Exhibit No.
Issues: Fuel Adjustment Clause
Natural Gas Hedging
Witness: Aaron J. Doll
Type of Exhibit: Direct Testimony
Sponsoring Party: The Empire District Electric Company
Case No. ER-2019-0374
Date Testimony Prepared: August 2019

Before the Missouri Public Service Commission

Direct Testimony

of

Aaron J. Doll

on behalf of

The Empire District Electric Company
A Liberty Utilities Company

August 2019

****DENOTES HIGHLY CONFIDENTIAL****
4 CSR 240-2.135(4)

PUBLIC VERSION

TABLE OF CONTENTS
DIRECT TESTIMONY
OF
AARON J. DOLL
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THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
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SUBJECT **PAGE**

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Aaron J. Doll. My business address is 602 South Joplin Avenue, Joplin, Missouri.

Q. WHO IS YOUR EMPLOYER AND WHAT POSITION DO YOU HOLD?

A. I am employed by Liberty Utilities Service Corp. as Director of Electrical Procurement for Liberty Utilities Central Region which includes The Empire District Electric Company ("Liberty-Empire" or the "Company"). I have held this position since June 2016.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Missouri State University in 2003 with a Bachelor of Science degree in Psychology and a minor in Philosophy. I received my Masters of Business Administration from Missouri State University in 2008. I have worked for Liberty-Empire for approximately 13 years. I worked in the Planning and Regulatory Department for six years as a Planning Analyst and was responsible for load forecasting, weather normalization, and sales and revenue variance analysis. In 2012, I transferred to the Supply Management Department as the Market Risk Manager and eventually the Manager of Market Settlements and Systems. In this capacity I worked to facilitate the migration of the daily power marketing activities from the Southwest Power Pool, Inc. ("SPP") Energy Imbalance Market ("EIS") to the SPP Integrated Marketplace ("IM") and oversaw the procurement of the Transmission Congestion Rights ("TCRs"). Additionally, I provided oversight of the meter management, market settlements, and market applications. In my current position I oversee the procurement of fuel for electrical generation, the day-to-day interfacing, systems, and settlements with SPP as it relates to the IM, the SPP working groups that report up to the Market Operations and Policy Committee ("MOPC"), the long term and short term load forecasting, and the production cost modeling.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR ANY OTHER STATE UTILITY COMMISSION?

A. Yes. I have testified on behalf of the Company before the Missouri Public Service Commission ("Commission"), the Oklahoma Corporation Commission, the Kansas Corporation Commission, and the Arkansas Public Service Commission.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS CASE?

A. I will provide testimony to support proposed changes to Liberty-Empire's Fuel Adjustment Clause ("FAC"), and I will also provide an update on Liberty-Empire's natural gas hedging methodology.

II. FUEL ADJUSTMENT CLAUSE REVISIONS

Q. PLEASE DESCRIBE THE PROPOSED REVISIONS TO THE FUEL & PURCHASED POWER ADJUSTMENT CLAUSE - RIDER FAC ("FAC TARIFF").

A. A marked up version of the FAC Tariff, showing all changes being proposed by the Company, is attached to my testimony as Schedule AJD-1. The first revision to the

FAC tariff is a modification of the Off-System Sales Revenue ("OSSR") definition currently on Sheet 17z. In the Company's current FAC Tariff, OSSR is defined as "Revenue from Off-System Sales (Excluding revenue from full and partial requirements sales to municipalities)." The proposed revision adds language further defining what is included in OSSR. OSSR includes sales from all generation assets of which all are currently included in rates and any sales from the assets that customers pay for are also credited back to customers. Future generation projects, such as the recently approved Wind Projects, will produce sales before the inclusion in rates of the associated generation costs. Therefore, in order to provide for equitable treatment of revenue in such situations, the Company proposes to modify the definition of OSSR to only include sales revenue received from generation projects that have been declared Commercially Operational and are being recovered through customer rates.

Q. PLEASE EXPLAIN HOW THE COMPANY RECEIVES OSSR?

A. Currently, Empire is a Network Service Customer of SPP and a Market Participant in the SPP IM. As a load serving entity of the SPP IM, Empire is required to purchase generation from the market to serve load and separately to offer available generation into the market for the purpose of providing a cost-effective generation supply to meet the energy needs of the SPP. On a daily basis, Empire submits hourly demand bids and generation offers into the Day-Ahead ("DA") market for the next day's operations. SPP will then determine the most cost effective generation mix to meet energy and operating reserve needs while maintaining the reliability standards of the bulk electric system ("BES"). The results of the DA market create financial positions for the next day's operations while deviations from the DA operating plan are addressed in real time by means of the Real-Time Balancing Market ("RTBM"). Since Empire's load is no longer served directly from its generators, any margin made from generation committed and dispatched in the SPP IM is returned to the Company's customers via the fuel adjustment clause as OSSR. This structure allows for a more efficient means of serving load while ensuring revenues received for energy generated from assets included in customer's rates are passed back through to the customers as an offset to the costs incurred as a result of generation. However, a generation project that is declared Commercially Operational but has not yet been reflected in customer's rates would sever the link between costs incurred and benefits received.

Q. IS THE FAC TARIFF LANGUAGE REGARDING OSSR AS IT IS CURRENTLY WRITTEN IN COMPLIANCE WITH MISSOURI LAW?

A. In certain circumstances, the current language regarding OSSR could cause a violation of Missouri law. Missouri statute 386.266 requires that a utility's FAC be "reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity." If the FAC Tariff is not modified to ensure that any revenues that the Company receives for a Commercially Operational project not yet in rates are excluded from the fuel adjustment clause, the Company would incur expense relating to generation without having the revenue offset of that expense, thereby compromising the Company's ability to earn a fair return on equity. A Rate Adjustment Mechanism ("RAM") cannot be reasonably designed to provide a sufficient opportunity for the Company to earn a fair return on equity if it allows revenues to pass through the FAC even though the Company's customers are not paying for the energy associated with those revenues. In summary, this proposed FAC Tariff modification seeks to create a fair and reasonable balance between the revenues received for electric generation and the costs incurred for that same generation.

Q. WILL THIS MODIFICATION EXCLUDE ALL BENEFITS FROM FUTURE GENERATION PROJECTS UNTIL THE COSTS ASSOCIATED WITH THAT GENERATION ARE INCLUDED IN RATES?

A. Not exactly. This language will ensure that the Company is not financially harmed by selling energy and distributing the revenues for that energy until the Company has gone through a general rate proceeding to seek recovery for the costs of a project that has enabled the production of the energy. However, generation projects have value beyond the energy sold into the SPP IM. As a Network Service Customer in SPP and a SPP IM Market Participant, we are required to abide by SPP governing documents including but not limited to: the SPP Market Protocols, SPP Open Access Transmission Tariff ("OATT"), and the SPP Planning and Operating Criteria. Attachment AA of the SPP OATT details Resource Adequacy requirements for Load Responsible Entities ("LRE"). An LRE is defined as an Asset Owner with registered load in the IM. An LRE is responsible for meeting the Planning Reserve Margin ("PRM") as set forth in the SPP Planning Criteria. The current SPP PRM is 12% for all entities unless at least 75% of an entity's firm capacity is comprised of hydro-based generation in which case the PRM is 9.89%. The PRM is determined by a probabilistic Loss of Load Expectation ("LOLE") study which analyzes SPP's ability to reliably serve the SPP Balancing Authority Area's forecasted peak demand. The LOLE study will be performed at least biennially with input from stakeholders to form the inputs and assumptions of the study. In short, the PRM is a dynamic calculated figure that LREs such as Liberty-Empire must abide by or risk incurring a Deficiency Payment as detailed in Section 14.2 of Attachment AA of the SPP OATT. As stated earlier, additional generation has value beyond the energy sold into the SPP IM and that value would be considered Deliverable

Capacity for the purpose of meeting the resource adequacy requirements of Attachment AA. If an LRE is short of the necessary capacity to meet the calculated PRM, that entity must attempt to obtain additional capacity or incur deficiency payments.

Q. HOW DOES AN LRE DEMONSTRATE THAT IT HAS SUFFICIENT DELIVERABLE CAPACITY TO MEET ITS PRM?

A. Annually, an LRE must submit a workbook indicating that it has sufficient Deliverable Capacity by: (a) demonstrating the resource(s) is (i) registered in the Integrated Marketplace or (ii) listed as a Designated Resource in the Network Integration Transmission Service Agreement; (b) submitting, or causing to be submitted, to the Transmission Provider the current Operational Test results as performed in accordance with the SPP Planning Criteria; (c) submitting, or causing to be submitted, to the Transmission Provider the current Capability Test results as performed in accordance with the SPP Planning Criteria; and (d) demonstrating that there is firm transmission service from the internal resource(s) to the LRE's load.[1]

There is nothing in the proposed FAC Tariff changes that would preclude Liberty-Empire from obtaining firm transmission and SPP IM registration which would allow a new generating asset to contribute to Resource Adequacy requirements for its customers as prescribed by SPP and detailed above. In fact, it is likely that Liberty-Empire will have already completed many if not all of these activities prior to a Commercial Operation declaration which would pave the way for a generation project not yet in rates to provide Resource Adequacy capacity. A PRM deficiency would

[1] SPP Open Access Transmission Tariff, Attachment AA Section 7.2.

result in a capacity purchase and a transmission deliverability study, both of which carry unknown financial costs, or a deficiency payment which currently can range from approximately $107,000 to $171,000 per MW-Year.

Q. WHAT IS THE SECOND FAC TARIFF REVISION BEING PROPOSED BY THE COMPANY?

A. Section 3 of Purchased Power Costs ("PP") details a fixed percentage of 34% of SPP costs associated with Network Transmission Service that is recoverable through the fuel adjustment clause and a fixed percentage of 50% of MISO costs associated with various transmission schedules that is recoverable through the fuel adjustment clause. The Company's proposed revision would modify the percentages that are recoverable through the FAC to 100% of SPP costs and 100% of MISO costs. Furthermore, the Company proposes to include Schedule 1a and Schedule 12 as further defined SPP costs that would be recoverable through the FAC at 100%.

Q. WHAT IS THE REASON FOR CHANGING THE PERCENTAGES TO REFLECT 100% RECOVERY OF SPP AND MISO TRANSMISSION COSTS?

A. The relationship between investment in the transmission system and improved reliability and economic operations is clear. The SPP has an Integrated Transmission Planning ("ITP") process that prescribes the approach and metrics that will be considered when evaluating transmission expansion. The approach focuses on reliability, economic benefits, and the achievement of public policy goals. Specific SPP working groups spend time and effort to oversee these areas of focus including the Economic Studies Working Group, Transmission Working Group, and the Operating Reliability Working Group. Empire has spent a myriad of time actively participating in these working groups and in the ITP process to ensure that our customers have access to reliable and cost effective energy. The benefits our customers are already receiving in part as a result of those efforts include adjusted production cost savings, lower resource adequacy requirements, and the ability to reliably accommodate lower cost generation delivery with increasing efficiency.

Q. ARE THERE ADDITIONAL REASONS THE FAC SHOULD BE CHANGED TO REFLECT 100% RECOVERY OF SPP AND MISO TRANSMISSION COSTS?

A. Yes. Effort is being spent to identify projects between SPP and neighboring Transmission Providers such as Midcontinent Independent System Operator ("MISO") and Associated Electric Cooperative Incorporated ("AECI") to help facilitate a more reliable and cost effective delivery of energy. The Joint Operating Agreement ("JOA") that SPP has with AECI requires a study to be performed every other year which is known as the Joint and Coordinated System Planning ("JCSP") study and has already resulted in two projects near Empire's zone that address high voltage and overloading issues. SPP and MISO have also been coordinating on seams efforts via the SPP-RSC/OMS Seams Coordination Effort ("RSC-OMS") and although no projects have yet been complete as a result of those efforts, the specific goals outlined in the group's Goals and Guiding Principles document include "Increase benefits to ratepayers in both markets by improving market-based transactions and operations across the seam.[2]"

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[2] SPP-RSC/OMS Seams Coordination Effort; Goals and Guiding Principles: https://www.spp.org/documents/59005/spp%20rsc%20oms%20goals%20and%20guiding%20principles%2010_1_18.pdf.

It is precisely because of these investments and these efforts that many of these benefits are possible. The primary mechanism by which these investments are funded is Schedule 11 Base Plan charges. Empire's status as a NITS customer obligates Schedule 11 costs and it is precisely this reason why the link between benefits received as a result of investment in the transmission system and the costs associated with that investment ought to be wed.

Q. HAVE THERE BEEN SIGNIFICANT DECREASES TO TRANSMISSION EXPENSE THAT ARE UNABLE TO BE SHARED WITH THE COMPANY'S CUSTOMERS DUE TO THE RESTRICTIONS IN THE FAC TARIFF?

A. Yes. In February 2016, a settlement was reached with a number of parties regarding a RTOR settlement. The MISO RTOR Settlement refers to the partial resolution of litigation brought by a number of MISO Transmission Service Agreement ("TSA") customers related to long-term Point-to-Point ("PTP") service agreements originally entered into with Entergy prior to their 2013 admittance into MISO. Upon Entergy granting functional control of its transmission facilities in Arkansas, Mississippi, Louisiana, and Texas, to MISO, transmission customers with long-term PTP TSAs were billed the significantly higher MISO RTOR rate. At issue was the application of a MISO system-wide rate for through and out transmission customers from the new MISO-South region which appeared to violate the no-cost-sharing rule in the Attachment FF of the MISO Tariff, in particular the FERC separation of new (South) and old (Legacy) regions for cost allocation and rate design purposes. After approximately two years of litigation, a settlement agreement was reached (subject to refund) between MISO and the TSA customers. The rate relief settlement schedules are as follows:

Schedule 7: Years 1 & 2 (2014 & 2015) the TSA Customers will be refunded for the difference between the MISO RTOR charged and the Entergy-only RTOR which is calculated based on the 2014 & 2015 Attachment O formula rate, respectively. Years 3 (2016) - 9 (2022) the TSA Customers will pay the then-current Entergy RTOR plus a systematically increasing portion of the difference between the then-current MISO and then-current Entergy RTOR. Year 10 the TSA customers will begin paying the full then-current MISO RTOR.

Schedule 26: The TSA customers will be refunded for Years 1 & 2 (2014 & 2015) for Schedule 26 payments. Years 3-5 (2016-2018) the TSA customers will pay no Schedule 26 charges. Years 6-12 (2019-2025) the TSA customers will pay a systematically increasing amount (increasing by 12.5% annually) of the then-current MISO schedule 26 rate. Year 13 the TSA customers will pay the then-current MISO Schedule 26 rate. However, if transmission investment were to occur in the new MISO-South region, the TSA customers would be charged the applicable Schedule 26 charges. Again, due to the limited sharing of transmission expense in the Company's Missouri FAC, Liberty-Empire's customers were not able to realize a significant portion of this refund.

Please see Empire's Initial Comments filed in Case No. EX-2016-0294 for additional discussion of this issue. These Comments filed by Liberty-Empire in the Commission's FAC rulemaking docket are attached to this testimony as Schedule AJD-2 and incorporated by reference.

Q. DOES THE COMPANY PASS THROUGH TRANSMISSION EXPENSE VIA A FUEL ADJUSTMENT MECHANISM OR TRACKER IN THE OTHER JURISDICTIONS IN WHICH IT OPERATES?

A. Yes. In Kansas, Empire has an approved Transmission Delivery Charge ("TDC") rider for the recovery of transmission-related costs. In Oklahoma, Empire has a Southwest Power Pool Transmission Tariff ("Schedule SPPTC") for the recovery of SPP Base Plan expenses. In Arkansas, Empire has a Transmission Cost Recovery Rider ("TCR Rider") for the recovery of net transmission costs.

Q. DID THE COMMISSION AMEND THE FAC RULE TO INCLUDE A LISTING OF THE SPECIFIC TRANSMISSION CHARGES TO BE INCLUDED IN A UTILITY'S FAC?

A. No. In its Order of Rulemaking in Case No. EX-2016-0294, Response to Comment #2, the Commission held that the rule already "allows for the recovery of transportation costs." The Commission further held that "the determination of which of the specific costs and how much of those costs to include" is reserved for the Commission's determination based on the individual facts of each case.

Q. IS THE COMPANY PROPOSING ANY OTHER CHANGES TO THE FAC TARIFF IN THIS PROCEEDING?

A. Yes. The third change that the Company is proposing is that under Purchased Power Section 1, that language listing exclusions, specifically "all charges under the Southwest Power Pool ("SPP") Schedule 1a and 12 and congestion management charges and revenues" be removed. Additionally, the Company proposes that Sheet 17w specifically list "Auction Revenue Rights and Transmission Congestion Rights" as an SPP cost or revenue that is recoverable with other identified 555 General Ledger ("GL") accounts.

Q. WHAT ARE AUCTION REVENUE RIGHTS AND TRANSMISSION CONGESTION RIGHTS?

A. In the SPP IM, TCRs have replaced the use of energy and native load schedules as congestion hedges. TCRs are financial instruments, defined along a nodal path with a source location and sink location that entitle the owner to a stream of hourly revenues or charges based on the difference in day-ahead (DA) marginal congestion costs (MCC) along that path. TCRs are either seasonal or monthly in duration and can be on-peak and/or off-peak products. A TCR may either be purchased during a TCR auction (annual/monthly) or may be self-converted from an Auction Revenue Right ("ARR"). Owners of confirmed physical firm transmission rights are entitled to candidate ARR's which can then be nominated for allocation during an ARR allocation (annual/monthly). If a candidate ARR is nominated for allocation and the allocation is granted, the holder may now either hold the ARR, in which case they would be entitled to any charges or revenues resulting from the auction clearing prices during a TCR auction or may attempt to self-convert the ARR into a TCR.

Q. DOES ARR/TCR ACTIVITY CURRENTLY FLOW THROUGH THE FAC TARIFF?

A. No. Subject to the aforementioned FAC Tariff language and more specifically Schedule E of the Stipulation and Agreement approved by the Commission in Case No. ER-2016-0023, sub-accounts 555990 and 555995, where ARR and TCR activity are recorded, are excluded from the list of approved sub-accounts for FAC inclusion. Schedule E of the Stipulation and Agreement in ER-2016-0023 is included as Schedule AJD-3 in this testimony.

Q. WHY SHOULD ARR/TCR ACTIVITY FLOW THROUGH LIBERTY-EMPIRE'S FAC?

A. ARRs and TCRs are a basis hedge for the load and represent the financial equivalent of physical transmission rights. The value of the TCR is to ensure that if the Locational Marginal Price ("LMP") at a load node is resulting in customers paying a higher price for energy than the generators for which they have physical transmission rights, that they have an opportunity to be hedged to mitigate financial risk. Since TCR settlements are derived from the basis differential between DA load and DA generation, they are recorded in a 555 purchase power account and often result in a negative expense that is an offset to the congestion cost built into the DA energy cost paid for by the load.

III. NATURAL GAS HEDGING REVISIONS

Q. THE OPC CHALLENGED THE PRUDENCE OF LIBERTY-EMPIRE'S GAS HEDGING COSTS IN COMMISSION CASE NO. EO-2017-0065. WHAT WAS THE RESULT OF THAT CASE?

A. The Staff of the Commission found no imprudence on the part of Liberty-Empire, and the Commission issued its Amended Report and Order on February 28, 2018, approving Staff's recommendation and denying OPC's request for a prudence disallowance. The Commission's decision was affirmed by the Missouri Court of Appeals in Case No. WD81627.

Q. WHAT ACTIONS DID LIBERTY-EMPIRE TAKE IN RESPONSE TO THE CONCERNS RAISED BY OPC AND THE COMMISSION IN CASE NO. EO-2017-0065?

A. Liberty-Empire took prompt action in response to those concerns, undertook a complete review of its gas hedging policy, and reached out to Staff, OPC, the Missouri Department of Economic Development – Division of Energy ("DE"), and counsel for the Midwest

Energy Consumers Group ("MECG") to discuss possible changes in its natural gas hedging policy.

Q. PLEASE EXPLAIN THE PROCESS THAT WAS USED TO REVIEW LIBERTY-EMPIRE'S GAS HEDGING POLICY.

A. Discussions with Liberty-Empire's Risk Management Oversight Committee ("RMOC") beginning in January 2018 resulted in a third party review of Liberty-Empire's Risk Management Policy ("RMP"). The review, which was submitted for bid to multiple parties, was conducted by Risk Management Incorporated ("RMI") and included:

- A review of Liberty-Empire's current RMP and documentation
- A comparison of Liberty-Empire's risk management activities to industry standards
  - Specific focus on regulated utilities and review of state regulatory trends on fuel hedging activities
- Identify strengths and weaknesses of the current RMP
- Make recommendations for improvements based on best practices

After a thorough review of Empire's RMP, Senior Vice President of RMI Dan Conrath presented his findings to the RMOC on September 19, 2018, including a summarization of the results, and answered questions from RMOC attendees. Immediately following the presentation, the RMOC voted to suspend current hedging requirements for a finite period of time to allow for stakeholder discussion regarding the findings of the third party review and Liberty-Empire's path forward.

Q. WHAT WAS THE NEXT STEP TAKEN IN RESPONSE TO THE CONCERNS RAISED BY OPC AND THE COMMISSION IN CASE NO. EO-2017-0065?

A. The Company then scheduled a series of meetings with interested stakeholders to review the third party review and ascertain any comments or suggestions from interested parties. Following the stakeholder review process and internal discussion, a proposal was brought forward to stakeholders on June 11, 2019, outlining modifications to Liberty-Empire's natural gas hedging activities. The Company then proceeded to present to the RMOC those same modifications on July 19, 2019.

Q. HAS THE COMPANY FORMALLY ADOPTED CHANGES TO ITS NATURAL GAS HEDGING POLICY?

A. Yes. On July 19, 2019, the Company, through its RMOC, adopted a revised natural gas hedging plan. Although some of the tables will be dynamic and disaggregated into the appropriate sections of the Risk Management Policy or altogether different documents, a holistic example is attached to my testimony as Schedule AJD-4. Changes to the Company's natural gas hedging policy include:

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- ** **
- ** **
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- ** .**

Q. HAS THE COMPANY ADOPTED ANY OTHER CHANGES TO ITS NATURAL GAS HEDGING PROCESS?

A. Yes. Empire will work with interested stakeholders to meet annually to review the natural gas hedging policy and to listen to any comments or concerns regarding the past hedging year and the upcoming hedging year.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4	1st	Revised Sheet No. 17u
Canceling P.S.C. Mo. No.	5	Sec.	4		Original Sheet No. 17u

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after XXXX XX, 2019

The two six-month accumulation periods, the two six-month recovery periods and filing dates are set forth in the following table:

Accumulation Periods	**Filing Dates**	**Recovery Periods**
September–February	By April 1	June–November
March–August	By October 1	December–May

The Company will make a Fuel Adjustment Rate (“FAR”) filing by each Filing Date. The new FAR rates for which a filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FAR filings shall be accompanied by detailed workpapers with subaccount detail supporting the filing in an electronic format with all formulas intact.

DEFINITIONS

ACCUMULATION PERIOD:
The six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purpose of determining the FAR.

RECOVERY PERIOD:
The billing months during which a FAR is applied to retail customer usage on a per kilowatt-hour (“kWh”) basis.

BASE ENERGY COST:
Base energy cost is ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchase Power Adjustment (“FPA”).

BASE FACTOR (“BF”):
The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case. BF = $0.02488 per kWh for each accumulation period.

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4	1st	Revised Sheet No.	17v
Canceling P.S.C. Mo. No.	5	Sec.	4		Original Sheet No.	17v

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after XXXX XX, 2019

APPLICATION

FUEL & PURCHASE POWER ADJUSTMENT

$$FPA = \{[(FC + PP + E – OSSR - REC - B) * J] * 0.95\} + T + I + P$$

Where:

FC = Fuel Costs Incurred to Support Sales:

The following costs reflected in Federal Energy Regulatory Commission ("FERC") Accounts 501 and 506: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuels (i.e. tires, and bio-fuel), fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments assessed by coal suppliers, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, combustion product disposal revenues and expenses, consumable costs related to Air Quality Control Systems ("AQCS") operation, such as ammonia, lime, limestone, and powdered activated carbon, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

The following costs reflected in FERC Accounts 547 and 548: natural gas generation costs related to commodity, oil, transportation, fuel losses, hedging costs for natural gas and oil, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees.

PP = Purchased Power Costs:

1. Costs and revenues for purchased power reflected in FERC Account 555. Such costs include:

DATE OF ISSUE August 14, 2019 DATE EFFECTIVE September 13, 2019
ISSUED BY Sheri Richard, Director Rates and Regulatory Affairs, Joplin, MO

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4	1st	Revised Sheet No.	17w
Canceling P.S.C. Mo. No.	5	Sec.	4		Original Sheet No.	17w

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after XXXX XX, 2019

A. SPP costs or revenues for SPP's energy and operating market settlement charge types and market settlement clearing costs or revenues including:

i. Energy;
ii. Ancillary Services;
  a. Regulating Reserve Service
  b. Energy Imbalance Service
  c. Spinning Reserve Service
  d. Supplemental Reserve Service
iii. Revenue Sufficiency;
iv. Revenue Neutrality;
v. Demand Reduction;
vi. Grandfathered Agreements;
vii. Virtual Energy including Transaction Fees;
viii. Pseudo-tie; and
ix. Miscellaneous;
x. Auction Revenue Rights
xi. Transmission Congestion Rights

B. Non-SPP costs or revenue as follows:

i. If received from a centrally administered market (e.g. PJM / MISO), costs or revenues of an equivalent nature to those identified for the SPP costs or revenues specified in sub part A of part 1 above;
ii. If not received from a centrally administered market:
  a. Costs for purchases of energy; and
  b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and

C. Settlements, insurance recoveries, and subrogation recoveries for purchased power expenses.

2. Costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles.

3. Transmission service costs reflected in FERC Account 565:

DATE OF ISSUE August 14, 2019 DATE EFFECTIVE September 13, 2019
ISSUED BY Sheri Richard, Director Rates and Regulatory Affairs, Joplin, MO

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4	1st	Revised Sheet No.	17x
Canceling P.S.C. Mo. No.	5	Sec.	4		Original Sheet No.	17x

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after XXXX XX, 2019

A. One hundred percent (100%) of SPP costs associated with Network Transmission Service:
   i. SPP Schedule 2 – Reactive Supply and Voltage Control from Generation or Other Sources Service;
   ii. SPP Schedule 3 – Regulation and Frequency Response Service; and
   iii. SPP Schedule 11 – Base Plan Zonal Charge and Region-wide Charge.
   iv. SPP Schedule 1a – Tariff Administration
   v. SPP Schedule 12 – FERC Assessment

B. One hundred percent (100%) of Mid-Continent Independent System Operator ("MISO") costs associated with:

   i. Network transmission service;
   ii. Point-to-point transmission service;
   iii. System control and dispatch; and
   iv. Reactive supply and voltage control.

4. Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which SPP or another market participant bills / credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR;
   A. The Company may include the new charge type cost or revenue in its FAR filings if the Company believes the new charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be, subject to the requirement that the Company make a filing with the Commission as outlined in B below and also subject to another party's right to challenge the inclusion as outlined in E. below;

   B. The Company will make a filing with the Commission giving the Commission notice of the new charge type no later than 60 days prior to the Company including the new charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such new charge type cost or revenue, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements;

   C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new charge type costs or revenues by amount, description and location within the monthly reports;

   D. The Company shall account for the new charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues;

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4	1st	Revised Sheet No. 17y
Canceling P.S.C. Mo. No.	5	Sec.	4		Original Sheet No. 17y

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RIDER FAC
For service on and afterXXXXXX, 2019

E. If the Company makes the filing provided for by B above and a party challenges the inclusion, such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new charge type, a party shall make a filing with the Commission based upon the contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. A party wishing to challenge the inclusion of a charge type shall include in its filing the reasons why it believes the Company did not show that the new charge type possesses the characteristic of the costs or revenues listed in Factors PP or OSSR, as the case may be, and its filing shall be made within 30 days of the Company's filing under B above. In the event of a timely challenge, the Company shall bear the burden of proof to support its decision to include a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P; and

F. A party other than the Company may seek the inclusion of a new charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company's next FAR filing. Such a filing shall give the Commission notice that such party believes the new charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such new charge type cost or revenue, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new charge type does not possess the characteristic of the costs or revenues listed in Factors PP or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new charge type. In the event of a timely challenge, the party seeking the inclusion of the new charge type shall bear the burden of proof to support its contention that the new charge type should be included in the Company's FAR filings. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4	1st	Revised Sheet No. 17z
Canceling P.S.C. Mo. No.	5	Sec.	4		Original Sheet No. 17z

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after XXXXXX2019

E = Net Emission Costs: The following costs and revenues reflected in FERC Accounts 509 and 411 (or any other account FERC may designate for emissions expense in the future): emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging.

OSSR = Revenue from Off-System Sales (Excluding revenue from full and partial requirements sales to municipalities and revenue from generation facilities declared Commercially Operational and not yet in rates):

The following revenues or costs reflected in FERC Account 447: all revenues from off-system sales and SPP energy and operating market including (see Note A. below):

i. Energy;
ii. Capacity Charges associated with Contracts shorter than 1 year;
iii. Ancillary Services including;
   a. Regulating Reserve Service
   b. Energy Imbalance Service
   c. Spinning Reserve Service
   d. Supplemental Reserve Service
iv. Revenue Sufficiency;
v. Losses;
vi. Revenue Neutrality;
vii. Demand Reduction;
viii. Grandfathered Agreements;
ix. Pseudo-tie;
x. Miscellaneous; and
xi. Hedging.

REC = Renewable Energy Credit Revenue reflected in FERC Account 456 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard.

HEDGING COSTS:

Hedging costs are defined as realized losses and costs (including broker commission fees and margins) minus realized gains associated with mitigating volatility in the Company's cost of fuel, fuel additives, fuel transportation, emission allowances and purchased power costs, including but not limited to, the Company's use of derivatives whether over-the-counter or exchanged traded including, without limitation, futures or forward contracts, puts, calls, caps, floors, collars and swaps.

Note A Should FERC require any item covered by factors FC, PP, E, REC or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E, REC or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

B = Net base energy cost is calculated as follows:

$B = (S_{AP} * \$0.02488)$

S_{AP} = Actual net system input at the generation level for the accumulation period.

J = $\frac{\text{Missouri retail kWh sales}}{\text{Total system kWh sales}}$

Where Total system kWh sales includes sales to municipalities that are associated with Empire and excludes off-system sales.

T = True-up of over/under recovery of FAC balance from prior recovery period as included in the deferred energy cost balancing account. Adjustments by Commission order pursuant to any prudence review shall also be placed in the FPA for collection unless a separate refund is ordered by the Commission.

I = Interest applicable to (i) the difference between Total energy cost (FC + PP + E – OSSR – REC) and Net base energy costs (“B”) multiplied by the Missouri energy ratio (“J”) for all kWh of energy supplied during an AP until those costs have been billed; (ii) refunds due to prudence reviews (“P”), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings (“T”) provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company’s short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

FUEL ADJUSTMENT RATE

The FAR is the result of dividing the FPA by estimated recovery period S_{RP} kWh, rounded to the nearest \$0.00000. The FAR shall be adjusted to reflect the differences in line losses that occur at primary and secondary voltage by multiplying the average cost at the generator by 1.0429 and 1.0625, respectively. Any FAR authorized by the Commission shall be billed based upon customers’ energy usage on and after the authorized effective date of the FAR. The formula for the FPA is displayed below

$$FAR = \frac{FPA}{S_{RP}}$$

Where:

S_{RP} = Forecasted Missouri NSI kWh for the recovery period.

$$= \text{Forecasted total system NSI} * \frac{\text{Forecasted Missouri retail kWh sales}}{\text{Forecasted total system kWh sales}}$$

Where Forecasted total system NSI kWh sales includes sales to municipalities that are associated with Empire and excludes off-system sales.

PRUDENCE REVIEW

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

TRUE-UP OF FPA

In conjunction with an adjustment to its FAR, the Company will make a true-up filing with an adjustment to its FAC on the first Filing Date that occurs after completion of each Recovery Period. The true-up adjustment shall be the difference between the FPA revenues billed and the FPA revenues authorized for collection during the true-up recovery period, i.e. the true-up adjustment. Any true-up adjustments or refunds shall be reflected in item T above and shall include interest calculated as provided for in item I above.

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 7th Revised Sheet No. 17ac

Canceling P.S.C. Mo. No. 5 Sec. 4 6th Revised Sheet No. 17ac

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after XXXX XX, 2019

	Accumulation Period Ending		XXXX XX, 2019
1	Total Energy Cost (TEC) = (FC + PP + E – OSSR - REC)		
2	Net Base Energy Cost (B)	-	
	2.1 Base Factor (BF)		0.02488
	2.2 Accumulation Period NSI (S_{AP})		
3	(TEC-B)		
4	Missouri Energy Ratio (J)	*	
5	(TEC - B) * J		
6	Fuel Cost Recovery	*	95.00%
7	(TEC - B) * J * 0.95		
8	True-Up Amount (T)	+	
9	Prudence Adjustment Amount (P)	+	
10	Interest (I)	+	
11	Fuel and Purchased Power Adjustment (FPA)	=	
12	Forecasted Missouri NSI (S_{RP})	÷	
13	Current Period Fuel Adjustment Rate (FAR)	=	
14	Current Period FAR_{PRIM} = FAR x VAF_{PRIM}		
15	Current Period FAR_{SEC} = FAR x VAF_{SEC}		
16	VAF_{PRIM} = 1.0429		1.0429
17	VAF_{SEC} = 1.0625		1.0625

DATE OF ISSUE August 14, 2019 DATE EFFECTIVE September 13, 2019
ISSUED BY Sheri Richard, Director Rates and Regulatory Affairs, Joplin, MO

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of a Proposed Amendment to the	)	
Commission's Fuel Adjustment Clause Rules	)	File No. EX-2016-0294

EMPIRE'S INITIAL COMMENTS

COMES NOW The Empire District Electric Company, a Liberty Utilities company ("Empire"), and submits these Initial Comments regarding the proposed changes to Rule 4 CSR 240-20.090 and in response to the *Notice of Public Hearing and Notice to Submit Comments* contained in the Missouri Register publication on July 2, 2018. In this regard, Empire respectfully states as follows to the Missouri Public Service Commission ("Commission"):

1. Empire appreciates the opportunity to participate in this rulemaking and provide comments regarding possible changes to the Commission's Fuel Adjustment Clause ("FAC") rules.

2. Empire concurs in the Comments jointly filed herein by Ameren Missouri, KCP&L, and KCP&L-GMO (the "Joint Utility Filing").

3. In addition, Empire is filing its own Initial Comments which serve to emphasize the need for the Commission's FAC rules to allow for the inclusion of both fuel-related revenues, including transportation, and fuel and purchased power costs, including transportation.

►The Commission's Current Treatment of MISO and SPP Transmission Costs

4. In Case No. ER-2014-0258, the Commission concluded that only the following Midcontinent Independent System Operator ("MISO") transmission costs, and no off-setting transmission revenues, should be included in Ameren Missouri's FAC: "1) costs to transmit electric power it did not generate to its own load (true purchased power) and 2) costs to transmit excess electric power it is selling to third parties to locations outside of MISO (off-system

sales)."[1] A similar decision was reached in Case No. ER-2014-0351 regarding the inclusion of Southwest Power Pool ("SPP") transmission costs in the FAC for Empire.

5. Stemming from the decisions made in Case Nos. ER-2014-0258 and ER-2014-0351 cited above, the Commission approved Empire's FAC to include the following transmission (transportation) percentages: 50% of MISO non-administrative costs and 34% of SPP non-administrative costs. For Empire's most recent rate case, ER-2016-0023, the same percentages were maintained. As such, Empire's current FAC includes 50% of MISO non-administrative costs and 34% of SPP non-administrative costs as components. Currently, no transmission (transportation) revenues are included in Empire's FAC.

6. The FAC statute, section 386.266, authorizes the Commission to approve FACs that allow rate adjustments based on changes in "prudently incurred fuel and purchased power costs, including transportation." The Commission must then determine: (1) what are fuel costs, (2) what are purchased power costs, and (3) what are the associated transportation costs. The Commission's FAC rules guide the Commission in answering these three questions. As stated in the Joint Utility Filing, the rules should not contain provisions that can be used as a sword to advance a point of view on policy issues regarding the FAC.

►The Commission's current treatment of MISO and SPP transmission costs creates the potential for customer harm and does not accurately reflect the interrelationship between investment in the transmission system under the functional control of the RTOs and the efficiencies created by the market.

7. Empire's base fuel rate since 2014 has declined from $28.12/MWh to the current base fuel rate of $24.15/MWh. This reduction is due in part to lower production costs resultingfrom the efficiencies created by Empire's participation in the SPP IM.[2] There is an inextricable link

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[1] Ameren Report and Order, pp. 111-115.

[2] Empire is a member of the SPP regional transmission organization ("RTO"). Participation in the SPP Integrated Marketplace ("IM") is facilitated by a robust transmission system that economically commits and

between the investment in the transmission system under the functional control of SPP and the efficiencies created by the SPP IM. In "The Value of Transmission," the 2016 SPP study published from the Battle Group, the benefits quantified by an Adjusted Production Cost ("APC") study determined that more than $660,000/day ($240 MM/year) were realized in the first year of the IM and that this calculation excluded benefits from a more efficient interchange with neighbors and is expected to increase, as transmission investment in Extra High Voltage ("EHV"), Balanced Portfolio, and Priority Projects move into completion.

8. According to Attachment O of the SPP Open Access Transmission Tariff ("OATT"), the transmission planning process requires analysis of solutions and alternatives to the Transmission Planning Assessment, which includes the cost effectiveness of the proposed solution including: "benefits resulting from dispatch savings, loss reductions, avoided projects, applicable environmental impacts, reduction in required operating reserves, interconnection improvements, congestion reduction," etc. This language speaks to the tie between improved economics that are evaluated and created when investing in the transmission system as it relates to improved production costs. The economic value facilitated by the robust transmission system is undeniable. Exclusion of the majority of transmission costs from recovery as a component of fuel, however, continues to be the practice of the Commission.

9. It is unjust for a utility to pass on the benefits (lower fuel and purchased power costs) facilitated by transmission upgrades, while withholding the costs associated with those upgrades (transportation charges). Also, as illustrated by the specific examples contained below, the lack of total transmission expense and revenue as an included component of the FAC creates the potential for customer harm. Empire's current FAC lacks a mechanism to return to customers

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dispatches resources to serve load while operating within the security constraints of the Bulk Electric System ("BES"). Empire has been a market participant in the SPP IM since its inception in March of 2014.

certain refunds and adjustments received by Empire, may create a disincentive regarding Empire's role in evaluating and advocating for transmission investment that is calculated to lower production costs, and is inconsistent with the treatment afforded fuel and purchased power in other states. For these reasons, Empire believes it is critical that the changes suggested in the Joint Utility Filing be implemented and that the Commission's FAC rules allow for the inclusion of both fuel-related revenues, including transportation, and fuel and purchased power costs, including transportation.

►Example 1: Balanced Portfolio Transfers

10. The Balanced Portfolio Transfers ("BP Transfers") are a good example of the interconnected nature of transmission revenue and transmission expense. The BP Transfers refer to the transfers of Schedule 11 zonal revenue requirements from the zone to the region.[3]

11. Since the Empire zone was not initially "in balance" with the approved portfolio of projects, a systematic set of zonal-to-regional transfers over the course of 10 years was designed to ensure a "balance." The transfers began in October 2012 (realized November 2012 as Schedule 11 settlements are one month in arrears), and, for Empire, resulted in a systematic increase of approximately $1.26 million each year for the first five years and then held constant for the next five years at approximately $6.3 million. Since the BP projects were all completed in mid-2015, however, it was determined that year 6 would true-up the estimated costs of the BP projects to the actual costs and hold those reallocated values steady for years 6-10. Although the projects as a group came in under budget, the allocation of benefits was not quantified to be

[3] The reason for these transfers is a collection of regional economic projects, called Balanced Portfolio projects, approved by the SPP for the purpose of reducing congestion on the SPP transmission system resulting in lower generation production costs. The term "balanced" refers to language in Attachment O of the SPP OATT, which requires the sum of benefits must at least equal to, if not exceed, the costs for each zone. If any zone is deficient, the tariff allows for a portion of the zonal revenue requirement to be transferred to the region for the purpose of achieving a "balance" - or a benefit/cost ratio of at least 1.0.

commensurate between the different zones. When taking into account the estimated-to-actual cost variance on a project by project basis, a reallocation occurred in various zones (including Empire's) which resulted in an increase for the years' 6-10 amount of approximately $900,000/year, or $7.196 million total transfer/year. Beginning in October 2015, Empire did not have enough zonal revenue requirements to transfer another $1.26 million from the zone to the region. As a result, a significant portion of the transfer was received as Schedule 9 revenue.

12. Schedule 9 revenue does not flow through Empire's Missouri FAC. Empire believes the intent of the BP Transfers are to credit back the zone for transmission investments out of balance. Thus, Empire decided the revenue should be credited to transmission expense in the form of negative expense (rather than transmission revenue). The resulting adjustment by Empire ensures expenditures for transmission investment will be credited back to the intended accounts for the month. Without these manual measures to reclassify transmission revenue to negative transmission expense, Empire's customers would not receive any portion of the systematic reduction in costs.

13. The SPP transmission settlement process is esoteric, and although Empire has attempted to understand the provenance of all charges and adjustments to charges, the lack of full transmission charge and revenue inclusion in the FAC inhibits Empire's ability to credit back the Company's customers in all appropriate circumstances.

►**Example 2: Revenue Sharing**

14. Per Attachment L of the SPP OATT, most of the point-to-point ("PTP") revenue is distributed based on an allocation of 50% to a transmission owner ("TO") revenue requirement ratio share and 50% to a flow-based methodology referred to as MW-mile. Empire is a single TO zone, so the facilities that comprise the Company's TO revenue requirement ratio share are

paid for by the load in the Empire zone. The MW-mile allocation uses linear analysis to determine the distribution of flows for transactions and then uses the energy distribution factor as a basis for flow-based allocation. Again, Empire's customers that have paid for the facilities in the zone ought to receive the revenue associated with transactions that utilized those facilities.

15. In 2016, new transmission charges were created to reflect seams revenue from MISO. MISO seams revenue refers to compensation paid from MISO to SPP and distributed proportionally to members related to the use of the SPP transmission system along the SPP-MISO seam connecting MISO Midwest to MISO South. On March 25, 2016, FERC issued Order ER16-791, approving a settlement in which MISO will compensate SPP members $16,000,000 for retroactive usage for the time period of January 2014 to February 2016 and begin paying SPP for Available System Capacity Usage that MISO accesses subject to refund. SPP will use the following distribution methodology: Total Charge multiplied by the MW-Mile factor determines the Transmission owner's portion which is then divided proportionally between Schedules 7, 8, and 11 based on the ratio of the prior year PTP Revenues. Again, the lack of inclusion of any amount of transmission revenue in Empire's Missouri FAC prevented Empire from passing those refunds back to customers through the FAC.

►Example 3: Network Integration Transmission Service

16. Like most load serving entities in the SPP IM, Empire is a Network Integration Transmission Service ("NITS") customer. Per Section 28.1 of the SPP OATT, this service allows for "…Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their network load." As a result of its status as a NITS customer, Empire is allowed to serve its load in a highly efficient manner by leveraging a market that supports the most economic commitment and dispatch as its objective

function. Per Section 34 of the SPP OATT, "The Network Customers shall pay the Transmission Provider for any Direct Assignment Facilities, Directly Assigned Upgrade Costs, Ancillary Services, Base Plan Zonal Charges (Schedule 11), Region-wide Charges (Schedule 11) and applicable study costs, consistent with Commission Policy."

17. The primary investment mechanism by which the BES (Bulk Electric System) in SPP is funded is Base Plan Zonal and Regional charges. As a NITS customer, Empire supports BES investment via Schedule 11 charges that are dynamic, as most investment included in the Annual Transmission Revenue Requirement ("ATRR") of Schedule 11 is updated annually via formula rate mechanisms. It is just and reasonable for Empire and other NITS customers in SPP to fund the BES, because the network load is receiving benefits of a more efficient and reliable grid.

18. As the ATRR calculations change, however, the low percentage of transmission charge inclusion in Empire's FAC breaks the link between just and reasonable costs incurred and the resulting benefits received. First, it is unjust for a utility to pass on the benefits (lower fuel and purchased power costs) facilitated by transmission upgrades, while withholding the costs associated with those upgrades (transportation charges). Furthermore, recent events such as the Tax Cut and Jobs Act of 2017 provided cost reductions that could have been passed on to Empire's Missouri customers but for the low percentage of transmission costs included in Empire's FAC.

19. Empire's Plum Point facility incurs Regional Through and Out Rate ("RTOR") expense due to the plant's physical location in the MISO regional transmission organization footprint and its subsequent pseudo-tie into the SPP balancing authority ("BA"). The RTOR that Empire incurs via its Schedule 7 payment to MISO is formulated from the Attachment O filings of the Entergy companies within MISO. In June 2018, the Entergy RTOR rate dropped from

$2.89/KW-month to $2.60/Kw-month. This nearly 10% drop in Schedule 7 charges, coupled with a reduction in the Entergy RTOR in June 2016, translated into a 14% reduction from March 2017 to present in transmission expense that cannot be fully passed on to Empire's Missouri customers due to the design of Empire's Missouri FAC. (*See* the MISO RTOR section below for more information.)

►Example 4: MISO Regional Through and Out Rate

20. The MISO Regional Through and Out Rate ("RTOR") Settlement refers to the partial resolution of litigation brought by a number of MISO Transmission Service Agreement ("TSA") customers related to long-term PTP service agreements originally entered into with Entergy prior to their 2013 admittance into MISO. Upon Entergy granting functional control of its transmission facilities in Arkansas, Mississippi, Louisiana, and Texas, to MISO, transmission customers with long-term PTP TSAs were billed the significantly higher MISO RTOR rate. At issue was the application of a MISO system-wide rate for through and out transmission customers from the new MISO-South region which appeared to violate the no-cost-sharing rule in the Attachment FF of the MISO Tariff, in particular the FERC separation of new (South) and old (Legacy) regions for cost allocation and rate design purposes.

21. After approximately two years of litigation, a settlement agreement was reached (subject to refund) between MISO and the TSA customers. Based on the rate relief settlement schedules and the limited sharing of transmission expense in the Company's FAC, Empire's customers were not able to realize a significant portion of this refund.

► The FACs approved by the Missouri Commission are inconsistent with the treatment afforded fuel and purchased power in other states.

22. Currently, other states in which Empire operates have mechanisms allowing for the sharing of transmission cost and revenues. Arkansas has a Transmission Cost Recovery Rider

that allows for the pass through of both transmission expense and revenues annually, including inclusion of MISO RTOR charges. In Oklahoma, a SPP Transmission Tariff allows for the sharing of Schedule 11 charges, credits, and refunds with Empire's customers. Although Empire currently does not have a Transmission Delivery Charge ("TDC") tariff for Kansas, neighboring market participant Westar does have the TDC tariff, which allows for the sharing of various SPP transmission schedules with its customers.

WHEREFORE, Empire respectfully submits these Initial Comments and looks forward to further discussion regarding possible FAC rule changes.

Respectfully submitted,

BRYDON, SWEARENGEN & ENGLAND, P.C.

By:

/s/ Diana C. Carter
Diana C. Carter MBE#50527
312 E. Capitol Avenue
P. O. Box 456
Jefferson City, Missouri 65102
Phone: (573) 635-7166
Fax: (573) 635-3847
E-mail: dcarter@brydonlaw.com

CERTIFICATE OF SERVICE

I hereby certify that the above document was filed in EFIS on this 6th day of August, 2018, with notification of the same being sent to all parties of record.

/s/ Diana C. Carter

SCHEDULE AJD-3

List of Sub-Accounts Included and Excluded for FAC

GL	Descriptions
501	**Included:**
501042	Fuel -Coal
501045	Fuel -Oil
501054	Fuel -Natural Gas
501183	Sales Of Ash
501211	Ineffect (Gain)Loss Deri Steam
501212	Effective (Gn)Lss Deriv Steam
501216	NonFAS133Deriv(Gain)/LossSteam
501300	Fuel -Tires
501401	Ops Mtls-Fuel Handling
501607	Fuel Adm E Trader Commission
501	**Excluded:**
501011	Conv & Seminar-Fuel
501400	Ops Labor-Fuel Handling
501601	Fuel Administration -Asbury
501604	Fuel Administration -Riverton
501605	Fuel Administration Plum Point
547	**Included:**
547205	Natural Gas SLCC Tolling
547206	Nat Gas-Tollng SLCC Ineffectiv
547207	Nat Gas-Tolling SLCC Effective
547208	Comb Turb Fuel Sales -Nat Gas
547210	Combust Turb Fuel Natural Gas
547211	Ineffect (Gain)Loss Deriv Gas
547212	Effective (Gain)Loss Deriv Gas
547213	Fuel -No 2 Oil Fuel
547301	NonFAS133 Deriv (Gain)/Loss
547607	Fuel Adm E Traders Commission
547	**Excluded:**
547605	Fuel Adm State Line
547606	Fuel Adm Energy Center
547210	Natural gas fixed transportation & fixed storage only
411	**Included:**
411800	Gains-Disposition Emmiss Allow
509	**Included:**
509052	Emission Allowance Exp

GL	Descriptions
506	**Included:**
506127	Limestone Expense -Iatan
506128	Powdered Activated Carbon
506129	Ammonia Expense
506201	Limestone Expense
506202	Ammonia Expense
506203	Powdered Activated Carbon
506204	Lime Expense
548	**Included:**
548202	Ammonia Expense
447	**Included:**
447113	Gen Ark Off-Sys Sale-Resale
447124	Gen Ks Off-System Sale-Resale
447133	Gen Mo Off-Sys Sale-Resale
447143	Gen Ok Off-Sys Sales-Resale
447810	SPP IM Revenue -AR
447820	SPP IM Revenue -KS
447830	SPP IM Revenue -MO
447840	SPP IM Revenue -OK
447850	SPP IM Revenue
447860	Bilateral/Off Line Aux Revenue
447	**Excluded:**
447430	Aec -Off-Sys-Missouri
447540	Oklahoma G R D A Off-System
447610	Energy Imbalance -Arkansas
447620	Energy Imbalance -Kansas
447630	Energy Imbalance -Missouri
447640	Energy Imbalance -Oklahoma
457	**Excluded:**
457137	Ot El RvOffSys LTFSTF PTP Trns
457138	Ot El RvOffSys NnFrm PTP Trns
457139	Ot El RvOffSys NITS Rev
457140	Oth El Rev-Off-Sys Losses
457141	Sch 11 NITS
457142	Sch 11 PTP
457160	Sch 1 PTP

GL	Descriptions
555	**Included:**
555430	Direct Purchases
555431	Purchase Power Tolling Fees
555432	Energy Imbalance
555437	Interrupt Svc Compensation
555800	DA Asset Energy
555810	DA Non-Asset Energy
555820	DA Virtual Energy
555840	DA Reg-Up
555850	DA Reg-Down
555860	DA Spinning
555870	DA Supplemental
555880	DA Other
555900	RT Asset Energy
555910	RT Non-Asset Energy
555920	RT Virtual Energy
555940	RT Reg-Up
555950	RT Reg-Down
555960	RT Spinning
555970	RT Supplemental
555980	RT Other
555	**Excluded:**
555990	TCR Activity
555995	ARR Activity
565	**Included:**
565413	Trans Of Electricity By Others
565414	SPP Fixed Chg -Native Load Exclude S1-A
565416	Non SPP Fixed Chg -Native Load
565417	PP Non SPP Var -Native Load
565418	Gen Non SPP Var -Native Load
565419	Off Sys Sales Trans Costs
565	**Excluded:**
565414	SPP Schedule 1-A only
565415	SPP Var Chg Schedule 12
456	**Included:**
456071	Misc Elec Rev-Green Credits-AR
456072	Misc Elec Rev-Green Credits-KS
456073	Misc Elec Rev-Green Credits-MO
456074	Misc Elec Rev-Green Credits-OK
456075	REC Revenue

AFFIDAVIT OF AARON J. DOLL

STATE OF MISSOURI)
) ss
COUNTY OF JASPER)

On the 6 day of August, 2019, before me appeared Aaron J. Doll, to me personally known, who, being by me first duly sworn, states that he is the Director Electric Procurement of The Empire District Electric Company – Liberty Utilities Central and acknowledges that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

Aaron J. Doll

Subscribed and sworn to before me this 6 day of August, 2019.

ANGELA M. CLOVEN
Notary Public - Notary Seal
State of Missouri
Commissioned for Jasper County
My Commission Expires: November 01, 2019
Commission Number: 15262659

Notary Public

My commission expires: 11/01/19.