Exhibit No.: ________________
Issue(s) Tariff Issue/Fuel Adjustment Clause
Witness/Type of Exhibit: Mantle/Rebuttal
Sponsoring Party: Public Counsel
Case No.: ER-2020-0311

REBUTTAL TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2020-0311

July 27, 2020

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to Implement Rate Adjustments Related to the Company's Fuel and Purchase Power Adjustment (FAC) Required in 20 CSR 4240-20.090	))))))	Case No. ER-2020-0311

VERIFICATION OF LENA M. MANTLE

Lena M. Mantle, under penalty of perjury, states:

1. Attached hereto and made a part hereof for all purposes is my rebuttal testimony in the above-captioned case.

3. My answer to each question in the attached rebuttal testimony is true and correct to the best of my knowledge, information, and belief.

Lena M. Mantle

Lena M. Mantle
Senior Analyst
Office of the Public Counsel

REBUTTAL TESTIMONY

OF

LENA M. MANTLE, P.E.

THE EMPIRE DISTRICT ELECTRIC COMPANY

FILE NO. ER-2020-0311

Q. What is your name and business address?

A. My name is Lena M. Mantle and my business address is P.O. Box 2230, Jefferson City, Missouri 65102.

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

A. I am employed by the Missouri Office of the Public Counsel ("OPC") as a Senior Analyst.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the OPC.

Q. What are your experience, education and other qualifications, particularly on the topics to which you are testifying?

A. I was employed by the OPC in my current position as Senior Analyst in August 2014. In this position, I have provided expert testimony in electric, gas, and water cases before the Commission on behalf of the OPC. I am a Registered Professional Engineer in the State of Missouri.

Prior to being employed by the OPC, I worked for the Staff of the Missouri Public Service Commission ("Staff") from August 1983 until I retired as Manager of the Energy Unit in December 2012. During my employment at the Missouri Public Service Commission ("Commission"), I worked as an Economist, Engineer, Engineering Supervisor and Manager of the Energy Unit. After the Missouri Legislature passed Section 366.266, RSMo. in 2005, enabling the electric utilities to request a fuel adjustment clause ("FAC"), I was instrumental in the development and application of the Commission's FAC rules and the FAC's of the electric utilities in Missouri.

Attached as Schedule LMM-R-1 is a brief summary of my experience with OPC and Staff and a list of the Commission cases in which I filed testimony, Commission rulemakings in which I participated, and Commission reports in rate cases to which I contributed as Staff. Attached as Schedule LMM-R-2 is the *Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper* that I wrote to provide background and a description on various aspects of the FAC in Missouri.

Q. What is the purpose of your rebuttal testimony?

A. The tariff sheets of the Empire District Electric Company ("Empire") define the fuel adjustment clause ("FAC") the Commission approved for Empire. Specifically, Empire tariff sheets PSC Mo. No. 5, Sec. 4, Original Sheet No. 17u through 17ab ("FAC tariff sheets") which I have attached as Schedule LMM-R-3 to this testimony define the FAC that was in effect for the accumulation period. The purpose of my rebuttal testimony is to show how certain costs Empire has proposed for its FAC accumulation period of September 2019 through February 2020 ("accumulation period") are not costs Empire's FAC tariff sheets allow recovery of through Empire's FAC surcharge.

Q. Which costs that Empire requested in the accumulation period should not be included in its FAC costs?

A. Empire included in its FAC costs for the accumulation period an adjustment to recover the cost of unburnable coal from its customers through Empire's FAC. After the Asbury plant stopped generating electricity on December 12, 2019, it was determined, according to David Eaton, Asbury Plant Manager, that the coal remaining at the plant site had "too much clay and/or rock mixed in to be considered a viable coal for combustion."[1] In other words, the coal that remained at the Asbury plant site was unburnable; it could not be used to generate steam to produce electricity. Therefore, this unburnable coal was no longer fuel. The cost of unburnable coal is not allowed through the FAC.[2]

Q. Is OPC asking in this case for the Commission to find that Empire retired Asbury on December 12, 2019?

A. No. That is not a matter for this case. This case is about Empire asking to recover costs through its FAC that are not associated with the generation of electricity and not included in its FAC tariff sheets.

Q. What experience do you have in the development of tariff sheets implementing the FAC in Missouri?

A. As manager of the Commission's Energy Department, I was instrumental in the creation of tariff sheets to implement the first FAC in Missouri after the passage of Section 386.266 RSMo. for Aquila, Inc. (now known as Evergy Missouri West) in case no. ER-2007-0004. In that case, the tariff sheets to implement the base rates were approved effective May 25, 2007. However, the tariff sheets to implement the FAC were not effective until 46 days later on July 5, 2007. The implementation of the FAC of Aquila, Inc. was delayed because there were statutory requirements of the tariff sheets that Aquila had not incorporated in its proposed FAC tariff sheets and there was a difference in understanding of the Commission order.

Q. How many tariff sheets described that first FAC?

A. Four.

[1] Empire response to OPC Data Request 8001 attached as Schedule LMM-R-4.
[2] OPC reserves the right to review other costs included in this accumulation period to determine if the costs are appropriate for recovery through Empire's FAC in the FAC prudence audit of this accumulation period.

Q. How many tariff sheets describe Empire's current FAC?

A. Nine.

Q. What necessitated the increase in the number of FAC tariff sheets?

A. As my staff and I began the process of reviewing FAC filings for FAC rate changes and FAC prudence reviews after the approval of that first FAC, we began to realize that vague FAC tariff sheets resulted in misunderstandings regarding what costs and revenues flowed through the FAC. For example, the very first FAC tariff sheets only mentioned three costs – variable fuel components related to the Company's electric generating plants; purchased power energy charges; and emission allowance costs. It was soon discovered that different parties had different ideas regarding what each of these costs included. To reduce confusion and provide clarification, the description of the FAC in the tariff sheets was expanded as general rate cases were filed and the Commission approved FACs for each of the electric utilities. Since coming to the OPC, I have worked to get better descriptions of these costs included in direct testimony and in the FAC tariff sheets.

Q. What in Empire's FAC tariff sheets does Ms. Emery point to that allows costs of unburnable coal through the FAC?

A. Ms. Emery does not point to any FAC tariff language that *allows* costs of unburnable coal to flow through the FAC. Instead, Ms. Emery tries to argue that the cost of unburnable coal should be included because Original Tariff Sheet No. 17v does *not exclude* the cost of unburnable coal.[3]

[3] Supplemental direct testimony, p 9.

Q. Do you agree that the cost of unburnable coal should flow through the FAC because Original Tariff Sheet No. 17v does not exclude the cost of unburnable coal?

A. No. Empire's original FAC tariff sheet no. 17x explicitly states "Costs and revenues *not specifically detailed* in Factors FC, PP, E, or OSSR *shall not be included* in the Company's FAR filings." (Emphasis added) That which it is not included is, by definition, excluded.

Q. Do Empire's FAC tariff sheets include unburnable coal?

A. No. Empire tariff sheet PSC Mo. No. 5, Sec. 4, Original Sheet no. 17v describes the fuel costs that can flow through the FAC as follows:

> 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.

As explained in much greater detail in the testimony of OPC witness John Riley, the cost of coal that is not burned to produce steam cannot be properly reflected in account 501 or 506. Because the unburnable coal cannot be reflected in FERC account 501 or 506 it is not included in Empire's tariff sheets.

Q. The definition of fuel costs includes "fuel adjustments included in commodity and transportation costs." Is this fuel inventory adjustment that Empire made not a fuel adjustment included in commodity and transportation costs?

A. No. First, the cost of this fuel cannot be properly reflected in account 501 or 506 under any circumstances because it was not burned to produce steam for electric generation. However, even if one looks past that, this adjustment still could not qualify as "a fuel adjustment included in commodity and transportation costs." The key is the word "included." This is not an adjustment included in the commodity cost because the cost of the commodity, including any adjustments, was recorded in FERC account 151 when the coal was purchased. Such an adjustment will only become a 501 cost when that coal is burned. Instead, this is an adjustment to bringing the total balance of the remaining coal inventory down to zero because the Asbury generating facility was shutdown. It is therefore effectively a decommissioning cost.[4]

Q. If a cost is not excluded in the FAC tariff sheet, does that mean that the cost can be included in the FAC by merely recording it in a FERC account mentioned in the FAC tariff sheets?

A. No. Once again, Empire's original FAC tariff sheet no. 17x explicitly states "Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR *shall not be included in the Company's FAR filings*." (emphasis added) The deciding factor is not just which account the cost was recorded in but also whether or not it is listed on the FAC tariff sheets.

[4] OPC is not taking a position in this case on the recovery of the cost of unburnable coal, which Empire may still seek in a future case. However, it is the position of OPC that this cost cannot not be recovered through the FAC under the terms of this tariff.

Q. Does Ms. Emery allude to other parts of the FAC tariff sheets in her supplemental testimony to support Empire's claim that the expense for this unburnable coal be passed to the customers in the FAC?

A. Yes. Ms. Emery makes the statement that unburned coal expenses were necessary to "support sales."[5] This statement is presumably in reference to the beginning of the definition of FC that states "FC = Fuel Costs Incurred to Support Sales."

Q. Was the cost of this unburnable coal incurred to "support sales"?

A. No. In the context of the FAC tariff sheets, "sales" refers to the generation of electricity or kilowatt-hours ("kWh"). Costs to support sales implies that there is a direct relationship between the cost and the amount of kWh generated. The more generation, the greater the cost. This "adjustment" is not a cost of coal burned. It is the cost of coal that *cannot* be burned. No electricity was generated from this coal and no electricity ever will be generated from it. It is a write-off of an asset that cannot be used. Again, effectively a decommissioning cost that Empire is attempting to recover from its customers through the FAC. As such, it is not an expense incurred to support sales and the FAC is not the appropriate recovery mechanism for this cost.

Q. Does this conclude your rebuttal testimony?

A. Yes.

[5] Supplemental direct testimony, pp 7 and 9.

Education and Work Experience Background of

Lena M. Mantle, P.E.

In my position as Senior Analyst for the Office of the Public Counsel ("OPC") I provide analytic and engineering support for the OPC in electric, gas, and water cases before the Commission. I have worked for the OPC since August, 2014.

I retired on December 31, 2012 from the Public Service Commission Staff as the Manager of the Energy Unit. As the Manager of the Energy Unit, I oversaw and coordinated the activities of five sections: Engineering Analysis, Electric and Gas Tariffs, Natural Gas Safety, Economic Analysis, and Energy Analysis sections. These sections were responsible for providing Staff positions before the Commission on all of the electric and gas cases filed at the Commission. This included reviews of fuel adjustment clause filings, resource planning compliance, gas safety reports, customer complaint reviews, territorial agreement reviews, electric safety incidents and the class cost-of-service and rate design for natural gas and electric utilities.

Prior to being the Manager of the Energy Unit, I was the Supervisor of the Engineering Analysis Section of the Energy Department from August, 2001 through June, 2005. In this position, I supervised engineers in a wide variety of engineering analysis including electric utility fuel and purchased power expense estimation for rate cases, generation plant construction audits, review of territorial agreements, and resolution of customer complaints all the while remaining the lead Staff conducting weather normalization in electric cases.

From the beginning of my employment with the Commission in the Research and Planning Department in August, 1983 through August, 2001, I worked in many areas of electric utility regulation. Initially I worked on electric utility class cost-of-service analysis, fuel modeling and what has since become known as demand-side management. As a member of the Research and Planning Department under the direct supervision of Dr. Michael Proctor, I participated in the development of a leading-edge methodology for weather normalizing hourly class energy for rate design cases. I took the lead in developing personal computer programming of this methodology and applying this methodology to weather-normalize electric usage in numerous electric rate cases. I was also a member of the team that assisted in the development of the Missouri Public Service Commission electronic filing and information system ("EFIS").

I received a Bachelor of Science Degree in Industrial Engineering from the University of Missouri, at Columbia, in May, 1983. I am a registered Professional Engineer in the State of Missouri.

Lists of the cases I have filed testimony as an OPC, the Missouri Public Service Commission rules in which I participated in the development of or revision to, the Missouri Public Service Commission Testimony Staff reports that I contributed to and the cases that I provided testimony in follow.

Office of Public Counsel Case Listing

Case	Filing Type	Issue
ER-2019-0374	Direct, Rebuttal, Surrebuttal	Weather Norm Rider, Fuel Adjustment Clause
ER-2019-0355	Direct, Rebuttal	Fuel Adjustment Clause, Unregulated Competition tariff sheet
EO-2019-0067 & EO-2019-0068	Rebuttal	Prudence of GMO steam auxiliary costs and GMO and KCPL's wind PPAs
EA-2019-0010	Rebuttal, Surrebuttal	Energy Market Prices, Customer Protections
GO-2019-0058 & GO-2019-0059	Direct, Rebuttal	Weather
ER-2018-0145 & ER-2018-0146	Direct, Rebuttal, Surrebuttal	Purchased Power, Customer Bills, Crossroads, Resource Planning
EO-2018-0092	Rebuttal, Surrebuttal	OPC Opposition of Request for Approval of Changes to Resource Plan
WR-2017-0285	Direct, Rebuttal, Surrebuttal	Normalized base usage
GR-2017-0215 & GR-2017-0216	Direct, Rebuttal, Surrebuttal	Energy Efficiency and Low-Income Programs
EO-2017-0065	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause Prudence Review
ER-2016-0285	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2016-0179	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause,
ER-2016-0156	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause, Resource Planning
ER-2016-0023	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
WR-2015-0301	Direct, Rebuttal, Surrebuttal	Revenues, Environmental Cost Recovery Mechanism
ER-2014-0370	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2014-0351	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2014-0258	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
EC-2014-0224	Surrebuttal	Policy, Rate Design

Missouri Public Service Commission Rules

4 CSR 240-3.130	Filing Requirements and Schedule of Fees for Applications for Approval of Electric Service Territorial Agreements and Petitions for Designation of Electric Service Areas
4 CSR 240-3.135	Filing Requirements and Schedule of Fees Applicable to Applications for Post-Annexation Assignment of Exclusive Service Territories and Determination of Compensation
4 CSR 240-3.161	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms Filing and Submission Requirements
4 CSR 240-3.162	Electric Utility Environmental Cost Recovery Mechanisms Filing and Submission Requirements
4 CSR 240-3.190	Reporting Requirements for Electric Utilities and Rural Electric Cooperatives
4 CSR 240-14	Utility Promotional Practices
4 CSR 240-18	Safety Standards
4 CSR 240-20.015	Affiliate Transactions

4 CSR 240-20.017	HVAC Services Affiliate Transactions
4 CSR 240-20.090	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms
4 CSR 240-20.091	Electric Utility Environmental Cost Recovery Mechanisms
4 CSR 240-22	Electric Utility Resource Planning
4 CSR 240-80.015	Affiliate Transactions
4 CSR 240-80.017	HVAC Services Affiliate Transactions

Staff Direct Testimony Reports

ER-2012-0175	Capacity Allocation, Capacity Planning
ER-2012-0166	Fuel Adjustment Clause
ER-2011-0028	Fuel Adjustment Clause
ER-2010-0356	Resource Planning Issues
ER-2010-0036	Environmental Cost Recovery Mechanism
HR-2009-0092	Fuel Adjustment Rider
ER-2009-0090	Fuel Adjustment Clause, Capacity Requirements
ER-2008-0318	Fuel Adjustment Clause
ER-2008-0093	Fuel Adjustment Clause, Experimental Low-Income Program
ER-2007-0291	DSM Cost Recovery

Missouri Public Service Commission Staff Testimony

Case No.	Filing Type	Issue
ER-2012-0175	Rebuttal, Surrebuttal	Resource Planning Capacity Allocation
ER-2012-0166	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EO-2012-0074	Direct/Rebuttal	Fuel Adjustment Clause Prudence
EO-2011-0390	Rebuttal	Resource Planning Fuel Adjustment Clause
ER-2011-0028	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EU-2012-0027	Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2010-0356	Rebuttal, Surrebuttal	Resource Planning Allocation of Iatan 2
EO-2010-0255	Direct/Rebuttal	
ER-2010-0036	Supplemental Direct, Surrebuttal	Fuel Adjustment Clause
ER-2009-0090	Surrebuttal	Capacity Requirements
ER-2008-0318	Surrebuttal	Fuel Adjustment Clause
ER-2008-0093	Rebuttal, Surrebuttal	Fuel Adjustment Clause Low-Income Program
ER-2007-0004	Direct, Surrebuttal	Resource Planning
GR-2007-0003	Direct	Energy Efficiency Program Cost Recovery
ER-2007-0002	Direct	Demand-Side Program Cost Recovery

Missouri Public Service Commission Staff Case Listing (cont.)

Case No.	Filing Type	Issue
ER-2006-0315	Supplemental Direct, Rebuttal	Energy Forecast Demand-Side Programs Low-Income Programs
ER-2006-0314	Rebuttal	Jurisdictional Allocation Factor
EA-2006-0309	Rebuttal, Surrebuttal	Resource Planning
ER-2005-0436	Direct, Rebuttal, Surrebuttal	Low-Income Programs Energy Efficiency Programs Resource Planning
EO-2005-0329	Spontaneous	Demand-Side Programs Resource Planning
EO-2005-0293	Spontaneous	Demand-Side Programs Resource Planning
ER-2004-0570	Direct, Rebuttal, Surrebuttal	Reliability Indices Energy Efficiency Programs Wind Research Program
EF-2003-0465	Rebuttal	Resource Planning
ER-2002-424	Direct	Derivation of Normal Weather
EC-2002-1	Direct, Rebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-2001-672	Direct, Rebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-2001-299	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EM-2000-369	Direct	Load Research
EM-2000-292	Direct	Load Research
EM-97-515	Direct	Normalization of Net System
ER-97-394, et. al.	Direct, Rebuttal, Surrebuttal	Weather Normalization of Class Sales Weather Normalization of Net System Energy Audit Tariff
EO-94-174	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
ER-97-81	Direct	Weather Normalization of Class Sales Weather Normalization of Net System TES Tariff
ER-95-279	Direct	Normalization of Net System
ET-95-209	Rebuttal, Surrebuttal	New Construction Pilot Program
EO-94-199	Direct	Normalization of Net System
ER-94-163	Direct	Normalization of Net System
ER-93-37	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EO-91-74, et. al.	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EO-90-251	Rebuttal	Promotional Practices Variance
ER-90-138	Direct	Weather Normalization of Net System
ER-90-101	Direct, Rebuttal, Surrebuttal	Weather Normalization of Class Sales Weather Normalization of Net System

Case No.	Filing Type	Issue
ER-85-128, et. al.	Direct	Demand-Side Update
ER-84-105	Direct	Demand-Side Update

Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper

Lena M. Mantle, P.E.
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Office of the Public Counsel

Revised January 14, 2020

Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper

Introduction

The purpose of this whitepaper is to provide a general description of the history of electric utility fuel adjustment clauses ("FACs") in Missouri prior to and after the passage of Section 386.266 Revised Missouri Statutes ("RSMo") in 2005[1] and provide an understanding of the functionality of the FACs currently implemented throughout the state of Missouri. This whitepaper is not an exhaustive description of the FAC in Missouri but is intended to provide a basic understanding of the history and application of Section 386.266 in a neutral and unbiased manner.

Recovery of Fuel and Purchased Power Costs Prior to Section 386.266 RSMo

In the 1979 Missouri Supreme Court opinion of *Utility Consumer Council of Missouri, Inc. v. P.S.C*,[2] the Court concluded FAC surcharges were unlawful because they allowed rates to go into effect without considering all relevant factors. The Court warned "to permit such a clause would lead to the erosion of the statutorily-mandated fixed rate system." [3] The Court further explained, "If the legislature wishes to approve automatic adjustment clauses, it can of course do so by amendment of the statutes and set up appropriate statutory checks, safeguards, and mechanisms for public participation."[4]

After this Supreme Court opinion, fuel and purchased power costs for Missouri investor-owned utilities were normalized in general rate proceedings and included in the determination of the utility's revenue requirement from which rates were set. This provided an incentive to the electric utility that, if it managed its activities in a manner that allowed it to reliably serve its customers at a cost lower than what was included in its revenue requirement in the last rate case, all the savings were retained by the electric utility. If actual fuel costs were greater than the normalized costs included in the revenue requirement, the electric utility absorbed the increased costs. When the electric utility believed that it could no longer absorb the increased

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[1] Section 386.266 RSMo. was Truly Agreed To and Finally Passed by the Missouri House of Representatives and Senate on April 27, 2005. Governor Matt Blunt signed this legislation on July 14, 2005.
http://www.senate.mo.gov/05info/BTS_Web/Actions.aspx?SessionType=R&BillID=5755

[2] State ex rel. Utility Consumers Council, Inc. v. P.S.C., 585 S.W.2d 41(MO. 1979).

[3] Id. at 57.

[4] Id.

costs, the electric utility would ask the Commission for an increase in its rates. This incentive worked well for the Missouri electric utilities and their customers for the next twenty-five years. The two largest investor-owned electric utilities, Union Electric Company ("Union Electric") and Kansas City Power & Light Company ("KCPL") went for a period of twenty years without a rate increase – not necessarily because fuel costs were over-estimated in revenue requirement but because their total costs were less than the revenue collected due to a variety of factors.

During this time, the investor-owned utilities built to meet their customers' needs. There were no centralized markets for electricity. If a utility had more generation than its customers needed, the excess capacity and generation were sold to neighboring utilities through long-term (10 to 20 years) contracts. This was the case in Missouri. Due to inaccurate forecasts that projected high growth of electricity demand, Union Electric and KCPL built excess generation in the 1970's and 1980's. Capital costs of these plants were included in the customers' rates of these electric utilities. Excess generation and capacity from these utilities and other regional providers that also over-built was sold through long-term contracts on a cost-plus basis to the smaller investor-owned electric utilities in the state. This resulted in minimal rate increase requests for these smaller investor-owned electric utilities and offset some of the capital costs of the excess generation built by Union Electric Company and KCPL. Eventually the large utilities' customers load requirements grew and these utilities needed the generation they had built in the 1970's and 1980's to meet their own customers' needs. With this excess generation no longer available, to meet their customers' needs, the smaller electric utilities began to build the least cost option - natural-gas fired generation plants. While these plants were inexpensive to build, the fuel cost was uncertain and in the late 1990's and early 2000's were very volatile.

In the early 1990's, restructuring of the electric utilities began occurring in other parts of the nation. In the mid-1990's the Missouri Legislature considered restructuring Missouri's investor-owned electric utility companies. At the end of 2000, after two months of extraordinarily cold weather and continued reports of extreme storage withdrawals, the commodity price of natural gas spiked to nearly $10 per thousand cubic feet ("Mcf") in late December after remaining consistently between $1/Mcf to $3/Mcf since the inception of the unregulated wholesale natural gas markets in the 1980s.[5] These wildly fluctuating natural gas prices had little impact on the total fuel costs of KCPL and Union Electric since most of their customers' needs were met through nuclear and coal generation. However, the fluctuating natural gas prices significantly impacted the smaller electric utilities' fuel and purchased power costs.

[5] Missouri Public Service Commission Case No. GW-2001-398,EFIS case GW201398xxx, Item no. 44, Final Report of the Missouri Public Service Commission's Natural Gas Commodity Price Task Force, August 29, 2001.

Overview of Section 386.266 RSMo

The provisions of Section 386.266 RSMo, also known as Senate Bill 179 ("SB 179"), took effect on January 1, 2006.[6] This section gives the Missouri Public Service Commission ("Commission"), among other things, the authority to approve rate schedules authorizing periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased power costs, including transportation costs. An FAC is such a mechanism. The statute, in addition to requiring approval from the Commission before implementing an FAC, includes other provisions including some consumer protections. It requires the Commission to approve, modify, or reject FACs only as a part of a general rate case proceeding in which all costs and relevant factors are considered. It allows the Commission to include in an FAC features designed to provide incentives to improve the efficiency and cost-effectiveness of the electric utility's fuel and purchased-power procurement activities. If the Commission approves an FAC, the electric utility with the FAC must file a general rate case so that all rates are reviewed and reset no later than four years after the order implementing the FAC. Prudence reviews of the costs included in an FAC are to be conducted at least every eighteen months and true-ups to adjust for over and under recoveries are required at least annually. Amounts charged/refunded to the customers through an FAC are required to be separately disclosed on each customer's bill.

Section 386.266.1, which is the provision that grants the Commission the authority to approve, reject or modify FACs, applies only to investor-owned electric utilities in Missouri. At the time it became effective, there were four investor-owned electric utilities in Missouri – Union Electric, KCPL, Aquila, Inc. ("Aquila"), and the Empire District Electric Company ("Empire"). Union Electric subsequently did business as AmerenUE and is now doing business as Ameren Missouri. Aquila subsequently did business as KCP&L – Greater Missouri Operations Company ("GMO") and is now doing business as Evergy Missouri West ("Evergy West"). KCPL is now doing business as Evergy Missouri Metro ("Evergy Metro").

Development of Commission Rules Regarding FACs

Section 386.266.9 RSMo gives the Commission the authority to promulgate rules to govern the structure, content, and operation of FACs. The Commission is also given the authority to promulgate rules regarding the procedures for the submission, frequency, examination, hearing, and approval of FACs. Soon after Section 386.266 RSMo went into effect, the Staff of the Public Service Commission ("Staff") began the work of developing rules governing the

[6] Section 386.266.12 RSMo.

implementation of this section. Initially there were two rules: one rule provided the filing and information requirements necessary for requesting approval, continuation, modification, and discontinuation of an FAC along with filing and submission requirements for changes to the FAC rates and true-ups. It also provided the contents of quarterly surveillance reports and monthly reporting requirement for electric utilities that are allowed an FAC. A second rule provided the structure and governance requirements for an FAC.

In its development of the initial rules, Staff worked diligently with a broad group of stakeholders - including representatives from electric utilities, large customers, AARP, and the Office of the Public Counsel ("OPC") in the development of proposed rules to present to the Commission. Auditors, engineers, economists, and attorneys worked together in over fifteen workshops collaborating to develop specific language to propose rules to the Commission to implement the provisions of Section 386.266 RSMo pertaining to FACs. The Commission opened Case No. EX-2006-0472 on June 15, 2006 with a finding of necessity for rules to establish and implement an FAC and began the formal rulemaking process with the proposed rules developed through the collaborative workshop process. Public hearings regarding the proposed FAC rules were held in Kansas City, St. Louis, Overland, Cape Girardeau, Jefferson City and Joplin in late August 2006 and early September 2006. Written comments were received from seven individuals and fourteen groups or companies. The Commission issued its final orders of rulemaking on September 21, 2006.[7] The final order was published in the December 1, 2006 *Missouri Register* effective January 30, 2007.[8]

The Commission opened a working docket in November 2010 to assist in reviewing its FAC rules. Comments from interested parties were filed in this case in early 2011. Three workshops were held in the spring and summer of 2015 regarding these rules. An order with a finding of necessity was issued in Case No. EX-2016-0294 in November 2016 with a final order of rulemaking for a single rule, *4 CSR-240-20.090 Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms*, that combined the previous two rules, being filed on October 4, 2018. This rule and the rescission of 4 CSR 240-3.161 became effective on January 30, 2019. With the transfer of the Commission from the Department of Economic Development to the Department of Commerce and Insurance on August 28, 2019, this rule is now 20 CSR 4240-20.090.

[7] Missouri Public Service Commission, Case No. EX-2006-0472, EFIS items 27 and 28
[8] http://s1.sos.mo.gov/CMSImages/adrules/moreg/previous/2006/v31n23/v31n23b.pdf

Key Provisions of the FAC Rule

Despite concerns that an FAC would contribute to over-earnings by electric utilities by the non-utility parties that participated in developing the proposed rules and those that provided comments in the formal rulemaking process, the resulting FAC rules, and the subsequent revised rule, do not contain an earnings test. In FAC proceedings, the Commission is only required to review the costs and revenues included in the FAC. Decreases in expenses and increases in revenues not included in the FAC are not considered by the Commission. However, utilities with an FAC are required by the Commission rule to submit quarterly surveillance reports to Staff, OPC, and other parties. These surveillance reports include rate base quantifications, capital quantifications and income statements for the electric utilities as a whole.[9] The information from these reports includes the earnings of the electric utility for the prior quarter and could be used in an over-earnings complaint case.[10]

Because the statute requires adjustments to FAC rates to reflect increases and decreases in prudently incurred costs, the rule requires that FAC recoveries be based on historical costs.[11] Therefore, before the electric utility can begin billing to recover FAC costs, the costs in the utility's FAC must be incurred and any revenues included in the FAC to offset those costs must be received. Interest at the utility's short-term debt rate is applied to the net of these costs and revenues and recovered or returned to the ratepayers through the FAC rate.

The rule is not prescriptive regarding the design of FAC rates. However, 20 CSR 4240-20.090(13) does require that FAC rates reflect differences in losses incurred in the delivery of electricity at different voltage levels for different rate classes based on system loss studies that must be conducted at least every four years.

While Section 386.266.1 allows the Commission to include features in an FAC designed to provide the electric utilities with incentives to improve the efficiency and cost-effectiveness of the utilities fuel and purchased-power procurement activities, the rule is not prescriptive regarding what such an incentive feature would look like. Instead it allows incentive features to be proposed in rate cases in which an electric utility requests the establishment, continuation or modification of an FAC.[12] Incentive features can be proposed for the Commission's consideration by any of the parties in rate cases in which the electric utility is proposing the establishment, continuation, or modification of an FAC.

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[9] 20 CSR 4240-20.090(6).

[10] However, the Commission, in File no. EC-2014-0223, stated that these surveillance reports alone do not provide a complete or accurate picture of earnings sufficient to reset the utility's rates.

[11] 20 CSR 4240-20.090(2)(F)

[12] 20 CSR 4240-20.090(14)

Section 386.266 is silent regarding the inclusion in an FAC of any fuel related type of revenues. The Commission rule does not require the inclusion of fuel related revenues, such as off-system sales revenues,[13] in an FAC. The rule does require that if an FAC includes revenues from off-system sales, the FAC include prudently incurred fuel and purchased power costs associated with off-system sales.[14]

History of Requests for FACs

Empire was the first electric utility to request cost recovery of fuel costs under Section 386.266 RSMo when it filed Case No. ER-2006-0315 on February 1, 2006. This case was filed while the Commission rules were being drafted. In this case, Empire did not request an FAC. Instead it requested an Energy Cost Rider ("ECR") to recover costs between rate cases. Due to a stipulation Empire had entered into in a prior rate case, the Commission required Empire to remove from its pleadings and other filings its request and support for an ECR.[15] Prior to Empire's next rate case, Case No. ER-2008-0093 filed on October 1, 2007, the Commission FAC rules had been finalized and were effective. The Commission granted Empire an FAC in its July 30, 2008, *Report and Order* in ER-2008-0093. The Commission has authorized continuation of an FAC with modifications in all general rate cases subsequently filed by Empire.

On July 3, 2006 two of Missouri's investor-owned electric utilities filed general rate increase cases in which they requested an FAC. Union Electric, then doing business as AmerenUE, requested the Commission grant it an FAC in Case No. ER-2007-0002 and Aquila requested an FAC in Case No. ER-2007-0004. While the FAC rules were not final at this time, the Commission had, just eighteen days earlier, sent proposed rules to the Missouri Office of the Secretary of State for publication in the Missouri Register. The Commission's determination of the final FAC rules occurred while these rate cases were pending.

In its May 22, 2007 *Report and Order* in the AmerenUE case ER-2007-0002, the Commission concluded:

> After carefully considering the evidence and arguments of the parties, and balancing the interests of ratepayers and shareholders, the Commission

[13] Off-system sales revenues are the revenues from sales of energy by the electric utility above what is needed by the utility's customers.
[14] 20 CSR 4240-20.090(1)(L).
[15] Case No. ER-2006-0315, EFIS item 57, *Order Clarifying Continued Applicability of the Interim Energy Charge*, effective May 12, 2006.

> concludes that AmerenUE's fuel and purchased power costs are not volatile enough [to] justify the implementation of a fuel adjustment clause at this time.

AmerenUE filed another general rate increase case on April 4, 2008, again seeking the Commission's approval of an FAC in Case No. ER-2008-0318. In its January 27, 2009 *Report and Order*[16] in this case, the Commission authorized AmerenUE to implement an FAC. The Commission has authorized continuation of an FAC with modifications in all general rate cases subsequently filed by Union Electric now doing business as Ameren Missouri.

The Commission authorized the first FAC for a Missouri investor-owned electric utility under Section 386.266 RSMo in its May 17, 2007 *Report and Order* in Aquila's general rate proceeding in case ER-2007-0004. FAC base rates were approved for each of Aquila's two rate districts, then designated as Aquila Networks-MPS and Aquila Networks-L&P. The actual effective date of Aquila's FAC was delayed when the Commission found that the proposed FAC tariff sheets filed by Aquila were not consistent with its *Report and Order*. Tariff sheets implementing the FAC consistent with the Commission's *Report and Order* were approved on June 29, 2007 effective July 5, 2007. Following this rate case, Great Plains Energy acquired Aquila and renamed it GMO. The Commission has authorized the continuation of an FAC with modifications in all general rate cases subsequently filed by GMO. When GMO combined the rates of Aquila Networks-MPS and Aquila Networks-L&P in case ER-2016-0156, a single FAC rate was applicable to all of GMO's customers regardless of which utility previously served the customers.

KCPL was the last Missouri electric utility to be granted an FAC. At the time that SB 179 was being debated at the Legislature, KCPL was negotiating a regulatory plan that would address financial considerations of KCPL's investment in the Iatan 2 Power Plant and other investments, and the timeliness of the recovery of the costs of these investments. As a part of the *Stipulation and Agreement*[17] in that case, KCPL agreed, among other items, that prior to June 1, 2015, it would not seek to utilize any mechanism authorized in SB 179. Therefore, KCPL did not request an FAC until the general rate case ER-2014-0370 it filed on October 30, 2014. The Commission granted KCPL an FAC in its September 2, 2015 *Report and Order*.[18] Tariff sheets implementing an FAC for KCPL became effective September 29, 2015. The Commission has authorized the continuation of an FAC with modifications in all general rate cases subsequently filed by KCPL.

[16] Case No. ER-2008-0318, EFIS item no. 589, page 70.
[17] Case No. EO-2005-0329, EFIS item no. 1.
[18] Case No. ER-2014-0370, EFIS item no. 592, page 30.

General Structure of FACs in Missouri

While there are some differences in the details of each electric utility's FAC, the general structure of the FACs of each of the electric utilities is the same. An estimate of the FAC costs and revenues, known as Net Base Energy Cost or NBEC, is identified and included in the permanent rates[19] of each electric utility. The FAC rate is based on the difference between the FAC costs included in permanent rates and the actual FAC costs incurred. FAC costs are tracked in a designated accumulation period and the difference between actual FAC costs and NBEC is recovered or returned in a designated recovery period.

Even though the rule is not prescriptive regarding the design of the FAC rate, in practice, all of the electric utility's FAC rates are volumetric rates based on customer energy usage. A base factor is calculated in each general rate proceeding as the NBEC divided by the rate case normalized kilowatt-hours ("kWh").[20]

To derive a rate to be charged the customers after FAC costs have been incurred, the difference between the actual costs incurred (actual net energy cost or ANEC) and the costs already included in the permanent rates (NBEC), either positive or negative, is divided by the expected energy use of the utility's customers over the recovery period. Because the FAC rule requires voltage losses to be taken into account in the FAC, a fuel adjustment rate (FAR) is calculated for each of the voltage levels that the utility provides service at based on loss factors derived in the last rate case. These loss-adjusted FARs are the rates used to bill the FAC to the customers.

Accumulation and Recovery Periods

An accumulation period is the time over which the electric utility incurs the ANEC. Commission rule allows up to four accumulation periods a year but requires at least one accumulation period a year. The Recovery Period is the time period over which the difference between the accumulation period ANEC and NBEC is billed to the utility's customers.

[19] Permanent rates are only set in rate cases. There are typically 2 sets of permanent rates for each customer class – a rate for the four summer months and a rate for the other eight months.
[20] The base factor is typically thought of as the portion of the permanent rates that is recovering the FAC costs and revenues.

The accumulation periods and recovery periods for the electric utilities are shown in the table below.

Electric Utility	Accumulation Periods	Recovery Periods
Ameren Missouri	February through May	October through May
	June through September	February through September
	October through January	June through January
Evergy Metro	January through June	October through September
	July through December	April through March
Evergy West	June through November	March through February
	December through May	September through August
Empire	September through February	June through November
	March through August	December through May

The recovery periods are twice as long as the accumulation periods for Ameren Missouri, Evergy Metro, and Evergy West. The purpose of having recovery periods longer than the accumulation periods is to reduce the FAR and minimize the impact of the change in rates on the customers' bills. Ameren Missouri's accumulation periods are four months and the costs from the four month accumulation period are billed (recovered or returned) over eight months. The accumulation periods of Evergy Metro and Evergy West are six months while the recovery periods are twelve months. Empire is the only utility where the recovery period is the same length as the accumulation period - both are six months.

The timing of recovery periods for Ameren Missouri, Evergy Metro, and Empire were set to minimize the number of times during a year that changes in rates impact bills. The FAC base rates for all of the electric utilities change twice a year. FAC base rates are higher in the summer months of June through September for Ameren Missouri, Evergy Metro, and Every West because the cost to provide electricity is higher in these summer months for these utilities. The lower, non-summer FAC base rates are billed in October through May.

The timing of the recovery periods of Ameren Missouri means that customers see both permanent rates and FAR changes in June and October and then see another rate change, due to the change in the FAR, in February. Without alignment of the timing of recovery periods, customers of Ameren Missouri could be impacted by changes in rates up to five times a year – twice in permanent rates and three times for the FAC rates.

Similarly, one of the FAC recovery periods for Evergy Metro occurs in October when permanent rates also change. One of Empire's recovery periods begins in the same month that the permanent rates change for summer resulting in rates changing for Empire's customers only three times a year. The timing of FAC rate changes for Evergy Metro and Empire results in their customers seeing changes in rates just three times a year.

Calculation of Fuel Adjustment Rates

At the end of the accumulation period, the NBEC is calculated for the accumulation period based on the FAC Base Rate set in the rate case ($/kWh) and the actual energy consumed (kWh) by the electric utility's customers in the accumulation period. This NBEC is compared to the Actual Net Energy Costs (ANEC) incurred during that accumulation period. The FAR for the accumulation period is then calculated based on the difference between the actual historical costs incurred (ANEC) and the FAC costs billed in the permanent rates (NBEC) divided by the expected usage of the utility's customers over the recovery period and then adjusted for delivery losses.

This is the FAR that the customer is billed for Empire since the recovery period is the same length as the accumulation period. For the other three electric utilities that have recovery periods that are twice as long as the accumulation periods, the FAR that is billed the customer is actually the sum of the loss adjusted FARs for two consecutive accumulation periods.

Price Signal Resulting From FACs

There is a common misconception that FACs provide customers more accurate price signals than the permanent rates. There are several reasons Missouri's FAC does not provide accurate price signals to customers. Timing is essential to provide an accurate price signal. Missouri's FAC is based on historical costs so customers are not billed the difference in the FAC costs until months after the costs are incurred. For example, fuel costs incurred in January for Evergy Metro are not billed to its customers until the recovery period that begins in October. At the time that a change in fuel costs is seen on the customers' bills, it is no longer an accurate representation of the fuel cost the utility is experiencing at that time.

Another reason that FACs in Missouri do not provide accurate price signals is that the accumulation periods bill costs or return savings to customers aggregated over several months. Increases in FAC costs in one month may be offset by decreases in FAC costs in the next month. In addition, the accumulation periods cross seasons of the year when FAC costs typically vary because the load requirements of the customers vary. For these reasons, the length of the accumulation period mutes any price signal.

Long recovery periods designed to reduce FAC rate volatility to customers also mutes the price signal to customers. For example, for Evergy Metro any increase in costs in January is recovered over the time period of October of that same year through September of the next year. An increase in January is spread out over the twelve months of the recovery period so an increase in January combined with changes for all the months in the accumulation period and then spread over twelve months of estimated usage. This is the price signal that the customer is reacting to – not the actual increase in costs that occurred in January. In addition, the customer would not even be billed for the increase in costs in January until the October billing month. If FAC costs are volatile, the customer may be reacting to an increase in cost in the previous year during a time period when costs are actually decreasing. In this instance, the FAC is sending the wrong price signal to the customer.

For these reasons the design and application of FACs in Missouri do not send accurate price signals to customers.

True-Up of FACs

SB 179 requires that true-ups of FACs occur at least annually.[21] The purpose of a true-up is to make sure that the electric utility recovers all the costs that it is entitled or all amounts due to the customers are refunded. Section 386.266 requires the true-up amount include interest at the electric utility's short-term interest rate.

In practice, true-ups occur after the end of each recovery period. Because Evergy Metro, Evergy West, and Empire have two recovery periods a year, there are two FAC true-ups a year for these electric utilities. There are three FAC true-ups a year for Ameren Missouri since it has three recovery periods a year. A true-up is simply a comparison of the actual FAC billed the customers in the recovery period to the difference between the actual FAC costs and NBEC in the corresponding accumulation period. This difference, either negative or positive, is added as a true-up amount, including interest, to the FAC costs to be billed in the next recovery period.

[21] Section 386.266.4(2)

The true-up amount is keyed off of the FAC billed not the FAC revenues recovered. This is to reduce complexity of how to deal with under-paid bills. While the FAC amount is separately identified on the customer's bill, the customer that only pays a portion of their bill does not designate what portion of the bill they are paying. The unpaid portion of the bill is treated as uncollectible. The rate case treatment for uncollectibles is determined in the rate case and is not dealt with in the FAC.

Prudence Reviews

Section 386.266.4(4) requires prudence reviews of the costs in the FAC to occur at least every eighteen (18) months. Since the first FAC under section 386.266 was approved for GMO, the first prudence audit was conducted on GMO's FAC, followed by prudence audits on Empire's, Ameren Missouri's, and KCPL's FACs. [22] In Ameren Missouri's first prudence audit case, EO-2010-0255, the Commission determined that Ameren Missouri "acted imprudently, improperly and unlawfully when it excluded revenues" derived from power sales agreements from its FAC.[23] Because these power sales agreements crossed over two prudence review time periods, the Commission, in Ameren Missouri's second prudence audit, EO-2012-0074, made the same finding.[24]

Imprudence has been alleged in four additional cases – EO-2011-0390,[25] EO-2017-0065,[26] EO-2019-0067,[27] and EO-2019-0068.[28] The Commission, in its *Report and Orders* in these cases found no imprudence.

Incentive Mechanism

SB 179 allows the Commission to include, in an FAC, incentives to improve the efficiency and cost-effectiveness of the electric utilities' fuel and purchased power procurement.[29] The Commission, for each of the electric utilities, found that allowing the utility to have one hundred percent recovery of its FAC costs through an FAC would act as a disincentive for the utility to control FAC costs. The Commission determined that recovering a share of the difference between the NBEC and ANEC allows the electric utility a sufficient opportunity to earn a fair return on equity while protecting customers by providing an incentive to control costs. The Commission has set that sharing percentage, for all of the electric utilities, to be

[22] Case Nos. EO-2009-0115, EO-2010-0084 and EO-2010-0255 for GMO, Empire and Ameren Missouri respectively.
[23] Case No. E0-2010-0255, *Report and Order,* page 2.
[24] Case No. EO-2012-0074, *Report and Order,* page 2.
[25] Hedging practices of GMO.
[26] Hedging practices of Empire.
[27] Allocation of GMO steam auxiliary power costs and wind purchased power agreements.
[28] KCPL allowing RECs to expire and wind purchased power agreements.
[29] Section 386.266.1.

95%/5%, i.e. 95% of any increase in FAC costs above the NBEC would be billed to the customers and the electric utility absorbs 5%, while 95% of a decrease in FAC costs below the NBEC would be credited to customers and the electric utility retains 5% of the decrease.[30]

Given this incentive mechanism, the amount to be billed through the FAC is 95% of the difference between the ANEC and the NBEC. The result of this incentive mechanism is that, when costs are above the amounts included in permanent rates, the electric utility recovers almost 100% of the FAC costs. If FAC costs are below the amounts included in permanent rates, the utility recovers greater than 100% of its FAC costs. The table below shows examples of what occurs when actual costs are greater, equal to, and less than what is in the NBEC.

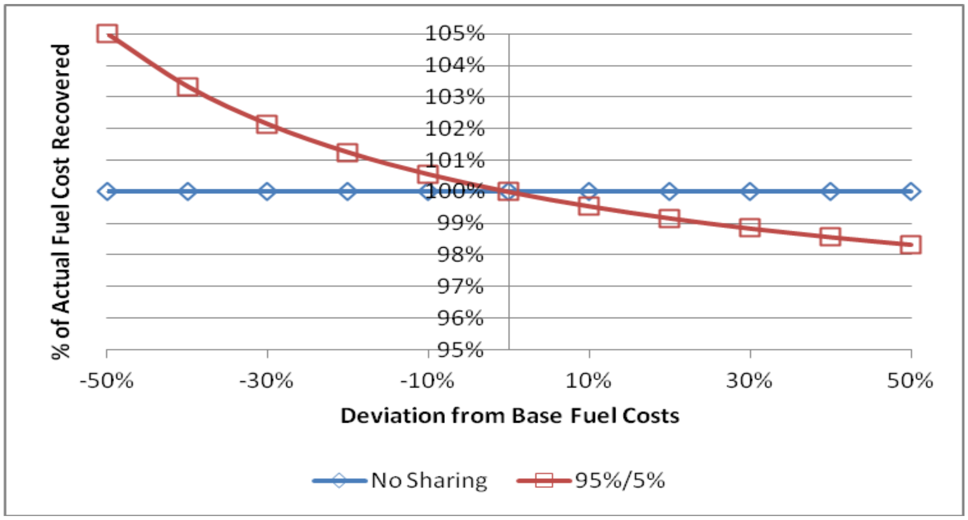
Impact of 95%/5% Sharing Mechanism

NBEC	ANEC	Diff	FAC Amt Billed to Customers	Amt Absorbed/ (Retained) by Company	Total billed to Customers	% FAC Costs Billed
$100	$150	$50	$47.50	$2.50	$147.50	98.3%
$100	$110	$10	$9.50	$0.50	$109.50	99.5%
$100	$100	$0	$0	$0	$100.00	100.0%
$100	$90	($10)	($9.50)	($0.50)	$90.50	100.6%
$100	$50	($50)	($47.50)	($2.50)	$52.50	105%

This table shows the incentive mechanism allows the utility to bill its customers for 98.3% of its FAC costs when its ANEC is 50% higher than what is included in permanent rates, i.e., if the actual FAC costs incurred are 50% higher than what was included in the permanent rates, the electric utility recovers 98.3% of its actual FAC costs.[31] Likewise, if actual fuel costs are 50% lower than what is included in permanent rates, the utility will recover 105% of its actual FAC costs. If the utility manages to reduce its actual FAC costs any amount below the NBEC, it will recover more than 100% of its FAC costs. This relationship is shown in the graph below.

[30] While parties in rate cases have proposed different sharing percentages and/or different incentive mechanisms, the only incentive mechanism implemented has been a 95%/5% sharing of the difference between ANEC and NBEC.

[31] For a utility to bill only 95% of its actual costs, the actual FAC costs would need to be over 1,000 times greater than the costs included in permanent rates.



These relationships hold true regardless of the magnitude of the NBEC.

Importance of Correct NBEC

Because Missouri's FAC is based on the difference between a subset of normalized costs and revenues set in a rate case and actual costs and revenues, it is important that the costs and revenues included in the NBEC of the FAC are the same as the costs and revenues included in permanent rates. The table below shows three different scenarios. To simplify the example, in these scenarios there is no sharing of the difference between ANEC and NBEC. All of the difference between the ANEC and NBEC is billed or returned to the customers.

Net Base Energy Cost (NBEC)	FAC Costs in Permanent Rates	Actual Net Energy Cost (ANEC)	Billed FAC Costs	Total FAC Costs Billed	Total billed as % of ANEC
Scenario 1 - NBEC Equal FAC Costs in Rates					
$100.00	$100.00	$110.00	$10.00	$110.00	100.00%
$100.00	$100.00	$100.00	$0.00	$100.00	100.00%
$100.00	$100.00	$90.00	-$10.00	$90.00	100.00%
Scenario 2 - NBEC Lower than FAC Costs in Rates					
$100.00	$110.00	$110.00	$10.00	$120.00	109.09%
$100.00	$110.00	$100.00	$0.00	$110.00	110.00%
$100.00	$110.00	$90.00	-$10.00	$100.00	111.11%
Scenario 3 - NBEC Higher than FAC Costs in Rates					
$100.00	$90.00	$110.00	$10.00	$100.00	90.91%
$100.00	$90.00	$100.00	$0.00	$90.00	90.00%
$100.00	$90.00	$90.00	-$10.00	$80.00	88.89%

The first scenario is a correct treatment of NBEC and FAC costs in rates. NBEC is equal to the FAC costs included in permanent rates. In this scenario, when ANEC is higher than NBEC, the total FAC costs billed the customer is the $100 billed in the permanent rates and $10 billed through the FAC for a total of $110. When the ANEC is the same as the NBEC, the customers are billed nothing through the FAC and the utility recovers all of its FAC costs through its permanent rates. Lastly, when the actual costs are less than the NBEC, the customers' bills are reduced and the utility recovers all of its actual fuel costs.

In Scenario 2, the NBEC designated in the FAC is less than the FAC costs in permanent rates. In this scenario, the customers always pay more than intended. Even when ANEC is the same as the FAC costs included in permanent rates, the customer pays for the difference between the ANEC and NBEC. In this scenario, the customers always pay more than the actual FAC costs because the fuel costs included in the permanent rates is greater than the costs used to calculate the NBEC.

In Scenario 3, the NBEC is set higher than the FAC costs included in rates. In this scenario, the electric utility does not collect the actual energy costs because the amount of FAC costs included in rates is less than the NBEC set in the FAC. The amount recovered is the lower FAC costs included in rates and the difference between the higher NBEC and ANEC. In this scenario, the company does not receive the revenues that are intended with an FAC.

These scenarios show the importance of insuring that the FAC costs included in permanent rates are the same as the FAC NBEC. If they are not set correctly, either the customers overpay or the company is not afforded the opportunity to recover its costs as intended.

Conclusion

The FAC in Missouri is continually being refined and defined. The design of the FAC is considered and typically modified slightly in each rate case. There have been instances where a utility came in for a general rate case only because it was required to do so by Section 386.266. And there have been many cases that were filed before the general rate case required by 386.266. It is the intent of this whitepaper to give the reader a basic understanding of the working of the FAC in Missouri.

Questions and suggestions for improvement of this white paper may be directed to its author, Lena Mantle at lena.mantle@opc.mo.gov

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after September 14, 2016

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 = $0.02415 per kWh for each accumulation period.

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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, excluding all charges under Southwest Power Pool (“SPP”) Schedules 1a and 12 and congestion management charges and revenues. Such costs include:

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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;

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:

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A. Thirty-four percent (34%) 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.

B. Fifty percent (50%) 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; and provided further, should the SPP or another market participant implement a new charge type, exclusive of changes in transmission revenue, not included the Stipulation and Agreement, Schedule E, "List of Sub-Accounts Included and Excluded for FAC" approved by Commission order in Case No. ER-2016-0023:

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;

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RIDER FAC
For service on and after September 14, 2016

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.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after September 14, 2016

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):

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:

$B = (S_{AP} * \$0.02415)$

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 1.0464 and 1.0657, 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

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

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after September 14, 2016

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.

Data Request Received: 04/14/20 | Date of Response: 4/29/20
Request No. 8001 | Respondent: Peter Thompson

Submitted by: Lena Mantle.

REQUEST:

Empire's Electric Net Fuel & Purchased Power report for December 2019 provided in submission BFMR-2020-0367 states the following:

Asbury was derated due to fuel quality issues prior to consuming all of its recoverable coal inventory on December 12th at which point it did not operate for the remainder of the month. As a result, the unit produced only 5,386 MWh (approximately 95.0% less than budget since it was budgeted to operate normally all month). Asbury yielded over $2.2 million in unfavorable market margin largely due to increased costs due to its limited operation and coal inventory adjustments that increased its costs by over $1.9 million.

Please provide the following information:

A. A detailed explanation of the increased cost due to Asbury's limited operation along with all general ledger entries for these increased costs.

B. A detailed explanation of the coal inventory adjustments with all general ledger entries for this adjustment.

RESPONSE:

A. The increased cost as reported in the Net Fuel & Purchased Power report for December 2019 is primarily attributable to a coal inventory adjustment ($) and a limited amount of generation (MWh). Refer to the attachment labeled: "*DR 8001.A Asbury Costs.xlsx*".

B. Per David Eaton, the Asbury Plant Manager and a professional engineer, there was no recoverable or usable coal at the Asbury Plant as of 12/31/19. Therefore, Accounting adjusted the inventory balances for both blend and PRB coal to zero with 12/31/19 general ledger entry BURNEXP19. Please see DR 8001.B Inventory Adjustments Entry and Support.pdf.

CURGEN FUEL EXP & PP									
Journal ID	**Account**	**Amount**	**Line Descr**	**Status**	**Period**	**Product**	**Dept**	**Year**	
BURNEXP19	501042	271,924.87	Coal Burn Expense	P	12	FS	110	2019	Coal burn
BURNEXP19	501042	544.49	Oil Burn Hndling - 60%	P	12	FS	110	2019	Portion of oil burn related to coal handling
BURNEXP19	501042	1,925,886.33	Coal Burn Expense - Adj	P	12	FS	110	2019	Write-off of coal inventory due to no usable coal left at plant
UNDIST19B	501042	203.09	Undistributed Coal Burn Exp	P	12	FS	110	2019	Entry moves miscellaneous charges to coal expense.
UNDIST19C	501042	209.02	Undistributed Coal Burn Exp	P	12	FS	110	2019	Entry moves miscellaneous charges to coal expense.
UNDIST19	501042	175,094.13	Undistributed Coal Burn Exp	P	12	FS	110	2019	Entry moves miscellaneous charges to coal expense.
	501042 Total	2,373,861.93							
BURNEXP19	501045	20,084.86	Oil Burn Exp	P	12	FS	110	2019	Oil burn
	501045 Total	20,084.86							
ALO1200001	501601	420.16	PAYROLL ACCRUAL ALLOC	P	12	PA	150	2019	"Other" costs of coal payroll accrual
APA0056436	501601	300.00	AP Accruals	P	12	FE	150	2019	"Other" costs of coal AP accrual
ALO1100001	501601	(310.55)	PAYROLL ACCRUAL ALLOC	P	12	PA	150	2019	"Other" costs of coal payroll accrual
PAY0056606	501601	865.15		P	12	PRS	150	2019	"Other" costs of coal payroll accrual
PAY0056515	501601	442.02		P	12	PRS	150	2019	"Other" costs of coal payroll accrual
	501601 Total	1,716.78							
	Grand Total	2,395,663.57							

Asbury Resource Cost per FPP	2,395,664.00
Variance Due to Rounding on FPP	(0.43)

PeopleSoft Financials

Journal Entry Detail Report

Run Date: 4/17/20

Run Time: 4:06:07 PM

Header Unit:	GL001	**Ledger Group:**	ACTUALS	**Total Debits:**	**2218803.55**
Journal ID:	BURNEXP19	**Source:**	ONL	**Total Credits:**	**2218803.55**
Journal Date:	12/31/19	**Reversal:**	None	**Journal Lines:**	**9**
Header Description:	Coal and Oil Burn Exp for December 2019	**Reversal Date:**			

Unit: **GL001** **Ledger:** **ACTUALS**

	Account	Dept	Product	Journal Line Description	Journal Line Ref	Monetary Amount	Statistical Amount
3	501042	110	FS	Coal Burn Expense	-----	**271,924.87**	
4	501045	110	FS	Oil Burn Exp	-----	**20,084.86**	
7	502093	110	FS	Oil Burn Hndling - 40%	-----	**363.00**	
8	501042	110	FS	Oil Burn Hndling - 60%	-----	**544.49**	
9	151100	110	FS	Coal Inventory	-----	**-271,924.87**	
10	151200	110	FS	Distillate Oil	-----	**-20,084.86**	
11	151200	110	FS	Oil Inventory Handling Asbury	-----	**-907.49**	
12	501042	110	FS	Coal Burn Expense - Adj	-----	**1,925,886.33**	
13	151100	110	FS	Coal Inventory - Adj	-----	**-1,925,886.33**	

FUEL CONSUMED
Dec-19
ASBURY

Coal Burn

	Tons	Price	$		Account
PRB	3,836.625	56.4011	216,389.87	A	
Blended	728.220	76.2613	55,535.00	B	
Total	4,564.845		271,924.87		

Coal Inventory Adjustment

	Tons	Price	$		Account
PRB	15,046.278	56.4010	848,625.80	C	
Blended	14,125.916	76.2613	1,077,260.53	D	
Total	29,172.194		1,925,886.33		

Oil Burn

	Gallons	Price	$		Account
Generation	9,767.000	2.0564	20,084.86	E	
Handling	441.300	2.0564	907.49	F	
	60% of handling		544.49		
	40% of handling		363.00		
	Total Handling		907.49		

Summary

		DR.	CR.
Coal Burn Expense	110-501042	271,924.87	
Coal Burn Expense- Adj	110-501042	1,925,886.33	-
Oil Burn Generation	110-501045	20,084.86	
Oil Burn Handling - 40%	110-502093	363.00	
Oil Burn Handling - 60%	110-501042	544.49	
Coal Inventory	110-151100		271,924.87
Coal Inventory-Adj	110-151100	-	1,925,886.33
Oil Inventory Burn	110-151200		20,084.86
Oil Inventory Handling	110-151200		907.49
Undist. Exp.	110-152057		
Total		2,218,803.55	2,218,803.55

EMPIRE DISTRICT ELECTRIC COMPANY
INVENTORY WORKSHEET
2019

ASBURY - PRB COAL

MONTH	BEG TONS	PURCH TONS	ADJUST TONS	TRANSF OUT TONS	SUBTOTAL TONS	BURNED TONS	BURN INV ADJ TONS	INTRANSIT TONS	END TONS
1/31/2019	230,359.432	0.000			230,359.432	(39,709.800)		15,174.380	205,824.012
2/28/2019	205,824.012	30,169.060			235,993.072	(53,434.875)	(2,079.680)	15,118.400	195,596.917
3/31/2019	195,596.917	30,351.980			225,948.897	(68,470.350)			157,478.547
4/30/2019	157,478.547	30,262.230			187,740.777	(37,554.563)			150,186.214
5/31/2019	150,186.214	14,474.830			164,661.044	(16,196.603)		-	148,464.441
6/30/2019	148,464.441	60,567.760			209,032.201	(51,807.308)			157,224.893
7/31/2019	157,224.893	45,645.530			202,870.423	(49,809.825)	132.600	15,199.130	168,392.328
8/31/2019	168,392.328	0.000			168,392.328	(36,243.675)			132,148.653
9/30/2019	132,148.653	0.000			132,148.653	(40,479.075)			91,669.578
10/31/2019	91,669.578	0.000			91,669.578	(24,693.825)			66,975.753
11/30/2019	66,975.753	0.000			66,975.753	(48,092.850)			18,882.903
12/31/2019	18,882.903	0.000			18,882.903	(3,836.625)	(15,046.278)		0.000 1
	230,359.432	211,471.390	0.000	0.000		(470,329.374)	(16,993.358)	45,491.910	0.000

MONTH	BEG INITIAL $	PURCH INITIAL $	ADJUST INITIAL $	TRANSF OUT INITIAL $	SUBTOTAL INITIAL $	BURNED INITIAL $	BURN INV ADJ INITIAL $	INTRANSIT INITIAL $	END INITIAL $	WTD AVG $/TON	MONTH $/TON
1/31/2019	2,767,652.28	8,806.98			2,776,459.26	(478,610.31)	-	185,886.16	2,483,735.11	12.0527	0.0000
2/28/2019	2,483,735.11	388,592.97			2,872,328.08	(650,366.55)	(25,312.20)	194,678.35	2,391,327.68	12.1712	12.8805
3/31/2019	2,391,327.68	396,239.80			2,787,567.48	(844,732.40)	-		1,942,835.08	12.3372	13.0548
4/30/2019	1,942,835.08	395,037.32			2,337,872.40	(467,655.71)	-		1,870,216.69	12.4527	13.0538
5/31/2019	1,870,216.69	183,984.40			2,054,201.09	(202,057.48)	-		1,852,143.61	12.4753	12.7106
6/30/2019	1,852,143.61	781,043.57			2,633,187.18	(652,616.66)	-		1,980,570.52	12.5970	12.8954
7/31/2019	1,980,570.52	587,736.77			2,568,307.29	(630,582.42)	1,678.69	195,707.66	2,135,111.22	12.6598	12.8761
8/31/2019	2,135,111.22	4,015.75			2,139,126.97	(460,410.65)	-		1,678,716.32	12.7032	0.0000
9/30/2019	1,678,716.32	0.00			1,678,716.32	(514,213.79)	-		1,164,502.53	12.7032	0.0000
10/31/2019	1,164,502.53	0.00			1,164,502.53	(313,693.07)	-		850,809.46	12.7033	0.0000
11/30/2019	850,809.46	4,850.81			855,660.27	(614,419.82)	-		241,240.45	12.7757	0.0000
12/31/2019	241,240.45	0.00			241,240.45	(49,015.19)	(192,225.26)		0.00	12.7756	0.0000
	2,767,652.28	2,750,308.37	0.00	0.00		(5,878,374.05)	(215,858.77)	576,272.17	(0.00)		

MONTH	BEG FREIGHT $	PURCH FREIGHT $	ADJUST FREIGHT $	TRANSF OUT FREIGHT $	SUBTOTAL FREIGHT $	BURNED FREIGHT $	BURN INV ADJ FREIGHT $	INTRANSIT FREIGHT $	END FREIGHT $	WTD AVG $/TON	MONTH $/TON
1/31/2019	5,731,937.47	230,539.33			5,962,476.80	(1,027,824.64)	-	287,891.25	5,222,543.41	25.8834	0.0000
2/28/2019	5,222,543.41	837,898.58			6,060,441.99	(1,372,239.65)	(53,407.43)	284,358.75	4,919,153.66	25.6806	27.7734
3/31/2019	4,919,153.66	810,323.23			5,729,476.89	(1,736,230.05)	-		3,993,246.84	25.3574	26.6975
4/30/2019	3,993,246.84	835,448.36			4,828,695.20	(965,903.36)	-		3,862,791.84	25.7200	27.6070
5/31/2019	3,862,791.84	530,843.22			4,393,635.06	(432,172.34)	-		3,961,462.72	26.6829	36.6735
6/30/2019	3,961,462.72	1,367,137.72			5,328,600.44	(1,320,661.53)	-		4,007,938.91	25.4918	22.5720
7/31/2019	4,007,938.91	1,139,607.14			5,147,546.05	(1,263,854.58)	3,364.54	284,593.75	4,171,649.76	25.3736	24.9665
8/31/2019	4,171,649.76	269,359.37			4,441,009.13	(955,854.44)	-		3,485,154.69	26.3730	0.0000
9/30/2019	3,485,154.69	206,743.13			3,691,897.82	(1,130,884.16)	-		2,561,013.66	27.9375	0.0000
10/31/2019	2,561,013.66	202,911.36			2,763,925.02	(744,543.52)	-		2,019,381.50	30.1510	0.0000
11/30/2019	2,019,381.50	207,657.09			2,227,038.59	(1,599,154.59)	-		627,884.00	33.2514	0.0000
12/31/2019	627,884.00	195,891.22			823,775.22	(167,374.68)	(656,400.54)		0.00	43.6255	0.0000
	5,731,937.47	6,834,359.75	0.00	0.00		(12,716,697.54)	(706,443.43)	856,843.75	0.00		

MONTH	BEG TOTAL $	PURCH TOTAL $	ADJUST TOTAL $	TRANSF OUT TOTAL $	SUBTOTAL TOTAL $	BURNED TOTAL $	BURN INV ADJ TOTAL $	INTRANSIT TOTAL $	END TOTAL $	WTD AVG $/TON	MONTH $/TON
										39.5972	40.3116
1/31/2019	8,499,589.75	239,346.31	-	-	8,738,936.06	(1,506,434.95)	-	473,777.41	7,706,278.52	37.9361	0.0000
2/28/2019	7,706,278.52	1,226,491.55	-	-	8,932,770.07	(2,022,606.20)	(78,719.63)	479,037.10	7,310,481.34	37.8518	40.6540
3/31/2019	7,310,481.34	1,206,563.03	-	-	8,517,044.37	(2,580,962.45)	-	-	5,936,081.92	37.6946	39.7524
4/30/2019	5,936,081.92	1,230,485.68	-	-	7,166,567.60	(1,433,559.07)	-	-	5,733,008.53	38.1727	40.6608
5/31/2019	5,733,008.53	714,827.62	-	-	6,447,836.15	(634,229.82)	-	-	5,813,606.33	39.1582	49.3842
6/30/2019	5,813,606.33	2,148,181.29	-	-	7,961,787.62	(1,973,278.19)	-	-	5,988,509.43	38.0888	35.4674
7/31/2019	5,988,509.43	1,727,343.91	-	-	7,715,853.34	(1,894,437.00)	5,043.23	480,301.41	6,306,760.98	38.0334	37.8426
8/31/2019	6,306,760.98	273,375.12	-	-	6,580,136.10	(1,416,265.09)	-	-	5,163,871.01	39.0762	0.0000
9/30/2019	5,163,871.01	206,743.13	-	-	5,370,614.14	(1,645,097.95)	-	-	3,725,516.19	40.6407	0.0000
10/31/2019	3,725,516.19	202,911.36	-	-	3,928,427.55	(1,058,236.59)	-	-	2,870,190.96	42.8543	0.0000
11/30/2019	2,870,190.96	212,507.90	-	-	3,082,698.86	(2,213,574.41)	-	-	869,124.45	46.0271	0.0000
12/31/2019	869,124.45	195,891.22	-	-	1,065,015.67	(216,389.87)	$\boxed{(848,625.80)}$ C	-	(0.00)	56.4011	0.0000
	8,499,589.75	9,584,668.12	0.00	0.00		(18,595,071.59)	(922,302.20)	1,433,115.92	(0.00)		
									Jan		
									Feb		
									Mar		

Burn A

LMM-R-4

EMPIRE DISTRICT ELECTRIC COMPANY
INVENTORY WORKSHEET
2019

ASBURY - BLENDED COAL

MONTH	BEG TONS	PURCH TONS	TRANSF IN TONS	TRANSF OUT TONS	SUBTOTAL TONS	BURNED TONS	BURN INV ADJ TONS	INTRANSIT TONS	END TONS
1/31/2019	1,009.800	0.000			1,009.800	(37.100)			972.700
2/28/2019	972.700	803.540			1,776.240	(448.380)			1,327.860
3/31/2019	1,327.860	5,531.270			6,859.130	(3,302.960)			3,556.170
4/30/2019	3,556.170	5,085.480			8,641.650	(2,970.650)			5,671.000
5/31/2019	5,671.000	15,577.980			21,248.980	(1,208.506)			20,040.474
6/30/2019	20,040.474	510.900			20,551.374	(3,818.438)			16,732.936
7/31/2019	16,732.936	3,111.880			19,844.816	(3,105.800)	(144.160)		16,594.856
8/31/2019	16,594.856	3,620.140			20,214.996	(2,360.620)			17,854.376
9/30/2019	17,854.376	334.140			18,188.516	(2,956.340)	(8.260)		15,223.916
10/31/2019	15,223.916	3,488.790			18,712.706	(1,426.760)			17,285.946
11/30/2019	17,285.946	1,369.350			18,655.296	(3,801.160)			14,854.136
12/31/2019	14,854.136	0.000			14,854.136	(728.220)	(14,125.916)		0.000
	1,009.800	39,433.470	0.000	0.000		(26,164.934)	(14,278.336)	0.000	0.000

2

MONTH	BEG INITIAL $	PURCH INITIAL $	TRANSF IN INITIAL $	TRANSF OUT INITIAL $	SUBTOTAL INITIAL $	BURNED INITIAL $	BURN INV ADJ INITIAL $	INTRANSIT INITIAL $	END INITIAL $	WTD AVG $/TON	MONTH $/TON
1/31/2019	82,803.60	0.00			82,803.60	(3,042.20)	-		79,761.40	82.0000	0.0000
2/28/2019	79,761.40	65,890.28			145,651.68	(36,767.16)	-		108,884.52	82.0000	82.0000
3/31/2019	108,884.52	453,564.14			562,448.66	(270,842.72)	-		291,605.94	82.0000	82.0000
4/30/2019	291,605.94	408,585.21			700,191.15	(240,697.51)	-		459,493.64	81.0252	80.3435
5/31/2019	459,493.64	1,082,557.21			1,542,050.85	(87,702.01)	-		1,454,348.84	72.5706	69.4928
6/30/2019	1,454,348.84	44,443.62			1,498,792.46	(278,475.25)	-		1,220,317.21	72.9291	86.9908
7/31/2019	1,220,317.21	284,142.48			1,504,459.69	(235,454.42)	(10,928.94)		1,258,076.33	75.8112	91.3089
8/31/2019	1,258,076.33	289,726.39			1,547,802.72	(180,745.83)	-		1,367,056.89	76.5671	80.0318
9/30/2019	1,367,056.89	20,558.91			1,387,615.80	(225,541.54)	(677.32)		1,161,396.94	76.2908	61.5278
10/31/2019	1,161,396.94	287,902.00			1,449,298.94	(110,502.56)	-		1,338,796.38	77.4500	82.5220
11/30/2019	1,338,796.38	95,303.16			1,434,099.54	(292,208.85)	-		1,141,890.69	76.8736	69.5974
12/31/2019	1,141,890.69	(9,095.16)			1,132,795.53	(55,535.00)	(1,077,260.53)		0.00	76.2613	0.0000
	82,803.60	3,023,578.24	0.00	0.00		(2,017,515.05)	(1,088,866.79)	0.00	0.00		

MONTH	BEG FREIGHT $	PURCH FREIGHT $	TRANSF IN FREIGHT $	TRANSF OUT FREIGHT $	SUBTOTAL FREIGHT $	BURNED FREIGHT $	BURN INV ADJ FREIGHT $	INTRANSIT FREIGHT $	END FREIGHT $	WTD AVG $/TON	MONTH $/TON
1/31/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
2/28/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
3/31/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
4/30/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
5/31/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
6/30/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
7/31/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
8/31/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
9/30/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
10/31/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
11/30/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
12/31/2019	0.00	0.00			0.00	-	-		0.00	0.0000	0.0000
	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00		

MONTH	BEG TOTAL $	PURCH TOTAL $	TRANSF IN TOTAL $	TRANSF OUT TOTAL $	SUBTOTAL TOTAL $	BURNED TOTAL $	BURN INV ADJ TOTAL $	INTRANSIT TOTAL $	END TOTAL $	WTD AVG $/TON	MONTH $/TON
										52.3761	
1/31/2019	82,803.60	-	-	-	82,803.60	(3,042.20)	-	-	79,761.40	82.0000	0.0000
2/28/2019	79,761.40	65,890.28	-	-	145,651.68	(36,767.16)	-	-	108,884.52	82.0000	82.0000
3/31/2019	108,884.52	453,564.14	-	-	562,448.66	(270,842.72)	-	-	291,605.94	82.0000	82.0000
4/30/2019	291,605.94	408,585.21	-	-	700,191.15	(240,697.51)	-	-	459,493.64	81.0252	80.3435
5/31/2019	459,493.64	1,082,557.21	-	-	1,542,050.85	(87,702.01)	-	-	1,454,348.84	72.5706	69.4928
6/30/2019	1,454,348.84	44,443.62	-	-	1,498,792.46	(278,475.25)	-	-	1,220,317.21	72.9291	86.9908
7/31/2019	1,220,317.21	284,142.48	-	-	1,504,459.69	(235,454.42)	(10,928.94)	-	1,258,076.33	75.8112	91.3089
8/31/2019	1,258,076.33	289,726.39	-	-	1,547,802.72	(180,745.83)	-	-	1,367,056.89	76.5671	80.0318
9/30/2019	1,367,056.89	20,558.91	-	-	1,387,615.80	(225,541.54)	(677.32)	-	1,161,396.94	76.2908	61.5278
10/31/2019	1,161,396.94	287,902.00	-	-	1,449,298.94	(110,502.56)	-	-	1,338,796.38	77.4500	82.5220
11/30/2019	1,338,796.38	95,303.16	-	-	1,434,099.54	(292,208.85)	-	-	1,141,890.69	76.8736	69.5974
12/31/2019	1,141,890.69	(9,095.16)	-	-	1,132,795.53	(55,535.00)	$\boxed{(1,077,260.53)}$ D	-	0.00	76.2613	0.0000
	82,803.60	3,023,578.24	0.00	0.00		(2,017,515.05)	(1,088,866.79)	0.00	0.00		

Burn B

Jan > 5%
Feb
Mar
Apr

TO: Fuel Accountant - General Accounting
Fuel Contracts Manager - Energy Supply

December 2019

FROM: Mr. David Eaton, Asbury Plant Manager

	Unit No. 1
Unit 1 Gen. MW Meter	7647
Start Up	1490
M1 (AQCS Aux)	771
Total Net Generation Unit 1	5386

Generation Per Unit	7647
Auxiliaries - MW	660
Gross Generation Per Unit	8307
Total Gross Generation - MW	8307

COAL	BEGINNING INVENTORY	TONS RECEIVED	Inventory Adjustment	TONS BURNED	ENDING INVENTORY	
PEABODY	18,883.401	-	(15,046.78)	3,836.625	0.000	1 *
Tires	-	-		-	0.000	
Blend Coal - 1	14,854.336	-	(14,126.12)	728.220	0.000	2 *
TOTAL	33,737.737	-	(29,172.89)	4,564.845	0.000	

OIL	LEVEL	GALLONS	
Oil Beginning of the Month	11 ft. 10 in.	29,583	
OIL PURCHASED		-	
SUBTOTAL (in Gallons)		29,583	
BURNED IN HANDLING EQUIPMENT		441.3	
BURNED IN GENERATION		9,767	
TOTAL BURNED (in Gallons)		10,208	
Oil EOM	7 ft. 9 in.	19,375	3

* Adjustment amounts vary slightly, but difference is immaterial.

Memorandum

To: Kelsey Anderson, Fuel Accountant

From: David Eaton, Asbury Plant Manager /s/ DE

Date: 1/7/2020

RE: Asbury coal inventory

In my professional judgment, as of 12/31/2019, there is insufficient recoverable coal inventory to start the unit. The coal that remains in both the PRB and blend piles has too much clay and/or rock mixed in to be considered a viable coal for combustion.