ongoing and iterative process. While IRPs are formally updated every three years with annual updates in between, the plans themselves are continuously re-evaluated to reflect changing conditions and updated assumptions. Since the Company filed its 2022 IRP, the electric industry has experienced significant developments that directly impact resource planning. These include changes to SPP's resource adequacy requirements, such as increased planning reserve margins for both summer and winter seasons, and the introduction of performance-based accreditation ("PBA") for conventional generation and Effective Load Carrying Capability ("ELCC") for wind, solar, and energy storage resources – both of which are scheduled to take effect beginning in summer 2026. Additionally, FERC recently approved SPP's Expedited Resource Adequacy Study ("ERAS") process, which provides a fast-track pathway for certain generation projects to interconnect in response to rising load forecasts, generator retirements, and a backlog of interconnection requests. This process was not in place during earlier IRP cycles and represents another example of how planning assumptions must evolve with system needs. OPC witness Seaver acknowledges some of these changes, noting on Page 6, line 4-6, that "the changes in the supply-side additions in the 2022 to the 2025 preferred plan is certainly a result, at least in part, due to the change in SPP's resource accreditation." In fact, these changes are substantial and directly affect the type and timing of resources needed to meet seasonal reliability requirements. Given the magnitude of these developments, adjustments to preferred resource plan between IRP cycles are not only reasonable – they are necessary.

Q. How do you respond to OPC witness Seaver's statement about the "ideological plan that Liberty Utilities imposed on [The] Empire District Electric in Missouri" found on page 6 of his direct testimony?

A. It's important to place such statements in proper context. The SPP, excluding the developing Western expansion, spans approximately 552,885 square miles across all or parts of 14 states and serves over 18 million people. Its footprint includes more than 72,000 miles of transmission lines and over 1,000 generation resources. Liberty represents only a small fraction of SPP's vast and complex system. The changes SPP has made to its resource adequacy parameters are driven by broad regional challenges and evolving market conditions – not by any single utility's internal planning philosophy. Suggesting that Liberty Utilities imposed an "ideological plan" on Empire oversimplifies the realities of operating within a multi-state, highly regulated transmission and energy market. These developments reflect the collective needs of the SPP region and are shaped by diverse stakeholder input, regulatory oversight, and system-wide reliability considerations. For additional comments on alleged resource planning deficiencies see the rebuttal testimony of Liberty witness Aaron Doll.

Q. Do any of the resources from the most recent IRP's preferred resource plan have a direct impact on this rate case?

A. No.

Q. Does this conclude your rebuttal testimony at this time?

A. Yes.

VERIFICATION

I, Todd W. Tarter, under penalty of perjury, on this 18th day of August, 2025, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Todd W. Tarter