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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2022-0130

DIRECT TESTIMONY

OF

LINDA J. NUNN

ON BEHALF OF

EVERGY MISSOURI WEST

Kansas City, Missouri
January 2022

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DIRECT TESTIMONY

OF

LINDA J. NUNN

CASE NO. ER-2022-0130

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Linda J. Nunn. My business address is 1200 Main, Kansas City, Missouri 64105.

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

A: I am employed by Evergy Metro, Inc. I serve as Manager - Regulatory Affairs for Evergy Metro, Inc. d/b/a as Evergy Missouri Metro ("Evergy Missouri Metro"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West" or "Company"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("Evergy Kansas Metro"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a as Evergy Kansas Central ("Evergy Kansas Central") the operating utilities of Evergy, Inc.

Q: What are your responsibilities?

A: My responsibilities include the coordination, preparation and review of financial information and schedules associated with Company rate case filings and other regulatory filings.

Q: Please describe your education.

A: I received a Bachelor of Science Degree in Business Administration with a concentration in Accounting from Northwest Missouri State University.

Q: Please provide your work experience.

A: I became a Senior Regulatory Analyst with KCP&L in 2008, as a part of the acquisition of Aquila, Inc., by Great Plains Energy. In 2013, I was promoted to Supervisor - Regulatory Affairs. In 2018 I became Manager, Regulatory Affairs. Prior to my employment with KCP&L, I was employed by Aquila, Inc. for a total of eleven years. In addition to Regulatory, I have had experience in Accounting, Audit, and Business Services, where I had responsibility for guiding restructuring within the delivery division. In addition to my utility experience, I was the business manager and controller for two area churches. Prior to that, I was an external auditor with Ernst & Whinney.

Q: Have you previously testified in a proceeding before the Missouri Public Service Commission ("MPSC" or "Commission") or before any other utility regulatory agency?

A: Yes, I have testified before the MPSC, and I have provided written testimony in various dockets before the MPSC. I have also worked closely with many MPSC Staff on numerous filings as well as on rate case issues.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to discuss various adjustments made to the test year, introduce the discussion on jurisdictional allocations, and provide the required information associated with requesting to continue the Company's Fuel Adjustment Clause ("FAC"). As explained in the testimony of Company witness Ronald A. Klote, adjustments are made to the historical test year for known and measurable changes along with the annualization, normalization and amortization of certain assets, liabilities, revenues and expenses. In the following testimony, I will be discussing several of these adjustments.

II. JURISDICTIONAL ALLOCATIONS

Q: Have the jurisdictional allocations used in this Missouri West rate case filing changed in any significant way?

A: Regarding the allocations used to allocate costs to our five municipal customers who receive power based upon negotiated contracts, nothing has changed except for the updating of the data to the 12-months ended December 31, 2020.

Q: Have there been changes made to the electric/steam allocation factors?

A: Yes. In the stipulation and agreement from Case Nos. ER-2018-0146 ("2018 Case") and HR-2018-0231, Evergy Missouri West agreed to work with the parties to develop new steam allocation procedures.

Q: Provide some background on the Steam customers.

A: While the Evergy Missouri West steam business only has five customers, they represent over $28 million in Electric and Industrial Steam revenues. Additionally, they employ nearly 4,000 employees in St. Joseph, MO. The objective of this study is to establish an allocations methodology that is representative of the operations of the Lake Road Plant and its Electric/Steam businesses, and which provides for competitive rates that will help to ensure the continued operation of these businesses in the Evergy Missouri West service territory.

Q: What prompted the need to change to new allocation procedures?

A: The Lake Road plant provides Evergy Missouri West electric generation with multiple units which burn coal, natural gas and fuel oil. The Lake Road plant also serves five industrial steam customers that take steam service from the 900 lb. side of the plant. The 900lb system refers to the boiler operating pressure. Boilers 1, 2, 4 and 5 are 900 lb. boilers, meaning they operate at 900 PSI or Pounds per Square Inch. Boiler 8 is considered part of the 900 lb. system since it shares the same feedwater and supplies steam sales, but it operates at a lower pressure. Boiler 5 is capable of burning coal and natural gas. Boilers 1, 2, 4 and 8 can burn either natural gas or fuel oil. The 900 lb. side also produces electricity from three electric turbines supported by the above-mentioned boilers. The Lake Road plant also has an 1800 lb. system that consists of one boiler and one turbine. The 1800 lb. system's primary fuel was coal until June 2016, when it ceased burning coal due to environmental regulation compliance issues. It is capable of burning natural gas or fuel oil. The remainder of the plant is made up of three combustion turbines.

The discontinuance of burning coal on the 1800 lb. system has had a significant impact on plant operations and thus an impact on current plant allocations and is one of the primary reasons for changing the method for allocating costs at the Lake Road plant between the industrial steam and electric jurisdictions. The current allocation method for allocating plant operation and maintenance expenses relies heavily on a coal burn allocation between industrial steam and electric jurisdictions.

Additionally, outside factors in recent years have changed how the units at the Lake Road plant are dispatched for electricity. Some of those factors are the increased use of wind generation in the area, the abundance of natural gas along with lower gas prices and the Southwest Power Pool's ("SPP") launch of the Integrated Marketplace on March 1st of 2014.

Current electric dispatching by the SPP of the 900 lb. side is typically for peak generation, ancillary services and spinning reserve. When the units are online, they are typically operated at low loads. This results in multiple turbines and boilers being operated at low loads to cover the potential for full load generation.

The Company has determined that due to the way that the SPP is dispatching the 900 lb. side, the current steam demand allocation process should be changed to reflect how the plant is now being utilized.

Q: What other issues were taken into consideration into account when developing proposed new allocation factors?

A: In addition to the changes precipitated by the changes in how the Lake Road plant is run and dispatched, the company wanted to ensure that the concerns presented by the parties were addressed in the proposed new allocation methodology. One concern expressed by the MPSC Staff was that the company used outdated data to calculate the 900 lb. steam demand factor. The capacity test to establish the maximum fuel input to the boilers has been updated and the test was conducted in August 2020.

Another Staff concern was that the 1994 plant water use study that was prepared for Case No. EO-94-36 was provided as a reference to Step 3 of the Auxiliary Power Allocation process. Staff questioned whether or not this study was still representative of current operations. In 2020, a new water treatment plant was installed at Lake Road. Other changes at the plant consists of modern electrical switchgear equipment and a Digital Control System (DCS) that now allows daily automated metering of the auxiliary power. Auxiliary power readings will be collected on a daily basis. Auxiliary power load that supports electric generation will be charged to the electric customers. Auxiliary power load that supports the steam system will be charged to the steam customers. Auxiliary power loads that are shared on common equipment will be allocated on a daily basis according to the daily heat balance of the plant.

The Office of the Public Counsel ("OPC") had a concern relating to the identification and quantification of auxiliary power used to produce industrial steam. This issue was identified in the EO-2019-0067 Fuel Adjustment Clause prudence review case. The Company is proposing to use a direct assignment method to allocate auxiliary power to the Industrial Steam business. This direct allocation method for auxiliary power is detailed out in the attached manual which can be found in the appendix of this document. The Company is proposing to specifically identify and record on the books an amount for auxiliary power needed to serve the steam load.

Q: When was the last time that the electric/steam allocation factors were updated?

A: The only past updates made to the allocation factors used to allocate between the electric and steam businesses since Case No. ER-2012-0175, was to change the denominator for many of the allocators to accommodate the consolidation of former MPS and L&P divisions of KCP&L Greater Missouri Operations Company, now Evergy Missouri West, into one division.

Q: What changes are you proposing in this case?

A: The 900 lb. steam demand allocation factor is the primary driver of many of the other factors used to allocate between the electric and steam businesses. The 900 lb. steam demand allocator drives the allocation of plant in service and reserve which then impacts the calculation of the administrative and general expense allocator. The current 900 lb. steam demand allocation factor was calculated as follows: determine the maximum coincident peaks for each month in a three-year period. This produces 36 individual monthly maximum demands for the 900 lb. system. From these 36 values, the three highest amounts are taken for each calendar year. This results in nine values over the three years. The percentage of steam and electric operations use in each of these nine values is then determined. The last step in the process is to determine an average maximum coincident peak for the three highest values over the three years by adding each of the nine percentages for electric and industrial steam allocation factors and dividing by nine.

With the changes at the Lake Road plant, outside factors and changes in the SPP's dispatching, a more accurate method to determine the 900 lb. steam demand allocation factor should consider the maximum steam sales demand and the electric demand capability of the steam turbines. By taking the monthly maximum steam sales demand and dividing the sum of the maximum steam sales demand and the capability of the steam turbines demand for electric generation, the percentage would be representative of the percent of steam demand for the 900 lb. side. This method will better reflect how the 900 lb. plant is currently maintained and operated and better recognize the potential for full load generation.

Regarding the calculation of the Operations and Maintenance ("O&M") factor, historically the calculation took total Lake Road payroll times the coal burn factor (three-year average of coal burned for steam as a percentage of total coal burned) to get total steam payroll at Lake Road. This product was then divided by total Evergy Missouri West steam production payroll to get the O&M factor. This factor was then applied in the revenue requirement model to all non-fuel steam production O&M.

The proposed method uses an equivalent employment factor instead of the coal burn factor to get steam payroll at Lake Road. The equivalent employment factor is the fraction of time spent by a typical Lake Road Plant operating crew on the operation of the industrial steam system, based upon a breakdown of each operator's time. A change to the O&M factor would also then impact the calculation of the administrative and general expense allocator.

Whereas prior allocation methodology has been discussed in rate cases in both written and verbal testimony, the methodology as such has not been itemized and documented thoroughly. As a part of this review process, the Company is proposing to use an allocations manual similar to the one used by the former St. Joe Light & Power and approved by the Commission in Case No. EO-94-36. These proposed allocation procedures are provided as Schedule LJN - 1 attached to this testimony.

See Schedule RAK – 6 for a listing of all proposed wholesale and electric/steam allocation factors.

III. FUEL ADJUSTMENT CLAUSE REQUIREMENTS

Q: Does the Company currently have an approved FAC?

A: Yes. The FAC was initially approved for Evergy Missouri West in Case No. ER-2007-0004 on May 17, 2007. Several modifications and clarifications have been made to the FAC in subsequent rate cases, all with the intent to improve the FAC and its processes.

Q: What are the rules for continuing an FAC?

A: The requirements for continuing an FAC are found in Section 386.266 RSMo. and Commission rule 20 CSR 4240-20.090 (2). The supporting information is summarized in the attached Schedules LJN - 2 through LJN - 8.

Q: Are you providing any other support for continuation of your FAC?

A: Yes. 20 CSR 4240-20.090 (13)(B) requires a system loss study be conducted no less than every four (4) years to be used in the general rate proceeding necessary to continue to utilize a Rate Adjustment Mechanism ("RAM"). The 2020 loss study is attached to my testimony as Schedule LJN - 5.

Q: Has the Company met all of the filing requirements to continue the FAC 20 CSR 4240-20.090 (2)?

A: Yes.

Q: Is the Company requesting to continue the FAC?

A: Yes.

Q: Is the Company proposing to make any changes in the FAC tariff?

A: Yes, the Company is proposing to make the following changes to the FAC tariff:

- The base rate has been re-based;
- Voltage level loss factors have been updated to take into consideration the output from the line loss study conducted for this case;
- The percentage of transmission which flows through the FAC has been updated;
- Added natural gas reservation charges to the tariff;
- Added unit train expenses;
- The listing of the SPP charge types was updated for new charge types added by SPP since the Company's last rate case as well as removed by SPP;
- The addition of SPP charge types necessitated the addition of an account under item PP, subaccount 555070;

- Expanded the FERC accounts impacted by the gains or losses to be reported for the sale of Renewable Energy Credits to be consistent throughout Evergy; and
- Added language associated with the implementation of new hedging programs.
- Note that although at this time we do not believe that changes to the FAC are warranted, a number of the customer programs that are being proposed in this case may have an impact on the calculation of the FAC. These impacts will be determined during the course of this proceeding.
- Although at this time we do not believe that changes to the FAC are warranted, the potential for the impact of an addition of a special high load factor market rate customer will be taken into consideration when finalizing the FAC tariffs.

Q: Are there any changes that you would like to highlight?

A: Yes, the Company is considering hedging opportunities due to the more volatile nature of the fuel and purchased power markets of late.

Q: Please give some background on the hedging topic as it relates to Evergy.

A: In Case No. ER-2016-0156 (”2016 Case”), it was stipulated that the Company would suspend all of its hedging activities associated with natural gas (cross-hedging related to purchased power and natural gas fuel hedging). Hedging practices ceased and the hedges were unwound with the gains and losses flowed through the FAC. In the same stipulation, the signatories agreed that the Company may resume its natural gas fuel hedging activities, but not the use of natural gas derivatives to cross-hedge purchased power, should the marketplace and/or other factors change such that resuming natural gas fuel hedging activities would be warranted. The Company also agreed to notify the Commission Staff and OPC if the Company decides to resume its natural gas fuel hedging activities. With the increased volatility we are seeing in the gas markets currently, the Company has decided that it would be prudent to resume hedging of natural gas and has notified Staff and OPC. In addition to natural gas hedging, the Company is requesting in this case to also resume cross hedging based upon the same volatility seen in the gas markets. See the testimony of Company witness Jessica Tucker for a more detailed discussion on this issue.

Q: Will the gains and losses associated with the hedging program flow through the FAC?

A: Since the purpose of entering into a hedging program is to mitigate and level out the volatility of the fuel and purchased power markets, the benefits and costs associated with the program should also flow through the FAC. This provides for balance, consistency and ensures the only appropriate level of net costs are charged to our customers.

Q: Will any of the changes to the FAC mentioned above cause any problems with the computation or administration of the FAC?

A: No. All costs and revenues associated with the proposed changes will be easily identifiable on the Company's books and records. The changes are intended to provide a more complete view of the costs incurred and revenues received by the company and to provide consistency between the two jurisdictions.

Q: Does the FAC help both customers and Company?

A: Yes. The FAC is a balanced recovery mechanism which provides the Company with recovery of the majority of its fuel and purchased power costs, and a portion of transmission costs net of off system sales above a base amount that is included in base rates, but also provides customers assurance that Evergy Missouri West is not over-recovering net fuel and purchased power costs. The FAC is needed to help address volatile and uncertain net fuel and purchased power costs, and to ensure the Company has an opportunity to earn a fair return in order to generally preserve the financial health of the Company. The net fuel and purchased power and transmission costs contained in the FAC for Evergy Missouri West represent approximately 33% of the overall costs of serving customers.

o**Q: Do you believe that the absence of an FAC is potentially harmful to the Company and/or the Customer?**

A: Yes. Without the proposed FAC, under increasing fuel cost scenarios, the Company would not have a reasonable opportunity to earn the rate of return authorized in this case. Conversely, if net fuel and purchased power, and transmission costs turn out to be lower after the setting of base rates, then the presence of an FAC will protect customers from paying higher prices than the Company's actual experience.

The FAC is designed to provide for full and timely recovery of 95% of the changes in net fuel costs by reflecting changes in such costs in rates. The net fuel costs included in the FAC are often much more significant, volatile, uncertain and much more difficult to control than other utility costs. Additionally, a continuation of the FAC helps to keep Evergy Missouri Metro on somewhat more comparable footing with utilities operating in other states. As it stands now, Evergy Missouri Metro is already at a disadvantage as compared to other Companies around the country. As supported in the Direct Testimony of Company Witness Ann Bulkley, 90 percent of the operating companies in her proxy group are allowed to directly recover fuel and purchased power costs without any sharing at all. In addition, her discussion of adjustment mechanisms in general shows that Missouri lags behind other states in this area and that of adjustment mechanisms it allows. Ms. Bulkley identifies that although Evergy Missouri Metro has access to some regulatory mechanisms, these are limited.

Removing the use of the FAC would contribute to the already challenging regulatory lag environment. The FAC continues to provide Evergy Missouri Metro with an increased opportunity to earn a fair return on equity because it mitigates to a certain extent the very significant regulatory lag which is prevalent when dealing with such large, uncertain and often volatile costs, by preventing deterioration in (or augmentation of) the utility's financial position (including relative credit standing, which is a key determinant of borrowing costs), and by ensuring recovery of actual net energy costs, which may vary substantially from expected levels.

This serves as Evergy Missouri Metro's explanation, compliant with Commission rule 20 CSR 4240-20.090(2)5, of how the FAC proposed by Evergy Missouri Metro is designed to provide the Company with a sufficient opportunity to earn a fair return on equity.

This serves as Evergy Missouri West's explanation, compliant with Commission rule 20 CSR 4240-20.090 (2) 5, of how the FAC proposed by Evergy Missouri West is designed to provide the Company with a sufficient opportunity to earn a fair return on equity.

Q: What protections exist for customers with regard to the FAC?

A: Beyond the semi-annual reviews performed for each filing of the FAC changes, the FAC is also audited through a detailed prudence review by the Staff no less frequently than at eighteen (18)-month intervals. OPC also participates in the review process. To date, no disallowances ordered by the Commission have occurred where the Company has been found to be imprudent in any aspects of the FAC.

IV. ACCOUNTING ADJUSTMENTS

RB-25/CS-111 IATAN 1 & IATAN COMMON REGULATORY ASSET

Q: Please explain adjustment RB-25.

A: As continued from ER-2018-0146 the ('2018 Case"), Evergy Missouri West included in a regulatory asset depreciation expense and carrying costs for the Iatan Unit 1 Air Quality Control System and Iatan common plant. Adjustment RB-25 establishes the anticipated rate base value as of May 31, 2022 by rolling forward the regulatory asset balance from the true-up date of the 2018 Case to the anticipated true-up date of May 31, 2022, for this current case.

Q: Was this regulatory asset included in rate base in the 2018 Case?

A: Yes.

Q: Please explain adjustment CS-111.

A: The Company continued the amortization of this regulatory asset based on the amortization levels established in the 2018 Case. The test year properly reflected the annual level of amortization expense thus the adjustment made to the test year was zero.

RB-26/CS-112 IATAN 2 REGULATORY ASSET

Q: Please explain adjustment RB-26.

A: As continued from the 2018 Case, Evergy Missouri West has included in a regulatory asset construction accounting impacts which included depreciation, carrying costs, operations and maintenance expenses and fuel and revenue impacts for the Iatan Unit 2 construction project. Adjustment RB-26 establishes the anticipated rate base value as of May 31, 2022 by rolling forward from the true-up date of the 2018 Case to the anticipated true-up date of May 31, 2022, for the current case.

Q: Was this regulatory asset included in rate base in the 2018 Case?

A: Yes.

Q: Please explain adjustment CS-112.

A: The Company continued the amortization of this regulatory asset based on the amortization levels established in and continued through previous cases. The test year properly reflected the annual level of amortization expense.

RB-50 PREPAYMENTS

Q: Please explain adjustment RB-50.

A: The Company normalized this rate base item based on a 13-month average of prepayment balances expect for new account 165005 - Prepaid Maintenance.

This account represents the maintenance fees for cloud software. For account 165005 - Prepaid Maintenance, the Company used the test year ending balance since the account is expected to continue to trend upward. For the remaining prepayment amounts, they appear to vary during the course of the year and thus the averaging method used minimizes these fluctuations.

Q: What is the most significant prepayment included?

A: The most significant prepayment relates to prepaid maintenance.

Q: What period was used for the 13-month averaging?

A: The Company used the period June 2020 through June 2021.

RB-70 CUSTOMER DEPOSITS

Q: Please explain adjustment RB-70.

A: The Company examined its customer deposit balances from June 2020 through June 2021. The analysis observed a declining balance during this period. Therefore, the Company chose to use the month ending balance at June 30, 2021 for customer deposits in rate base.

RB-71 CUSTOMER ADVANCES

Q: Please explain adjustment RB-71.

A: The Company examined customer advances balances for Missouri customers from June 2020 through June 2021 and observed that the balance changed only slightly during this period. Therefore, the Company chose to use the 13-month average of customer advances for inclusion as a rate base offset.

RB-72 MATERIALS AND SUPPLIES

Q: Please explain adjustment RB-72.

A: The Company reviewed the individual materials and supplies category balances during the period June 2020 through June 2021 to determine if there was a discernable trend, either upward or downward. If there was a trend, the test year-end balance was not adjusted. Otherwise, a 13-month average was used. This calculated balance is included in rate base.

RB-100/CS-100 ENERGY EFFICIENCY/DEMAND RESPONSE COSTS

Q: Please explain adjustment RB-100.

A: This regulatory asset was fully amortized in June 2020. The recovery of the Pre-MEEIA Energy Efficiency/Demand Response costs continued to be collected from customers and tracked in a prospective tracking regulatory liability account. The unamortized balance at the expected true-up date of May 2022 is included as a rate base offset.

Q: Please explain adjustment CS-100.

A: The regulatory asset for the deferred pre-Missouri Energy Efficiency Investment Act ("MEEIA") costs was fully amortized in June 2020. All test year expenses are removed from cost of service and the annual amortization of vintages 1, 2, 3, 4, and 5 are set to zero. The amortization back to customers of the over-collection recorded in the prospective tracking regulatory liability account is included in adjustment CS-113.

RB-101/CS-101 INCOME ELIGIBLE WEATHERIZATION PROGRAM

Q: Please explain adjustment RB-101.

A: In the 2018 Case the Company agreed to include the balance of unspent program funding in a regulatory liability account as a reduction to rate base. This adjustment rolls forward the unamortized deferred program costs from June 30, 2018, to May 31, 2022, as the Company continues to monitor overall spend.

Q: Please explain adjustment CS-101.

A: Per the 2018 Partial Stipulation & Agreement, Evergy Missouri West was authorized to increase the program funding level to $500,000 annually. The Company agreed that any unspent funds would continue to accrue interest at the AFUDC rate and not to recover Through-Put Disincentive in its programs. The unspent fund balance at the true-up date of June 2018 was authorized to amortize over four years. Vintage 1 will be fully amortized on November 22, 2022. Therefore, the test year expense is removed from cost of service. The annual amortization amount of Vintage 1 is set to zero. This adjustment proposes to amortize the unspent fund balance on May 31, 2022 over four years as well as adjusts for the test year to the $500,000 expected spend level.

R-21 FORFEITED DISCOUNTS

Q: Please explain adjustment R-21.

A: In R-21a, the Company normalized forfeited discounts by computing a Missouri-specific forfeited discount factor based on calendar year 2019 forfeited discounts and revenue and applying it to Missouri jurisdictional annualized and normalized revenues which then have MEEIA, FAC, and RESRAM revenues added back in as forfeited discounts can result from late payments including all retail revenue categories. In R-21b, the Company applied the forfeited discount factor to the requested revenue increase in this rate case to obtain the annualized level of forfeited discounts that are applicable to the revenues established in this rate case proceeding.

Q: Why was the period of the calendar year 2019 utilized versus the test year?

A: 2019 was the last full year before the Covid 19 pandemic. During the pandemic forfeited discounts, bad debt write-offs and many other payment areas, were drastically altered to accommodate customers whose income stream was affected by the pandemic.

<u>R-99/CS-99 NUCOR REVENUE/EXPENSE</u>

Q: Please describe the Nucor contract.

A: As per the Stipulation and Agreement in Case No. EO-2019-0244, an agreement was reached to approve the Special Incremental Load ("SIL") tariff to provide service to Nucor for a term of no greater than ten years. Evergy Missouri West agreed to monitor and report to Staff and OPC whether the revenues received under the SIL are sufficient to cover the incremental costs of providing service to Nucor. Evergy Missouri West has filed quarterly reports and to date has not received any feedback from Staff or OPC. According to the stipulation, if Nucor's revenues do not cover specified costs then revenue will be imputed in the rate case so that other Evergy Missouri West customers do not supplement Nucor's costs.

Q: Please explain this adjustment.

A: The Company analyzed the quarterly Nucor report that was completed for Q3 2021 and determined that Nucor revenues are sufficient to cover Nucor incremental costs. Thus, since there is not a revenue shortfall, no adjustment is needed at this time. Company will analyze again at true-up.

Q: Were there any cost adjustments associated with Nucor in this case filing?

A: Nucor purchased power costs were annualized and normalized as a part of the fuel, purchased power and off-system sales adjustment.

R-106 L&P REVENUE PHASE-IN AMORTIZATION

Q: Please explain adjustment R-106.

A: Based on the Non-Unanimous Stipulation and Agreement As To Certain Issues in Case No. ER-2012-0175 ("2012 S&A"), the previous agreement regarding L&P's phase-in revenues was terminated early, with an annual amount totaling $1,870,245 included in L&P's revenue requirement. The three-year inclusion of the annual amount in rates became effective January 26, 2013 and concluded at the end of January 2016. This amount continued to be collected through February 22, 2017, the effective date of new rates in Case No. ER-2016-0156 ("2016 Case"). Per the Non-Unanimous Stipulation and Agreement in the 2016 Case ("2016 S&A"), Evergy Missouri West established a regulatory liability to include the over-collected amount from February 2016 to the July 31, 2016 true-up date in that case. The amount totaling $935,123 began its amortization over four years in February 2017. The remaining over-recovery amount from August 2016 to February 22, 2017 was authorized to be amortized over four years in the Case No. ER-2018-0146. The regulatory liability will be fully amortized in January 2022. The test year amounts for credits refunded to customers are reversed and the annual amortizations are set to zero. The over-refunded amount is recorded in the prospective tracking regulatory asset account and included in adjustment CS-113.

<u>CS-11 OUT-OF-PERIOD ITEMS/MISCELLANEOUS ADJUSTMENTS</u>

Q: Please explain adjustment CS-11.

A: The Company adjusted certain expense transactions recorded during the test year from the cost of service filing in this rate case. The following is a listing of the various components:

<u>Remove charges from test year</u>- The Company has identified certain costs recorded during the test year for which it is not seeking recovery in this rate proceeding or which were adjustments to transactions recorded prior to the test period, netting to approximately $2.4 million. These costs for which the Company is not seeking recovery includes director and officer long-term incentive compensation, political questions in customer tracking survey, officer expense report items, 1KC 15th floor lease, and test year bonuses.

<u>Remove deferrals from the test year</u> – The Company has removed costs recorded during the test year for which deferral accounting has been granted or ordered by the Commission. A credit of approximately $27.8 million was removed. These deferrals are not ongoing expenses to the company and should therefore be removed from the cost of service. The deferrals include costs related to PISA accounting, COVID 19 Accounting Authority Order ("AAO") costs, deferred depreciation on Sibley generating plant, the return on Sibley rate base, and Sibley non-fuel operating and maintenance costs deferrals.

CS-4/CS-20 BAD DEBTS

Q: Please explain adjustment CS-4.

A: This adjustment is necessary to reflect in the revenue requirement model the test year provision for bad debt expense recorded on the books of Evergy Metro Receivables Company, ("EMRC").

Q: Please explain adjustment CS-20.

A: In adjustment CS-20a the Company adjusted bad debt expense applicable to the annualized and normalized revenues which then have MEEIA, FAC, and RESRAM revenues added back in as bad debts can result from write offs related to all retail revenue categories, by applying a Missouri-specific net bad debt write-off factor. In CS-20b, the Company established bad debt expense for the requested revenue adjustment in this rate case, again using the bad debt write-off factor.

Q: How was the bad debt write-off factor determined?

A: The Company examined net bad debt write-offs on a Missouri-specific basis as compared to the applicable revenues that resulted in the bad debts.

Q: Over what period was this experience analyzed?

A: Net bad debt write-offs were analyzed for the period of the full calendar year of 2019, while the related retail revenue was for the 12-month period July 2018 through June 2019.

Q: Why was the period of the calendar year 2019 utilized versus the test year?

A: 2019 was the last full year before the Covid 19 pandemic. During the pandemic bad debt write offs, and many other payment areas, were drastically altered to accommodate customers whose income stream was affected by the pandemic.

Q: Why were different periods used for the write-off percentage calculation?

A: There is a significant time lag between the date that revenue is recorded and the date that any resulting bad debt write-off is recorded due to time spent on various collection efforts. While the time expended can vary depending on circumstances, the Company assumed a six-month lag, representing the standard time span between when a customer is first billed and the time when an account is disconnected, and the receivable subsequently written off.

Q: The term "net" write-offs is used. What does it mean?

A: This term refers to accounts written off less recoveries received on accounts previously written off.

<u>CS-23 REMOVE FAC OVER/UNDER-COLLECTION</u>

Q: Please explain adjustment CS-23.

A: This adjustment reverses the amount of over and under recovery relating to the Fuel Adjustment Clause recorded during the test year. For a portion of the test year under recoveries were recorded to FERC account 557100. During the course of the year these under recoveries began to be recorded in account 501600. These accounts are used because generally accepted accounting principles ("GAAP") does not allow for the recording of a regulatory asset to be offset by revenue. Therefore, negative expenses are recorded when there is an under recovery. During the year the FAC moved from being under recovered to over recovered. The over recovered amounts were charged to FERC account 449110 offset by a regulatory liability. All of these balances are reversed in the rate case in order to remove all impacts of the FAC from revenue requirement. Doing this allows for the rebasing of the FAC according to requirements in the Code of State Regulations.

<u>CS-40/CS-41 TRANSMISSION AND DISTRIBUTION MAINTENANCE</u>

Q: Please explain adjustments CS-40 and CS-41.

A: These adjustments are for the purpose of including an appropriate level of transmission and distribution maintenance expense in this case. Since maintenance levels tend to fluctuate year over year, MMW included a 3-year average (2019, 2020, and test year) of transmission and distribution maintenance expense in its direct case as being the most representative level for ongoing expense. Evergy Missouri West will re-evaluate maintenance levels at the true-up date to determine if any different adjustment to the test year should be made at that point.

Q: Were there any other adjustments made to the test year amounts?

A: Yes, adjustments were made to test year distribution maintenance expenses related to storm costs in the test year since the Company is proposing reserve accounting for storms over $200,000 in this rate proceeding. See adjustment CS-72 in Company witness Ronald A. Klote's testimony for the explanation of that request.

<u>CS-42 GENERATION MAINTENANCE</u>

Q: Please explain adjustment CS-42.

A: This adjustment is for the purpose of including an appropriate level of generation maintenance expense in this case. Since the maintenance levels tend to fluctuate year over year, Evergy Missouri West included a 3-year average (2019, 2020, and test year) of generation maintenance expense in its direct case as being the most representative level for ongoing expense. Evergy Missouri West will re-evaluate maintenance levels at the true-up date to determine if any different adjustment to the test year should be made at that point.

CS-43 MAJOR MAINTENANCE

Q: Please explain adjustment CS-43.

A: This adjustment normalizes turbine overhaul maintenance.

Q: Please describe the turbine overhaul maintenance adjustment.

A: Scheduled steam turbine overhauls are typically on a multiple-year cycle, whereas combustion turbine overhauls typically are based on number of starts and hours run. Thus, actual expense can increase considerably in years corresponding to major maintenance service. To mitigate the large variability, major maintenance expense is spread out over the service life of the related equipment through an accrual process. This method provides a more consistent measurement of annual maintenance expense. In recent years this reserve has grown beyond the level of need for the overhauls. Therefore, I am proposing to reset the level of reserve needed for major maintenance on the power plants and to use the excess reserve to establish a storm reserve which is discussed in the Direct Testimony of Company Witness Ronald A. Klote. For all remaining excess major maintenance reserve after the establishment of a storm reserve we are proposing to amortize back to our customers over a four-year period.

Q: How was the turbine overhaul maintenance expense component computed?

A: First, an annualized accrual level was computed for each plant covered by the turbine overhaul maintenance account. Accrual amounts were analyzed using an average of spend over the past ten years in addition to input from each production plant to determine a proper level of major maintenance reserve needed moving forward. This annualized level was compared to the test year accrual to establish the annual deferral adjustment.

Q: Please describe the second part of this adjustment?

A: Secondly, the reserve balance was reset at the expense level established above times three years in order to have a reserve adequately funded to support future overhaul maintenance. After a portion was repurposed for a storm reserve, the excess reserve was amortized back to the customer over a four-year period.

CS-44 ECONOMIC RELIEF PROGRAM

Q: Please explain adjustment CS-44.

A: As part of the Report and Order in the 2016 Case, the ERP will be funded at $788,019 (50% from shareholders), with $394,009 included in the final revenue requirement. This issue was settled in the 2018 case without change to the process. Evergy Missouri West filed updated tariff language that removed the maximum number of customers language from the tariff and adds language that any excess funds will be spent until exhausted. This adjustment reflects the $394,009 customer funded annualized level compared to the actual expenses for the test year.

CS-48 IATAN 2 AND IATAN COMMON TRACKER

Q: Please explain adjustment CS-48.

A: In Case No. ER-2010-0356 ("2010 Case"), the Non-Unanimous Stipulation and Agreement As To Miscellaneous Issues ("2010 Misc. S&A") established a tracker for Iatan 2 and Iatan common O&M expenses. Since that time there have been six completed Vintages of operations and maintenance expenses that have been tracked. In the 2016 Case Evergy Missouri West requested that this tracker be discontinued since a normal level of historical operation and maintenance expenses has occurred for the Iatan 2 and common operations. The Company was authorized to amortize the deferred expenses for Vintages 2-6 over four years. Vintage 1 ended in January 2016. Its annual amortization was set to zero in the 2016 case. The remaining regulatory asset was fully amortized in February 2021. All test year expenses are removed from cost of service and the annual amortization of vintages 2-6 are set to zero. The over-collection is recorded in a prospective tracking regulatory liability account and included in adjustment CS-113.

<u>CS-70 INSURANCE</u>

Q: Please explain adjustment CS-70.

A: We annualized insurance costs based on premiums projected to be in effect on May 31, 2022. These premiums include the following types of coverage:
property, directors and officers, workers' compensation, bonds, fiduciary liability, excess liability, crime, cyber liability, auto liability, and various others.

Q: How were the premium amounts determined for each line of insurance coverage?

A: Evergy's Risk Management department provided estimated premium amounts expected to be in place at the true-up date.

Q: How are these premium amounts allocated to the appropriate business units throughout Evergy?

A: All of the insurance types are allocated using the General Allocator, except for property which will be discussed next and LaCygne lake liability which is allocated 100% to Metro.

Q: Please describe how the property insurance premium is allocated.

A: Property insurance is allocated to the various business units within Evergy based on its July 2021 replacement value provided by the Risk Management department.

Q: Does this adjustment take into consideration insurance billed to joint venture partners and affiliated companies?

A: Yes, it does. Metro's share of the replacement value was then multiplied by the percentage owned by each joint partner to determine how much is billed out from Metro for property insurance, which includes the amount billed to Evergy Missouri West.

Q: Does this same joint partner billing approach apply to insurance lines other than Property?

A: Yes, it does. However, the actual dollars billed in the test year to Evergy Missouri West was included as an addition to the premiums other than property.

Q: Please explain the adjustment amount.

A: The annualized premium amounts calculated above are increased by Evergy Missouri West's share of the joint partner billings, and then are compared to the test year amount to determine the adjustment.

CS-71 INJURIES AND DAMAGES

Q: Please explain adjustment CS-71.

A: The Company normalized Injuries and Damages ("I&D") costs based on average payout history during the 12-month periods ending December 2018, December 2019, and December 2020 as reflected by amounts relieved from FERC account 228.2. This account captures all accrued claims for general liability, workers' compensation, property damage, and auto liability costs. The expenses are included in FERC account 925 as the costs are accrued. The liability reserve is relieved when claims are paid under these four categories.

Q: Does account 925 also include costs charged directly to that account?

A: Yes, for smaller dollar claims that are recorded directly to expense, the Company averaged these expenses over the 12-month periods ending December 2018, December 2019 and December 2020.

Q: Why were multi-year averages chosen?

A: I&D claims and settlements of these claims can vary significantly from year-to-year. A period of 3 years was used to establish an appropriate on-going level of this expense by leveling out fluctuations in the payouts that can exist from one year to the next depending on claims activity and settlements.

CS-10 / CS-76 CUSTOMER DEPOSIT INTEREST

Q: Please explain adjustment CS-10.

A: This adjustment is necessary to include test year customer deposit interest from Missouri customers in cost of service. This moves customer deposit interest expense above the line on the income statement.

Q: Please explain adjustment CS-76.

A: The Company annualized customer deposit interest in accordance with the Company's tariff, which states that the interest rate established for each year for customer deposits will be based on the December 1 prime rate published in the *Wall Street Journal*, plus 100 basis points ("bps"). The rate used in this adjustment for Missouri deposits is the prime rate of 3.25% at December 1, 2020 plus 100 bps to equal 4.25%.

Q: What customer deposit balance was this interest rate applied to?

A: The interest rate was applied to the customer deposit balance determined in adjustment RB-70, discussed earlier in this testimony.

CS-77 CREDIT CARD PROGRAM

Q: Please explain adjustment CS-77.

A: Evergy Missouri West annualized credit card program expenses based on actual participation levels and costs at June 30, 2021.

Q: What is the status of the Evergy Missouri West credit card payment program?

A: Since inception, participation levels have been steadily increasing in the Evergy Missouri West territory including through the test year of this case. There have been some price efficiencies since the merger, however, to offset cost increases due to the increased levels of participation leaving a zero adjustment to the test year. This expense will be analyzed again at the true-up date for any changes that may occur.

CS-9/CS-78 ACCOUNTS RECEIVABLE SALES FEES

Q: Please explain adjustments CS-9 and CS-78.

A: The test year level of bank fees is first included in cost of service through adjustment CS-9, wherein fees recorded during the test year on EMRC's books are moved to the income statement in the revenue requirement model. The Company then annualized these fees by using a 13-month average of total fees for July 2020 through July 2021 and multiplying this by 12. The annual facility fee of $84,375 was then added to this total. This annualized amount was compared to test year amounts ending June 2021.

CS-80 RATE CASE COSTS

Q: Please explain adjustment CS-80.

A: Rate case expense is the incremental cost incurred by the utility to prepare and file a rate case. The Company annualized rate case costs by including projected costs for the current rate proceeding normalized over four years which will be trued-up as part of the true-up process in this rate case. Annualized rate case costs were then compared to rate case expense amortizations included in the test year (of which the amount was zero) to properly reflect rate case expense in cost of service in this rate case.

Q: How was rate case cost related to the current Missouri rate proceeding estimated?

A: Evergy Missouri West estimated costs based on the consultants and attorneys it anticipates will be used in this case and based on the scope of work anticipated.

Q: In making this estimate did Evergy Missouri West anticipate a full rate case, including hearings, briefs, etc., as opposed to a settled case?

A: Yes, a full rate case was assumed.

CS-85 REGULATORY ASSESSMENTS

Q: Please explain adjustment CS-85.

A: The Company annualized Missouri regulatory assessments based on quarterly assessments projected to May 31, 2022. Evergy Missouri West annualized FERC Schedule 12 fees based upon budgeted fees for 2022.

CS-86 SCHEDULE 1A FEES

Q: Please explain adjustment CS-86.

A: Evergy Missouri West annualized SPP Schedule 1-A fees based upon projected rates for May 2022 times the 12 months projected May 2022 volumes.

Secondly, the North American Electric Reliability Corporation ("NERC") fees were annualized using the most recent quarterly NERC assessment multiplied times four.

Thirdly, the Midcontinent Independent System Operator ("MISO") fees were annualized by taking the 12 months projected May 2022 MISO Schedule 10

Energy and Demand fees and adding to that the 12 months projected MISO RTO Administration Fees on Point-to-Point services.

This total as compared to the test year amount produces the adjustment.

CS-89 METER REPLACEMENT

Q: Please explain adjustment CS-89.

A: Adjustment CS-89 adjusts the test year for any change in the meter reading contract rate associated with AMI meters. This adjustment annualizes the composite meter reading cost per meter for January through June 2021 as compared to the test year per books amount.

CS-90 ADVERTISING

Q: Please explain adjustment CS-90.

A: According to past precedence, any expenses such as event sponsorships and public image advertising have been removed with this adjustment.

Q: Please describe what types of advertising costs typically are allowed for recovery in a rate proceeding.

A: As per past Commission practice, advertising costs that are allowed for recovery include items that provide customer information such as bill inserts that provide customer service contact information, billing practices, cold weather rule information, "call before you dig" advertisements, etc.

CS-91 DSM ADVERTISING COSTS

Q: Please explain this adjustment.

A: As part of the 2010 Misc. Stipulation & Agreement the Company agreed to capitalize and amortize demand-side management advertising costs over a ten-year period effective June 25, 2011. The regulatory asset was fully amortized in June 2021. The test year expense is removed from cost of service and the annual amortization amount is set to zero. The over-collection is prospectively tracked as a regulatory liability and included in CS-113.

CS-92 DUES AND DONATIONS

Q: Please explain adjustment CS-92

A: This adjustment removes certain types of dues and donations from the test year cost of service that relate to sponsorships or rotary memberships.

CS-95 AMORTIZATION OF MERGER TRANSITION COSTS

Q: Please explain this adjustment.

A: As per the Stipulation and Agreement in Case No. EM-2018-0012, merger of Great Plains Energy Incorporated. and Westar Energy, Inc., this adjustment amortizes the total allowed transition costs over a ten-year period. The adjustment amount is zero as the test year already includes a full year amortization.

CS-98 MEEIA

Q: Please explain why Evergy Missouri West is making this adjustment.

A: In Case No. EO-2015-0241, the Company was granted a Demand Side Investment Mechanism ("DSIM") rider in its MEEIA cycle 2 filing. The Company continues to collect these program costs through MEEIA cycle 3. Since these costs are collected outside of base rates, they need to be eliminated from the cost of service to be set in this case. This adjustment removes MEEIA related expenses recorded during the test year from its cost of service.

CS-105 TRANSOURCE - TRANSFERRED ASSET VALUE

Q: Please explain adjustment CS-105.

A: In the 2016 Case, Evergy Missouri West established a regulatory liability associated with the transmission assets transferred to Transource Missouri through the true-up date in that case of July 31, 2016. The total amount of $5,661,434 was being amortized and returned to ratepayers over a three-year period which became effective February 22, 2017. As a result of the 2018 Case, the remaining liability recorded from August 2016 to February 22, 2017, the effective date of rates in the 2016 case, was authorized to amortize over four years. The regulatory liability was fully amortized in February 2020. All test year expenses are removed from cost of service and the annual amortizations are set to zero. The over-refunded amount is recorded in the prospective tracking regulatory asset account and included in adjustment CS-113.

CS-107 L&P ICE STORM AAO ADJUSTMENT

Q: Please explain adjustment CS-107.

A: In December 2007, Evergy Missouri West incurred significant costs associated with an ice storm that struck its L&P service territory. The Company filed an AAO application to defer these costs and amortize them over a five-year period beginning January 2008. On March 20, 2008, the Commission approved the AAO filing in Case No. EU-2008-0233. As a result of the 2012 S&A, the L&P Ice Storm AAO was amortized through September 2013. As part of the Stipulation, the Company agreed to track the over-recovery of the ice storm beginning October 1, 2013, by recording the monthly amount collected through rates to a regulatory liability account for future refund to retail customers in a subsequent rate proceeding. In the 2016 Case, Evergy Missouri West established a regulatory liability through the true-up date for that case of July 31, 2016. A total of $4,503,403 was deferred and began amortization and a return to the ratepayers on February 22, 2017 for a four-year period. As a result of the 2018 Case, the remaining liability recorded from August 2016 to February 22, 2017, was authorized to amortize over four years. The regulatory liability was fully amortized in June 2021. All test year expenses are removed from cost of service and the annual amortizations are set to zero. The over-refunded amount is recorded in the prospective tracking regulatory asset account and included in adjustment CS-113.

CS-110 TRANSOURCE ACCOUNT REVIEW

Q: Please explain adjustment CS-110.

A: In the 2016 Case, Evergy Missouri West was required to establish a regulatory liability in the amount of $122,840 to be amortized over a three-year period which began February 22, 2017. This regulatory liability is the result of a review of all Transource related charges from project creation in August of 2010 to August of 2013. The review consisted of the following four areas:

Labor – Labor charges of all the project participants were reviewed.

Non-Labor – All invoices were reviewed for the vendors who supported the Transource project.

Expense Reports – Expense reports of the Transource project participants were reviewed.

Facilities Allocation – A portion of common facilities was allocated to the Transource project.

The regulatory liability was fully amortized in February 2020. The test year expense is removed from cost of service and the annual amortization is set to zero. The over-refunded amount is recorded in the prospective tracking regulatory asset account and included in adjustment CS-113.

CS-113 PROSPECTIVE TRACKING AMORTIZATION

Q: Please explain adjustment CS-113.

A: Adjustment CS-113 provides for prospective tracking of a regulatory asset or liability that will be amortized over an appropriate period in a future case. Pursuant to the Non-Unanimous Stipulation and Agreement in the 2016 case:

> In each future GMO general rate case, the Signatories agree that the balance of each amortization relating to regulatory assets or liabilities that remains, after full recovery by GMO (regulatory asset) or full credit to GMO customers (regulatory liability), shall be applied as offsets to other amortizations which do not expire before GMO's new rates from that rate case take effect. In the event no other amortization expires before GMO's new rates from that rate case take effect, then the remaining unamortized balance shall be a new regulatory liability or asset that is amortized over an appropriate period of time. For example, the Demand Side Management ("DSM") amortizations, once fully recovered, will be used to offset (reduce) other vintages of DSM amortizations, each reducing other vintages as those become fully recovered and, in the event no other vintages remain to be amortized, the DSM amortizations will be applied to other amortizations that do not end before new rates take effect.

This adjustment includes prospective tracking of regulatory assets and liabilities. The section of regulatory assets consists of two components. The first component addresses the regulatory assets that were prospectively tracked as of June 30, 2018 and authorized for a 4-year amortization in the 2018 Case. The second component addresses the regulatory assets that were prospectively tracked after June 30, 2018, the true-up date in the 2018 Case, through November 30, 2022, essentially the effective date of new rates in current rate case. The section of regulatory liabilities includes the amounts that were prospectively tracked after June 30, 2018, the true-up date in the 2018 Case, until November 30, 2022.

Q: Please discuss the regulatory assets of adjustment CS-113.

A: The first component addressed the prospective tracking regulatory asset associated with lease abatement for 1 KC Place. The over-refunded amount prospectively tracked from June 30, 2016 to February 22, 2017, the effective date of new rates in the 2016 Case was authorized to be amortized for 4 years in the 2018 Case. The amortization will end November 30, 2022. Therefore, the test year expense is removed from cost of service and the annual amortization amount is set to zero. The second component addresses the prospectively tracking regulatory assets associated with regulatory liabilities that have been fully amortized after June 30, 2018 or will be fully amortized by November 2022 before new rates take effect. The following is a listing of the regulatory liabilities and prospective tracking periods.

- L&P Ice Storm AAO: June 2021 - November 2022
- Transource – Transferred Asset Value: February 2020 - November 2022
- Transource Account Review: February 2020 - November 2022
- L&P Revenue Phase-In: January 2022 - November 2022

The total amount of the prospective tracking regulatory assets is $7,746,976. The Company proposes to net the prospective tracking regulatory assets with liabilities before amortization.

Q: Please discuss the regulatory liabilities of adjustment CS-113.

This section includes the prospectively tracking regulatory liabilities associated with the regulatory assets that have been fully amortized after June 30, 2018 or will be fully amortized by November 30, 2022 before new rates take effect. The following is a listing of the regulatory liabilities and prospective tracking periods.

- DSM Advertising Costs: June 2021 – November 2022
- DSM Program Costs: June 2020 – November 2022
- Iatan 2 and Common O&M Tracker: February 2021 – November 2022

The total amount of the prospective tracking regulatory liabilities is $9,446,045.

After offsetting the assets of $7,746,976, the Company proposes to amortize the net balance of $1,699,069 over four years.

Q: **Why is the Company proposing to make this change in how prospectively tracked regulatory assets and liabilities are set in rates?**

A: Netting the prospectively tracked regulatory assets and liabilities through the end of the month prior to the effective date of rates, will allow Evergy Missouri West to significantly reduce the level of difficulty associated with tracking each of the assets and liabilities individually and will allow the company to clean up its books and records as it also provides back to the customers the net impact over a four-year period. The prospective tracking approach for regulatory assets and liabilities can become administratively burdensome if not cleaned up and simplified on a periodic basis. Doing so in a general rate case ensures appropriate amounts are charged/returned to retail customers while relieving the administrative burden.

CS-116 RENEWABLE ENERGY STANDARDS COSTS

Q: Please explain adjustments CS-116.

A: Evergy Missouri West filed tariff sheets in Case No. EO-2014-0151 to establish a Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") which was approved by the Commission and became effective December 1, 2014. Since these costs are recovered through the RESRAM, they should not be included in the cost of service for the current rate case filing. Adjustment CS-116 removes the RESRAM expenses that were recorded during the test year ending June 30, 2021.

CS-131 AMORTIZATION OF ELECTRIFICATION DEFERRED ASSET

Q: Please explain adjustment CS-131.

A: On February 24, 2021, Evergy Missouri West filed an application in Docket No. ET-2021-0269 requesting the Commission authorize the Company to use a deferral accounting mechanism to track the Transportation Electrification Pilot Program costs (incentive rebates and other program costs such as customer education and program administration) to a regulatory asset for recovery of prudently incurred costs for inclusion in rates in future rate cases through expense amortization. The Company is proposing to amortize the deferral over a period of 4 years. The Company does not currently have approval to defer the costs. A decision is expected from the Commission prior to the true-up period in this case. This adjustment is a placeholder for use if needed.

CS-133 AMORTIZATION OF REGULATORY ASSET – CUSTOMER EDUCATION REGARDING RATE DESIGN

Q: Please explain adjustment CS-133.

A: In the Non-Unanimous Partial Stipulation and Agreement Regarding Class Revenue Shifts in the 2018 case, Evergy Missouri West was required to develop a customer education plan regarding the rate design decided in the case. Prudently incurred costs (including marketing, education, evaluation and administration costs) associated with this customer education plan were authorized to be deferred to a regulatory asset and recovered in the Company's next rate case.

CS-133 takes the anticipated balance at May 31, 2022 and establishes a four year amortization in the revenue requirement.

CS-134 AMORTIZATION OF REGULATORY ASSET – TOU PROGRAM COSTS

Q: Please explain adjustment CS-134.

A: The Non-Unanimous Partial Stipulation and Agreement Concerning Rate Design Issues in the 2018 Case included a number of requirements regarding the initiation and implementation of Time of Use ("TOU") rates. The stipulation provided that Evergy Missouri West is authorized to defer for recovery prudently incurred program costs (including marketing, education, evaluation and administration costs) associated with the TOU service to be offered by Evergy Missouri West. The stipulation also stated that in the next Evergy Missouri West rate case, the Company is authorized to recover prudently incurred program costs at the level represented by the percentage of customers enrolled in the TOU service at the time of filing of the rate cases compared to the target level, not to exceed 100% recovery of costs. The stipulation stated that Evergy Missouri West will need to demonstrate that such percentage is not simply a result of transferring customers to a lower rate but based on efforts directly related to changing customer behavior through marketing and education. The projected balance at May 31, 2022, for the deferred costs associated with the TOU service will be amortized over four years. An annual amortization amount was included in Adjustment CS-134.

V: <u>MONTHLY AND QUARTERLY SURVEILLANCE REPORTING</u>

Q: How often does Evergy Missouri West provide surveillance reporting to the Commission Staff?

A: Evergy Missouri West prepares and emails to one Commission Staff person its surveillance reports monthly.

Q: Does Evergy Missouri West provide surveillance reporting for any other timeframe?

A: Yes, according to the regulations associated with the FAC, MEEIA and RESRAM, Evergy Missouri West files in EFIS quarterly surveillance reports which are the exact same reports that are emailed for the quarter months. In addition, Evergy Missouri West provides a quarterly Steam Management Report with the filing of the Quarterly Cost Adjustment found in the Evergy Missouri West Steam tariffs.

Q: What is Evergy Missouri West asking the Commission to authorize?

A: Evergy Missouri West would like to eliminate as unnecessary the monthly surveillance reporting. Now that quarterly reports are required under the rider regulations, the monthly reports have become redundant.

Q: Will this change impact the quarterly Steam Management Report?

A: Yes, currently the report is provided on the 15th of the month following the end of the quarter. This timing does not allow for the report to include the quarter end month. By changing the timing to match the quarterly electric surveillance report filing the Steam customers will receive data that includes the 12-months ended information at quarter end. The Company intends to discuss this change with the five Steam customers.

Q: Will this change harm any party?

A: No. Quarterly surveillance reporting provides sufficient information for parties to analyze the financial situation of the Company.

Q: Does this conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2022-0130

AFFIDAVIT OF LINDA J. NUNN

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Linda J. Nunn, being first duly sworn on his oath, states:

1. My name is Linda J. Nunn. I work in Kansas City, Missouri, and I am employed by Evergy Metro, Inc. as Manager – Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Evergy Missouri West consisting of forty-four (44) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Linda J. Nunn
____
Linda J. Nunn

Subscribed and sworn before me this 7th day of January 2022.

____
Notary Public

My commission expires: 4/26/2025

ANTHONY R. WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2025
PLATTE COUNTY
COMMISSION #17279952

EVERGY MISSOURI WEST ELECTRIC/STEAM ALLOCATION PROCEDURES MANUAL DRAFT 2021

Contents

DRAFT

I. CAPITAL PLANT ALLOCATION – Lake Road

A. Lake Road Capital Plant Assigned 100% to Electric

The following Lake Road capital plant is to be allocated 100% to Electric, with the noted exceptions:

- Lake Road Unit 1 through 4 turbines (Account 310-316). Does not include the Boilers which are allocated or steam specific utility accounts ending in xxx09 listed in subsection B below.
- All combustion turbine generators and associated equipment (Account 342-346).
- Turbine building and other buildings and structures housing and/or associated with the 100% electric generation facilities (Account 311 & 341). Does not include steam specific utility accounts ending in xxx09 listed in subsection B below.

B. Lake Road Capital Plant 100% Assigned to Industrial Steam

The following Lake Road Capital plant is to be allocated 100% to Industrial Steam:

- All steam specific plant utility accounts ending in xxx09 such as 31009, 31109, 31209, 31509, 37509, 37609, 37909, 38009 and 38109

C. Lake Road Capital Plant Common to Electric and Industrial Steam

The following Lake Road capital plant is to be allocated between Electric and Industrial Steam, using the allocation methods specified and applied to any balance to be allocated after allocations in subsections A and B above.

1. All Boilers and Turbines in account 312, 314 and 316
   Allocation – Property remaining to be allocated for account 312, 314 and 316 will be allocated first by applying the 900lb Steam Demand Allocation Factor as described below. Then each individual plant account, 312, 314 or 316, will be allocated based on the ratio derived from the total allocated to steam or electric over the sum total plant cost of each individual plant account 312, 314 or 316.

   The 900lb Steam Demand Allocation Factor is determined by dividing the Calculated Fuel for Steam Sales Average Peak hour ($Fuel_{Steam}$) in mmBtus/hr by the Full Load Fuel Input to the Boilers.

2. Land & Land Rights, Structures, Accessory Equipment, Software and General Plant (Account 303, 310, 311, 315 and 391 through 398).

   Allocation - Allocate based on the "Electric/Steam Plant Factor" which is the ratio derived from the total plant allocated to industrial steam and electric as calculated in subsections A, B and C above for Accounts 312, 314, 316 and 341 through 346 combined.

D. Reserve for Depreciation Allocation – Lake Road

The following Lake Road reserve for depreciation will be allocated between Electric and Industrial Steam, using the allocation methods specified:

1. Structures, Accessary Equipment, Software and General Plant (Account 303, 311, 315 and 391 through 398). Does not include steam specific utility accounts ending in xxx09.

   Allocation - Allocate based on the ratio derived from the total plant cost allocated to industrial steam and electric as calculated in subsections A, B and C above for Accounts 312, 314, 316, 341 through 346 combined.

2. Boiler Plant (Account 312). Does not include steam specific utility accounts ending in xxx09.
   Allocation – Allocate based on the ratio derived from the total plant cost allocated to industrial steam and electric for 312 Accounts only. See subsection C (1) Allocation above.

3. Turbogenerator Plant (Account 314)

   Allocation – Allocate based on the ratio derived from the total plant cost allocated to industrial steam and electric for 314 Accounts only. See subsection C (1) Allocation above.

4. Miscellaneous Plant Equipment (Account 316)
   Allocation – Allocate based on the ratio derived from the total plant cost allocated to industrial steam and electric for 316 Accounts only. See subsection C (1) Allocation above.

5. Combustion turbine generators and associated structures and equipment (Accounts 341-346)
   Allocation – Allocate 100% to Electric

6. Steam specific plant utility accounts ending in xxx09 such as 31009, 31109, 31209, 31509, 37509, 37609, 37909, 38009 and 38109.

   Allocation – Allocate 100% to Industrial Steam

II. INVENTORY – Fuel - Lake Road

The fuel inventory will be allocated based on the minimum fuel inventory levels required for each operation, recognizing the fact that the LR electrical load is not predictable, and a larger fuel inventory is required to sustain system reliability during extended periods of abnormally high electrical generation at LR. The Coal fuel inventory quantities above and beyond the minimum coal inventory levels will be allocated based on a 50/50 split between electric and steam. This split is premised on the need to maintain a 60-day average burn on coal inventory, while electric load is totally unpredictable. The Oil fuel inventory will be allocated 100% to Electric due to the precedence that is given to electrical generation over steam sales when an emergency is declared by the SPP.

III. INVENTORY – Materials and Supplies - Lake Road

Materials and Supplies Inventory for Lake Road will be allocated based on the Allocated Plant Base Factor. This factor is described in Section VII below.

IV. OTHER RATE BASE ITEMS – Lake Road

A. Prepayments

Prepayments for Lake Road will be allocated based on the Allocated Plant Base Factor. This factor is described in Section VII below.

B. Regulatory Assets and Liabilities

Regulatory Assets and Liabilities will be allocated on the unique circumstance of each asset or liability.

1. Missouri DSM Programs, Iatan 1 and Common, and Iatan 2 are allocated 100% to Electric.
2. ERISA Steam Tracker is allocated 100% to Steam.
3. FAS87 Pension Tracker and OPEB Tracker are allocated based on Electric After Steam Allocation (A&G) factor. The A&G factor is based on a 50/50 weighting between the Allocated Plant Base factor and Allocated O&M factor described below in Section V11.

C. Deferred Taxes

Deferred taxes for Lake Road will be allocated based on the Allocated Plant Base Factor. This factor is described in Section VII below.

D. Customer Advances and Deposits

Customer Advances and Deposits for Lake Road will be allocated 100% to Electric.

V. EXPENSE – FUEL

A. Fuel Expense Allocation

The procedure outlined in the January 1995, paper entitled "Exergy-Based Electric and Steam Allocation Procedure for Lake Road 900# Plant Fuel" (hereinafter referred to as the "Exergy Approach") should be used for the basis of allocations. (See pages 8-10 below).

B. Auxiliary Electric Power Allocation

The method of determining the amount of auxiliary electric power to be allocated to industrial steam and to electric users will be the method identified on page 11 below. The auxiliary electric power will be priced using the average system energy cost ($/MWH) for each month, which includes all Evergy Missouri West fuel related generation costs, fuel handing expenses and net purchased power expenses. Billing considerations and accounting for the auxiliary electric power charges will be treated through "steam transfer credits" (debit to 5067XX and credit to 504XXX).

VI. EXPENSES – Non-Fuel O&M Expense Allocation

Operation and Maintenance (O&M) expenses refer to expenses associated with the production, transmission and distribution functions. O&M expenses are classified in FERC accounts 500-514 and 546-598.

Non-Fuel O&M Accounts 500-514, the allocation is primarily based on the ratio of the allocated Steam Payroll to total non-fuel production Evergy Missouri West Payroll charged to O&M for the most recent full calendar year referred to as the "Electric After Steam Allocation (O&M) factor. The allocated Steam Payroll is derived by multiplying the total non-fuel production Lake Road Payroll charged to O&M for the most recent full calendar year by the Equivalent Employment Factor.

The Equivalent Employment Factor is the fraction of time spent by a typical Lake Road Plant operating crew on the operation of the industrial steam system, based upon a breakdown of each operator's time.

VII. EXPENSES – A&G Expense Allocation

Administrative and General (A&G) expenses refer to expenses associated with administrative and general functions of the company, as contrasted with expenses directly associated with the production and transmission and distribution functions. A&G expenses include salaries and wages, outside services, injuries and damages, employee benefits, regulatory commission expenses, advertising, rents and maintenance. A&G expenses are classified in FERC accounts 901 through 935.

Not all charges to A&G FERC accounts are allocable. Costs incurred which benefit only a particular utility's operations are directly charged to that utility's operations. Also, Customer Accounts, Customer Service and Sales Expenses are allocated 100% to Electric.

However, the majority of A&G expenses accounts 920-935 are allocated between electric and industrial steam operations based on the Electric After Steam Allocation (A&G) Factor which is two allocation factors that are given 50/50 weighting described below:

1. Allocated Plant Base Factor - Ratio of Total Steam plant after allocations from Section I, subsections A, B, and C above to the Evergy Missouri West Plant per the most current Form 1 filed excluding Asset Retirement plant accounts 317, 347 and 399.
2. Allocated O&M Factor - The most current Annual Surveillance filed is updated for the "Electric After Steam Allocation (O&M) factor" described in Section V1 above.

There should be reasonable correlation between the factor(s) used and the A&G costs incurred. The two factors selected include that correlation as A&G expenses primarily represent costs incurred in managing the Company's personnel and operating and maintenance activities and controlling the Company's investment in plant.

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VIII. EXPENSES – Property Taxes

Property Tax Expense is allocated based on the Allocated Plant Base Factor as described in Section VII, subsection 1. above.

DRAFT

Exergy-Based Electric and Steam Allocation Procedure for Lake Road 900# Plant Fuel

January 1995

The Lake Road 900# Plant fuel allocation is performed between steam electric constituencies based upon the amount of fuel energy required to supply each on a daily basis. To determine this allocation, the fuel energy is tracked on an exergy[1] basis through the 900# plant. The fuel "cost" per unit of exergy of flow streams within the plant are determined by the "cost" of input streams and second law efficiencies of plant equipment. The use of this method is strongly supported in technical literature dealing with the allocation of costs in cogeneration facilities.[2]

Fuel energy is based upon the "higher heating value" of the fuels and is considered to be 100% available to the boilers. That is, the exergy content and heating value of the fuels are assumed to be equal. One mmBtu[3] of fuel is defined as one cost unit. By tracking the exergy flow and its "cost" through the plant, the quantity of fuel energy required to supply a given flow stream is simply the exergy flow of the stream multiplied by the unit cost of that stream. Exergy is measured relative to the reference state of water at 14.3 psia (corresponding to the plant evaluation of 812 feet above sea level) and the plant well water temperature, typically 60º F.

The procedure begins with the total daily fuel, steam, water, and electricity flows to, from and within the 900# plant, along with the average thermodynamic conditions. Using heat and mass balance equations, an approximate daily 900# plant heat balance is determined. The major components in the heat balance are: 900# boilers (1-5), 200# boiler 8, 900# turbines and condensers (1-3), industrial steam system (high pressure and low pressure), pressure reducing valves, attemperating equipment, flash tanks, water treatment plant, general plant (pumps, feedwater heaters, 900# auxiliary steam loads), and Unit 4/6 (auxiliary steam). The daily total mass and exergy flows in and out of the above components are determined. After these quantities are known, a set of simultaneous equations is solved to determine the cost of the various flow streams. These equations are determined by equating the total costs in and cost of the individual components. That is the following equation is solved for each component.

$$\sum(E_i c_i) = \sum(E_e c_e) \qquad (1)$$

The above equation states that the sum of the products of incoming exergy flows (E_i) and their respective unit costs (c_i) is equal to the sum of the products of the exiting exergy flows (E_e) and their respective unit costs (c_e). Generally, the equation (1) has the following form.

$$\sum (M_i E_i c_i) = \sum (M_e E_e c_e) + W_e c_e$$

In equation (2), the M's represents flow in pounds per day, *E*'s represent exergy content of the fluid in Btu per pound, the W represents work generated by the device in Btu/day (i.e. turbine shaft work to a generator) and the c's represent the unit cost in Btu's of fuel per Btu of exergy.

As an example, consider a boiler consuming 100 mmBtu of fuel per hour at a cost of 1 (fuel Btu per exergy Btu), with a feedwater flow and exergy content of 100,000 lb/hr and 75 Btu/lb at a cost of 5, and delivering 100,000 lb/hr of steam with an exergy content of 600 Btu/lb. The cost of the steam would be determined from the following equation.

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[1] See "Definition of Exergy" on page 10.
[2] See Reference List on page 10.
[3] mmBtu = one million British thermal units = 10^6 Btu.

$$\left[100(10^6)\frac{\text{Btu}}{\text{hr}} \text{ x } 1 \ \frac{\text{fuel Btu}}{\text{exergy Btu}}\right] \text{fuel} +$$

$$\left[100(10^3)\ \frac{\text{lb}}{\text{hr}} \text{ x } 75\ \frac{\text{Btu}}{\text{lb}} \text{ x } 5\ \frac{\text{fuel Btu}}{\text{exergy Btu}}\right]\text{feedwater} \qquad (3)$$

$$= 100\ (10^3)\frac{\text{lb}}{\text{hr}} \text{ x } 600\ \frac{\text{Btu}}{\text{lb}} \text{ x } c_{\text{stm}}$$

Solving for c_{stm}, the steam cost is 2.29 fuel Btu per exergy Btu. The total cost of the steam is 137 mmBtu of fuel per hour (100,000 lb/hr x 600 Btu/lb x 2.29 Btu fuel/Btu exergy).

In the case of multiple outputs from a plant component, it is necessary to establish one or more auxiliary equations which relate to the costs of the exergy flows. Usually, this consists of simply equating the exiting costs ($c_{e1} = c_{e2} = c_{e3}$ …). That is, the output streams all share the incoming costs in proportion to their exergy contents. This approach is used for Lake Road Turbine 1: the cost per unit of exergy of the extraction steam is set equal to the cost of the shaft work developed in the high-pressure turbine section (shaft work is considered 100% available to the generator).

In some cases, it is necessary to apply different costs to the output flows. This is true with a low-pressure turbine and condenser combination. The two outputs are the shaft work to the generator and the condensate returning to the plant. If these two outputs were assigned the same cost, the condensate would become quite expensive as it would be charged with much of the exergy destruction and rejection in the condenser and cooling tower. However, these losses were incurred so that electric generation could take place, not for production of condensate. Therefore, the cost of the condensate should not reflect these losses. Generally, in this situation the condensate "by-product" is priced at zero or is assigned a cost per unit of exergy equal to that of the steam to the turbine. This shifts the cost of losses to the electric generation function, where it belongs. In the Lake Road Plant, fuel allocation calculations, condensate is priced at the same cost per unit of exergy as the incoming steam.

Exergy flows which are consumed in the general plant for the benefit of both steam and electric (e.g. 900# auxiliary steam) are assigned a cost of zero. This effectively "raises the price" of those exergy flows which are ultimately delivered to the steam or electric consumers and forces all fuel costs to be charged to these consumers in proportion to the exergy used by them.

<u>Fuel Energy Charged to Electric</u>

The daily fuel energy charged to electric is the total cost (mmBtu of fuel) or the turbine shaft work which drives the 900# plant generators plus the total cost of steam and condensates transferred to Unit 4/6.

<u>Fuel Energy Charged to Industrial Steam</u>

The daily fuel energy charged to industrial steam is the total cost (mmBtu of fuel) delivered to the industrial steam system. This includes the steam supplied through the 12", 14" and 16" header meters, the attemperating water supplied to the customer steam lines, and the steam delivered to the high-pressure steam customer plus the cost of exergy losses between plant and the high-pressure customer meter.

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The daily steam fuel allocation factor, X_s, is determined by dividing the mmBtu's of fuel charged to industrial steam from the above procedure by the total 900# and 200# boiler fuel mmBtu's consumed. This factor is used in the allocation of auxiliary power, described later.

FUEL ALLOCATION PROCEDURE REFERENCE LIST

Gaggioli, R. A., and El-Sayed, Y. M., "A Critial Review of Second Law Costing Methods" present at the Forth International Symposium of on Second Law Analysis of Thermal Systems; Rome, Italy; May 25 – 29, 1987

Gaggioli, R. A., "Proper Evaluation and Pricing of 'Energy'"

Gaggioli, R. A., El-Sayed, Y. M., El-Nahsar, A.M., Kamaluddin, B., "Second Law Efficiency and Costing Analysis of a Combined Power and Desalination Plant"; Journal of Energy Resources Technology, Vol. 110, pp 114-118, June 1988.

Lang, Fred D., Horn, Ken F., "Make Fuel-Consumption Index Basis of Performance Monitoring"' Power, Vol. 134, No.10, pp 19-22, October 1990.

Moran, M. J., Availability Analysis, pp 206-210, ASME Press, 1989

Reistad, G. M., and Gangglioli, R. A., "Available-Energy Costing", October 30, 1979.

Sandage, P. E., "Turbine By-pass System Evaluation & Costing", Sega, Inc., October 18, 1990.

"Exergy Costing in Multi-Product Plants"

DEFINITION OF EXERGY

Exergy is the thermodynamic quantity representing the maximum work than can be extracted from a given system or flow in an ideal, reversible process. It is calculated as $\mathbf{E = H - H_0 - T_0(S\text{-}S_0)}$ (neglecting kinetic and potential energy terms), in which H represents total enthalpy, S represents total entropy, and T represents absolute temperature. The subscript "0" indicates the property is at a reference states representative of ambient conditions or a "zero-energy level". Total exergy is measured in Btu and is often called "availability" or "available energy." (note that these terms are easily confused with other plant performance and thermodynamic quantities; "exergy" is more specific.) The term "exergy" often refers to specific exergy, which is the amount of exergy per unit of mass in a system or flow. Specific Exergy has units of Btu/lb and is calculated as $\mathbf{E = h - h_0 - T_0(s - s_0)}$ in which total enthalpy and entropy values are replaced with the corresponding specific enthalpy (h) and entropy (s). In practice, total exergy, E, of a fluid stream is usually calculated as the total mass flow, M, times specific exergy, or $\mathbf{E = Me}$.

DRAFT

AUXILIARY POWER ALLOCATION

The allocation of auxiliary power is performed in the following manner. First, the auxiliary power that can be attributed directly to electric or steam will be directly read. Auxiliary power, which is metered elsewhere in the plant, but benefits both electric and steam will be allocated based on the fuel allocation factor and applied to electric and steam.

The process is summarized in the following steps.

1. Meter the daily auxiliary power (kwhr) used to support electric generation utilizing automated meters and apply to Electric.
2. Meter the daily auxiliary power (kwhr) used to support the steam system utilizing automated meters and apply to Steam.
3. Auxiliary power on common steam and electric equipment will be collected daily by automated meters and will be allocated by the fuel allocation factor and applied to Electric and Steam.

DRAFT

Requirements to Establish, Continue or Modify the Rate Adjustment Mechanism ("RAM")
Evergy Missouri West ("EMW")

20 CSR 4240-20.090

(2) Establishment, Continuance, or Modification of a RAM. An electric utility may only file a request with the commission to establish, continue, or modify a RAM in a general rate proceeding and must rebase base energy costs in each general rate proceeding in which the Fuel Adjustment Clause ("FAC") is continued or modified. Any party in a general rate proceeding may seek to continue, modify, or oppose the RAM. The commission shall approve, modify, or reject such request only after providing the opportunity for a full hearing in a general rate proceeding. The commission shall consider all relevant factors that may affect the costs or overall rates and charges of the petitioning electric utility.

(A) The electric utility shall file the following supporting information, in electronic format, where available, with all links and formulas intact, as part of, or in addition to, its direct testimony:

1. An example of the notice to be provided to customers during the pendency of the general rate proceeding where the RAM is under consideration, which shall be approved by the commission. The notice shall include a description of how its proposed RAM shall be applied to monthly bills, the amount of the proposed change in base rates caused by the rebase of energy costs, and the estimated impact on a typical residential customer's bill resulting from the rebase of energy costs;

See Schedule LJN – 3.

2. An example customer bill(s) covering all of the electric utility's rate classes showing how the proposed RAM shall be separately identified on affected customers' bills in accordance with section (12);

See Schedule LJN - 4

3. Proposed RAM tariff sheets;

See Schedule LJN - 6

4. A detailed description of the design and intended operation of the proposed RAM;

The design and intended operation of the FAC is the same as approved in Case No. ER-2018-0146. The changes proposed in this filing are for the amounts contained in base rates as well as the changes listed in the body of my Direct Testimony.

Some key features of the FAC include:

- The FAC factor is based upon historical differences between the cost of fuel, energy and certain transmission costs net of off-system sales revenue built into base rates and the actual net costs of these items as incurred during the two six-month accumulation periods.
- There is 95% recovery of the difference between these actual net costs and the amounts built into base rates.

- Items considered in the FAC are non-labor generating plant fuel costs, purchased power energy and short-term capacity charges, emission allowance costs and revenue amortizations, transportation costs, and certain transmission costs. These costs are offset by off system sales revenues, and the net revenues from the sale of renewable energy credits. Carrying costs are calculated monthly at the Company's short term debt rate.
- The under or over recovery will be accumulated for 6 months. The collection period for the accumulation is 12 months.
- The base amount in the current tariff is $0.02240 per kWh.
- The proposed base amount for EMW FAC base rate is $0.02569 per kWh.
- The accumulation of actual net energy costs (ANEC) is compared to the base factor. The difference is the Fuel Adjustment Rate ("FAR").
- The FAR as designed in the rate schedule will be applied to customer bills on a per kilowatt-hour ("kWh") basis, as adjusted for voltage level (to take into account varying line losses at different service voltage levels).
- There are four voltage levels identified in the FAC tariff, primary, secondary, substation and transmission.
- The FAR formula includes the ability to accommodate adjustments made as a result of the true-up process or any prudence disallowances occurring as a result of prudence reviews.

5. A detailed explanation of how the proposed RAM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity;

See the body of my Direct Testimony.

6. A detailed explanation of how the proposed FAC shall be trued-up for over- and under-billing, or how and when the refundable portion of the proposed IEC shall be trued-up;

Each month there is an accrual to reflect the over/under recovered current month FAC fuel costs in General Ledger Account 182700 or 254651. The accrual calculation is Total FAC Actual Energy Costs less Base Energy Costs times the jurisdictional factor, times 95%.

After the defined 6-month accumulation periods (June-November and December-May) a filing in accordance with 20 CSR 4240-20.090(8)(A) is made with the Missouri Public Service Commission requesting a new cost adjustment factor. The collection/return periods for these FAC factors are 12-month periods (March-February and September-August).

Activity in account 182700 or 254651 is manually tracked by accumulation period and separately identifies the accrual recovery, interest and over/under recovery balance for each open accumulation period.

After the 12-month recovery period is complete, a true-up filing is made, and any remaining over/under recovery identified is included as part of the next FAC filing.

7. A detailed description of how the electric utility's monthly short-term borrowing rate will be defined and how it will be applied, during the accumulation period and the recovery period, to over- and under-billed amounts and prudence disallowances;

The short-term borrowing rate is defined as daily LIBOR plus the applicable Margin. The daily amounts are averaged to get an annual rate for that month. This rate divided by 12 is applied monthly to the outstanding FAC balances one month in arrears. The applicable margin is for Eurodollar Advances as defined in the Pricing Schedule of the current EMW Revolving Credit Agreement.

8. A detailed description of how the proposed RAM is compatible with the requirement for prudence reviews in section (11);

EMW's FAC is compatible with the requirement for prudence reviews for several reasons. EMW's FAC is based on actual fuel and purchased power costs, including transportation and emissions costs and revenues, net of actual off-system sales revenues and the net revenues associated with the sale of RECs, which simplifies the prudence review. The fuel and purchased power costs included in the FAC are well defined in the FAC tariff, including specific references to the Federal Energy Regulatory Commission ("FERC") accounts in which the costs are recorded. Moreover, 20 CSR 4240-20.090(5), requires the filing monthly of all the supporting data for the fuel and purchased power costs, revenues, plant generation, and related information, all of which can be used as part of the prudence review process. These reports are currently being submitted by EMW on a monthly basis. This includes providing monthly fuel burn and generating statistics for each of the generating plants. All contracts for fuel, transportation, and purchased power will also be available for review in connection with the prudence review process. 20 CSR 4240-20.090 sets forth the definitions, structure, operation, and procedures relevant to a Fuel Adjustment Clause. Section (11) is specific to prudence reviews, requiring a review no less frequently than at eighteen (18)-month intervals.

The Company agrees that prudence reviews should occur no less frequently than at 18-month intervals. This requirement is also in the FAC tariff.

The Company anticipates that parties to any prudence review proceeding would apply the standard of determining whether decisions were prudent given the facts known at the time those decisions were made, as opposed to a "hindsight" review. If Staff or other parties believe that the evidence supports a prudence adjustment, they have the opportunity to bring that proposal to the Commission for an evidentiary hearing and decision.

9. A detailed explanation of the fuel and purchased power costs, including transportation, that are to be considered in determining the amount to be recovered under the proposed RAM with identification of the specific account and any other designation ordered by the commission where that cost will be recorded on the electric utility's book and records.

The FERC Code of Federal Regulations is the basis for the Company's accounting codes. Fuel used in the production of steam for the generation of electricity is included in FERC account 501. Fuel used in other power generation (Combustion Turbines) is included in FERC account 547. Purchased Power is in FERC account 555. Transmission of electricity by others is included in FERC account 565. Emission Allowance costs and amortizations are in FERC account 509.

Please see the proposed tariff sheets included in Schedule LJN - 6 for the complete listing of all costs that need to be considered for recovery under the proposed continuation of the RAM along with the specific accounts that will be used for each cost item on the Company's utility books and records.

Accounts provided were known as of the time of this filing; however, they may be revised in the future as business needs arise.

10. A detailed explanation of the fuel related revenues that are to be considered in determining the amount to be recovered under the proposed RAM with identification of the specific account and any other designation ordered by the commission where that revenue will be recorded on the electric utility's books and records;

The FERC Code of Federal Regulations is the basis for the Company's accounting codes. Sales for resale are recorded in FERC account 447. Net revenues from the sale of emission allowances and renewable energy credits are recorded in FERC account 509 as an offset to expense. Once the Company is authorized to implement the Green Pricing REC program, retail revenues associated with the program will be included in the R factor and flowed back to our customers at 95%.

Please see the proposed tariff sheets included in Schedule LJN - 6 for the complete listing of all revenue accounts that need to be considered in the determination of the amount eligible for recovery under the proposed continuation of the RAM along with the specific accounts that will be used for each revenue item on the Company's utility books and records.

This accounting process, and the information used to support the recording of these entries, creates a paper audit trail to enable the audit of the accounts.

11. A detailed explanation of any incentive feature in the proposed RAM with the expected benefit and cost each feature is intended to produce for both the electric utility and its Missouri retail customers;

In the Report and Order for Case No. ER-2007-0004 issued May 17, 2007, the Commission explains the reasoning for allowing only 95% of FAC eligible costs to be collected from customers,

> "The Commission also finds after-the-fact prudence reviews alone are insufficient to assure Aquila will continue to take reasonable steps to keep its fuel and purchased power costs down, and the easiest way to ensure a utility retains the incentive to keep fuel and purchased power costs down is to not allow a 100% pass through of those costs.
> The Commission finds allowing Aquila to pass 95% of its prudently incurred fuel and purchased power costs, above those included in its base rates, through its fuel adjustment clause is appropriate. With a 95% pass-through, the Commission finds Aquila will be protected from extreme fluctuations in fuel and purchased power cost yet retain a significant incentive to take all reasonable actions to keep its fuel and purchased power costs as low as possible, and still have an opportunity to earn a fair return on its investment." (page 54)

> "The Commission concludes that a 95% pass-through would not violate Section 386.266.4(1), in that it would still afford Aquila a sufficient opportunity to earn a fair return on equity." (page 55)

The 95% pass-through feature remained unchanged in the settlement of Rate Case. Nos. ER-2009-0090, ER-2010-0356, ER-2012-0175, ER-2016-0156 and ER-2018-0146.

12. A detailed explanation of any rate volatility mitigation feature in the proposed RAM;

See the Direct Testimony of Jessica L. Tucker in this case for a discussion of the FAC and mitigation of market risk/price volatility. In addition, accumulating the FAC adjustment for a 6-month period with a corresponding 12-month revenue recovery period lessens rate volatility

13. A detailed explanation of any feature of the proposed RAM and any existing electric utility policy, procedure, or practice that ensures only prudent fuel and purchased power costs and fuel-related revenues are recovered through the proposed RAM, including, but not limited to, utilization of competitive bidding or other sourcing or sales practices;

The Company's FAC expenses are subject to periodic Prudence Reviews to ensure that only prudently incurred fuel and purchased power costs are collected from customers through the FAC.
Rules and procedures for contracts are outlined in the Sarbanes Oxley documentation.
The Company's books and records are audited annually by an independent public accounting firm.
The Company's internal audit staff performs periodic audits on the controls in place associated with the FAC.

14. A detailed explanation of any change to the electric utility's business risk resulting from implementation of the proposed RAM, in addition to any other changes in business risk the electric utility may experience;

See the Direct Testimony of Ann E. Bulkley.

15. A level of efficiency for each of the electric utility's generating units determined by the results of heat rate/efficiency tests or monitoring that were conducted or obtained on each of the electric utility's steam generators, including nuclear steam generators, heat recovery steam generators, steam turbines and combustion turbines within twenty-four (24) months preceding the filing of the general rate increase case.

> **A. The results should be filed in a table format by generating unit type, rated megawatt (MW) output rating, the numerical value of the latest result and the date of the latest result;**
>
> **B. The electric utility shall provide documentation of the actual test/monitoring procedures. The electric utility may, in lieu of filing the documentation of these procedures with the commission, provide them to the staff, OPC, and to other parties as part of the workpapers it provides in connection with its direct case filing. If the**

electric utility submits the results in workpapers, it will provide a statement in its testimony as to where the results can be found in workpapers;

See the Direct Testimony of Eric Peterson.

16. Information that shows that the electric utility has in place a long-term resource planning process;

See the Direct Testimony of Eric Perterson.

17. If the electric utility proposes to include emissions allowances costs or sales revenue in the proposed FAC and not in an environmental cost recovery mechanism, a detailed explanation of its emissions management policy, and its forecasted environmental investments, emissions allowances purchases, and emissions allowances sales;

See Direct Testimony of Jessica L. Tucker for the discussion of the allowance purchases and sales and the direct testimony of Eric Peterson for the explanation of forecasted environmental investments.

18. For each power generating unit the electric utility owns or controls, in whole or in part, the electric utility shall file graphs, accompanied by the data supporting the graphs, for each month over the immediately preceding five (5) years, showing the monthly equivalent availability factor, the monthly equivalent forced outage rate, and the length and timing of each planned outage of that unit; and

Please see Schedules LJN – 7 and LJN – 8 for the required information.

19. Authorization for the staff to release to all parties to the general rate proceeding in which the establishment, continuation, or modification of a RAM is requested, the previous five (5) years of historical surveillance monitoring reports the electric utility submitted in EFIS.

EMW authorizes the Staff to release to all parties to this case its previous five years of historical surveillance monitoring reports in accordance with 20 CSR 4240-20.090(2)(A)19.

IMPORTANT NOTICE

evergy

Evergy has filed a rate increase request with the Missouri Public Service Commission (“PSC”). The increase would total approximately ____ percent in the territory served as Evergy Missouri.

For the average residential customer the proposed increase would be approximately $____ per month.

Evergy has also asked the PSC to continue the Fuel Adjustment Clause (“FAC”). The FAC allows Evergy to adjust customers’ bills two times per year based on the varying cost of fuel and power purchased in the current volatile market. Any increase or decrease in fuel costs is reflected in the FAC. This means the customer bill is based on more current fuel costs.

A local public hearing (or evidentiary hearing) has been set before the PSC at ____o'clock, on (date) at ________, (address), City, Missouri. The hearing will be held in a facility that meets the accessibility requirements of the Americans with Disabilities Act. Any person who needs additional accommodations to participate in this hearing should call the Public Service Commission's hotline at **1-800-392-4211** (voice) or Relay Missouri at **711** before the hearing.

Consumers wishing to comment of the rate proposal may also: Mail a written comment to the Public Service Commission, P.O. Box 360, Jefferson City, Missouri 65102; Electronically submit a comment to the PSC by accessing the PSC's Electronic Filing and Information System at ***efis.psc.mo.gov/mpsc*** (please reference case number ________); or Contact the Office of the Public Counsel, P.O. Box 2230, Jefferson City, Missouri 65102, telephone **573-751-4857** or toll-free **866-922-2959**, ***opcservice@ded.mo.gov***. Comments are viewable by the public. Do not include any information in a public comment that you do not wish to be made public.

evergy

SCHEDULE LJN-4
CONTAINS CONFIDENTIAL INFORMATION
NOT AVAILABLE TO THE PUBLIC.

ORIGINAL FILED UNDER SEAL.

EVERGY

2020 Analysis of System Losses

December 2021

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December 20, 2021

Ms. Linda Nunn
Manager, Regulatory Affairs
Evergy
818 South Kansas Avenue
Topeka, KS 66612

RE: 2020 LOSS ANALYSIS – EVERGY

Dear Ms. Nunn:

Transmitted herewith are the results of the 2020 Analysis of System Losses for the Evergy power system consisting of Evergy Metro (MO and KS) and Missouri West. Our analysis develops cumulative expansion factors (loss factors) for both demand (peak/kW) and energy (average/kWh) losses by discrete voltage levels applicable to metered sales data. Our analysis considers only technical losses in arriving at our final recommendations.

On behalf of MAC, we appreciate the opportunity to assist you in performing the loss analysis contained herein. The level of detailed load and sales data by voltage level, coupled with the FERC-approved transmission loss factors, forms the foundation for determining reasonable and representative power losses on the Evergy system. Our review of these data and calculated loss results support the proposed loss factors as presented herein for your use in various cost of service, rate studies, and demand analyses.

Should you require any additional information, please let us know at your earliest convenience.

Sincerely,

Paul M. Normand
Principal

Enclosure
PMN/rjp

TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY

This report presents Evergy's 2020 Analysis of System Losses for the power systems as performed by Management Applications Consulting, Inc. (MAC). The study developed separate demand (kW) and energy (kWh) loss factors for each voltage level of service in the power system for Evergy consisting of Metro MO, Metro KS, Metro combined, and MO West. The cumulative loss factor results by voltage level, as presented herein, can be used to adjust metered kW and kWh sales data for losses in performing cost of service studies, determining voltage discounts, and other analyses which may require a loss adjustment.

The procedures used in the overall loss study emphasized the use of "in house" resources where possible. Extensive use was made of the Company's transformer plant investments in the model. In addition, measured and estimated load data provided a means of calculating reasonable estimates of losses by using a "top-down" and "bottom-up" procedure. In the "top-down" approach, losses from the high voltage system, through and including distribution substations, were estimated along with transformer loss estimates and metered data.

At this point in the analysis, system loads and losses at the input into the distribution substation system are known with reasonable accuracy. However, it is the remaining loads and losses on the distribution substations, primary system, secondary circuits, and services which are generally difficult to estimate. Estimated Company load data provided the starting point for performing a "bottom-up" approach for calculating the remaining distribution losses. Basically, this "bottom-up" approach develops loadings by first determining loads and losses at each level beginning at a customer's meter service entrance and then going through secondary lines, line transformers, primary lines, and finally distribution substation. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness prior to finalizing the loss factors. An overview of the loss study is shown on Figure 1.

Table 1, below, provides the final results from Appendix A for the 2020 calendar year. Exhibits 8 and 9 of Appendix A present a more detailed analysis of the final calculated summary results of losses by voltage segments and delivery service level in the Company's power system. These Table 1 cumulative loss expansion factors are applicable only to metered sales at the point of receipt for adjustment to the power system's input level. A separate Metro combined loss factor was also calculated on Exhibit 10 (Appendices A and B) which combines the separate loss factors from the Evergy Metro MO and Metro KS loss results on a load weighted basis.

TABLE 1
Loss Factors at Sales Level, Calendar Year 2020

Voltage Level of Service	Metro-MO Total (Appendix A)	Metro-KS Total (Appendix B)	Metro Composite	MO West Total (Appendix C)
Demand (kW)				
Transmission[1]	1.03000	1.03000	1.03000	1.03000
Substation	1.03709	1.03587	1.03694	1.03724
Primary Lines	1.05865	1.05695	1.05786	1.05618
Secondary	1.07994	1.07642	1.07822	1.08050
Energy (kWh)				
Transmission[1]	1.03000	1.03000	1.03000	1.03000
Substation	1.03776	1.03762	1.03775	1.03880
Primary Lines	1.04965	1.05008	1.04982	1.05026
Secondary	1.06899	1.07116	1.06997	1.07664
Losses – Net System Input[2]	6.09% MWh 7.14% MW	6.51% MWh 7.01% MW		6.69% MWh 7.16% MW
Losses – Net System Output[3]	6.49% MWh 7.69% MW	6.97% MWh 7.54% MW		7.17% MWh 7.71% MW

The net system input shown in Table 1 is the MWh losses of 6.09% for the total Evergy MO load using calculated losses divided by the total input energy to the system. The 6.49% represents the same MWh losses using system output instead of input as a reference. The net system input reference shown in Table 1 represents MW losses of 7.14% and 7.69% represents these MW losses at output. These results use the appropriate total losses for each but are divided by system output or sales. These calculations are all based on the data and results shown on Exhibits 1, 7 and 9 of each study.

Variable losses are primarily a function of equipment loading levels for a peak load hour, the loss factor derivations for any voltage level must consider both the load at that level plus the loads from lower voltages and their associated losses. As a result, cumulative losses on losses equates to additional load at higher levels along with future changes (+ or –) in loads throughout the power system. It is important to recognize that losses are multiplicative in nature (future) and not additive (test year only) for all future years to ensure total recovery.

[1] Reflects results for 345 kV, 138 kV, and 69 kV.
[2] Net system input equals firm sales plus losses, Company use less non-requirement sales and related losses. See Appendix A, Exhibit 1, for their calculations.
[3] Net system output uses losses divided by output or sales data as a reference.

The derivation of the cumulative loss factors shown in Table 1 have been detailed for all electrical facilities in Exhibit 9, page 1 for demand and page 2 for energy for all Appendices. Beginning on line 1 of page 1 (demand) under the secondary column, metered sales are adjusted for service losses on lines 3 and 4. This new total load (with losses) becomes the load amount for the next higher facilities of secondary conductors and their loss calculations. This process is repeated for all the installed facilities until the secondary sales are at the input level (line 45). The final loss factor for all delivery voltages using this same process is shown on line 46 and Table 1 for demand. This procedure is repeated in Exhibit 9, page 2, for the energy loss factors.

The loss factor calculation is simply the input required (line 45) divided by the metered sales (line 43).

An overview of the loss study is shown on Figure 1 on the next page. Figure 2 simply illustrates the major components that must be considered in a loss analysis.

Figure 1

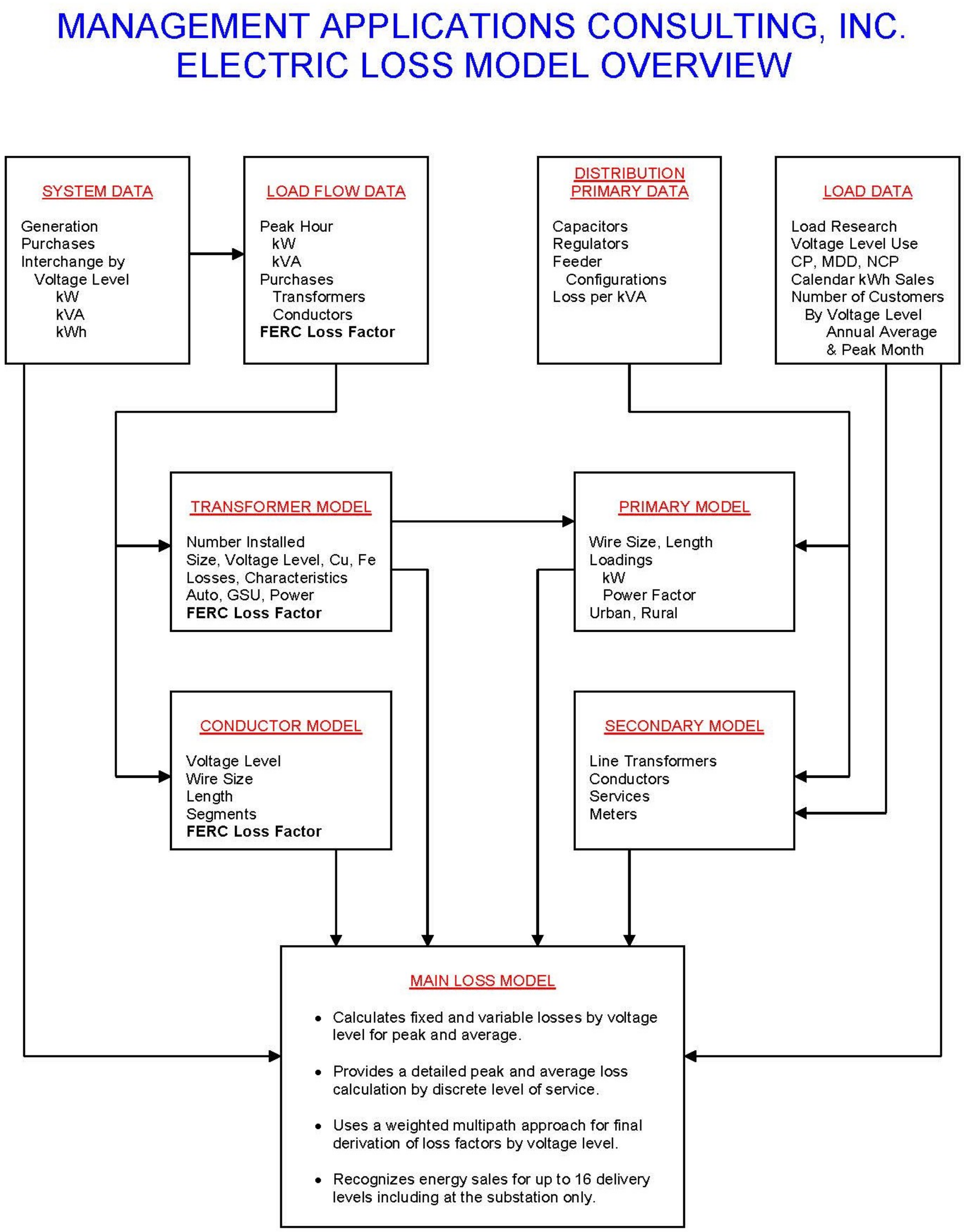

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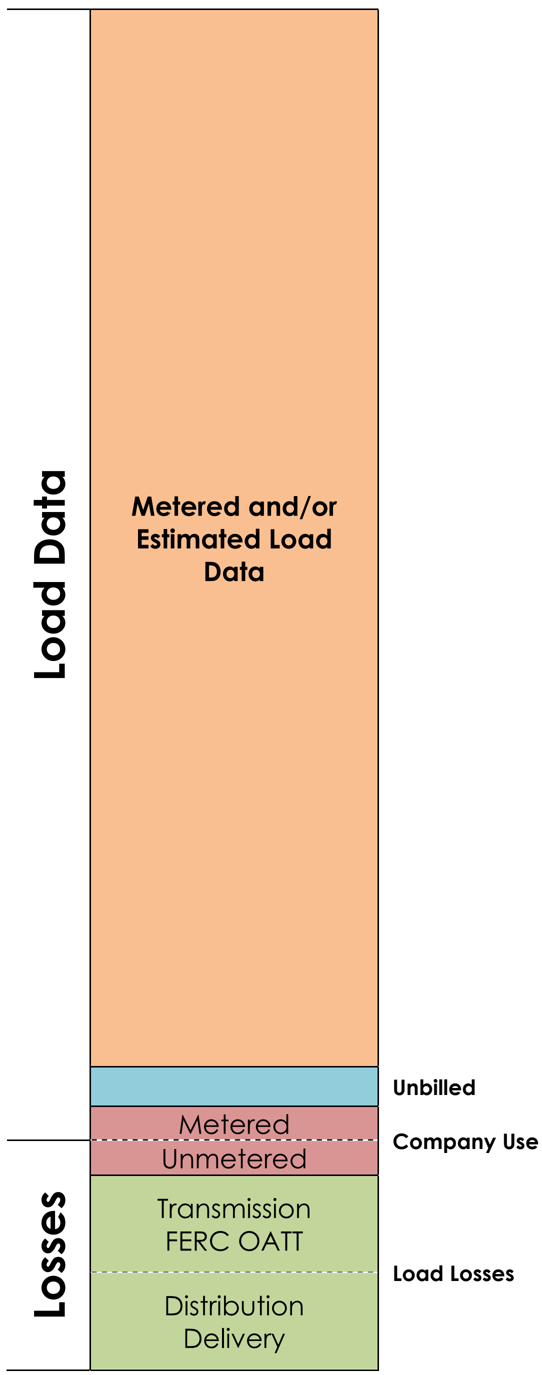
Figure 2
Major Energy and Loss Components



2.0 INTRODUCTION

This report of the 2020 Analysis of System Losses for the Evergy power system provides a summary of results, conceptual background or methodology, description of the analyses, and input information related to the study.

2.1 Conduct of Study

Typically, between five to ten percent of the total peak hour MW and annual MWH requirements of an electric utility is lost or unaccounted for in the delivery of power to customers. Investments must be made in facilities which support the total load which includes losses or unaccounted for load. Revenue requirements associated with load losses are an important concern to utilities and regulators in that customers must equitably share in all of these cost responsibilities. Loss expansion factors by voltage level are the mechanism by which customers' metered demand and energy data are mathematically adjusted to the generation or input level (point of reference) when performing cost and revenue calculations.

An acceptable accounting of losses can be determined for any given time period using available engineering, system, and customer data along with empirical relationships. This loss analysis for the delivery of demand and energy utilizes such an approach. A microcomputer loss model[4] is utilized as the vehicle to organize the available data, develop the relationships, calculate the losses, and provide an efficient and timely avenue for future updates and sensitivity analyses. Our procedures and calculations are similar with prior loss studies, and they rely on numerous databases that include customer statistics and power system investments at various voltage levels of service.

Company personnel performed most of the data gathering and data processing efforts and checked for reasonableness. MAC provided assistance as necessary to construct databases, transfer files, perform calculations, and check the reasonableness of results. Efforts in determining the data required to perform the loss analysis centered on information which was available from existing studies or reports within the Company. From an overall perspective, our efforts concentrated on five major areas:

1. System information concerning peak demand and annual energy requirements by voltage level,
2. High voltage power system analysis not required as using FERC-approved loss factors,
3. Distribution system primary and secondary loss calculations,
4. Derivation of fixed and variable losses by voltage level, and
5. Development of final cumulative expansion factors at each voltage for peak demand (kW) and annual energy (kWh) requirements at the point of delivery (meter).

[4]Copyright by Management Applications Consulting, Inc.

2.2 Electric Power Losses

Losses in power systems consist of primarily technical losses with a much smaller level of non-technical losses.

Technical Losses

Electrical losses result from the transmission of energy over various electrical equipment. The largest component of total losses during peaking conditions is power dissipation as a result of varying loading conditions and are oftentimes called load losses which are mostly related to the square of the current (I^2R). These peak hour losses can be very high percent of all technical losses during peak loading conditions. The remaining losses are called no-load and represent essentially fixed (constant) energy losses throughout the year. These no-load losses represent energy required to energize various electrical equipment regardless of their loading levels over the entire year. The major portion of these no-load losses consist of core or magnetizing energy related to installed transformers throughout the power system and generates the major component of annual losses on any distribution system.

The following Tables 2, 3, and 4 summarize the unadjusted fixed and variable losses by major functional categories from Exhibit 5 of Appendices A, B, and C:

TABLE 2 – METRO MO

	DEMAND (PEAK HOUR – MW)			ENERGY (ANNUAL AVERAGE – MWH)		
	FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
TRANS	6.05	44.35	50.40	53,121	197,364	250,485
(%)	12.00%	88.00%	100.00%	21.21%	78.79%	100.00%
SUBTRANS	0.00	0.00	0.00	0.00	0.00	0.00
(%)	N/A	N/A	N/A	N/A	N/A	N/A
DIST SUBS	5.13	3.60	8.73	45,080	12,373	57,453
(%)	58.76%	41.24%	100.00%	78.46%	21.54%	100.00%
PRIMARY	2.54	22.84	25.38	22,290	61,348	83,638
(%)	10.00%	90.00%	100.00%	26.65%	73.35%	100.00%
SECONDARY	10.62	12.24	22.86	93,328	28,028	121,357
(%)	46.48%	53.52%	100.00%	76.90%	23.10%	100.00%
TOTAL SYS	24.34	83.02	107.37	213,819	299,114	512,933
(%)	22.67%	77.33%	100.00%	41.69%	58.31%	100.00%
TOTAL DIST	18.29	38.68	56.97	160,698	101,749	262,447
(%)	32.11%	67.89%	100.00%	61.23%	38.77%	100.00%

TABLE 3 – METRO KS

	DEMAND (PEAK HOUR – MW)			ENERGY (ANNUAL AVERAGE – MWH)		
	FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
TRANS	5.50	40.37	45.87	48,355	143,878	192,233
(%)	12.00%	88.00%	100.00%	25.15%	74.85%	100.00%
SUBTRANS	0.00	0.00	0.00	0.00	0.00	0.00
(%)	N/A	N/A	N/A	N/A	N/A	N/A
DIST SUBS	4.25	3.55	7.80	37,362	9,442	46,804
(%)	54.54%	45.46%	100.00%	79.83%	20.17%	100.00%
PRIMARY	2.72	24.48	27.20	23,888	50,833	74,721
(%)	10.00%	90.00%	100.00%	31.97%	68.03%	100.00%
SECONDARY	10.45	12.63	23.08	91,770	22,946	114,716
(%)	45.27%	54.73%	100.00%	80.00%	20.00%	100.00%
TOTAL SYS	22.93	81.02	103.95	201,374	227,100	428,475
(%)	22.06%	77.94%	100.00%	47.00%	53.00%	100.00%
TOTAL DIST	17.42	40.65	58.07	153,020	83,222	236,242
(%)	30.00%	70.00%	100.00%	64.77%	35.23%	100.00%

TABLE 4 – MO WEST

	DEMAND (PEAK HOUR – MW)			ENERGY (ANNUAL AVERAGE – MWH)		
	FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
TRANS	6.45	47.28	53.73	56,635	193,356	249,991
(%)	12.00%	88.00%	100.00%	22.65%	77.35%	100.00%
SUBTRANS	0.00	0.00	0.00	0.00	0.00	0.00
(%)	N/A	N/A	N/A	N/A	N/A	N/A
DIST SUBS	5.98	4.95	10.93	52,490	14,872	67,363
(%)	54.69%	45.31%	100.00%	77.92%	22.08%	100.00%
PRIMARY	2.71	24.37	27.08	23,786	58,870	82,656
(%)	10.00%	90.00%	100.00%	28.78%	71.22%	100.00%
SECONDARY	15.57	16.00	31.57	136,802	32,091	168,893
(%)	49.33%	50.67%	100.00%	81.00%	19.00%	100.00%
TOTAL SYS	30.71	92.60	123.31	269,713	299,190	568,903
(%)	24.90%	75.10%	100.00%	47.41%	52.59%	100.00%
TOTAL DIST	24.26	45.32	69.58	213,078	105,833	318,911
(%)	34.86%	65.14%	100.00%	66.81%	33.19%	100.00%

Non-Technical Losses

These are unaccounted for energy losses that are related to energy theft, metering, non-payment by customers, and accounting errors. Losses related to these areas are generally very small and can be extremely difficult and subjective to quantify. Our efforts generally do not develop any meaningful level because we assume that improving technology and utility practices have minimized these amounts.

2.3 Loss Impacts from Distributed Generation (DG)

The impacts of losses on a power system from the installation of various DG facilities will depend somewhat on the penetration level, type of installations and location on a circuit. Based on the results presented in Tables 2, 3, and 4 of this loss study, the loss impacts are significantly different from looking at any single peak load hour versus the potential impacts over all hours of an entire year. Use of a typical uniform loss factor(s) for each voltage level may require additional consideration to recognize that a reduced consumption level could have little or no impact due to the recovery requirements for the high level of fixed losses over the entire hourly electric grid condition for any DG location.

2.4 Description of Model

The loss model is a customized applications model, constructed using the Excel software program. Documentation consists primarily of the model equations at each cell location. A significant advantage of such a model is that the actual formulas and their corresponding computed values at each cell of the model are immediately available to the analyst.

A brief description of the three (3) major categories of effort for the preparation of each loss model is as follows:

- Main tab which contains calculations for all primary and secondary losses, summaries of all conductor and transformer calculations from other tabs discussed below, output reports and supporting results.

- Transformer tab which contains data input and loss calculations for each distribution substation and high voltage transformer. Separate iron and winding losses are calculated for each transformer by identified type.

- Conductor tab containing summary data by major voltage level as to circuit miles, loading assumptions, and kW and kWh loss calculations. Separate loss calculations for each line segment were made using the Company's power flow data by line segment and summarized by voltage level in this model.

3.0 METHODOLOGY

3.1 Background

The objective of a Loss Study is to provide a reasonable set of energy (average) and demand (peak) loss expansion factors which account for system losses associated with the transmission and delivery of power to each voltage level over a designated period of time. The focus of this study is to identify the difference between total energy inputs and the associated sales with the difference being equitably allocated to all delivery levels. Several key elements are important in establishing the methodology for calculating and reporting the Company's losses. These elements are:

- Selection of voltage level of services,
- Recognition of losses associated with conductors, transformations, and other electrical equipment/components within voltage levels,
- Identification of customers and loads at various voltage levels of service,
- Review of generation or net power supply input at each level for the test period studied, and
- Analysis of kW and kWh sales by voltage levels within the test period.

The three major areas of data gathering and calculations in the loss analysis were as follows:

1. System Information (monthly and annual)
   - MWH generation and MWH sales.
   - Coincident peak estimates and net power supply input from all sources and voltage levels.
   - Customer load estimates, adjusted MWH sales, and number of customers in the customer groupings and voltage levels identified in the model.
   - System default values, such as power factor, loading factors, and load factors by voltage level.

2. High Voltage System

   These calculations were prepared separately and their results incorporated through the use of approved FERC loss factors for each generation.

3. Distribution System

   - Distribution Substations – Data was developed for modeling each substation as to its size and loading. Loss calculations were performed from this data to determine load and no load losses separately for each transformer.

   - Primary lines – Line loading and loss characteristics for representative primary circuits were obtained from the Company. These loss results developed kW loss per MW of load and a composite average was calculated to derive the primary loss estimate.

   - Secondary voltage transformers – Losses in line transformers were based on each customer service group's size, as well as the number of customers per transformer. Accounting and load data provided the foundation with which to model the transformer loadings and to calculate load and no load losses.

   - Secondary network – Typical secondary networks were estimated for conductor sizes, lengths, loadings, and customer penetration for residential and small general service customers.

   - Services – Typical services were estimated for each secondary service class of customers identified in the study with respect to type, length, and loading.

The loss analysis was thus performed by constructing the model in segments and subsequently calculating the composite until the constraints of peak demand and energy were met:

- Information as to the physical characteristics and loading of each transformer and conductor segment was modeled.

- Conductors, transformers, and distribution were grouped by voltage level, and unadjusted losses were calculated.

- The loss factors calculated at each voltage level were determined by "compounding" the per-unit losses. Equivalent sales at the supply point were obtained by dividing sales at a specific level by the compounded loss factor to determine losses by voltage level.

- The resulting demand and energy loss expansion factors were then used to adjust all sales to the generation or input level in order to estimate the difference.

- Reconciliation of kW and kWh sales by voltage level using the reported system kW and kWh was accomplished by adjusting the initial loss factor estimates until the mismatch or difference was eliminated.

3.2 Calculations and Analysis

This section provides a discussion of the input data, assumptions, and calculations performed in the loss analysis. Specific appendices have been included in order to provide documentation of the input data utilized in the model.

3.2.1 Bulk, Transmission and Subtransmission Lines

3.2.2 Transformers

Loss calculations for all high voltage were prepared separately and presented at FERC with the respective approved loss factors incorporated in each of these studies.

3.2.3 Distribution System

The load data at the substation and customer level, coupled with primary and secondary network information, was sufficient to model the distribution system in adequate detail to calculate losses.

Primary Lines

Primary line loadings take into consideration the available distribution load along with the actual customer loads including losses. Primary line loss estimates were prepared by the Company for use in this loss study. These estimates considered voltage levels, loadings, total circuit miles, and wire size. All of these factors were considered in calculating the actual demand (kW) and energy (kWh) for the primary system.

Secondary Voltage Transformers

Losses in line transformers were determined based on typical transformer sizes for each secondary customer service group and an estimated or calculated number of customers per transformer. Company records and estimates of load data provided the necessary database with which to model the loadings. These calculations also made it possible to determine separate winding and iron losses for distribution line transformers, based on a table of representative losses for various transformer sizes.

Secondary Conductor Circuits

A calculation of secondary conductor circuit losses was performed for loads served through these secondary line investments. Estimates of typical conductor sizes, lengths, loadings and customer class penetrations were made to obtain total circuit miles and losses for the secondary network. Customer loads which do not have secondary line requirements were estimated so that a reasonable estimate of losses and circuit miles of these investments could be made.

Service Drops and Meters

Service drops were estimated for each secondary customer reflecting conductor size, length and loadings to obtain demand losses. A separate calculation was also performed using customer maximum demands to obtain kWh losses. Meter loss estimates were also made for each customer and incorporated into the calculations of kW and kWh losses included in the Summary Results.

4.0 DISCUSSION OF RESULTS

A brief description of each Exhibit provided in Appendix A follows:

Exhibit 1 - Summary of Company Data

This exhibit reflects system information used to determine percent losses and a detailed summary of kW and kWh losses by voltage level. The loss factors developed in Exhibit 7 are also summarized by voltage level.

Exhibit 2 - Summary of Conductor Information

A summary of MW and MWH load and no load losses for conductors by voltage levels is presented. The sum of all calculated losses by voltage level is based on input data information provided in Appendix A. Percent losses are based on equipment loadings.

Exhibit 3 - Summary of Transformer Information

This exhibit summarizes transformer losses by various types and voltage levels throughout the system. Load losses reflect the winding portion of transformer losses while iron losses reflect the no load or constant losses. MWH losses are estimated using a calculated loss factor for winding and the test year hours times no load losses.

Exhibit 4 - Summary of Losses Diagram (2 Pages)

This loss diagram represents the inputs and output of power at system peak conditions. Page 1 details information from all points of the power system and what is provided to the distribution system for primary loads. This portion of the summary can be viewed as a "top down" summary into the distribution system.

Page 2 represents a summary of the development of primary line loads and distribution substations based on a "bottom up" approach. Basically, loadings are developed from the customer meter through the Company's physical investments based on load research and other metered information by voltage level to arrive at MW and MVA requirements during peak load conditions by voltage levels.

Exhibit 5 - Summary of Sales and Calculated Losses

Summary of Calculated Losses represents a tabular summary of MW and MWH load and no load losses by discrete areas of delivery within each voltage level. Losses have been identified and are derived based on summaries obtained from Exhibits 2 and 3 and losses associated with meters, capacitors and regulators.

Exhibit 6 - Development of Loss Factors, Unadjusted

This exhibit calculates demand and energy losses and loss factors by specific voltage levels based on sales level requirements. The actual results reflect loads by level and summary totals of losses at that level, or up to that level, based on the results as shown in Exhibit 5. Finally, the estimated values at generation are developed and compared to actual generation to obtain any difference or mismatch.

Exhibit 7 - Development of Loss Factors, Adjusted

The adjusted loss factors are the results of adjusting Exhibit 6 for any difference. All differences between estimated and actual are prorated to each level based on the ratio of each level's total load plus losses to the system total. These new loss factors reflect an adjustment in losses due only to the kW and kWh mismatch.

Exhibit 8 – Adjusted Losses and Loss Factors by Facility

These calculations present an expanded summary detail of Exhibit 7 for each segment of the power system with respect to the flow of power and associated losses from the receipt of energy at the meter to the generation for the Evergy power system.

Exhibit 9 – Summary of Losses by Delivery Voltage

These calculations present a reformatted summary of losses presented in Exhibits 7 and 8 by power system delivery segment as calculated by voltage level of service based on reported metered sales.

Exhibit 10 – Composite Summary of Losses for Evergy Metro Only

These calculations are based on using the individual loss results from their respective Exhibit 7 for Metro MO and KS on a load weighted basis by voltage level of service to derive the loss factors.

Appendix A

Results of 2020 Evergy Missouri and Metro Combined

(NOTE: All of the 0.000 high voltage values shown on Exhibits 2, 3, and 5 reflect results that have been included in the loss factor estimates of Exhibit 5, line 22, TOT TRANS LOSS FAC.)

METRO MO

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK	1,730	MW
ANNUAL SYSTEM INPUT	8,600,000	MWH
ANNUAL SALES	8,075,854	MWH
SYSTEM LOSSES @ INPUT	524,146	or 6.09%
SYSTEM LOAD FACTOR	56.6%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	--- MW ---	Input	% TOTAL	--- MWH ---	Input	% TOTAL
TRANS	345,161,115	50.4		40.80%	250,485		47.79%
	69,66,35		2.91%			2.91%	
PRIM SUBS	33,12,1	11.2		9.08%	59,908		11.43%
			0.65%			0.70%	
PRIMARY	33,12,1	32.6		26.37%	87,211		16.64%
			1.88%			1.01%	
SECONDARY	120/240,to,477	29.3		23.76%	126,542		24.14%
			1.70%			1.47%	
TOTAL		123.5		100.00%	524,146		100.00%
			7.14%			6.09%	

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND (Peak) d	1/d	ENERGY (Annual) e	1/e
TOT TRANS	345,161,115 69,66,35	1.03000	0.97087	1.03000	0.97087
PRIM SUBS	33,12	1.03709	0.96424	1.03776	0.96361
PRIMARY	33,12,1	1.05865	0.94460	1.04965	0.95270
SECONDARY	120/240,to,477	1.07994	0.92597	1.06899	0.93547

SUMMARY OF CONDUCTOR INFORMATION

EXHIBIT 2

DESCRIPTION				CIRCUIT MILES	LOADING % RATING	----- MW LOSSES ----- LOAD	NO LOAD	TOTAL	---- MWH LOSSES ---- LOAD	NO LOAD	TOTAL
--- BULK -----------	345 KV	OR GREATER									
TIE LINES				0.0	0.00%	0.000	0.000	0.000	0	0	0
BULK TRANS				0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT				0.0		0.000	0.000	0.000	0	0	0
--- TRANS ---------	115 KV	TO	345.00 KV								
TIE LINES				0	0.00%	0.000	0.000	0.000	0	0	0
TRANS1	161 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
TRANS2	115 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT				0.0		0.000	0.000	0.000	0	0	0
--- SUBTRANS ------	35 KV	TO	115 KV								
TIE LINES				0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS1	69 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS2	66 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS3	35 KV			0.0	0.00%	0.000	0.000	0.000	0	2	2
SUBTOT				0.0		0.000	0.000	0.000	0	2	2
PRIMARY LINES				5,601		22.756	2.538	25.293	61,103	22,290	83,393
SECONDARY LINES				3,386		2.413	0.000	2.413	4,184	0	4,184
SERVICES				4,133		2.759	0.618	3.377	6,708	5,431	12,139
TOTAL				13,120		27.927	3.156	31.083	71,995	27,723	99,718

SUMMARY OF TRANSFORMER INFORMATION EXHIBIT 3

DESCRIPTION		KV CAPACITY VOLTAGE	MVA	NUMBER TRANSFMR	AVERAGE SIZE	LOADING %	MVA LOAD	--------- MW LOSSES -------- LOAD	NO LOAD	TOTAL	------- MWH LOSSES ------ LOAD	NO LOAD	TOTAL
BULK STEP-UP		345	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - BULK			0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS1		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 STEP-UP		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 STEP-UP		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1 STEP-UP		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2 STEP-UP		66	0.0	0	0.0	0.00%	0	0.000	0.001	0.001	0	0	0
SUBTRAN3 STEP-UP		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
						DISTRIBUTION SUBSTATIONS							
TRANS1 -	161	33	205.6	8	25.7	46.78%	96	0.224	0.289	0.513	763	2,540	3,303
TRANS1 -	161	12	3,684.8	92	40.1	41.87%	1,543	3.304	4.753	8.057	11,372	41,748	53,120
TRANS1 -	161	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	12	42.3	6	7.1	33.39%	14	0.055	0.070	0.126	178	618	796
SUBTRAN1-	69	1	9.3	3	3.1	48.34%	4	0.019	0.020	0.038	60	174	234
SUBTRAN2-	66	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
PRIMARY - PRIMARY			116.0	21	5.5	29.80%	35	0.082	0.192	0.274	245	1,686	1,931
LINE TRANSFRMR			3,976.5	48,909	81.3	40.88%	1,626	7.065	10.007	17.071	17,136	87,897	105,034
		===========	===========	===========	===========			===========	===========	===========	===========	==========	===========
TOTAL			8,034	49,039				10.750	15.332	26.081	29,754	134,663	164,417

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 1730.25 MW

EXHIBIT 4 PAGE 1 of 2

BULK TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK LINES		
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK STEP UP		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

BULK-BULK		
LOADING	0.00%	
NO LOAD	0	MW
LOAD	0	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK-TRANS1 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRAN1-TRAN2 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

BULK-TRANS2 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS 1&2 STEP UPS		
LDNG TR1SU	0.00%	
NOLOAD1&2	0.000	MW
LOAD 1&2	0.000	MW
AVSIZ TR1SU	0.0	MVA
NUMBER	0	

TRANS1	161.0	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS2	115.0	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS CUST		
SUBS	0.000	MW
	0.000	MVA
LINES		MW
		MVA

SUBTRANS TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS1&2-SUBTRANS1		
LDNG TR2-ST	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVSIZ TR2	0	MVA
NUMBER	0	

SUBTR1&2-SUBTRANS2&3		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS1&2- SUBTRANS2		
LDNG TR2-ST:	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVSIZ TR2-ST	0.00	MVA
NUMBER	0	

TRANS1&2-SUBTRANS3	
LDNG TR2-ST2	0.00%
NO LOAD	0.00
LOAD	0.00
AVSIZ TR2-ST2	0.00
NUMBER	0

SUBTRANS1,2,&3 STEP UPS		
LDNG ST1SU	0.00%	
NO LOAD	0.001	MW
LOAD	0.000	MW
AVSIZ ST2	0.0	MVA
NUMBER	0	

SUBTRANS1	69	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS2	66	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS2	35	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS CUST	
SUBS - MW	0.000
MVA	0.000
LINES- MW	
MVA	

TO DISTRIBUTION SYSTEM

TOTAL 1657.5 MVA 1624.3 MW

TRANS1	1,638.8	MVA
	98.88%	
161 KV		

TRANS2	0.0	MVA
	0.00%	
115 KV		

SUBTRANS1	18.6	MVA
	1.12%	
69 KV		

SUBTRANS2	0.0	MVA
	0.00%	
66 KV		

SUBTRANS3	0.0	MVA
	0.00%	
35 KV		

FROM HIGH VOLTAGE SYSTEM

TOTAL 1,657 MVA 1,624 MW

TRANS1 1,638.8 MVA 98.88% 161 KV	TRANS2 0.0 MVA 0.00% 115 KV	SUBTRANS1 18.6 MVA 1.12% 69 KV	SUBTRANS2 0.0 MVA 0.00% 66 KV	SUBTRANS3 0.0 MVA 0.00% 35 KV

DISTRIBUTION SYSTEM LOAD

	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3
VOLTAGE	33	12	1	33	12	1	33	12	1	33	12	1	33	12	1
LOAD MVA	96	1,543	0	0	0	0	0	14	4	0	0	0	0	0	0
% SYS TOT	5.80%	93.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.85%	0.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NOLD LOSS	0.289	4.753	0.000	0.000	0.000	0.000	0.000	0.070	0.020	0.000	0.000	0.000	0.000	0.000	0.000
LOAD LOSS	0.224	3.304	0.000	0.000	0.000	0.000	0.000	0.055	0.019	0.000	0.000	0.000	0.000	0.000	0.000
AVG SIZE	25.7	40.1	0.0	0.0	0.0	0.0	0.0	7.1	3.1	0.0	0.0	0.0	0.0	0.0	0.0
NUMBER	8	92	0	0	0	0	0	6	3	0	0	0	0	0	0
DIVERSITY RATIO	1.000	1.000	0.000	0.000	0.000	0.000	0.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000

PRIMARY LINES
- LOADING 1586.159 MW
- @ SYS PF 1618.529 MVA
- LOAD LOSS 22.756 MW
- NOLD LOSS 2.538 MW
- TOT LOSS 25.293 MW

PRIM/PRIM TRANSF
- LOADING 34.571 MW
- NOLD LOSS 0.192 MW
- LOAD LOSS 0.082 MW
- AVG SIZE 5.52
- NUMBER 21

PRIM CUST LOADS
- NO LINES 0.000 MW
- CUST SUB 0.000 MVA
- NO LINES 29.000 MW
- CO. SUB 29.592 MVA
- PRIM WITH 79.250 MW
- LINES 86.141 MVA

LINE TRANSFORMERS
- LOADING 1481.341 MW MVA 1642.776
- NOLD LOSS 10.007 MW
- LOAD LOSS 7.065 MW
- AVG SIZE 81.3 KVA
- NUMBER 48909

SECONDARY LINES
- LOAD 395.887 MW
- LOAD LOSS 2.413 MW
- NOLD LOSS 0.000 MW
- TOT LOSS 2.413 MW

NO SECONDARY LINES
- LOAD 1068.383 MW

SERVICES
- LOAD 1461.857 MW
- LOAD LOSS 2.759 MW
- NOLD LOSS 0.618 MW
- TOT LOSS 3.377 MW

CUSTOMER SECONDARY LOAD

1458.480 MW

SUMMARY of SALES and CALCULATED LOSSES

EXHIBIT 5

LOSS # AND LEVEL	MW LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC	MWH LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC
1 BULK XFMMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0	0
2 BULK LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
3 TRANS1 XFMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
4 TRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
5 TRANS2TR1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
6 TRANS2BLK SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
7 TRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
TOTAL TRAN	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
8 STR1BLK SD												
9 STR1T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
10 SRT1T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
11 SUBTRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
12 STR2T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
13 STR2T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
14 STR2S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
15 SUBTRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
16 STR3T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
17 STR3T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
18 STR3S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
19 STR3S2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
20 SUBTRANS3 LINES	0.0	0.00	0.00	0.00	0.000000		0	2	0	2	0.0000000	
21 SUBTRANS TOTAL	0.0	0.00	0.00	0.00	0.000000	**FERC OATT**	0	2	0	2	0.0000000	**FERC OATT**
22 TOT TRANS LOSS FAC	**1,730.3**	**6.05**	**44.35**	**50.40**	**1.030000**	**1.030000**	**8,600,000**	**53,121**	**197,364**	**250,485**	**1.0300000**	**1.0300000**
DISTRIBUTION SUBST												
TRANS1	1,606.1	5.04	3.53	8.57	1.005365	0.000000	7,907,351	44,288	12,135	56,423	1.0071868	0.0000000
TRANS2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR1	18.3	0.09	0.07	0.16	1.009061	0.000000	89,863	792	238	1,030	1.0115941	0.0000000
SUBTR2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR3	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
WEIGHTED AVERAGE	1,624.3	5.13	3.60	8.73	1.005406	1.035568	7,997,214	45,080	12,373	57,453	1.0072361	1.0374532
PRIMARY INTRCHNGE	0.0				0.000000		0				0.0000000	
PRIMARY LINES	1,586.0	2.54	22.84	25.38	1.016260	1.052407	7,693,613	22,290	61,348	83,638	1.0109906	1.0488554
LINE TRANSF	1,481.3	10.01	7.06	17.07	1.011659	1.064677	6,989,913	87,897	17,136	105,034	1.0152557	1.0648564
SECONDARY	1,464.3	0.00	2.41	2.41	1.001650	1.066434	6,884,879	0	4,184	4,184	1.0006081	1.0655039
SERVICES	1,461.9	0.62	2.76	3.38	1.002315	1.068903	6,880,695	5,431	6,708	12,139	1.0017673	1.0673870
		===========	===========	===========				===========	===========	===========		
TOTAL SYSTEM		24.34	83.02	107.37				213,819	299,114	512,933		

DEVELOPMENT of LOSS FACTORS EXHIBIT 6
UNADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	CALC LOSS TO LEVEL b	SALES MW @ GEN c	CUM PEAK EXPANSION FACTORS d	1/d
BULK LINES	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	40.0	1.2	41.2	1.03000	0.97087
PRIM SUBS	29.0	1.0	30.0	1.03557	0.96565
PRIM LINES	79.3	4.2	83.4	1.05241	0.95020
SECONDARY	1,458.5	100.5	1,559.0	1.06890	0.93554
TOTALS	1,606.7	106.9	1,713.6		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	CALC LOSS TO LEVEL b	SALES MWH @ GEN c	CUM ANNUAL EXPANSION FACTORS d	1/d
BULK LINES	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0.00000	0.00000
TOTAL TRANS	340,959	10,229	351,188	1.03000	0.97087
PRIM SUBS	246,276	9,224	255,500	1.03745	0.96390
PRIM LINES	620,063	30,293	650,356	1.04886	0.95342
SECONDARY	6,868,556	462,851	7,331,407	1.06739	0.93687
TOTALS	8,075,854	512,597	8,588,451		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	41.20	351,188
PRIM SUBS	30.03	255,500
PRIM LINES	83.40	650,356
SECONDARY	1,558.97	7,331,407
SUBTOTAL	1,713.61	8,588,451
ACTUAL ENERGY	1,730.25	8,600,000
MISMATCH	(16.64)	(11,549)
% MISMATCH	-0.96%	-0.13%

DEVELOPMENT of LOSS FACTORS EXHIBIT 7
ADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW	SALES ADJUST	CALC LOSS TO LEVEL	SALES MW @ GEN	CUM PEAK EXPANSION FACTORS	
	a	b	c	d	e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	40.0	0.0	1.2	41.2	1.03000	0.97087
PRIM SUBS	29.0	0.0	1.1	30.1	1.03709	0.96424
PRIM LINES	79.3	0.0	4.6	83.9	1.05865	0.94460
SECONDARY	1,458.5	0.0	116.6	1,575.1	1.07994	0.92597
			123.5			
TOTALS	1,606.7	0.0	123.5	1,730.3		

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH	SALES ADJUST	CALC LOSS TO LEVEL	SALES MWH @ GEN	CUM ANNUAL EXPANSION FACTORS	
	a	b	c	d	e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	340,959	0	10,229	351,188	1.03000	0.97087
PRIM SUBS	246,276	0	9,300	255,576	1.03776	0.96361
PRIM LINES	620,063	0	30,785	650,848	1.04965	0.95270
SECONDARY	6,868,556	0	473,832	7,342,388	1.06899	0.93547
			524,146			
TOTALS	8,075,854	0	524,146	8,600,000		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	41.20	351,188
PRIM SUBS	30.08	255,576
PRIM LINES	83.90	650,848
SECONDARY	1,575.08	7,342,388
	1,730.25	8,600,000
ACTUAL ENERGY	1,730.25	8,600,000
MISMATCH	0.00	0
% MISMATCH	0.00%	0.00%

Adjusted Losses and Loss Factors by Facility EXHIBIT 8

Unadjusted Losses by Segment

	MW	Unadjusted	MWH	Unadjusted
Service Drop Losses	3.38	3.35	12,139	12,123
Secondary Losses	2.41	2.39	4,184	4,179
Line Transformer Losses	17.07	16.93	105,034	104,899
Primary Line Losses	25.38	25.16	83,638	83,531
Distribution Substation Losses	8.73	8.66	57,453	57,379
Transmission System Losses	50.40	50.40	250,485	250,485
Total	107.37	106.88	512,933	512,597

Mismatch Allocation by Segment

	MW	MWH
Service Drop Losses	-0.99	-534
Secondary Losses	-0.70	-184
Line Transformer Losses	-4.99	-4,622
Primary Line Losses	-7.41	-3,680
Distribution Substation Losses	-2.55	-2,528
Transmission System Losses	0.00	0
Total	-16.64	-11,549

Adjusted Losses by Segment

	MW	% of Total	MWH	% of Total
Service Drop Losses	4.33	3.5%	12,657	2.4%
Secondary Losses	3.10	2.5%	4,363	0.8%
Line Transformer Losses	21.91	17.7%	109,521	20.9%
Primary Line Losses	32.57	26.4%	87,211	16.6%
Distribution Substation Losses	11.21	9.1%	59,908	11.4%
Transmission System Losses	50.40	40.8%	250,485	47.8%
Total	123.52	100.0%	524,146	100.0%

Loss Factors by Segment	**MW**	**MWH**	
Retail Sales from Service Drops	1,458.480	6,868,556	
Adjusted Service Drop Losses	4.335	12,657	
Input to Service Drops	1,462.815	6,881,213	
Service Drop Loss Factor	**1.00297**	**1.00184**	
Output from Secondary	1,462.815	6,881,213	
Adjusted Secondary Losses	3.097	4,363	
Input to Secondary	1,465.911	6,885,576	
Secondary Conductor Loss Factor	**1.00212**	**1.00063**	
Output from Line Transformers	1,465.911	6,885,576	
Adjusted Line Transformer Losses	21.912	109,521	
Input to Line Transformers	1,487.823	6,995,098	
Line Transformer Loss Factor	**1.01495**	**1.01591**	
Retail Sales from Primary	74.000	597,779	
Req. Whls Sales from Primary	5.250	22,284	
Input to Line Transformers	1,487.823	6,995,098	
Output from Primary Lines	1,567.073	7,615,161	
Adjusted Primary Line Losses	32.570	87,211	
Input to Primary Lines	1,599.644	7,702,372	
Primary Line Loss Factor	**1.02078**	**1.01145**	
Output Pl from Distribution Substations	1,599.644	7,702,372	
Req. Whls Sales from Substations	0.000	0	
Retail Sales from Substations	29.000	246,276	
TotalOutput from Distribution Substations	1,628.644	7,948,648	
Adjusted Distribution Substation Losses	11.211	59,908	
Input to Distribution Substations	1,639.854	8,008,556	
Distribution Substation Loss Factor	**1.00688**	**1.00754**	
Retail Sales at from SubTransmission	40.000	340,959	
Req. Whls Sales from SubTransmission	0.000	0	
Non-Req. Whls Sales from SubTransmission	0.000	0	
Losses	0.000	0	4678
Input to Distribution Substations	1,639.854	8,008,556	
Output from SubTransmission	1,679.854	8,349,515	1,730.250
SubTransmission System Losses	50.396	250,485	50.396
Input to Transmission	1,730.250	8,600,000	50.396
TotTransmission System Loss Factor	**1.03000**	**1.03000**	50.396

DEMAND MW **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE**

	SERVICE LEVEL		SALES MW	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		1,458.5		1,458.5				
3	LOSSES			4.3	4.3				
4	INPUT				1,462.8				
5	**EXPANSION FACTOR**	**1.00297**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			3.1	3.1				
9	INPUT				1,465.9				
10	**EXPANSION FACTOR**	**1.00212**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			21.9	21.9				
14	INPUT				1,487.8				
15	**EXPANSION FACTOR**	**1.01495**							
16	**PRIMARY**								
17	SECONDARY				1,487.8				
18	SALES		74.0			74.0			
19	LOSSES			32.6	30.9	1.5			
20	INPUT				1,518.7	75.5			
21	**EXPANSION FACTOR**	**1.02078**							
22	**SUBSTATION**								
23	PRIMARY				1,518.7	75.5			
24	SALES		29.0				29.0		
25	LOSSES			11.2	10.5	0.5	0.2		
26	INPUT				1,529.2	76.1	29.2		
27	**EXPANSION FACTOR**	**1.00688**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				1,529.2	76.1	29.2		
37	SALES		40.0						40.0
38	LOSSES			50.2	45.9	2.3	0.9		1.2
39	INPUT				1,575.1	78.3	30.1		41.2
40	**EXPANSION FACTOR**	**1.03000**							
41	**TOTALS** LOSSES			123.4	116.6	4.3	1.1		1.2
42	% OF TOTAL			100%	94.52%	3.52%	0.87%		0.97%
43	SALES		1,601.5		1,458.5	74.0	29.0		40.0
44	% OF TOTAL		100.00%		91.07%	4.62%	1.81%		2.50%
45	INPUT		1,724.7		1,575.1	78.3	30.1		41.2
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.07994**	**1.05865**	**1.03709**		**1.03000**

ENERGY MWH **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE**

	SERVICE LEVEL		**SALES**	**LOSSES**	**SECONDARY**	**PRIMARY**	**SUBSTATION**	**SUBTRANS**	**TRANSMISSION**
1	**SERVICES**								
2	SALES		6,868,556		6,868,556				
3	LOSSES			12,657	12,657				
4	INPUT				6,881,213				
5	**EXPANSION FACTOR**	**1.00184**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			4,363	4,363				
9	INPUT				6,885,576				
10	**EXPANSION FACTOR**	**1.00063**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			109,521	109,521				
14	INPUT				6,995,098				
15	**EXPANSION FACTOR**	**1.01591**							
16	**PRIMARY**								
17	SECONDARY				6,995,098				
18	SALES		597,779.000			597,779			
19	LOSSES			87,211	80,110	6,846			
20	INPUT				7,075,208	604,625			
21	**EXPANSION FACTOR**	**1.01145**							
22	**SUBSTATION**								
23	PRIMARY				7,075,208	604,625			
24	SALES		246,276				246,276		
25	LOSSES			59,908	53,325	4,557	1,856		
26	INPUT				7,128,532	609,182	248,132		
27	**EXPANSION FACTOR**	**1.00754**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				7,128,532	609,182	248,132		
37	SALES		340,959						340,959
38	LOSSES			249,804	213,856	18,275	7,444		10,229
39	INPUT				7,342,388	627,457	255,576		351,188
40	**EXPANSION FACTOR**	**1.03000**							
41	**TOTALS** LOSSES			523,465	473,832	29,678	9,300		10,229
42	% OF TOTAL			100%	90.52%	5.67%	1.78%		1.95%
43	SALES		8,053,570		6,868,556	597,779	246,276		340,959
44	% OF TOTAL		100.00%		85.29%	7.42%	3.06%		4.23%
45	INPUT		8,576,610		7,342,388	627,457	255,576		351,188
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.06899**	**1.04965**	**1.03776**		**1.03000**

KCPL KS & MO | **DEVELOPMENT of LOSS FACTORS** | **EXHIBIT 10**
COMPOSITE | **ADJUSTED** **EXHIBIT 7** | PAGE 1 OF 2
LOSS FACTORS | **DEMAND**

LOSS FACTOR LEVEL	CUSTOMER SALES MW	SALES ADJUST	CALC LOSS TO LEVEL	SALES MW @ GEN	CUM PEAK FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	0.0	0.0	0.0	0.0	0.00000	0.97824
SUBTRANS	40.0	0.0	1.2	41.2	1.03000	0.97824
PRIM SUBS	33.0	0.0	1.2	34.2	1.03694	0.96437
PRIM LINES	147.3	0.0	8.5	155.8	1.05786	0.94061
SECONDARY	2,851.0	0.0	223.0	3,074.1	1.07822	0.91849
TOTALS	3,071.3	0.0	234.0	3,305.3	1.07618	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH	SALES **ADJUST**	CALC LOSS TO LEVEL	SALES MWH @ GEN	CUM ANNUAL FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
TOTAL TRANS	0	0	0	0	0.00000	0.00000
SUBTRANS	340959	0	10229	351188	1.03000	0.97087
PRIM SUBS	269,877	0	10,188	280,065	1.03775	0.96362
PRIM LINES	1,017,249	0	50,676	1,067,925	1.04982	0.95255
SECONDARY	12,617,891	0	882,932	13,500,823	1.06997	0.93460
TOTAL	14,245,976	0	954,024	15,200,000	1.06697	<COMPOSITE

KCPL Kansas

DEVELOPMENT of LOSS FACTORS
ADJUSTED **EXHIBIT 7**
DEMAND

EXHIBIT 10
PAGE 2 OF 2

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK FACTORS e	EXPANTION f=1/e
BULK LINES	0.0	0	0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0	0	0.0	0.00000	0.00000
TRANS LINES	0.0	0	0	0.0	0.00000	0.00000
TOTAL TRANS	0.0	0.0	0.0	0.0	0.00000	0.91849
SUBTRANS	0.0	0.0	0.0	0.0	0.00000	0.91849
PRIM SUBS	4.0	0.0	0.1	4.1	1.03587	0.91849
PRIM LINES	68.0	0.0	3.9	71.9	1.05695	0.91849
SECONDARY	1,392.6	0.0	106.4	1,499.0	1.07642	0.91849
TOTALS	1,464.6	0.0	110.4	1,575.0	1.07541	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES **ADJUST** b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNUAL FACTORS e	EXPANTION f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
TOTAL TRANS	0	0	0	0	0.00000	0.00000
SUBTRANS	0	0	0	0	0.00000	0.00000
PRIM SUBS	23,601	0	888	24,489	1.03762	0.96374
PRIM LINES	397,186	0	19,891	417,077	1.05008	0.95231
SECONDARY	5,749,335	0	409,099	6,158,434	1.07116	0.93357
TOTAL	6,170,122	0	429,878	6,600,000	1.06967	<COMPOSITE

KCPL Missouri

DEVELOPMENT of LOSS FACTORS
ADJUSTED **EXHIBIT 7**
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK FACTORS e	EXPANTION f=1/e
BULK LINES	0.0	0	0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0	0	0.0	0.00000	0.00000
TRANS LINES	0.0	0	0	0.0	0.00000	0.00000
TOTAL TRANS	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS	40.0	0.0	1.2	41.2	1.03000	0.97087
PRIM SUBS	29.0	0.0	1.1	30.1	1.03709	0.96424
PRIM LINES	79.3	0.0	4.6	83.9	1.05865	0.94460
SECONDARY	1458.5	0.0	116.6	1575.1	1.07994	0.92597
TOTALS	1,606.7	0.0	123.5	1,730.3	1.07688	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES **ADJUST** b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNUAL FACTORS e	EXPANTION f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
TOTAL TRANS	0	0	0	0	0.00000	0.00000
SUBTRANS	340,959	0	10,229	351,188	1.03000	0.97087
PRIM SUBS	246,276	0	9,300	255,576	1.03776	0.96361
PRIM LINES	620,063	0	30,785	650,848	1.04965	0.95270
SECONDARY	6,868,556	0	473,832	7,342,388	1.06899	0.93547
TOTAL	8,075,854	0	524,146	8,600,000	1.06490	<COMPOSITE

Appendix B

Results of 2020 Evergy Kansas and Metro Combined

(NOTE: All of the 0.000 high voltage values shown on Exhibits 2, 3, and 5 reflect results that have been included in the loss factor estimates of Exhibit 5, line 22, TOT TRANS LOSS FAC.)

METRO KS

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK	1,575	MW
ANNUAL SYSTEM INPUT	6,600,000	MWH
ANNUAL SALES	6,170,122	MWH
SYSTEM LOSSES @ INPUT	429,878	or 6.51%
SYSTEM LOAD FACTOR	47.7%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	--- MW ---	Input	% TOTAL	--- MWH ---	Input	% TOTAL
TRANS	345,161,115 69,66,35	45.9	2.91%	41.54%	192,233	2.91%	44.72%
PRIM SUBS	33,12,1	8.7	0.55%	7.85%	47,082	0.71%	10.95%
PRIMARY	33,12,1	30.2	1.92%	27.38%	75,165	1.14%	17.49%
SECONDARY	120/240,to,477	25.7	1.63%	23.23%	115,398	1.75%	26.84%
TOTAL		110.4	7.01%	100.00%	429,878	6.51%	100.00%

SUMMARY OF LOSS FACTORS

		CUMMULATIVE SALES EXPANSION FACTORS			
SERVICE	KV	DEMAND (Peak)		ENERGY (Annual)	
		d	1/d	e	1/e
TOT TRANS	345,161,115 69,66,35	1.03000	0.97087	1.03000	0.97087
PRIM SUBS	33,12	1.03587	0.96537	1.03762	0.96374
PRIMARY	33,12,1	1.05695	0.94612	1.05008	0.95231
SECONDARY	120/240,to,477	1.07642	0.92900	1.07116	0.93357

SUMMARY OF CONDUCTOR INFORMATION

EXHIBIT 2

DESCRIPTION		CIRCUIT MILES	LOADING % RATING	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
--- BULK -----------	345 KV OR GREATER								
TIE LINES		0.0	0.00%	0.000	0.000	0.000	0	0	0
BULK TRANS		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT		0.0		0.000	0.000	0.000	0	0	0
--- TRANS ---------	115 KV TO 345.00 KV								
TIE LINES		0	0.00%	0.000	0.000	0.000	0	0	0
TRANS1	161 KV	0.0	0.00%	0.000	0.000	0.000	0	0	0
TRANS2	115 KV	0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT		0.0		0.000	0.000	0.000	0	0	0
--- SUBTRANS ------	35 KV TO 115 KV								
TIE LINES		0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS1	69 KV	0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS2	66 KV	0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS3	35 KV	0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT		0.0		0.000	0.000	0.000	0	0	0
PRIMARY LINES		6,899		24.151	2.720	26.870	50,107	23,888	73,995
SECONDARY LINES		2,331		2.604	0.000	2.604	4,065	0	4,065
SERVICES		3,705		3.228	0.553	3.780	5,866	4,856	10,723
TOTAL		12,935		29.983	3.272	33.255	60,039	28,745	88,783

SUMMARY OF TRANSFORMER INFORMATION EXHIBIT 3

DESCRIPTION		KV CAPACITY VOLTAGE	MVA	NUMBER TRANSFMR	AVERAGE SIZE	LOADING %	MVA LOAD	--------- MW LOSSES -------- LOAD	NO LOAD	TOTAL	------- MWH LOSSES ------ LOAD	NO LOAD	TOTAL
BULK STEP-UP		345	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - BULK			0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS1		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 STEP-UP		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 STEP-UP		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1 STEP-UP		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2 STEP-UP		66	0.0	0	0.0	0.00%	0	0.000	0.001	0.001	0	0	0
SUBTRAN3 STEP-UP		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
							DISTRIBUTION SUBSTATIONS						
TRANS1 -	161	33	287.2	10	28.7	42.85%	123	0.268	0.392	0.660	719	3,442	4,161
TRANS1 -	161	12	2,833.2	78	36.3	50.49%	1,431	3.278	3.862	7.139	8,724	33,920	42,644
TRANS1 -	161	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
PRIMARY - PRIMARY			200.0	42	4.8	43.23%	86	0.325	0.340	0.665	726	2,985	3,711
LINE TRANSFRMR			3,919.4	58,416	67.1	39.63%	1,553	6.800	9.895	16.695	13,015	86,913	99,928
			===========	===========	===========	===========		===========	===========	===========	===========	==========	===========
TOTAL			7,240	58,546				10.671	14.489	25.160	23,183	127,260	150,443

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 1575 MW

BULK TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK LINES		
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK STEP UP		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

BULK-BULK		
LOADING	0.00%	
NO LOAD	0	MW
LOAD	0	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK-TRANS1 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRAN1-TRAN2 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

BULK-TRANS2 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS 1&2 STEP UPS		
LDNG TR1SU	0.00%	
NOLOAD1&2	0.000	MW
LOAD 1&2	0.000	MW
AVSIZ TR1SU	0.0	MVA
NUMBER	0	

TRANS1	161.0	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS2	115.0	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS CUST		
SUBS	0.000	MW
	0.000	MVA
LINES		MW
		MVA

SUBTRANS TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS1&2-SUBTRANS1		
LDNG TR2-ST	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVSIZ TR2	0	MVA
NUMBER	0	

SUBTR1&2-SUBTRANS2&3		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS1&2- SUBTRANS2		
LDNG TR2-ST:	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVSIZ TR2-ST	0.00	MVA
NUMBER	0	

TRANS1&2-SUBTRANS3	
LDNG TR2-ST2	0.00%
NO LOAD	0.00
LOAD	0.00
AVSIZ TR2-ST2	0.00
NUMBER	0

SUBTRANS1,2,&3 STEP UPS		
LDNG ST1SU	0.00%	
NO LOAD	0.001	MW
LOAD	0.000	MW
AVSIZ ST2	0.0	MVA
NUMBER	0	

SUBTRANS1	69	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS2	66	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS2	35	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS CUST	
SUBS - MW	0.000
MVA	0.000
LINES- MW	
MVA	

TO DISTRIBUTION SYSTEM

TOTAL 1553.6 MVA 1522.5 MW

TRANS1	1,553.6	MVA
	100.00%	
161 KV		

TRANS2	0.0	MVA
	0.00%	
115 KV		

SUBTRANS1	0.0	MVA
	0.00%	
69 KV		

SUBTRANS2	0.0	MVA
	0.00%	
66 KV		

SUBTRANS3	0.0	MVA
	0.00%	
35 KV		

FROM HIGH VOLTAGE SYSTEM

EXHIBIT 4 PAGE 2 of 2

TOTAL 1,554 MVA 1,522 MW

TRANS1	TRANS2	SUBTRANS1	SUBTRANS2	SUBTRANS3
1,553.6 MVA	0.0 MVA	0.0 MVA	0.0 MVA	0.0 MVA
100.00%	0.00%	0.00%	0.00%	0.00%
161 KV	115 KV	69 KV	66 KV	35 KV

DISTRIBUTION SYSTEM LOAD

	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3
VOLTAGE	33	12	1	33	12	1	33	12	1	33	12	1	33	12	1
LOAD MVA	123	1,431	0	0	0	0	0	0	0	0	0	0	0	0	0
% SYS TOT	7.92%	92.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NOLD LOSS	0.392	3.862	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LOAD LOSS	0.268	3.278	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AVG SIZE	28.7	36.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NUMBER	10	78	0	0	0	0	0	0	0	0	0	0	0	0	0
DIVERSITY RATIO	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

PRIMARY LINES		
LOADING	1511.175	MW
@ SYS PF	1542.015	MVA
LOAD LOSS	24.151	MW
NOLD LOSS	2.720	MW
TOT LOSS	26.870	MW

PRIM/PRIM TRANSF		
LOADING	86.445	MW
NOLD LOSS	0.340	MW
LOAD LOSS	0.325	MW
AVG SIZE	4.76	
NUMBER	42	

PRIM CUST	LOADS	
NO LINES	0.000	MW
CUST SUB	0.000	MVA
NO LINES	4.000	MW
CO. SUB	4.082	MVA
PRIM WITH	68.000	MW
LINES	73.913	MVA

LINE TRANSFORMERS				
LOADING	1415.640	MW	MVA	1569.816
NOLD LOSS	9.895	MW		
LOAD LOSS	6.800	MW		
AVG SIZE	67.1	KVA		
NUMBER	58416			

SECONDARY LINES		
LOAD	339.935	MW
LOAD LOSS	2.604	MW
NOLD LOSS	0.000	MW
TOT LOSS	2.604	MW

NO SECONDARY LINES		
LOAD	1059.010	MW

SERVICES		
LOAD	1396.340	MW
LOAD LOSS	3.228	MW
NOLD LOSS	0.553	MW
TOT LOSS	3.780	MW

CUSTOMER SECONDARY LOAD

1392.560 MW

SUMMARY of SALES and CALCULATED LOSSES

EXHIBIT 5

LOSS # AND LEVEL	MW LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC	MWH LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC
1 BULK XFMMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0	0
2 BULK LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
3 TRANS1 XFMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
4 TRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
5 TRANS2TR1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
6 TRANS2BLK SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
7 TRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
TOTAL TRAN	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
8 STR1BLK SD												
9 STR1T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
10 SRT1T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
11 SUBTRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
12 STR2T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
13 STR2T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
14 STR2S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
15 SUBTRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
16 STR3T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
17 STR3T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
18 STR3S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
19 STR3S2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
20 SUBTRANS3 LINES	0.0	0.00	0.00	0.00	0.000000		0	0	0	0	0.0000000	
21 SUBTRANS TOTAL	0.0	0.00	0.00	0.00	0.000000	**FERC OATT**	0	0	0	0	0.0000000	**FERC OATT**
22 TOT TRANS LOSS FAC	**1,575.0**	**5.50**	**40.37**	**45.87**	**1.030000**	**1.030000**	**6,600,000**	**48,355**	**143,878**	**192,233**	**1.0300000**	**1.0300000**
DISTRIBUTION SUBST												
TRANS1	1,522.5	4.25	3.55	7.80	1.005149	0.000000	6,405,928	37,362	9,442	46,804	1.0073602	0.0000000
TRANS2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR1	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR3	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
WEIGHTED AVERAGE	1,522.5	4.25	3.55	7.80	1.005149	1.035303	6,405,928	37,362	9,442	46,804	1.0073602	1.0375810
PRIMARY INTRCHNGE	0.0				0.000000		0				0.0000000	
PRIMARY LINES	1,510.8	2.72	24.48	27.20	1.018330	1.054280	6,335,958	23,888	50,833	74,721	1.0119339	1.0499634
LINE TRANSF	1,415.6	9.89	6.80	16.69	1.011934	1.066862	5,864,051	86,913	13,015	99,928	1.0173363	1.0681658
SECONDARY	1,398.9	0.00	2.60	2.60	1.001865	1.068852	5,764,123	0	4,065	4,065	1.0007057	1.0689197
SERVICES	1,396.3	0.55	3.23	3.78	1.002715	1.071754	5,760,058	4,856	5,866	10,723	1.0018651	1.0709133
		===========	===========	===========				===========	===========	===========		
TOTAL SYSTEM		22.93	81.02	103.95				201,374	227,100	428,475		

DEVELOPMENT of LOSS FACTORS EXHIBIT 6
UNADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	CALC LOSS TO LEVEL b	SALES MW @ GEN c	CUM PEAK EXPANSION FACTORS d	1/d
BULK LINES	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	0.0	0.0	0.0	1.03000	0.97087
PRIM SUBS	4.0	0.1	4.1	1.03530	0.96590
PRIM LINES	68.0	3.7	71.7	1.05428	0.94851
SECONDARY	1,392.6	99.9	1,492.5	1.07175	0.93305
TOTALS	1,464.6	103.8	1,568.3		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	CALC LOSS TO LEVEL b	SALES MWH @ GEN c	CUM ANNUAL EXPANSION FACTORS d	1/d
BULK LINES	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0.00000	0.00000
TOTAL TRANS	0	0	0	1.03000	0.97087
PRIM SUBS	23,601	887	24,488	1.03758	0.96378
PRIM LINES	397,186	19,845	417,031	1.04996	0.95241
SECONDARY	5,749,335	407,704	6,157,039	1.07091	0.93378
TOTALS	6,170,122	428,436	6,598,558		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	0.00	0
PRIM SUBS	4.14	24,488
PRIM LINES	71.69	417,031
SECONDARY	1,492.48	6,157,039
SUBTOTAL	1,568.31	6,598,558
ACTUAL ENERGY	1,575.00	6,600,000
MISMATCH	(6.69)	(1,442)
% MISMATCH	-0.42%	-0.02%

DEVELOPMENT of LOSS FACTORS EXHIBIT 7
ADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK EXPANSION FACTORS e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	0.0	0.0	0.0	0.0	1.03000	0.97087
PRIM SUBS	4.0	0.0	0.1	4.1	1.03587	0.96537
PRIM LINES	68.0	0.0	3.9	71.9	1.05695	0.94612
SECONDARY	1,392.6	0.0	106.4	1,499.0	1.07642	0.92900
			110.4			
TOTALS	1,464.6	0.0	110.4	1,575.0		

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNUAL EXPANSION FACTORS e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	0	0	0	0	1.03000	0.97087
PRIM SUBS	23,601	0	888	24,489	1.03762	0.96374
PRIM LINES	397,186	0	19,891	417,077	1.05008	0.95231
SECONDARY	5,749,335	0	409,099	6,158,434	1.07116	0.93357
			429,878			
TOTALS	6,170,122	0	429,878	6,600,000		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	0.00	0
PRIM SUBS	4.14	24,489
PRIM LINES	71.87	417,077
SECONDARY	1,498.98	6,158,434
	1,575.00	6,600,000
ACTUAL ENERGY	1,575.00	6,600,000
MISMATCH	0.00	0
% MISMATCH	0.00%	0.00%

Adjusted Losses and Loss Factors by Facility EXHIBIT 8

Unadjusted Losses by Segment

	MW	Unadjusted	MWH	Unadjusted
Service Drop Losses	3.78	3.77	10,723	10,721
Secondary Losses	2.60	2.60	4,065	4,064
Line Transformer Losses	16.69	16.64	99,928	99,912
Primary Line Losses	27.20	27.10	74,721	74,709
Distribution Substation Losses	7.80	7.77	46,804	46,797
Transmission System Losses	45.87	45.87	192,233	192,233
Total	103.95	103.75	428,475	428,436

Mismatch Allocation by Segment

	MW	MWH
Service Drop Losses	-0.44	-65
Secondary Losses	-0.30	-25
Line Transformer Losses	-1.92	-610
Primary Line Losses	-3.13	-456
Distribution Substation Losses	-0.90	-286
Transmission System Losses	0.00	0
Total	-6.69	-1,442

Adjusted Losses by Segment

	MW	% of Total	MWH	% of Total
Service Drop Losses	4.20	3.8%	10,787	2.5%
Secondary Losses	2.90	2.6%	4,089	1.0%
Line Transformer Losses	18.56	16.8%	100,522	23.4%
Primary Line Losses	30.24	27.4%	75,165	17.5%
Distribution Substation Losses	8.67	7.9%	47,082	11.0%
Transmission System Losses	45.87	41.5%	192,233	44.7%
Total	110.44	100.0%	429,878	100.0%

Loss Factors by Segment	**MW**	**MWH**	
Retail Sales from Service Drops	1,392.560	5,749,335	
Adjusted Service Drop Losses	4.203	10,787	
Input to Service Drops	1,396.763	5,760,122	
Service Drop Loss Factor	**1.00302**	**1.00188**	
Output from Secondary	1,396.763	5,760,122	
Adjusted Secondary Losses	2.896	4,089	
Input to Secondary	1,399.659	5,764,211	
Secondary Conductor Loss Factor	**1.00207**	**1.00071**	
Output from Line Transformers	1,399.659	5,764,211	
Adjusted Line Transformer Losses	18.561	100,522	
Input to Line Transformers	1,418.220	5,864,733	
Line Transformer Loss Factor	**1.01326**	**1.01744**	
Retail Sales from Primary	68.000	397,186	
Req. Whls Sales from Primary	0.000	0	
Input to Line Transformers	1,418.220	5,864,733	
Output from Primary Lines	1,486.220	6,261,919	
Adjusted Primary Line Losses	30.235	75,165	
Input to Primary Lines	1,516.455	6,337,084	
Primary Line Loss Factor	**1.02034**	**1.01200**	
Output Pl from Distribution Substations	1,516.455	6,337,084	
Req. Whls Sales from Substations	0.000	0	
Retail Sales from Substations	4.000	23,601	
TotalOutput from Distribution Substations	1,520.455	6,360,685	
Adjusted Distribution Substation Losses	8.671	47,082	
Input to Distribution Substations	1,529.126	6,407,767	
Distribution Substation Loss Factor	**1.00570**	**1.00740**	
Retail Sales at from SubTransmission	0.000	0	
Req. Whls Sales from SubTransmission	0.000	0	
Non-Req. Whls Sales from SubTransmission	0.000	0	
Losses	0.000	0	4678
Input to Distribution Substations	1,529.126	6,407,767	
Output from SubTransmission	1,529.126	6,407,767	1,575.000
SubTransmission System Losses	45.874	192,233	45.874
Input to Transmission	1,575.000	6,600,000	45.874
TotTransmission System Loss Factor	**1.03000**	**1.03000**	45.874

DEMAND MW — **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE**

	SERVICE LEVEL		SALES MW	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		1,392.6		1,392.6				
3	LOSSES			4.2	4.2				
4	INPUT				1,396.8				
5	**EXPANSION FACTOR**	**1.00302**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			2.9	2.9				
9	INPUT				1,399.7				
10	**EXPANSION FACTOR**	**1.00207**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			18.6	18.6				
14	INPUT				1,418.2				
15	**EXPANSION FACTOR**	**1.01326**							
16	**PRIMARY**								
17	SECONDARY				1,418.2				
18	SALES		68.0			68.0			
19	LOSSES			30.2	28.9	1.4			
20	INPUT				1,447.1	69.4			
21	**EXPANSION FACTOR**	**1.02034**							
22	**SUBSTATION**								
23	PRIMARY				1,447.1	69.4			
24	SALES		4.0				4.0		
25	LOSSES			8.7	8.3	0.4	0.0		
26	INPUT				1,455.3	69.8	4.0		
27	**EXPANSION FACTOR**	**1.00570**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				1,455.3	69.8	4.0		
37	SALES		0.0						0.0
38	LOSSES			45.9	43.7	2.1	0.1		0.0
39	INPUT				1,499.0	71.9	4.1		0.0
40	**EXPANSION FACTOR**	**1.03000**							
41	**TOTALS** LOSSES			110.4	106.4	3.9	0.1		0.0
42	% OF TOTAL			100%	96.36%	3.51%	0.13%		0.00%
43	SALES		1,464.6		1,392.6	68.0	4.0		0.0
44	% OF TOTAL		100.00%		95.08%	4.64%	0.27%		0.00%
45	INPUT		1,575.0		1,499.0	71.9	4.1		0.0
46	**CUMMULATIVE EXPANSION LOSS FACTORS**				**1.07642**	**1.05695**	**1.03587**		**NA**
	(from meter to system input)				1.09238				

ENERGY MWH — SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE

	SERVICE LEVEL		SALES	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		5,749,335		5,749,335				
3	LOSSES			10,787	10,787				
4	INPUT				5,760,122				
5	**EXPANSION FACTOR**	**1.00188**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			4,089	4,089				
9	INPUT				5,764,211				
10	**EXPANSION FACTOR**	**1.00071**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			100,522	100,522				
14	INPUT				5,864,733				
15	**EXPANSION FACTOR**	**1.01744**							
16	**PRIMARY**								
17	SECONDARY				5,864,733				
18	SALES		397,186.000			397,186			
19	LOSSES			75,165	70,397	4,768			
20	INPUT				5,935,130	401,954			
21	**EXPANSION FACTOR**	**1.01200**							
22	**SUBSTATION**								
23	PRIMARY				5,935,130	401,954			
24	SALES		23,601				23,601		
25	LOSSES			47,082	43,932	2,975	175		
26	INPUT				5,979,062	404,929	23,776		
27	**EXPANSION FACTOR**	**1.00740**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				5,979,062	404,929	23,776		
37	SALES		0						0
38	LOSSES			192,233	179,372	12,148	713		0
39	INPUT				6,158,434	417,077	24,489		0
40	**EXPANSION FACTOR**	**1.03000**							
41	**TOTALS** LOSSES			429,878	409,099	19,891	888		0
42	% OF TOTAL			100%	95.17%	4.63%	0.21%		0.00%
43	SALES		6,170,122		5,749,335	397,186	23,601		0
44	% OF TOTAL		100.00%		93.18%	6.44%	0.38%		0.00%
45	INPUT		6,600,000		6,158,434	417,077	24,489		0
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.07116**	**1.05008**	**1.03762**		**NA**

KCPL KS & MO | **DEVELOPMENT of LOSS FACTORS** | **EXHIBIT 10**
COMPOSITE | **ADJUSTED** **EXHIBIT 7** | PAGE 1 OF 2
LOSS FACTORS | **DEMAND**

LOSS FACTOR LEVEL	CUSTOMER SALES MW	SALES ADJUST	CALC LOSS TO LEVEL	SALES MW @ GEN	CUM PEAK FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	0.0	0.0	0.0	0.0	0.00000	0.97824
SUBTRANS	40.0	0.0	1.2	41.2	1.03000	0.97824
PRIM SUBS	33.0	0.0	1.2	34.2	1.03694	0.96437
PRIM LINES	147.3	0.0	8.5	155.8	1.05786	0.94061
SECONDARY	2,851.0	0.0	223.0	3,074.1	1.07822	0.91849
TOTALS	3,071.3	0.0	234.0	3,305.3	1.07618	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH	SALES **ADJUST**	CALC LOSS TO LEVEL	SALES MWH @ GEN	CUM ANNUAL FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
TOTAL TRANS	0	0	0	0	0.00000	0.00000
SUBTRANS	340959	0	10229	351188	1.03000	0.97087
PRIM SUBS	269,877	0	10,188	280,065	1.03775	0.96362
PRIM LINES	1,017,249	0	50,676	1,067,925	1.04982	0.95255
SECONDARY	12,617,891	0	882,932	13,500,823	1.06997	0.93460
TOTAL	14,245,976	0	954,024	15,200,000	1.06697	<COMPOSITE

KCPL Kansas — **DEVELOPMENT of LOSS FACTORS** — **EXHIBIT 10**
ADJUSTED **EXHIBIT 7** — PAGE 2 OF 2
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK FACTORS e	EXPANTION f=1/e
BULK LINES	0.0	0	0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0	0	0.0	0.00000	0.00000
TRANS LINES	0.0	0	0	0.0	0.00000	0.00000
TOTAL TRANS	0.0	0.0	0.0	0.0	0.00000	0.91849
SUBTRANS	0.0	0.0	0.0	0.0	0.00000	0.91849
PRIM SUBS	4.0	0.0	0.1	4.1	1.03587	0.91849
PRIM LINES	68.0	0.0	3.9	71.9	1.05695	0.91849
SECONDARY	1,392.6	0.0	106.4	1,499.0	1.07642	0.91849
TOTALS	1,464.6	0.0	110.4	1,575.0	1.07541	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES **ADJUST** b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNUAL FACTORS e	EXPANTION f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
TOTAL TRANS	0	0	0	0	0.00000	0.00000
SUBTRANS	0	0	0	0	0.00000	0.00000
PRIM SUBS	23,601	0	888	24,489	1.03762	0.96374
PRIM LINES	397,186	0	19,891	417,077	1.05008	0.95231
SECONDARY	5,749,335	0	409,099	6,158,434	1.07116	0.93357
TOTAL	6,170,122	0	429,878	6,600,000	1.06967	<COMPOSITE

KCPL Missouri — **DEVELOPMENT of LOSS FACTORS**
ADJUSTED **EXHIBIT 7**
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK FACTORS e	EXPANTION f=1/e
BULK LINES	0.0	0	0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0	0	0.0	0.00000	0.00000
TRANS LINES	0.0	0	0	0.0	0.00000	0.00000
TOTAL TRANS	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS	40.0	0.0	1.2	41.2	1.03000	0.97087
PRIM SUBS	29.0	0.0	1.1	30.1	1.03709	0.96424
PRIM LINES	79.3	0.0	4.6	83.9	1.05865	0.94460
SECONDARY	1458.5	0.0	116.6	1575.1	1.07994	0.92597
TOTALS	1,606.7	0.0	123.5	1,730.3	1.07688	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES **ADJUST** b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNUAL FACTORS e	EXPANTION f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
TOTAL TRANS	0	0	0	0	0.00000	0.00000
SUBTRANS	340,959	0	10,229	351,188	1.03000	0.97087
PRIM SUBS	246,276	0	9,300	255,576	1.03776	0.96361
PRIM LINES	620,063	0	30,785	650,848	1.04965	0.95270
SECONDARY	6,868,556	0	473,832	7,342,388	1.06899	0.93547
TOTAL	8,075,854	0	524,146	8,600,000	1.06490	<COMPOSITE

Appendix C

Results of 2020 Evergy Missouri West (MO West)

(NOTE: All of the 0.000 high voltage values shown on Exhibits 2, 3, and 5 reflect results that have been included in the loss factor estimates of Exhibit 5, line 22, TOT TRANS LOSS FAC.)

MO WEST

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK	1,845	MW
ANNUAL SYSTEM INPUT	8,583,034	MWH
ANNUAL SALES	8,008,468	MWH
SYSTEM LOSSES @ INPUT	574,566	or 6.69%
SYSTEM LOAD FACTOR	53.0%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	--- MW ---	Input	% TOTAL	--- MWH ---	Input	% TOTAL
TRANS	345,161,115 69,66,35	53.7	2.91%	40.69%	249,991	2.91%	43.51%
PRIM SUBS	33,12,1	12.3	0.67%	9.31%	68,559	0.80%	11.93%
PRIMARY	33,12,1	30.5	1.65%	23.08%	84,124	0.98%	14.64%
SECONDARY	120/240,to,477	35.5	1.93%	26.91%	171,892	2.00%	29.92%
TOTAL		132.0	7.16%	100.00%	574,566	6.69%	100.00%

SUMMARY OF LOSS FACTORS

		CUMMULATIVE SALES EXPANSION FACTORS			
SERVICE	KV	DEMAND (Peak)		ENERGY (Annual)	
		d	1/d	e	1/e
TOT TRANS	345,161,115 69,66,35	1.03000	0.97087	1.03000	0.97087
PRIM SUBS	33,12	1.03724	0.96410	1.03880	0.96265
PRIMARY	33,12,1	1.05618	0.94681	1.05026	0.95215
SECONDARY	120/240,to,477	1.08050	0.92550	1.07664	0.92881

SUMMARY OF CONDUCTOR INFORMATION

EXHIBIT 2

DESCRIPTION				CIRCUIT MILES	LOADING % RATING	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
--- BULK -----------	345 KV	OR GREATER									
TIE LINES				0.0	0.00%	0.000	0.000	0.000	0	0	0
BULK TRANS				0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT				0.0		0.000	0.000	0.000	0	0	0
--- TRANS ---------	115 KV	TO	345.00 KV								
TIE LINES				0	0.00%	0.000	0.000	0.000	0	0	0
TRANS1	161 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
TRANS2	115 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT				0.0		0.000	0.000	0.000	0	0	0
--- SUBTRANS ------	35 KV	TO	115 KV								
TIE LINES				0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS1	69 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS2	66 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS3	35 KV			0.0	0.00%	0.000	0.000	0.000	0	3	3
SUBTOT				0.0		0.000	0.000	0.000	0	3	3
PRIMARY LINES				11,011		23.725	2.708	26.433	57,165	23,786	80,951
SECONDARY LINES				4,305		4.024	0.000	4.024	7,528	0	7,528
SERVICES				4,795		4.469	0.716	5.185	11,960	6,293	18,254
TOTAL				20,112		32.218	3.425	35.643	76,654	30,082	106,736

SUMMARY OF TRANSFORMER INFORMATION

EXHIBIT 3

DESCRIPTION		KV VOLTAGE	CAPACITY MVA	NUMBER TRANSFMR	AVERAGE SIZE	LOADING %	MVA LOAD	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
BULK STEP-UP		345	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - BULK			0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS1		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 STEP-UP		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 STEP-UP		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1 STEP-UP		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2 STEP-UP		66	0.0	0	0.0	0.00%	0	0.000	0.001	0.001	0	0	0
SUBTRAN3 STEP-UP		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
DISTRIBUTION SUBSTATIONS													
TRANS1 -	161	33	495.7	8	62.0	40.16%	199	0.388	0.614	1.002	1,226	5,391	6,617
TRANS1 -	161	12	2,684.9	94	28.6	40.38%	1,084	2.448	3.597	6.045	7,553	31,597	39,150
TRANS1 -	161	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	33	156.2	14	11.2	28.48%	44	0.099	0.236	0.335	305	2,077	2,382
SUBTRAN1-	69	12	850.7	61	13.9	46.99%	400	1.777	1.290	3.067	5,095	11,331	16,425
SUBTRAN1-	69	1	139.9	17	8.2	44.08%	62	0.239	0.238	0.478	694	2,094	2,787
SUBTRAN2-	66	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
PRIMARY - PRIMARY			371.6	84	4.4	44.90%	167	0.646	0.621	1.267	1,705	5,453	7,158
LINE TRANSFRMR			5,415.2	101,346	53.4	31.82%	1,723	7.506	14.858	22.364	12,602	130,509	143,111
			===========	===========	===========	===========		===========	===========	===========	===========	==========	===========
TOTAL			10,114	101,624				13.103	21.455	34.558	29,180	188,452	217,632

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 1844.7 MW EXHIBIT 4 PAGE 1 of 2

BULK TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK LINES		
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK STEP UP		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

BULK-BULK		
LOADING	0.00%	
NO LOAD	0	MW
LOAD	0	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK-TRANS1 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRAN1-TRAN2 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

BULK-TRANS2 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS 1&2 STEP UPS		
LDNG TR1SU	0.00%	
NOLOAD1&2	0.000	MW
LOAD 1&2	0.000	MW
AVSIZ TR1SU	0.0	MVA
NUMBER	0	

TRANS1	161.0	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS2	115.0	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS CUST		
SUBS	0.000	MW
	0.000	MVA
LINES		MW
		MVA

SUBTRANS TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS1&2-SUBTRANS1		
LDNG TR2-ST	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVSIZ TR2	0	MVA
NUMBER	0	

SUBTR1&2-SUBTRANS2&3		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS1&2- SUBTRANS2		
LDNG TR2-ST:	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVSIZ TR2-ST	0.00	MVA
NUMBER	0	

TRANS1&2-SUBTRANS3	
LDNG TR2-ST2	0.00%
NO LOAD	0.00
LOAD	0.00
AVSIZ TR2-ST2	0.00
NUMBER	0

SUBTRANS1,2,&3 STEP UPS		
LDNG ST1SU	0.00%	
NO LOAD	0.001	MW
LOAD	0.000	MW
AVSIZ ST2	0.0	MVA
NUMBER	0	

SUBTRANS1	69	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS2	66	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS2	35	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS CUST	
SUBS - MW	0.000
MVA	0.000
LINES- MW	
MVA	

TO DISTRIBUTION SYSTEM

TOTAL 1789.1 MVA 1753.3 MW

TRANS1	1,283.2	MVA
	71.73%	
161 KV		

TRANS2	0.0	MVA
	0.00%	
115 KV		

SUBTRANS1	505.8	MVA
	28.27%	
69 KV		

SUBTRANS2	0.0	MVA
	0.00%	
66 KV		

SUBTRANS3	0.0	MVA
	0.00%	
35 KV		

FROM HIGH VOLTAGE SYSTEM

TOTAL 1,789 MVA 1,753 MW

TRANS1	TRANS2	SUBTRANS1	SUBTRANS2	SUBTRANS3
1,283.2 MVA	0.0 MVA	505.8 MVA	0.0 MVA	0.0 MVA
71.73%	0.00%	28.27%	0.00%	0.00%
161 KV	115 KV	69 KV	66 KV	35 KV

DISTRIBUTION SYSTEM LOAD

	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3
VOLTAGE	33	12	1	33	12	1	33	12	1	33	12	1	33	12	1
LOAD MVA	199	1,084	0	0	0	0	44	400	62	0	0	0	0	0	0
% SYS TOT	11.13%	60.60%	0.00%	0.00%	0.00%	0.00%	2.49%	22.34%	3.45%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NOLD LOSS	0.614	3.597	0.000	0.000	0.000	0.000	0.236	1.290	0.238	0.000	0.000	0.000	0.000	0.000	0.000
LOAD LOSS	0.388	2.448	0.000	0.000	0.000	0.000	0.099	1.777	0.239	0.000	0.000	0.000	0.000	0.000	0.000
AVG SIZE	62.0	28.6	0.0	0.0	0.0	0.0	11.2	13.9	8.2	0.0	0.0	0.0	0.0	0.0	0.0
NUMBER	8	94	0	0	0	0	14	61	17	0	0	0	0	0	0
DIVERSITY RATIO	1.000	1.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000

PRIMARY LINES		
LOADING	1693.036	MW
@ SYS PF	1727.588	MVA
LOAD LOSS	23.725	MW
NOLD LOSS	2.708	MW
TOT LOSS	26.433	MW

PRIM/PRIM TRANSF		
LOADING	166.842	MW
NOLD LOSS	0.621	MW
LOAD LOSS	0.646	MW
AVG SIZE	4.42	
NUMBER	84	

PRIM CUST LOADS		
NO LINES	0.000	MW
CUST SUB	0.000	MVA
NO LINES	49.400	MW
CO. SUB	50.408	MVA
PRIM WITH	90.700	MW
LINES	98.587	MVA

LINE TRANSFORMERS			
LOADING	1574.637	MW	MVA 1745.372
NOLD LOSS	14.858	MW	
LOAD LOSS	7.506	MW	
AVG SIZE	53.4	KVA	
NUMBER	101346		

SECONDARY LINES		
LOAD	586.407	MW
LOAD LOSS	4.024	MW
NOLD LOSS	0.000	MW
TOT LOSS	4.024	MW

NO SECONDARY LINES		
LOAD	965.866	MW

SERVICES		
LOAD	1548.249	MW
LOAD LOSS	4.469	MW
NOLD LOSS	0.716	MW
TOT LOSS	5.185	MW

CUSTOMER SECONDARY LOAD

1543.064 MW

SUMMARY of SALES and CALCULATED LOSSES

EXHIBIT 5

LOSS # AND LEVEL	MW LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC	MWH LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC
1 BULK XFMMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0	0
2 BULK LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
3 TRANS1 XFMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
4 TRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
5 TRANS2TR1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
6 TRANS2BLK SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
7 TRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
TOTAL TRAN	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
8 STR1BLK SD												
9 STR1T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
10 SRT1T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
11 SUBTRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
12 STR2T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
13 STR2T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
14 STR2S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
15 SUBTRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
16 STR3T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
17 STR3T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
18 STR3S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
19 STR3S2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
20 SUBTRANS3 LINES	0.0	0.00	0.00	0.00	0.000000		0	3	0	3	0.0000000	
21 SUBTRANS TOTAL	0.0	0.00	0.00	0.00	0.000000	**FERC OATT**	0	3	0	3	0.0000000	**FERC OATT**
22 TOT TRANS LOSS FAC	**1,844.7**	**6.45**	**47.28**	**53.73**	**1.030000**	**1.030000**	**8,583,034**	**56,635**	**193,356**	**249,991**	**1.0300000**	**1.0300000**
DISTRIBUTION SUBST												
TRANS1	1,257.6	4.21	2.84	7.05	1.005635	0.000000	5,799,363	36,989	8,779	45,767	1.0079546	0.0000000
TRANS2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR1	495.7	1.76	2.12	3.88	1.007889	0.000000	2,286,014	15,502	6,093	21,595	1.0095368	0.0000000
SUBTR2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR3	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
WEIGHTED AVERAGE	1,753.3	5.98	4.95	10.93	1.006271	1.036460	8,085,377	52,490	14,872	67,363	1.0084014	1.0386535
PRIMARY INTRCHNGE	0.0				0.000000		0				0.0000000	
PRIMARY LINES	1,692.4	2.71	24.37	27.08	1.016260	1.053313	7,706,716	23,786	58,870	82,656	1.0108415	1.0499140
LINE TRANSF	1,574.6	14.86	7.51	22.36	1.014407	1.068488	7,012,018	130,509	12,602	143,111	1.0208346	1.0717885
SECONDARY	1,552.3	0.00	4.02	4.02	1.002599	1.071265	6,868,907	0	7,528	7,528	1.0010972	1.0729645
SERVICES	1,548.2	0.72	4.47	5.19	1.003360	1.074865	6,861,379	6,293	11,960	18,254	1.0026674	1.0758266
		===========	===========	===========				===========	===========	===========		
TOTAL SYSTEM		30.71	92.60	123.31				269,713	299,190	568,903		

DEVELOPMENT of LOSS FACTORS EXHIBIT 6
UNADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	CALC LOSS TO LEVEL b	SALES MW @ GEN c	CUM PEAK EXPANSION FACTORS d	1/d
BULK LINES	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	29.5	0.9	30.4	1.03000	0.97087
PRIM SUBS	49.4	1.8	51.2	1.03646	0.96482
PRIM LINES	90.7	4.8	95.5	1.05331	0.94939
SECONDARY	1,543.1	115.5	1,658.6	1.07486	0.93035
TOTALS	1,712.7	123.0	1,835.7		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	CALC LOSS TO LEVEL b	SALES MWH @ GEN c	CUM ANNUAL EXPANSION FACTORS d	1/d
BULK LINES	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0.00000	0.00000
TOTAL TRANS	241,668	7,250	248,918	1.03000	0.97087
PRIM SUBS	311,633	12,046	323,679	1.03865	0.96279
PRIM LINES	612,042	30,549	642,591	1.04991	0.95246
SECONDARY	6,843,125	518,891	7,362,016	1.07583	0.92952
TOTALS	8,008,468	568,736	8,577,204		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	30.39	248,918
PRIM SUBS	51.20	323,679
PRIM LINES	95.54	642,591
SECONDARY	1,658.58	7,362,016
SUBTOTAL	1,835.71	8,577,204
ACTUAL ENERGY	1,844.70	8,583,034
MISMATCH	(8.99)	(5,830)
% MISMATCH	-0.49%	-0.07%

DEVELOPMENT of LOSS FACTORS EXHIBIT 7
ADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK EXPANSION FACTORS e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	29.5	0.0	0.9	30.4	1.03000	0.97087
PRIM SUBS	49.4	0.0	1.8	51.2	1.03724	0.96410
PRIM LINES	90.7	0.0	5.1	95.8	1.05618	0.94681
SECONDARY	1,543.1	0.0	124.2	1,667.3	1.08050	0.92550
			132.0			
TOTALS	1,712.7	0.0	132.0	1,844.7		

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNUAL EXPANSION FACTORS e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	241,668	0	7,250	248,918	1.03000	0.97087
PRIM SUBS	311,633	0	12,092	323,725	1.03880	0.96265
PRIM LINES	612,042	0	30,761	642,803	1.05026	0.95215
SECONDARY	6,843,125	0	524,463	7,367,588	1.07664	0.92881
			574,566			
TOTALS	8,008,468	0	574,566	8,583,034		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	30.39	248,918
PRIM SUBS	51.24	323,725
PRIM LINES	95.80	642,803
SECONDARY	1,667.28	7,367,588
	1,844.70	8,583,034
ACTUAL ENERGY	1,844.70	8,583,034
MISMATCH	0.00	0
% MISMATCH	0.00%	0.00%

Adjusted Losses and Loss Factors by Facility EXHIBIT 8

Unadjusted Losses by Segment

	MW	Unadjusted	MWH	Unadjusted	
Service Drop Losses	5.19	5.17	18,254	18,244	
Secondary Losses	4.02	4.01	7,528	7,524	
Line Transformer Losses	22.36	22.28	143,111	143,036	
Primary Line Losses	27.08	26.98	82,656	82,613	
Distribution Substation Losses	10.93	10.89	67,363	67,327	
Transmission System Losses	53.73	53.73	249,991	249,991	
Total	123.31	123.04	568,903	568,736	
Mismatch Allocation by Segment					
	MW		MWH		
Service Drop Losses	-0.67		-334		
Secondary Losses	-0.52		-138		
Line Transformer Losses	-2.89		-2,616		
Primary Line Losses	-3.50		-1,511		
Distribution Substation Losses	-1.41		-1,232		
Transmission System Losses	0.00		0		
Total	-8.99		-5,830		
Adjusted Losses by Segment					
	MW	% of Total	MWH	% of Total	
Service Drop Losses	5.84	4.4%	18,578	3.2%	
Secondary Losses	4.53	3.4%	7,662	1.3%	
Line Transformer Losses	25.17	19.1%	145,652	25.3%	
Primary Line Losses	30.48	23.1%	84,124	14.6%	
Distribution Substation Losses	12.30	9.3%	68,559	11.9%	
Transmission System Losses	53.73	40.7%	249,991	43.5%	
Total	132.04	100.0%	574,566	100.0%	
Loss Factors by Segment	**MW**		**MWH**		
Retail Sales from Service Drops	1,543.064		6,843,125		
Adjusted Service Drop Losses	5.836		18,578		
Input to Service Drops	1,548.899		6,861,703		
Service Drop Loss Factor	**1.00378**		**1.00271**		
Output from Secondary	1,548.899		6,861,703		
Adjusted Secondary Losses	4.529		7,662		
Input to Secondary	1,553.429		6,869,365		
Secondary Conductor Loss Factor	**1.00292**		**1.00112**		
Output from Line Transformers	1,553.429		6,869,365		
Adjusted Line Transformer Losses	25.169		145,652		
Input to Line Transformers	1,578.598		7,015,017		
Line Transformer Loss Factor	**1.01620**		**1.02120**		
Retail Sales from Primary	84.000		583,501		
Req. Whls Sales from Primary	6.700		28,541		
Input to Line Transformers	1,578.598		7,015,017		
Output from Primary Lines	1,669.298		7,627,059		
Adjusted Primary Line Losses	30.476		84,124		
Input to Primary Lines	1,699.773		7,711,183		
Primary Line Loss Factor	**1.01826**		**1.01103**		
Output Pl from Distribution Substations	1,699.773		7,711,183		
Req. Whls Sales from Substations	0.000		0		
Retail Sales from Substations	49.400		311,633		
TotalOutput from Distribution Substations	1,749.173		8,022,816		
Adjusted Distribution Substation Losses	12.298		68,559		
Input to Distribution Substations	1,761.471		8,091,375		
Distribution Substation Loss Factor	**1.00703**		**1.00855**		
Retail Sales at from SubTransmission	29.500		241,668		
Req. Whls Sales from SubTransmission	0.000		0		
Non-Req. Whls Sales from SubTransmission	0.000		0		
Losses	0.000		0		4678
Input to Distribution Substations	1,761.471		8,091,375		
Output from SubTransmission	1,790.971		8,333,043		1,844.700
SubTransmission System Losses	53.729		249,991		53.729
Input to Transmission	1,844.700		8,583,034		53.729
TotTransmission System Loss Factor	**1.03000**		**1.03000**		53.729

	DEMAND MW				SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE				EXHIBIT 9 PAGE 1 of 2
	SERVICE LEVEL		**SALES MW**	**LOSSES**	**SECONDARY**	**PRIMARY**	**SUBSTATION**	**SUBTRANS**	**TRANSMISSION**
1	**SERVICES**								
2	SALES		1,543.1		1,543.1				
3	LOSSES			5.8	5.8				
4	INPUT				1,548.9				
5	**EXPANSION FACTOR**	**1.00378**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			4.5	4.5				
9	INPUT				1,553.4				
10	**EXPANSION FACTOR**	**1.00292**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			25.2	25.2				
14	INPUT				1,578.6				
15	**EXPANSION FACTOR**	**1.01620**							
16	**PRIMARY**								
17	SECONDARY				1,578.6				
18	SALES		84.0			84.0			
19	LOSSES			30.5	28.8	1.5			
20	INPUT				1,607.4	85.5			
21	**EXPANSION FACTOR**	**1.01826**							
22	**SUBSTATION**								
23	PRIMARY				1,607.4	85.5			
24	SALES		49.4				49.4		
25	LOSSES			12.3	11.3	0.6	0.3		
26	INPUT				1,618.7	86.1	49.7		
27	**EXPANSION FACTOR**	**1.00703**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				1,618.7	86.1	49.7		
37	SALES		29.5						29.5
38	LOSSES			53.5	48.6	2.6	1.5		0.9
39	INPUT				1,667.3	88.7	51.2		30.4
40	**EXPANSION FACTOR**	**1.03000**							
41	**TOTALS** LOSSES			131.8	124.2	4.7	1.8		0.9
42	% OF TOTAL			100%	94.22%	3.58%	1.40%		0.67%
43	SALES		1,706.0		1,543.1	84.0	49.4		29.5
44	% OF TOTAL		100.00%		90.45%	4.92%	2.90%		1.73%
45	INPUT		1,837.6		1,667.3	88.7	51.2		30.4
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.08050**	**1.05618**	**1.03724**		**1.03000**

ENERGY MWH **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** **EXHIBIT 9**

	SERVICE LEVEL		SALES	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		6,843,125		6,843,125				
3	LOSSES			18,578	18,578				
4	INPUT				6,861,703				
5	**EXPANSION FACTOR**	**1.00271**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			7,662	7,662				
9	INPUT				6,869,365				
10	**EXPANSION FACTOR**	**1.00112**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			145,652	145,652				
14	INPUT				7,015,017				
15	**EXPANSION FACTOR**	**1.02120**							
16	**PRIMARY**								
17	SECONDARY				7,015,017				
18	SALES		583,501.000			583,501			
19	LOSSES			84,124	77,373	6,436			
20	INPUT				7,092,390	589,937			
21	**EXPANSION FACTOR**	**1.01103**							
22	**SUBSTATION**								
23	PRIMARY				7,092,390	589,937			
24	SALES		311,633				311,633		
25	LOSSES			68,559	60,608	5,041	2,663		
26	INPUT				7,152,998	594,978	314,296		
27	**EXPANSION FACTOR**	**1.00855**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				7,152,998	594,978	314,296		
37	SALES		241,668						241,668
38	LOSSES			249,118	214,590	17,849	9,429		7,250
39	INPUT				7,367,588	612,827	323,725		248,918
40	**EXPANSION FACTOR**	**1.03000**							
41	**TOTALS** LOSSES			573,693	524,463	29,326	12,092		7,250
42	% OF TOTAL			100%	91.42%	5.11%	2.11%		1.26%
43	SALES		7,979,927		6,843,125	583,501	311,633		241,668
44	% OF TOTAL		100.00%		85.75%	7.31%	3.91%		3.03%
45	INPUT		8,553,059		7,367,588	612,827	323,725		248,918
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.07664**	**1.05026**	**1.03880**		**1.03000**

Appendix D

Discussion of Hoebel Coefficient

COMMENTS ON THE HOEBEL COEFFICIENT

The Hoebel coefficient represents an established industry standard relationship between peak losses and average losses and is used in a loss study to estimate energy losses from peak demand losses. H. F. Hoebel described this relationship in his article, "Cost of Electric Distribution Losses," Electric Light and Power, March 15, 1959. A copy of this article is attached.

Within any loss evaluation study, peak demand losses can readily be calculated given equipment resistance and approximate loading. Energy losses, however, are much more difficult to determine given their time-varying nature. This difficulty can be reduced by the use of an equation which relates peak load losses (demand) to average losses (energy). Once the relationship between peak and average losses is known, average losses can be estimated from the known peak load losses.

Within the electric utility industry, the relationship between peak and average losses is known as the loss factor. For definitional purposes, loss factor is the ratio of the average power loss to the peak load power loss, during a specified period of time. This relationship is expressed mathematically as follows:

(1) $F_{LS} \cong A_{LS} \div P_{LS}$

where: F_{LS} = Loss Factor
A_{LS} = Average Losses
P_{LS} = Peak Losses

The loss factor provides an estimate of the degree to which the load loss is maintained throughout the period in which the loss is being considered. In other words, loss factor is the ratio of the actual kWh losses incurred to the kWh losses which would have occurred if full load had continued throughout the period under study.

Examining the loss factor expression in light of a similar expression for load factor indicates a high degree of similarity. The mathematical expression for load factor is as follows:

(2) $F_{LD} \cong A_{LD} \div P_{LD}$

where: F_{LD} = Load Factor
A_{LD} = Average Load
P_{LD} = Peak Load

This load factor result provides an estimate of the degree to which the load loss is maintained throughout the period in which the load is being considered. Because of the similarities in definition, the loss factor is sometimes called the "load factor of losses." While the definitions are similar, a strict equating of the two factors cannot be made. There does exist, however, a relationship between these two factors which is dependent upon the shape of the load duration curve. Since resistive losses vary as the square of the load, it can be shown mathematically that the loss factor can vary between the extreme limits of load factor and load factor squared. The relationship between load factor and loss factor has become an industry standard and is as follows:

$$(3)\ F_{LS} \cong H*F_{LD}^2 + (1-H)*F_{LD}$$

where:
F_{LS} = Loss Factor
F_{LD} = Load Factor
H = Hoebel Coefficient

As noted in the attached article, the suggested value for H (the Hoebel coefficient) is 0.7. The exact value of H will vary as a function of the shape of the utility's load duration curve. In recent years, values of H have been computed directly for a number of utilities based on EEI load data. It appears on this basis, the suggested value of 0.7 should be considered a lower bound and that values approaching unity may be considered a reasonable upper bound. Based on experience, values of H have ranged from approximately 0.85 to 0.95. The standard default value of 0.9 is generally used.

Inserting the Hoebel coefficient estimate gives the following loss factor relationship using Equation (3):

$$(4)\ F_{LS} \cong 0.90*F_{LD}^2 + 0.10*F_{LD}$$

Once the Hoebel constant has been estimated and the load factor and peak losses associated with a piece of equipment have been estimated, one can calculate the average, or energy losses as follows:

$$(5)\ A_{LS} \cong P_{LS} * [H*F_{LD}^2 + (1-H)*F_{LD}]$$

where:
A_{LS} = Average Losses
P_{LS} = Peak Losses
H = Hoebel Coefficient
F_{LD} = Load Factor

Loss studies use this equation to calculate energy losses at each major voltage level in the analysis.

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FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided February 22, 2017 through December 6, 2018)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:
An accumulation period is the six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate ("FAR"). The two six-month accumulation periods each year through December 21, 2020, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

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

A recovery period consists of the months during which the FAR is applied to customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES:
Costs eligible for the Fuel and Purchased Power Adjustment ("FPA") will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, purchased power energy charges including applicable Southwest Power Pool ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off-system sales, all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, and revenue from the sale of Renewable Energy Certificates or Credits ("REC"). Eligible costs do not include the purchased power demand costs associated with purchased power contacts in excess of one year. Likewise revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) periodically subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("S_{RP}") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregated over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR multiplied by kWh billed.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided February 22, 2017 through December 6, 2018)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR – R)

FC = Fuel Costs Incurred to Support Sales:
The following costs reflected in Federal Energy Regulatory Commission ("FERC") Account Number 501:

Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], applicable taxes, natural gas costs, alternative fuels (i.e. tires, bio-fuel), fuel quality adjustments, fuel adjustments included in commodity and transportation costs, oil costs for commodity, propane costs, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for fuel expenses in the 501 Accounts.

Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to native load;

Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to off-system sales;

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone, powder activated carbon, urea, sodium bicarbonate, trona, sulfur, and RESPond, or other consumables which perform similar functions;

Subaccount 501400 and 501420: residual costs and revenues associated with combustion product, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.

The following costs reflected in FERC Account Number 547:

Subaccount 547000: natural gas, and oil costs for commodity, transportation, storage, taxes, fees and fuel losses, and settlement proceeds, insurance recoveries, subrogation recoveries for fuel expenses,

Subaccount 547020: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to native load;

Subaccount 547030: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to off-system sales;
Subaccount 547300: fuel additives.

E = Net Emission Costs:
The following costs and revenues reflected in FERC Account Number 509:

Subaccount 509000: NOx and SO_2 emission allowance costs and revenue amortizations offset by revenues from the sale of NOx and SO_2 emission allowances including any associated broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers).

PP = Purchased Power Costs:
The following costs or revenues reflected in FERC Account Number 555:

Subaccount 555005: capacity charges for capacity purchases one year or less in duration;

Subaccount 555000: purchased power costs, energy charges from capacity purchases of any duration, insurance recoveries, and subrogation recoveries for purchased power expenses, charges and credits related to the SPP Integrated Marketplace ("IM").

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Subaccount 555021: the allocation of the allowed costs in the 555000 account attributed to intercompany purchases for native load;

Subaccount 555030: the allocation of the allowed costs in the 555000 account attributed to purchases for off-system sales;

Subaccount 555031: the allocation of the allowed costs in the 555000 account attributed to intercompany purchases for off system sales.

TC = Transmission Costs:

The following costs reflected in FERC Account Number 565:

Subaccount 565000: non-SPP transmission used to serve off-system sales or to make purchases for load, excluding any transmission costs associated with the Crossroads Power Plant and 39.62% of the SPP transmission service costs which includes the schedules listed below as well as any adjustments to the charges in the schedules below:

Schedule 7 – Long Term Firm and Short Term Point to Point Transmission Service
Schedule 8 – Non Firm Point to Point Transmission Service
Schedule 9 – Network Integration Transmission Service
Schedule 10 – Wholesale Distribution Service
Schedule 11 – Base Plan Zonal Charge and Region Wide Charge

Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;

Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;

Subaccount 565030: the allocation of the allowed costs in account 565000 attributed to off-system sales.

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:
Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM. Off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year shall be excluded from OSSR component;
Subaccount 447012: capacity charges for capacity sales one year or less in duration;

Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.

R = Renewable Energy Credit Revenue:
Revenues reflected in FERC account 509000 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard.

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, or R shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) 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 centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC:

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

A. The Company may include the new schedule, charge type cost or revenue in its FAR filings if the Company believes the new schedule, charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed below or in the schedules listed in TC, 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 schedule or charge type no later than 60 days prior to the Company including the new schedule, charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such change, 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, TC or OSSR as the case may be, and identify the preexisting schedule, or market settlement charge type(s) which the new schedule or 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 schedule, charge type costs or revenues by amount, description and location within the monthly reports;

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

If the Company makes the filing provided for in 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 schedule or charge type, a party shall make a filing with the Commission based upon that party's contention that the new schedule, charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC or OSSR, as the case may be. A party wishing to challenge the inclusion of a schedule or charge type shall include in its filing the reasons why it believes the Company did not show that the new schedule or charge type possesses the characteristics of the costs or revenues listed in Factors TC, 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 schedule or 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;

FORMULAS AND DEFINITIONS OF COMPONENTS (Continued)

F. A party other than the Company may seek the inclusion of a new schedule or 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 date of January 1 or July 1. Such a filing shall give the Commission notice that such party believes the new schedule or 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, TC or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such change, provide a description of the new schedule or charge type demonstrating that it possesses the characteristics of, and is of the nature of, the schedules, costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule or market settlement charge type(s) which the new schedule or 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 schedule or charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new schedule or charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new schedule or charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC, 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 schedule or charge type does not possess the characteristic of the costs or revenues listed in Factors PP, TC or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new schedule or charge type. In the event of a timely challenge, the party seeking the inclusion of the new schedule or charge type shall bear the burden of proof to support its contention that the new schedule or 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.

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC are listed below:

Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Regulation Service Deployment Adjustment Amount
Real Time Regulation Down Service Amount
Real Time Regulation Down Service Distribution Amount
Real Time Regulation Non-Performance
Real Time Regulation Non-Performance Distribution
Real Time Regulation Up Service Amount
Real Time Regulation Up Service Distribution Amount
Real Time Spinning Reserve Amount
Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount
Real Time Asset Energy Amount
Real Time Non-Asset Energy Amount
Real Time Virtual Energy Amount
Transmission Congestion Rights Funding Amount
Transmission Congestion Rights Daily Uplift Amount
Transmission Congestion Rights Monthly Payback Amount
Transmission Congestion Rights Annual Payback Amount
Transmission Congestion Rights Annual Closeout Amount
Transmission Congestion Rights Auction Transaction Amount
Auction Revenue Rights Funding Amount
Auction Revenue Rights Uplift Amount

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)

Auction Revenue Rights Monthly Payback Amount
Auction Revenue Annual Payback Amount
Auction Revenue Rights Annual Closeout Amount
Day Ahead Virtual Energy Transaction Fee Amount
Day Ahead Demand Reduction Amount
Day Ahead Grandfathered Agreement Carve Out Daily Amount
Grandfathered Agreement Carve Out Distribution Daily Amount
Day Ahead Grandfathered Agreement Carve Out Monthly Amount
Grandfathered Agreement Carve Out Distribution Monthly Amount
Day Ahead Grandfathered Agreement Carve Out Yearly Amount
Grandfathered Agreement Carve Out Distribution Yearly Amount
Day Ahead Make Whole Payment Amount
Day Ahead Make Whole Payment Distribution Amount
Miscellaneous Amount
Reliability Unit Commitment Make Whole Payment Amount
Real Time Out of Merit Amount
Reliability Unit Commitment Make Whole Payment Distribution Amount
Over Collected Losses Distribution Amount
Real Time Joint Operating Agreement Amount
Real Time Reserve Sharing Group Amount
Real Time Reserve Sharing Group Distribution Amount
Real Time Demand Reduction Amount
Real Time Demand Reduction Distribution Amount
Real Time Pseudo Tie Congestion Amount
Real Time Pseudo Tie Losses Amount
Unused Regulation Up Mileage Make Whole Payment Amount
Unused Regulation Down Mileage Make Whole Payment Amount
Revenue Neutrality Uplift Distribution Amount

Should FERC require any item covered by components FC, E, PP, TC, OSSR or R to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR or R. 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 the Rider FAC to be recorded in the account.

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. Net Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor ("BF")

S_{AP} = Net system input ("NSI") in kWh for the accumulation period, at the generation level.

BF = Company base factor costs per kWh: $0.02055

J = Missouri Retail Energy Ratio = Retail kWh sales/total system kWh

Where: total system kWh equals retail and full and partial requirement sales associated with GMO.

T = True-up amount as defined below.

I = Interest applicable to (i) the difference between Missouri Retail ANEC and B for all kWh of energy supplied during an accumulation period until those costs have been recovered; (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 adjustment amount, if any.

FAR = FPA/S_{RP}

Single Accumulation Period Secondary Voltage FAR_{Sec} = FAR * VAF_{Sec}

Single Accumulation Period Primary Voltage FAR_{Prim} = FAR * VAF_{Prim}

Annual Secondary Voltage FAR_{Sec} = Aggregation of the two Single Accumulation Period Secondary Voltage FARs still to be recovered

Annual Primary Voltage FAR_{Prim} = Aggregation of the two Single Accumulation Period Primary Voltage FARs still to be recovered

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period retail NSI in kWh, at the generation level..

VAF = Expansion factor by voltage level
- VAF_{Sec} = Expansion factor for lower than primary voltage customers
- VAF_{Prim} = Expansion factor for primary and higher voltage customers

TRUE-UPS

After completion of each recovery period, the Company shall make a true-up filing by the filing date of its next FAR filing. Any true-up adjustments shall be reflected in component "T" above. Interest on the true-up adjustment will be included in component "I" above.

The true-up amount shall be the difference between the revenues billed and the revenues authorized for collection during the RP as well as any corrections identified to be included in the current FAR filing. Any corrections included will be discussed in the testimony accompanying the true-up filing.

PRUDENCE REVIEWS

Prudence reviews of the costs subject to this Rider 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 FAC shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in component "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in component "I" above.

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DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

An accumulation period is the six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate ("FAR"). The two six-month accumulation periods each year through four years from the effective date of this tariff sheet, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

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

A recovery period consists of the months during which the FAR is applied to customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES:

Costs eligible for the Fuel and Purchased Power Adjustment ("FPA") will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, purchased power energy charges including applicable Southwest Power Pool ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off-system sales, all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, and revenue from the sale of Renewable Energy Certificates or Credits ("REC"). Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year. Likewise, revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) periodically subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("S_{RP}") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregated over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR multiplied by kWh billed.

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FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR – R)

FC = Fuel Costs Incurred to Support Sales:
The following costs reflected in Federal Energy Regulatory Commission (“FERC”) Account Number 501:
Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], applicable taxes, natural gas costs, fuel quality adjustments, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), oil costs for commodity, propane costs, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for fuel expenses in the 501 Accounts.
Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to native load;
Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to off-system sales;
Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems (“AQCS”) operations, such as ammonia, hydrated lime, lime, limestone, limestone inventory adjustment, powder activated carbon, urea, propane, sodium bicarbonate, calcium bromide, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400 and 501420: residual costs and revenues associated with combustion byproducts, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

The following costs reflected in FERC Account Number 547:

Subaccount 547000: natural gas and oil costs for commodity, transportation, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), storage, taxes, fees and fuel losses, and settlement proceeds, insurance recoveries, subrogation recoveries for fuel expenses,

Subaccount 547020: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to native load;

Subaccount 547030: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to off-system sales;

Subaccount 547300: fuel additives and consumable costs for Air Quality Control Systems (“AQCS”) operations, such as ammonia or other consumables which perform similar functions.

E = Net Emission Costs:
The following costs and revenues reflected in FERC Account Number 509:

Subaccount 509000: NOx and SO_2 emission allowance costs, including any associated broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) offset by revenue amortizations and revenues from the sale of NOx and SO_2 emission allowances.

PP = Purchased Power Costs:
The following costs or revenues reflected in FERC Account Number 555:

Subaccount 555005: capacity charges for capacity purchases one year or less in duration;

Subaccount 555000: purchased power costs, energy charges from capacity purchases, insurance recoveries, and subrogation recoveries for purchased power expenses, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), and charges and credits related to the SPP Integrated Marketplace (“IM”) or other IMs, excluding the amounts associated with purchased power agreements associated with the Renewable Energy Rider tariff.

Subaccount 555030: the allocation of the allowed costs in the 555000 account attributed to purchases for off-system sales;

Subaccount 555035: purchased power costs associated with the WAPA agreement.

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

TC = Transmission Costs:
The following costs reflected in FERC Account Number 565:

Subaccount 565000: non-SPP transmission used to serve off-system sales or to make purchases for load, excluding any transmission costs associated with the Crossroads Power Plant and 47.20% of the SPP transmission service costs which includes the schedules listed below as well as any adjustments to the charges in the schedules below:

Schedule 7 – Long Term Firm and Short Term Point to Point Transmission Service
Schedule 8 – Non Firm Point to Point Transmission Service
Schedule 9 – Network Integration Transmission Service
Schedule 10 – Wholesale Distribution Service
Schedule 11 – Base Plan Zonal Charge and Region Wide Charge

excluding amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.

Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;

Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;

Subaccount 565030: the allocation of the allowed costs in account 565000 attributed to off-system sales.

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:

Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM, excluding (1) the amounts associated with purchased power agreements associated with the Renewable Energy Rider tariff, and (2) off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year. Additional revenue will be added at an imputed 75% of the unsubscribed portion associated with the Solar Subscription Rider valued at market price;

Subaccount 447012: capacity charges for capacity sales;
Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.
Subaccount 447035: the off-systems sales revenues associated with the WAPA agreement.

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

R = Renewable Energy Credit Revenue:
Revenues reflected in FERC account 509000 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard.

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, or R shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) 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 centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC:

A. The Company may include the new schedule, charge type cost or revenue in its FAR filings if the Company believes the new schedule, charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed below or in the schedules listed in TC, 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 schedule or charge type no later than 60 days prior to the Company including the new schedule, charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such change, 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, TC or OSSR as the case may be, and identify the preexisting schedule, or market settlement charge type(s) which the new schedule or 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 schedule, charge type costs or revenues by amount, description and location within the monthly reports;

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

E. If the Company makes the filing provided for in 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 schedule or charge type, a party shall make a filing with the Commission based upon that party's contention that the new schedule, charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC or OSSR, as the case may be. A party wishing to challenge the inclusion of a schedule or charge type shall include in its filing the reasons why it believes the Company did not show that the new schedule or charge type possesses the characteristics of the costs or revenues listed in Factors TC, 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 schedule or 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

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FORMULAS AND DEFINITIONS OF COMPONENTS (Continued)

F. A party other than the Company may seek the inclusion of a new schedule or 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 date of January 1 or July 1. Such a filing shall give the Commission notice that such party believes the new schedule or 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, TC or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such change, provide a description of the new schedule or charge type demonstrating that it possesses the characteristics of, and is of the nature of, the schedules, costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule or market settlement charge type(s) which the new schedule or 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 schedule or charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new schedule or charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new schedule or charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC, 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 schedule or charge type does not possess the characteristic of the costs or revenues listed in Factors PP, TC or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new schedule or charge type. In the event of a timely challenge, the party seeking the inclusion of the new schedule or charge type shall bear the burden of proof to support its contention that the new schedule or 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.

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC are listed below:

Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Regulation Service Deployment Adjustment Amount
Real Time Regulation Down Service Amount
Real Time Regulation Down Service Distribution Amount
Real Time Regulation Non-Performance
Real Time Regulation Non-Performance Distribution
Real Time Regulation Up Service Amount
Real Time Regulation Up Service Distribution Amount
Real Time Spinning Reserve Amount
Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount
Real Time Asset Energy Amount
Real Time Non-Asset Energy Amount
Real Time Virtual Energy Amount
Transmission Congestion Rights Funding Amount
Transmission Congestion Rights Daily Uplift Amount
Transmission Congestion Rights Monthly Payback Amount
Transmission Congestion Rights Annual Payback Amount
Transmission Congestion Rights Annual Closeout Amount
Transmission Congestion Rights Auction Transaction Amount
Auction Revenue Rights Funding Amount
Auction Revenue Rights Uplift Amount

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)

- Auction Revenue Rights Monthly Payback Amount
- Auction Revenue Annual Payback Amount
- Auction Revenue Rights Annual Closeout Amount
- Day Ahead Virtual Energy Transaction Fee Amount
- Day Ahead Demand Reduction Amount
- Day Ahead Demand Reduction Distribution Amount
- Day Ahead Grandfathered Agreement Carve Out Daily Amount
- Grandfathered Agreement Carve Out Distribution Daily Amount
- Day Ahead Grandfathered Agreement Carve Out Monthly Amount
- Grandfathered Agreement Carve Out Distribution Monthly Amount
- Day Ahead Grandfathered Agreement Carve Out Yearly Amount
- Grandfathered Agreement Carve Out Distribution Yearly Amount
- Day Ahead Make Whole Payment Amount
- Day Ahead Make Whole Payment Distribution Amount
- Miscellaneous Amount
- Reliability Unit Commitment Make Whole Payment Amount
- Real Time Out of Merit Amount
- Reliability Unit Commitment Make Whole Payment Distribution Amount
- Over Collected Losses Distribution Amount
- Real Time Joint Operating Agreement Amount
- Real Time Reserve Sharing Group Amount
- Real Time Reserve Sharing Group Distribution Amount
- Real Time Demand Reduction Amount
- Real Time Demand Reduction Distribution Amount
- Real Time Pseudo Tie Congestion Amount
- Real Time Pseudo Tie Losses Amount
- Unused Regulation Up Mileage Make Whole Payment Amount
- Unused Regulation Down Mileage Make Whole Payment Amount
- Revenue Neutrality Uplift Distribution Amount

Should FERC require any item covered by components FC, E, PP, TC, OSSR or R to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR or R. 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 the Rider FAC to be recorded in the account.

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B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. Net Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor ("BF")

S_{AP} = Net system input ("NSI") in kWh for the accumulation period, at the generation level.

BF = Company base factor costs per kWh: $0.02240

J = Missouri Retail Energy Ratio = Retail kWh sales/total system kWh

Where: total system kWh equals retail and full and partial requirement sales associated with GMO.

T = True-up amount as defined below.

I = Interest applicable to (i) the difference between Missouri Retail ANEC and B for all kWh of energy supplied during an accumulation period until those costs have been recovered; (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 adjustment amount, if any.

FAR = FPA/S_{RP}

Single Accumulation Period Secondary Voltage FAR_{Sec} = FAR * VAF_{Sec}
Single Accumulation Period Primary Voltage FAR_{Prim} = FAR * VAF_{Prim}
Single Accumulation Period Substation Voltage FAR_{Sub} = FAR * VAF_{Sub}
Single Accumulation Period Transmission Voltage FAR_{Trans} = FAR * VAF_{Trans}

Annual Secondary Voltage FAR_{Sec} = Aggregation of the two Single Accumulation Period Secondary Voltage FARs still to be recovered
Annual Primary Voltage FAR_{Prim} = Aggregation of the two Single Accumulation Period Primary Voltage FARs still to be recovered
Annual Substation Voltage FAR_{Sub} = Aggregation of the two Single Accumulation Period Substation Voltage FARs still to be recovered
Annual Transmission Voltage FAR_{Trans} = Aggregation of the two Single Accumulation Period Transmission Voltage FARs still to be recovered

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period retail NSI in kWh, at the generation level.

VAF = Expansion factor by voltage level
VAF_{Sec} = Expansion factor for lower than primary voltage customers
VAF_{Prim} = Expansion factor for primary to substation voltage customers
VAF_{Sub} = Expansion factor for substation to transmission voltage customers
VAF_{Trans} = Expansion factor for transmission voltage customers

TRUE-UPS

After completion of each recovery period, the Company shall make a true-up filing by the filing date of its next FAR filing. Any true-up adjustments shall be reflected in component "T" above. Interest on the true-up adjustment will be included in component "I" above.

The true-up amount shall be the difference between the revenues billed and the revenues authorized for collection during the RP as well as any corrections identified to be included in the current FAR filing. Any corrections included will be discussed in the testimony accompanying the true-up filing.

PRUDENCE REVIEWS

Prudence reviews of the costs subject to this Rider 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 FAC shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in component "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in component "I" above.

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DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:
An accumulation period is the six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate ("FAR"). The two six-month accumulation periods each year through four years from the effective date of this tariff sheet, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

Accumulation Periods	Filing Dates	Recovery Periods
June – November	By January 1	March – February
December – May	By July 1	September – August

A recovery period consists of the months during which the FAR is applied to customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES:
Costs eligible for the Fuel and Purchased Power Adjustment ("FPA") will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, reservation charges, purchased power energy charges including applicable Southwest Power Pool ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with -purchased power and off-system sales, and the cost described below associated with the company's hedging programs all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, and revenue from the sale of Renewable Energy Certificates or Credits ("REC"). Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year. Likewise, revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) periodically subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("S_{RP}") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregated over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR multiplied by kWh billed.

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FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR – R)

FC = Fuel Costs Incurred to Support Sales:
The following costs reflected in Federal Energy Regulatory Commission ("FERC") Account Number 501:
Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance, leases, depreciation and applicable taxes, natural gas costs including reservation charges, fuel quality adjustments, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange),oil costs for commodity, propane costs, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for fuel expenses in the 501 Accounts.

Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, 501400 and 501420 accounts attributed to native load;

Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, 501400 and 501420 accounts attributed to off-system sales;

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

The following costs reflected in FERC Account Number 547:

Subaccount 547000: natural gas and oil costs for commodity, transportation, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), storage, taxes, fees and fuel losses, hedging costs for natural gas, oil, and natural gas used to cross-hedge purchase power for sales,and settlement proceeds, insurance recoveries, subrogation recoveries for fuel expenses, and broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange).
Subaccount 547020: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to native load;
Subaccount 547027: natural gas reservation charges;
Subaccount 547030: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to off-system sales;Subaccount 547300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia or other consumables which perform similar functions.

E = Net Emission Costs:
The following costs and revenues reflected in FERC Account Number 509:

Subaccount 509000: NOx and SO_2 emission allowance costs, including any associated hedging costs, and broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) offset by revenue amortizations and revenues from the sale of NOx and SO_2 emission allowance and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange)

PP = Purchased Power Costs:
The following costs or revenues reflected in FERC Account Number 555:

Subaccount 555005: capacity charges for capacity purchases one year or less in duration;
Subaccount 555000: purchased power costs, energy charges from capacity purchases, insurance recoveries, and subrogation recoveries for purchased power expenses,hedging costs including broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange), charges and credits related to the SPP Integrated Marketplace ("IM") or other IMs, including energy, revenue neutrality, make whole and

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

PP = Purchased power Costs (continued):

out of merit payments and distributions, over collected losses payments and distributions, Transmission Congestion Rights ("TCR") and Auction Revenue Rights ("ARR") settlements, virtual energy costs, revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, load/export charges, ancillary services including non-performance and distribution payments and charges and other miscellaneous SPP Integrated Market charges including uplift charges or credits, excluding the amounts associated with purchased power agreements associated with the Renewable Energy Rider tariff.

Subaccount 555030: the allocation of the allowed costs in the 555000 account attributed to purchases for off-system sales;

Subaccount 555035: purchased power costs associated with the WAPA agreement.
Subaccount 555070: SPP purchased power administration fees.

TC = Transmission Costs:
The following costs reflected in FERC Account Number 565:

Subaccount 565000: non-SPP transmission used to serve off-system sales or to make purchases for load, excluding any transmission costs associated with the Crossroads Power Plant and 59.31% of the SPP transmission service costs which includes the schedules listed below as well as any adjustments to the charges in the schedules below:

Schedule 7 – Long Term Firm and Short Term Point to Point Transmission Service
Schedule 8 – Non Firm Point to Point Transmission Service
Schedule 9 – Network Integration Transmission Service
Schedule 10 – Wholesale Distribution Service
Schedule 11 – Base Plan Zonal Charge and Region Wide Charge

excluding amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.

Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;
Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;
Subaccount 565030: the allocation of the allowed costs in account 565000 attributed to off-system sales.

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:

Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM, or other IMs, including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, TCR and ARR settlements, demand reductions, virtual energy costs and revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non-performance and distribution payments and SPP uplift revenues or credits, hedging costs, excluding (1) the amounts associated with purchased power agreements associated with the Renewable Energy Rider tariff, and (2) off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year. ;

Subaccount 447012: capacity charges for capacity sales;
Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.
Subaccount 447035: the off-systems sales revenues associated with the WAPA agreement.

R = Renewable Energy Credit Revenue:
Revenues reflected in FERC account 509000 and gains and losses to be recorded in FERC accounts 411800 and 411900 from the sale of Renewable Energy Credits (RECs) that are not needed to meet the Renewable Energy Standards less the cost associated with making the sale.

Revenues from excess RECs sold for the benefit of specific tariff participation less the cost associated with making the sale.

Hedging costs are defined as realized losses and costs (including broker commissions, fees, and margins) minus realized gains associated with mitigating volatility in the Company's cost of fuel, fuel additives, fuel transportation, emission allowances, transmission and power purchases or sales, including but not limited to, the Company's use of derivatives whether over-the counter or exchange traded including, without limitation, futures or forward contracts, puts, calls, caps, floors, collars, swaps, TCRs, virtual energy transactions, or similar instruments

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FORMULAS AND DEFINITIONS OF COMPONENTS (Continued)

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, or R shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) 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 centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC:

A. The Company may include the new schedule, charge type cost or revenue in its FAR filings if the Company believes the new schedule, charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed below or in the schedules listed in TC, 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 schedule or charge type no later than 60 days prior to the Company including the new schedule, charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such change, 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, TC or OSSR as the case may be, and identify the preexisting schedule, or market settlement charge type(s) which the new schedule or 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 schedule, charge type costs or revenues by amount, description and location within the monthly reports;

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

E. If the Company makes the filing provided for in 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 schedule or charge type, a party shall make a filing with the Commission based upon that party's contention that the new schedule, charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC or OSSR, as the case may be. A party wishing to challenge the inclusion of a schedule or charge type shall include in its filing the reasons why it believes the Company did not show that the new schedule or charge type possesses the characteristics of the costs or revenues listed in Factors TC, 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 schedule or 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

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

F. A party other than the Company may seek the inclusion of a new schedule or 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 date of January 1 or July 1. Such a filing shall give the Commission notice that such party believes the new schedule or 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, TC or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such change, provide a description of the new schedule or charge type demonstrating that it possesses the characteristics of, and is of the nature of, the schedules, costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule or market settlement charge type(s) which the new schedule or 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 schedule or charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new schedule or charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new schedule or charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC, 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 schedule or charge type does not possess the characteristic of the costs or revenues listed in Factors PP, TC or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new schedule or charge type. In the event of a timely challenge, the party seeking the inclusion of the new schedule or charge type shall bear the burden of proof to support its contention that the new schedule or 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.

SPP IM charge/revenue types that are included in the FAC are listed below:

Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Regulation Service Deployment Adjustment Amount
Real Time Regulation Down Service Amount
Real Time Regulation Down Service Distribution Amount
Real Time Regulation Non-Performance
Real Time Regulation Non-Performance Distribution
Real Time Regulation Up Service Amount

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)

Real Time Regulation Up Service Distribution Amount
Real Time Spinning Reserve Amount
Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount
Real Time Asset Energy Amount
Real Time Non-Asset Energy Amount
Real Time Virtual Energy Amount
Transmission Congestion Rights Funding Amount
Transmission Congestion Rights Daily Uplift Amount
Transmission Congestion Rights Monthly Payback Amount
Transmission Congestion Rights Annual Payback Amount
Transmission Congestion Rights Annual Closeout Amount
Transmission Congestion Rights Auction Transaction Amount
Auction Revenue Rights Funding Amount
Auction Revenue Rights Uplift Amount
Auction Revenue Rights Monthly Payback Amount
Auction Revenue Annual Payback Amount
Auction Revenue Rights Annual Closeout Amount
Day Ahead Demand Reduction Amount
Day Ahead Demand Reduction Distribution Amount
Day Ahead Grandfathered Agreement Carve Out Daily Amount
Grandfathered Agreement Carve Out Distribution Daily Amount
Day Ahead Grandfathered Agreement Carve Out Monthly Amount
Grandfathered Agreement Carve Out Distribution Monthly Amount
Day Ahead Grandfathered Agreement Carve Out Yearly Amount
Grandfathered Agreement Carve Out Distribution Yearly Amount
Day Ahead Make Whole Payment Amount
Day Ahead Make Whole Payment Distribution Amount
Day Ahead Combined Interest Resource Adjustment Amount
Real Time Combined Interest Resource Adjustment Amount
Integrated Marketplace Clearing Administration Service
Integrated Marketplace Facilitation Administration Service
Transmission Congestion Rights Administration Service
Miscellaneous Amount
Reliability Unit Commitment Make Whole Payment Amount
Real Time Out of Merit Amount

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)

- Reliability Unit Commitment Make Whole Payment Distribution Amount
- Over Collected Losses Distribution Amount
- Real Time Joint Operating Agreement Amount
- Real Time Reserve Sharing Group Amount
- Real Time Reserve Sharing Group Distribution Amount
- Real Time Demand Reduction Amount
- Real Time Demand Reduction Distribution Amount
- Real Time Pseudo Tie Congestion Amount
- Real Time Pseudo Tie Losses Amount
- Unused Regulation Up Mileage Make Whole Payment Amount
- Unused Regulation Down Mileage Make Whole Payment Amount
- Revenue Neutrality Uplift Distribution Amount

Should FERC require any item covered by components FC, E, PP, TC, OSSR or R to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR or R. 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 the Rider FAC to be recorded in the account.

B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. N e t Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor (“BF”)

S_{AP} = Net system input (“NSI”) in kWh for the accumulation period, at the generation level.

BF = Company base factor costs per kWh: $0.02569

J = Missouri Retail Energy Ratio = Retail kWh sales/total system kWh

Where: total system kWh equals retail and full and partial requirement sales associated with GMO.

T = True-up amount as defined below.

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I = Interest applicable to (i) the difference between Missouri Retail ANEC and B for all kWh of energy supplied during an accumulation period until those costs have been recovered; (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 adjustment amount, if any.

FAR = FPA/S_{RP}

Single Accumulation Period Secondary Voltage FAR_{Sec} = FAR * VAF_{Sec}
Single Accumulation Period Primary Voltage FAR_{Prim} = FAR * VAF_{Prim}
Single Accumulation Period Substation Voltage FAR_{Sub} = FAR * VAF_{Sub}
Single Accumulation Period Transmission Voltage FAR_{Trans} = FAR * VAF_{Trans}

Annual Secondary Voltage FAR_{Sec} = Aggregation of the two Single Accumulation Period Secondary Voltage FARs still to be recovered
Annual Primary Voltage FAR_{Prim} = Aggregation of the two Single Accumulation Period Primary Voltage FARs still to be recovered
Annual Substation Voltage FAR_{Sub} = Aggregation of the two Single Accumulation Period Substation Voltage FARs still to be recovered
Annual Transmission Voltage FAR_{Trans} = Aggregation of the two Single Accumulation Period Transmission Voltage FARs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period retail NSI in kWh, at the generation level.

VAF = Expansion factor by voltage level
VAF_{Sec} = Expansion factor for lower than primary voltage customers
VAF_{Prim} = Expansion factor for primary to substation voltage customers
VAF_{Sub} = Expansion factor for substation to transmission voltage customers
VAF_{Trans} = Expansion factor for transmission voltage customers

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

TRUE-UPS

After completion of each recovery period, the Company shall make a true-up filing by the filing date of its next FAR filing. Any true-up adjustments shall be reflected in component "T" above. Interest on the true-up adjustment will be included in component "I" above.

The true-up amount shall be the difference between the revenues billed and the revenues authorized for collection during the RP as well as any corrections identified to be included in the current FAR filing. Any corrections included will be discussed in the testimony accompanying the true-up filing.

PRUDENCE REVIEWS

Prudence reviews of the costs subject to this Rider 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 FAC shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in component "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in component "I" above.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided the Effective Date of This Tariff Sheet and Thereafter)

Accumulation Period Ending:			
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R)		
2	Net Base Energy Cost (B)	-	
	2.1 Base Factor (BF)		$0.02569
	2.2 Accumulation Period NSI (S_{AP})		
3	(ANEC-B)		
4	Jurisdictional Factor (J)	x	
5	(ANEC-B)*J		
6	Customer Responsibility	x	
7	95% *((ANEC-B)*J)		
8	True-Up Amount (T)	+	
9	Interest (I)	+	
10	Prudence Adjustment Amount (P)	+	
11	Fuel and Purchased Power Adjustment (FPA)	=	
	11.1 PISA Deferral (Sec. 393.1400)		
	11.2 FPA Subject to Recover in True-Up		
12	Estimated Recovery Period Retail NSI (S_{RP})	÷	
13	**Current Period Fuel Adjustment Rate (FAR)**	**=**	
14	Current Period FAR_{Sec} = FAR x VAF_{Sec}		
15	Prior Period FAR_{Sec}	+	
16	Current Annual FAR_{Sec}	=	
17	Current Period FAR_{Prim} = FAR x VAF_{Prim}		
18	Prior Period FAR_{Prim}	+	
19	Current Annual FAR_{Prim}	=	
20	Current Period FAR_{Sub} = FAR x VAF_{Sub}		
21	Prior Period FAR_{Sub}	+	
22	Current Annual FAR_{Sub}	=	
23	Current Period FAR_{Trans} = FAR x VAF_{Trans}		
24	Prior Period FAR_{Trans}	+	
25	Current Annual FAR_{Trans}	=	
26	VAF_{Sec} = 1.0766		
27	VAF_{Prim} = 1.0503		
28	VAF_{Sub} = 1.0388		
29	VAF_{Trans} = 1.0300		