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Missouri Public
Service Commission

Ms. Colleen Dale, Secretary
Missouri Public Service Commission
P.O. Box 360
Jefferson City, Missouri 65102-0360

Re: ER-2007-0002

Dear Ms. Dale:

Enclosed for filing please find the State of Missouri's brief in the above referenced matter. The State is filing both an NP and HC version of the brief. Due to the fact that the Commission's presiding officer is requiring all parties to provide ten written copies of items filed the State will not be filing this via EFIS.

Sincerely,

JEREMIAH W. (JAY) NIXON
Attorney General

Douglas E. Micheel
Assistant Attorney General

Enclosures

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2007-0002

BRIEF OF OFFICE OF ADMINISTRATION AND DEPARTMENT OF ECONOMIC DEVELOPMENT

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I. Introduction

Union Electric Company d/b/a UE ("UE" or "Company") filed proposed tariffs with the Missouri Public Service Commission ("Commission") designed to increase rates for electric service by approximately $360 million on July 7, 2005, thus initiating Case No. ER-2007-0002. Subsequent to that tariff filing on September 29, 2006, UE also filed, over the objection of certain parties, its proposed fuel adjustment clause ("FAC") tariffs.

Although UE initially requested over $360 million in increased revenue, due to corrections, settlements and the abandonment of certain positions taken in its direct case at the time of the hearing UE was seeking a rate increase of approximately $260 million. (Tr. p. 187, l. 17-20.)[1]. On the other hand, the Office of Administration and Department of Economic Development (herein after "State of Missouri") have recommended that UE should have its rates reduced by approximately $71.6 million. As a result of the true-up UE is now seeking a rate increase of approximately $245.4 million and the State is recommending a rate decrease of approximately $71.9 million. (See: Revised True-up Reconciliation.)

This large gulf between the State's case and UE's case exists because the Company's positions taken in litigation are individually unique and creative, while at the same time consistent in one theme. Every new legal theory and novel ratemaking approach UE presented in this case pushes the limits of any rational view of just and

[1] Citations to the record will be abbreviated as follows: "Ex." for Exhibit, "Tr." for Transcript, and "l." for Line number.

reasonable rates, indicating an aggressive regulatory posture. Now that the record evidence has been heard it is evident that UE's positions on the issues are indeed unique, creative, aggressive and mostly wrong.

II. Contested Issues

A. Electric Energy, Inc.

The Joppa plant is a coal-fired power plant near Joppa, Illinois that was built in the 1950's to supply power for the Atomic Energy Commission ("AEC") as well as for its sponsoring utilities. UE and several other "sponsoring utilities" purchased equity interests in EE, Inc. and secured financing to construct and operate Joppa. Under long-term power supply agreements ("PSAs"), UE and the other sponsoring companies were obligated to take and pay for any excess power. (Ex. 501, p. 18, l. 20-23,.p.19, l.1-5, l. 19-22.) Through the PSA sales arrangement, EE Inc. essentially shifted all of the operating risks and costs associated with the Joppa Station to its sponsoring utilities. (Ex. 501, p. 20, l. 1-2.)

Historically, EE, Inc. has been treated as jurisdictional by the Commission in all rate cases. (Ex. 503, p. 9, l.113-20.) By historically including EE Inc.'s cost-based charges as purchased power expenses in rate cases, UE ratepayers have funded EE Inc.'s operating expenses and provided a reasonable return on and return of EE Inc.'s investment in Joppa for many years. (Ex. 501, p. 20, l.18-22.) This is analogous to including the 40% share in UE's rate base and operating expenses, while treating energy sales to AEC as revenue credits. (Ex. 501, p. 20, l. 22; p.21, l.1-2 .) UE even guaranteed the financing that built Joppa in 1954 and guaranteed other EE, Inc. debt in 1977. (Ex. 501, p. 21, l. 12-28; p. 22, l. 1-15.) Further, EE Inc. continues to benefit from UE affiliation through the purchasing pool that buys coal, mostly from another UE affiliate. (Ex. 501, p. 22, l.17-25.)

UE for decades has used its share of Joppa's low-cost power to serve its native load or to engage in profitable off-system sales. Until December 31, 2005, EE Inc. sold power to the sponsoring utilities at cost-based prices. (Ex. 501, p. 19, l. 19-20.) This long term arrangement created a regulatory claim on the Joppa Plant for the benefit of UE ratepayers, because the market value of this asset is the result of constructing, operating and maintaining the Joppa plant, largely at ratepayer risk and expense. (Ex.501,p. 23, l. 2-11)

The issue at this time arises because Ameren allowed the long-standing cost-based PSA arrangement between UE and EEI to expire, even though its 80% ownership interest and control of EE, Inc. continue this equitable, cost-based power supply arrangement for the benefit of UE and its ratepayers. (Ex. 503, p. 11, l. 13-17.) Immediately after the PSA was allowed to expire, EE Inc. began selling Joppa energy at much higher market-based prices and recorded sharply increased revenues and earnings on this affiliate's books. On its investment in the 40 percent ownership, UE is now realizing windfall profits, which have increased from an average historical return under the PSA of 15.1% in 2005 to 184.8% in 2006. (Ex. 501, p. 24, l. 5-9, pp. 26-27) The profit increase on EE, Inc.'s books occurred with no significant change in plant investment levels or operations and cannot be attributed management action for which any allowing economic windfall should be retained as a reward or incentive, but is solely a result of the PSA expiration. (Ex. 501, p. 27, l. 14; p.28, l. 1-2.)

1. The Joppa Plant Is A Regulatory Asset, Despite Contrary Ameren Affiliate Arrangements

The State believes that the market value of EE Inc.'s Joppa Plant, and its income stream, should be treated as a regulatory asset, where it will continue to benefit Missouri ratepayers. (Ex. 501, p. 23, l. 2-8.) Joppa's market value is the result of constructing, operating, and maintaining, largely at ratepayer risk and expense, an established asset that has appreciated in value and produces a valuable income stream. (Ex. 501, p. 23, l. 8-11.) The Company has conceded that it is not aware of any prior year in which EE Inc. experienced any operating losses while UE ratepayers were paying cost-based contract prices for the UE share of output from Joppa. (Ex. 501, p. 20, l.10-14.) Absent a showing by UE that its shareholders have borne significant risks arising from such operations outside of regulation, there is no basis to treat UE's share of EE Inc. as anything but a regulatory asset. (Ex. 501, p. 23, l. 14-18.)

When the cost-based contract expired, UE management shifted the market value of its share of Joppa Station from the ratepayers to its shareholders, by moving the income stream created by Joppa to its non-regulated accounts. (Ex. 501, p. 24, l. 5-16.) Fairness and equity dictates an outcome in which the ratepayers, who shouldered the costs and risks associated with Joppa for half a century through their rates, are not denied continuing benefit from Joppa's profitable output. (Ex. 501, p. 24,l. 23; p. 25, l. 1-3.)

Unless corrected by the Commission, UE will be able to extract the market value of Joppa's output for the sole benefit of its shareholders, with an unjustified increase in UE's revenue requirement. (Ex. 501, p. 28, l.2-5.)

To correct the problem the Commission should impute UE's share of EE Inc.'s excessive revenue and income to UE and its ratepayers, in the manner indicated in corrected State Accounting Schedule C-4. (Ex. 501, p. 28, l. 9-20; Ex. 518.) Previously, under similar circumstances of abusive affiliate relationships, this Commission (and many other commissions) has imputed revenues from affiliates arising from joint operations, such as telephone companies directory publishing affiliates, i.e. the Yellow pages. (Ex. 501, p. 29, l. 18-23; p. 30, l. 1-8.) An appropriate method to impute revenue is to calculate the difference between the 2005 and 2006 monthly averages to find the 'excess' profit not being achieved within EE, Inc. (Ex. 501, p. 28, l. 9-20; Ex. 518.) The annualized excess profit amount, after allocating for the 40% owned by UE and factoring up for taxes, represents a reasonable equitable imputation that, under the State's proposal comes to about $73 million. (Ex. 518, State Revised Schedule C-4.)

The State's position that the Joppa plant be treated as a regulatory asset is a treatment used by regulatory agencies when a utility is engaged in unreasonable affiliate transactions seeking to create a windfall for shareholders. (Ex. 504, p. 40, l. 15-23.) Use of the "regulatory asset" concept is not unusual in this context of regulatory remedies. (Ex. 504, p. 41, l. 1-3.) For example, the Washington Supreme Court upheld imputation of directory publishing revenues by the Washington Utilities and Transportation Commission, stating at page 25 of its Opinion:

> The company also argues that is being treated differently from other companies in the business and that the character of the asset as a "regulatory asset" does not give the Commission the right to impute income. The fact is that the company is different from other companies competing for the business. The record shows that US West did not develop this lucrative business by its initiative, skill, investment or risk-taking in a competitive market. Rather, it did so because it was the sole provider of local telephone service, and as such owned the underlying customer databases and had established business relationships with virtually all of the potential advertisers in the yellow pages. Therefore the Commission reasonably concluded that the yellow pages business is quite unlike businesses of other unregulated companies which were developed in, or derive their profitability from, the competitive marketplace.[2]

Many other regulatory commissions and courts have found similarly in instances where utility affiliate arrangements were structured to unreasonably remove a valuable asset or profitable business segment from regulatory jurisdiction. Imputation is a widely recognized regulatory tool where an affiliate owns and operates an asset or business segment that should be treated as a "regulatory asset", in spite of utility holding company asset conveyances or affiliate contract terms to the contrary.[3]

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[2] *U S WEST Comm. Inc. v. Wash. Util. & Transp. Comm.*, 134 Wn2d 74, 949 P.2d 1337 (1997), p,27

[3] Oklahoma Supreme Court, *Turpin v. Oklahoma Corporation Comm'n.* 769 P.2d 1309, 1327 (Okla. 1988); Utah Supreme Court, *US West Communications, Inc., Petitioner, v. Public Service Commission of Utah, Respondent.* No.980082 filed January 7, 2000. See also *State ex rel. Utils. Comm'n v. Southern Bell Tel. & Tel. Co.*, 299 S.E. 2d 763, 765 (N.C. 1983); *In re Rochester Tel. Corp. v. Public Serv. Comm'n*, 87 N.Y. 2d 17, 660 N.E. 2d 1112, 1116-18, 637 N.Y.S.2d 333 (1995); *In re Northwestern Bell Tel. Co.*, 367 N.W.2d 655, 660-61 (Minn. Ct. App. 1985). Other regulatory decisions include: *General Tel. Co. of the Northwest v. Idaho Pub. Utils. Comm'n*,712 P.2d 643, 651 (Idaho 1986); *In re US West Communications, Inc.*, 165 Pub. Util. Rep. 4th (PUR) 235, 250-51 (Utah Pub. Serv. Comm'n Nov. 6, 1995); *Alabama Pub. Serv. Comm'n v. South Central Bell Tel. Co.*, 130 Pub. Util. Rep. 4th (PUR) 92, 93-96 (Ala. Pub. Serv. Comm'n Feb 13, 1992); *In re Rates & Charges of Mountain States Tel. & Tel. Co. v. Corporation Comm'n*, 99 N.M. 1, 653 P.2d 501, 505 (1982); *In re New England Tel. & Tel. Co.*, 157 Pub. Util. Rep. 4th (PUR) 112, 163-65 (Vt. Pub. Serv. Bd. Oct. 5, 1994); *In re South Central Bell Tel. Co.*, 121 Pub. Util. Rep. 4th (PUR) 338, 347-50 (La. Pub. Serv. Comm'n Apr. 1, 1991); *Pacific Northwest Bell Tel. Co. v. Katz*, 853 P.2d 1346, 1348-49 (Or. Ct. App. 1993); *In re New York Tel. Co. v. Public Serv. Comm'n*,72 N.Y.2d 419, 530 N.E. 2d 843, 845, 534 N.Y.S.2d 136 (1988)"

2. UE's Legal Rationale for Removal of the Joppa Plant

UE attempts to rationalize its removal of the Joppa Plant from regulation by arguing that the Directors of EE, Inc., to fulfill their fiduciary duty, had no choice upon expiration of the PSA but to commence selling the plant at market prices while retaining the windfall profits solely for shareholders. (Ex.1, p.29, ll7-21, p.30, ll-6) Despite its claims that it does not control EE, Inc's. Board of Directors the record evidence establishes that it does control the Board of Directors and in the past has used that control to ensure certain outcomes. Mr. Rainwater, UE's CEO and a former EE, Inc. board member, noted that UE and the other Ameren affiliates on EE, Inc.'s board of directors always vote together. (Tr. p. 1962, l. 16-20.) And, that Ameren effectively controls EE, Inc. (Tr. p. 1965, l. 8-12.) However, the record evidence establishes that UE and Ameren pick and choose when and how to assert that control. When seeking the approval of the Federal Energy Regulatory Commission ("ERC") for its merger with Illinois Power Company, Ameren assured FERC that the only other owner of EE, Inc. stock, Kentucky Utilities Company, would be able to receive its 20% output of energy if it so desired. (Ex. 8, p. 4 to Naslund Depo., Ex. 262.) In this instance; Ameren was assuring the FERC that its Directors on EE, Inc.'s board would take certain actions. This Ameren testimony flies in the face of UE's claims that it or Ameren does not control the EE, Inc. directors. How could Ameren make this commitment to FERC if Ameren did not control these directors? While the State's proposed adjustment is not dependent upon reversal of EE, Inc. board decisions, it is apparent that the Commission's obligation to approve just and reasonable rates for Missouri ratepayers is not trumped by alleged fiduciary duties of directors of utility affiliates who conspire to remove valuable regulatory assets for the sole benefit of shareholders.

UE presented the testimony of Professor Robert Downs respecting the duty of corporate board members. (Tr. p. 2360, l. 1-6.) However, witness Downs' testimony is not relevant to the decision the Commission must render with respect to this issue. Nor is witness Downs competent, by his own admission, to provide any opinion with respect to the regulatory process. Witness Downs testified that he is not an expert in regulatory law and that he was not offering any testimony with respect to regulatory law. (Tr. p. 2359, l. 14-24.) Unfortunately for UE the question of whether or not the Commission should adopt the State's recommendation with respect to treatment of EE, Inc. in this proceeding is one controlled by regulatory law.

In fact, it appears that witness Downs is operating under the incorrect belief that the State's proposed EE, Inc. revenue imputation in some way changes or nullifies the actions taken by the EE, Inc. Board of Directors. (Ex. 45, p.11, l.12-19) The State's adjustment does no such thing. When asked on cross-examination witness Downs was unable to articulate the State's position in this proceeding respecting treatment of EE, Inc. (Tr. p. 2360, l. 7-25; p. 2361, l. 1-25.) Professor Downs candidly testified that he did not know enough about regulatory law to know whether the Commission could accept his views with respect to fiduciary duties of the EE, Inc. board members and still accept and make an adjustment recommended for ratemaking purposes by one of the other parties. (Tr. p. 2363, l. 5-14.)

3. UE's Risk of Loss Rationale for Removal of the Joppa Plant

Remarkably, UE also attempts to also build an argument that, as a matter of equity, it is reasonable for shareholders to now become the sole beneficiaries of Joppa Plant output because of stock ownership "below the line" or because of hypothetical risks that may have been borne by shareholders, but that did not ever materialize. (Ex. 35, p.12, l3-20, Ex.36, p3, l1-12.) UE witness Moehn asserted that the PSA between UE and EE, Inc. was not different than typical purchase power contracts. (Ex. 35, p. 15, l. 16-23, p.16, l1-17.) However, cross-examination of witness Moehn establishes that this PSA was indeed much different than a typical PSA. Witness Moehn admitted that UE was guaranteeing EE, Inc.'s debt (Tr. p. 2196, l. 8-18.); the PSA guaranteed EE, Inc. a 15% after tax return on equity (Tr. p. 2197, l. 7-22.); the PSA committed UE to buy all the EE, Inc. energy that others would not (Tr. p. 2199, l. 15-24.); and that the PSA unconditionally committed UE and the other sponsoring companies to provide cost support to EE, Inc., a provision Mr. Moehn conceded was "very unusual".(Tr. p. 2345, l14-23.) All of these undisputed facts demonstrate that the PSA was not a run of the mill PSA, but rather a unique arrangement with an affiliate.

UE witness Moehn also alleges that UE's shareholders bore all the risk of loss with respect to UE's investment in EE, Inc. Thus, he concludes that UE rate payers are no longer entitled to any participation in Joppa Plant benefits. However, when pressed, witness Moehn admitted on the record that his claims of shareholder exposure to risks were speculative. Witness Moehn asserted that if some type of catastrophic failure had occurred at the Joppa plant UE's shareholders were at risk. (Ex. 35, p. 4, l. 18-23, p.5, l1-

2.) However, Exhibit 515 demonstrates that witness Moehn was unsure of any "catastrophic failure" or "equally bad and unforeseen events" that have occurred at EE, Inc. Witness Moehn admitted his assertion regarding such risk was pure speculation, (Tr. p. 2208, l. 4-16.), that insurance was maintained on the Joppa Plant and even if catastrophic uninsured losses were incurred, they would have been recoverable under the PSA , (Tr. p. 2213, l.25, p. 2214, l. 1-13.) Witness Moehn also asserted that UE would never have sought recovery of any uneconomic Joppa Plant costs from ratepayers because shareholders were at risk on this below the line investment and that UE had no assurances of cost recovery regarding the Joppa plant from the Commission. (Ex. 35 p.4, l.4-23.p.5,.1-2.) Exhibit 516 shows UE was unable to identify any Commission denial of cost recovery with respect to the Joppa plant. Of course, this claim is not unique to Joppa and EE, Inc. Witness Moehn admitted EE, Inc was treated the same as all UE plants. (Tr. p. 2207, l. 7-24.) Witness Moehn alleged that imprudent costs resulting from the EE, Inc. contract would be borne by UE shareholders. (Ex.35, p. 5, l.8-11.) But he admitted there has never been a prudence adjustment with respect to the PSA with EE, Inc. (Tr. p. 2208, l. 24-25; p. 2209, l. 1-2.) Simply put, UE has not demonstrated any risks visited upon its shareholders as a result of the PSA with EE, Inc. and its investment in EE, Inc. As State witness Mr. Brosch points out in his testimony it was UE's ratepayers that have funded EE, Inc.'s operating expenses and provided a reasonable return on and return of EE, Inc.'s investment in Joppa for many years. Mr. Brosch exhaustively responded to each of the improper characterizations and fallacious arguments raised by Mr. Moehn at pages 20 through 41 of his Surrebuttal. (Ex.504.)

Witness Moehn in his surrebuttal testimony asserted that Mr. Brosch's position did not reflect the undisputed facts and rested on incorrect legal opinions that he was not competent to make. (Ex.37, p. 7, l. 22-24.) Mr. Moehn during cross-examination essentially recanted this claim. To explain this claim, Mr. Moehn argued that the State's adjustment would force EE, Inc. to sell power to UE at cost. (Tr. p. 2228, l. 6-17.) However, Witness Moehn admitted the State's proposal does no such thing. (Tr. p. 2228, l. 18-23; Tr. p. 2229, l. 3-17.) The State's recommended rate-making adjustment is not dependent on Commission action to compel EE, Inc. voting action by Ameren management. The State's adjustment recognizes and corrects the inequitable outcome created in Missouri by management actions that were actually taken. (Ex. 503, l. 17-25.)

The record evidence supports the adoption of the State's proposed adjustment on this issue. The value of the State's adjustment can be found on Corrected Schedule C-4, page 1 of 1, that was admitted into evidence as Exhibit 518HC/NP.

B. Return On Equity:

The State has adopted UE's proposed capital structure and almost all of its capital costs. (Ex. 506, p. 9, l. 19; p. 10, l. 8.) The State and UE are in agreement on most of UE's proposed capital structure and capital costs. The only difference between the State and UE is the return on equity.

The State has calculated UE's return on equity ("ROE") to be 9.0%. Other than UE, none of the other parties have proposed a ROE over 9.8%. Further, in 2006 the average ROE given by state commissions was 10.36%. (Ex. 519, p. 7.) Yet, UE has gone well beyond that, and requested 12.0% or 12.2%. Its position is beyond any measure of reasonableness and is the result of creative intellectual cherry-picking of methods and variables by its ROE witnesses.

The United States Supreme Court mandated that the rate of return for a utility must be: 1) comparable to the return on investments in other enterprises having a corresponding risk; and 2) sufficient to a) assure confidence in the financial integrity of the utility, b) maintain support of the utility's credit, and c) attract capital, Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923), and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944).

1. The State's calculation of Return on Equity

The State's position is that UE's ROE should be 9% as calculated by Dr. Woolridge primarily using the discounted cash flow ("DCF") method. Dr. Woolridge also used the capital asset pricing method ("CAPM").

2. Discounted Cash Flow

The discounted cash flow model ("DCF") is the best measure of the common equity cost rate for public utilities. It was used by virtually all parties in this hearing including UE[4], and is currently used by virtually all large investment firms. (Ex. 506, p.20, l. 17-18.) Under the DCF model, the current common stock price is equal to the discounted value of all future dividends investors expect to receive from investment in the company. (Ex. 506, p. 20, l. 8-13.) The rate at which investors discount those future dividends is the market's expected or required return on that common stock. Thus, that discount rate is the cost of common equity. (Ex. 506, p. 20, l. 7.)

a. The 3 Variables Used to Calculate ROE Under DCF

Three variables are needed to calculate ROE under the DCF model, 1) the current dividend yield, 2) the growth adjustment factor, and 3) investor's expected growth rate. With UE, the current dividend payment and stock price are directly observable. Thus, the primary issue is estimating the investors' expected growth rate. (Ex. 506, p. 23, l. 12-15.)

i. Current Dividend Yield

The inventor of DCF, Prof. Myron Gordon, calculates the dividend yield by dividing the yearly dividend by the current stock price. (Ex. 506, p. 24, l. 18; p. 25, l. 2.) It is agreed that UE's average monthly dividend yield between July and December, 2006 was 4.0%. And in December alone the average dividend yield was 3.8%. (Ex. 506, p. 24, l. 11-15.) Thus, to calculate the cost of common equity for UE, a dividend yield of 3.9% should be used representing of the mean between the six month average and the then current yield. (Ex. 506, p. 24, l. 14-15.)

[4] See Ex. 52 p. 17, Ex. 49 p. 16

ii. Growth Adjustment Factor

The dividend yield must be adjusted by the growth adjustment factor. Dividends obviously fluctuate over time, and different companies announce and pay dividends at different times. To account for these fluctuations, it is common for analysts to adjust the dividend yield by a fraction of the long-term expected growth rate. (Ex. 506, p. 25, l. 8-9.) Therefore, UE's dividend yield should be adjusted upwards by half of its expected growth over the coming year. (Ex. 506, p. 26, l. 1-2.) Since UE's expected growth is 5%, its growth adjustment factor is 1.025. (Ex. 506, p. 30, l. 9.)

iii. Investor's Expected Growth Rate

The growth component of DCF represents investors' expectation of UE's long-term dividend growth rate. Investors look at the historical and projected growth of earnings, dividends per share, and internal and book values when assessing long-term growth potential. (Ex. 506, p. 26, l. 6-9.) Of those, long-term growth rates are the most important, especially when the growth is internally generated. (Ex. 506, p. 27, l. 16-18.) A great deal of published information is used to calculate the investor's expectations, including *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). (Ex. 506, p. 26, l. 12-20.) That published information represents a compilation of many experts. Looking at the reports, the DCF growth rate indicators from the 30 similar public utilities was:

Growth Rate Data Source	Growth rate among the 30 similar public utilities.
Historic *Value Line* Growth in EPS, DPS and BVPS.	**2.9%**
Projected *Value Line* Growth in EPS, DPS, BVPS.	**4.0%**
Internal Growth ROE Retention Rate	**3.7%**
Mean/Median Projected EPS Growth from First Call, Reuters, and Zacks	**5.9% / 5.0%**

An expected growth rate of 5.0% is the most reasonable. It is closer to the higher estimates because the data show that projected growth rates are generally higher than historical growth rates and more weight should be given to projected growth rates. (Ex. 506, p. 29, l. 9-16.)

b. Using the 3 Variables to Calculate Cost of Equity

UE's cost of equity is 9.0%. As stated above, the dividend yield is 3.9%, the adjustment is 1.025 and the most reasonable expected growth rate is 5.0%. With these three variables UE's cost of equity under the DCF model is calculated as follows:

Cost of Equity = (Dividend Yield x growth adjustment) + expected rate of growth.

UE's Equity Cost Rate	Dividend Yield	Growth adjustment	DCF Growth Rate
9.0%	3.9%	1.0250	5.0%

Source: Woolridge direct p. 30 and Exhibit_JRW-7

c. Reduced risk and recent tax law changes have lowered common equity cost rates.

The equity risk premium is the return premium required to purchase stocks, with their greater risk, instead of bonds. Recently, the risk premium for common stock has declined thus lowering the cost of common equity. Leading academics have found the forward-looking equity risk premium to be between 3-4%. (Ex. 506, p. 6, l. 4.) Those academics argue that historical risk premiums are upwardly biased measures of expected equity risk premiums. (Ex. 506, p. 6, l. 5-6.) For instance, Alan Greenspan stated that equity risk premiums have declined in recent years due to more information available in real-time. (Ex. 506, p. 6, l. 18; p. 7, l. 18.) Also, the 2003 Jobs and Growth Tax Relief Reconciliation Act reduced the taxation on corporate dividends for individuals from about 30% to about 15%. That reduced the cost of equity because investors can now pay less for same return. The actual numerical reduction is debatable, but could be as large as 100 basis points. (Ex. 506, p. 8, l. 13-14 .) Regardless of the exact amount, the facts support a conclusion that common equity cost rates have been lowered.

3. Capital Asset Pricing Model

State witness Dr. Woolridge also used the Capital Asset Pricing Model ("CAPM") to calculate UE's return on equity. The CAPM is described by the following equation: $K = Rf + \beta(Rm - Rf)$, where, K = the cost of common equity for the security being analyzed, Rf = the risk free rate, β = beta = the company or industry-specific beta risk measure, Rm = market return, and (Rm - Rf) = market risk premium.

The formula states that the cost of common equity is equal to the risk free rate of interest plus beta multiplied by the difference between the return on the market and the risk free rate (the market risk premium). (Ex. 506, p. 31, l. 1-27; p. 32, l. 1-5.)

a. The Beta for UE

Using the CAPM formula, the cost of common equity is equal to the risk free rate plus some proportion of the market risk premium - that proportion being equal to beta. The overall market has a beta of 1.0. Firms with a beta less than 1.0 are assumed to be less risky than the market; while firms with beta greater than 1.0 are assumed to be more risky than the market. The appropriate beta to use in the CAPM formula is the beta that represents the risk in the industry being analyzed. Therefore, Dr. Woolridge utilized the betas of comparable companies when calculating a return on equity capital for UE. The beta for his group of comparable companies ranged from 0.65 to 1.30, with a mean of 0.89. (Ex. 506, p. 35, l. 13, & Schedule JRW-8 p.1-2.)

b. Ex-Ante Equity Risk Premium

Dr. Woolridge calculated 4.20% for the Ex-Ante Equity Risk Premium by taking the average of the results of five different varieties of equity risk premium studies with a total of 16 individual studies. (Ex. 506, p. 48, l. 14-20 & Schedule JRW-8, p. 3.) The varieties of studies included all of the major, recognized methods for determining the equity risk premium such as Ibbotson, Puzzle Research, equity surveys of CFO's and financial forecasters, and the Building Block approach. (Ex. 506, p. 48, l. 14-20.) Lastly, Dr. Woolridge's Ex Ante Risk Premium is consistent with the equity risk premiums of leading investment firms. (Ex. 506, p. 49, l. 3-5.)

c. The Risk-Free Rate

Dr. Woolridge performed a CAPM analysis using 4.75% for the risk-free rate. This rate took into account the recently revived 30-year Treasury bond. (Ex. 506, p. 33, l. 6-7.) With that revival the market may again focus on 30-year yield as the benchmark for long-term capital costs in the U.S. (Ex. 506, p. 33, l. 7-8.) During 2006, the yields on the 10- and 30- year Treasuries have increased and have been in the 4.50%-5.25% range. (Ex. 506, p. 33, l. 2-3, 8-9.) As of December 4, 32006 the rates on the 10- and 30- year Treasuries were 4.43% and 4.55%, respectively. Given this range and movement, 4.75% is the risk-free rate. (Ex. 506, p. 33, l. 9-12.)

d. The Calculation of ROE under the CAPM Model

Using the CAPM model, Dr. Woolridge calculated that UE's ROE was 8.5%, which is lower than the 9% he calculated under the DCF model. The CAPM was calculated, using the above variables, as follows:

Risk-Free Interest Rate	**4.75%**
Beta	**0.89**
Ex-Ante Equity Risk Premium	**4.20%**
CAPM Cost of Equity	**8.5%**

Source Ex. 506, Schedule JRW-8, p. 1

4. UE's Witnesses propose ROE beyond any reasonable measure

The UE witnesses engage in financial cherry-picking, choosing variables and methods, not based on accepted practices but rather on what gives UE the opportunity to earn the highest possible return on equity. Both McShane and Van der Weide consistently choose methods and data sources that are internally contradictory and not widely accepted. Further, when compared against the zone of reasonableness, the other parties' calculations, and ROE's from around the country, UE's ROE proposals are so high that they are beyond logic and common sense.

a. UE's Proposed ROE's Are Well-Beyond Any ROE Given to Any Utility in the Country.

Looking at national numbers it is clear that UE's proposed ROE should not be adopted. Although the parties differ on the level of risk that UE faces, no witness has testified that UE has more than an average level of risk. (Tr. p. 2879, l. 25; Tr. p. 2880, l. 1-7.) In 2006, the average ROE authorized by regulatory bodies was 10.36% with a median of 10.25%. (Ex. 519) Yet UE's witnesses feel as though it should be awarded an ROE that is 175 or 195 basis points above the national median for ROE's awarded in 2006. (Ex. 519, p. 7.) UE's estimates are even 75 to 95 basis points *above* the next-highest ROE in the entire country, KCP&L. (Ex. 519, p. 7.) Dr. Van der Weide's estimate is even well over the highest utility ROE that he knew of, the 11.6 given to Edison International in California. (Tr. p. 2878, l. 14-23.) Simple logic dictates that if UE has average risk, then half of utilities have more risk, yet every single utility in 2005 and 2006 was given a ROE less than what UE's witnesses propose. (Ex. 519, p. 6-7.) Further, in 2006 only one utility actually broke the 11.0% barrier, while three were under 9.9%. (Ex. 519, p. 6-7.) Lastly, many witnesses and Commissioners touched on the difficulties currently faced by Central Illinois Public Service (CIPS), the regulated utility in Illinois owned by UE. And despite all of its challenges, CIPS was given a ROE of 10.08% in November, 2006. (Ex. 519, p. 7.) Yet UE still asked for sky-high ROE's of 12% and 12.2%.

b. McShane and Van der Weide Are Well Outside the Zone of Reasonableness

In past cases, this Commission has discussed a concept known as the zone of reasonableness for determining ROE. While the State feels that each case is unique and should be decided on its own facts, we bring up the zone here because it illustrates just how off-base the two UE witnesses are in their cherry-picked ROE proposals. In a nutshell, the zone of reasonableness for ROE according to this Commission is a range extending 100 basis points above and below the average of awarded ROE's utilities in the industry under consideration. (Tr. p. 2848, l. 5-10.) In 2006, the national average was 10.36%. (Ex. 519, p. 7.) Thus, the zone that this Commission would consider to be reasonable is between 9.36% and 11.36%. That means Ms. McShane's and Dr. Van der Weide's proposals are 64 and 84 basis points beyond the upper limit of what this Commission even considers to be reasonable.

c. The 10,000 Foot Level View of UE's ROE

Not only do the national numbers show how outlandish UE's numbers are. They also show the reasonableness of the non-UE witnesses. If we look at UE from the proverbial 10,000 foot level, we can see that it is based in the Midwest, has an overwhelming coal and nuclear fuel mix, and is generally agreed to be in decent financial shape. Thus, it is quite logical to assume that its ROE should be below the national median of 10.25%. (Ex. 519, p. 7.) And in fact, that is where the non-UE parties fall in their calculations of ROE, between 9% and 9.8%. Further, if we were to re-visit the zone of reasonableness, we would see the bottom of it extend to 9.25% and include nearly every non-UE witness. And also see that UE's ROE proposals are at least 75 basis points beyond the very limit of what this Commission considers reasonable.

d. The DCF Models of the UE Witnesses Are Seriously Flawed

As mentioned, the UE witnesses engage in financial cherry-picking that is not appropriate. This is apparent in Ms. McShane's and Dr. Van der Weide's DCF approaches. There are a good deal of problems with their DCF analysis, but the four most serious are: (1) both relied on the upwardly biased forecasts of Wall Street analysts and *Value Line* to determine growth rate for their DCF models, (2) both have made inappropriate adjustments to their dividend yields based on the quarterly payment of dividends, (3) Dr. Van der Wiede's DCF results for his electric utility and gas groups have been weighted to give the greatest weight to companies with business operations outside of electric utility and gas distribution services, and (4) Ms. McShane provided no justification for using projected GDP growth as a long-term growth expectation proxy in her DCF model.

i. The UE witnesses only used EPS growth forecasts of Wall Street analysts for DCF growth rate, despite wide knowledge that such forecasts are upwardly biased.

In today's 24-hour financial news cycle, it seems barely a day goes by without a story on how an analyst inflated a forecast for personal gain, or how analysts' forecasts are overly optimistic. As in many things, the information age has caused people to lose faith in the Wall Street wags, and every smart investor has acquired a cynical, questioning demeanor about forecasts on Wall Street. The position is adequately stated by Dr. Woolridge, "it seems highly unlikely the investors today would rely exclusively on the forecasts of analysts… while ignoring historical growth." (Ex. 507, p.10, l. 4-5.)

Yet, two highly paid, highly educated people are arguing that in calculating UE's ROE, one should only use analysts' forecasts. Both Ms. McShane and Dr. Van der Weide used only Wall Street analysts' forecasts to estimate the growth rate of earnings per share. (Tr. p. 2830, l. 22- p. 2831, l.16 & p. 2855, l.18-p. 2856, l.19.) Analysts' forecasts were presumably used because the two witnesses cherry-picked the highest available forecasts. They are asking this Commission to suspend common sense and blindly follow the analysts without questioning their predictions, when both common sense and empirical evidence show otherwise. Clearly neither of those witnesses listened to forecasters predictions of near-infinite growth for Enron five years ago and bought Enron stock, otherwise they would know better than put blind faith in biased Wall Street analysts.

One really only needs to open any *Wall Street Journal* or turn on CNBC to see that analysts' predictions of growth are quite inflated. But there are also empirical studies proving analysts' overly optimistic predictions. Dr. Woolridge's empirical study found that over the past 20 years there have been only six quarters where firms actually met or exceeded analysts' 3-5 year EPS growth expectations. (Ex. 507, p. 11, l.8-16.) Over the entire past 20 years Wall Street analysts have continually forecasted 3-5 year EPS growth rates at a mean of 15.32%, but those same firms only delivered an average actual EPS growth rate of 8.75%. (Ex. 507, p. 11, l. 8-16.) Post-2000, such forecasts are still high, with predicted rates still around 15%, despite the collapse of the stock market, 9/11, the Iraq war, the $1.5 billion securities settlement. (Ex. 507, p. 12, l.1-5; p. 13, l. 5-10.) Meanwhile historic growth is still around 7%. (Ex. 507, p. 13, l. 9-10.) The results are similar when one looks at only utility companies; the overall predicted growth, 4.41%, is again more than half the actual growth, 1.99%. (Ex. 507, p. 14, l. 11-13.) Further, analysts tend to miss downturns in EPS growth. (Ex. 507, p. 14, l. 13-14.)

Dr. Van der Weide defends the analysts with his own study that was published[5] 15 years ago and only covered 65 companies between 1981 and 1983. (Ex. 507, p. 17, l. 15-17.) Since then, there have been many studies that are much larger and more comprehensive. (Ex. 507, p. 17, l. 19-21.) And, perhaps more seriously, there are six fundamental errors within Dr. Van der Weide's study. First, he rejected historical growth rates in favor of analyst's growth rates, but then decided that the accuracy of analysts predictions was irrelevant. (Tr. p. 2855, l. 8-24.) That effectively said that only certain people's high estimates matter, regardless of their accuracy, thereby basing his study on speculative guesses. Second, his regression model is unspecified, thus Dr. Van der Weide was unable to conclude whether one growth rate measure was better than the other. (Ex. 507, p. 18, l. 1-2.) That meant that analysts' EPS forecasts could be upwardly biased but still appear to provide better measures of expected growth. (Ex. 507, p. 18, 9-11.) Third, he did not perform any tests to determine if the difference between historic

[5] It is unclear if that study was ever actually published. (Tr. p. 2857, l. 5-17).

and projected growth measures was statistically significant. (Ex. 507, p. 18, l. 15-17.) Fourth, Dr. Van der Weide did not use both historical and analysts' projections growth measures, to asses if either should be used. (Ex. 507, p. 18, l. 13-15.) Fifth, this study did not separate results from electric utilities from the other companies in the study, leaving in potentially high numbers from companies completely unrelated to UE. (Tr. p. 2856, l. 25; Tr. p. 2857, l. 1-4.) Sixth, a study cited by Dr. Van der Weide for support, the Craig and Malkeil study, actually said that long term growth rates for regulated utilities are some of the most difficult to forecast. (Tr. p. 2858, l. 19-21.) Yet those long-term forecasts are the basis of Dr. Van der Weide's opinion and study.

In Kathleen McShane's calculation of EPS for similar utilities she used a utility that was three times higher than all of the other utilities, despite her testimony that such outliers skew calculation results. (Tr. p. 2828, l. 1-15.) She also completely ignored historical data in her calculation of ROE under the DCF model, even though she admitted that such is important to investors. (Tr. p 2831, l. 4-16.)

The EPS growth rates predicted by *Value Line* are also much higher than actual growth rates. Over the past 20 years, *Value Line* has predicted growth rates over even that of Wall Street analysts at 16.1%. (Ex. 507, p. 15, l. 12-13.) While actual growth has only been 7%. (Ex. 507, p. 15, l. 13-14.) As further evidence of *Value Line*'s upward bias, it only predicted negative growth for 1% of its 2,611 companies.

ii. Adjusting DCF models to reflect quarterly timing is in error and results in an overstated equity cost rate.

Both Dr. Van der Weide and Ms. McShane adjust the dividend yield term of their DCF models to reflect the quarterly timing of dividend payments. (Ex. 507, p. 8, l. 20-21.) But the quarterly timing adjustment is in error and results in an overstated equity cost rate for two reasons. First, according to the creator of the DCF model, Dr. Myron Gordon, the appropriate dividend yield adjustment is the expected dividend for the next quarter multiplied by four. (Ex. 507, p.9, l. 1-2.) The quarterly adjustments proposed by UE are clearly inconsistent with this approach. Second, a major study refuted that an adjustment is required to reflect quarterly timing issues. (Ex. 507, p. 9, l. 3-5.) Quite simply it states that too many rate cases have come and gone and too many utilities have survived and sustained market prices above book to make downward bias in the conventional calculation of required return a likely reality. (Ex. 507, p. 9, l. 16-21.)

iii. Dr. Van der Weide weighted his DCF results to favor companies with business interests outside of electric utility and gas distribution.

In calculating DCF, Dr. Van der Weide chose to give more weight to companies with highest equity cost rates. (Ex. 507, p. 7, l. 17-20.) But those companies have significant interests outside of electric utility and gas distribution such as TXU and Dominion Resources. (Ex. 507, p. 7, l.17; p. 8, l. 4.) Thus, they are not comparable to UE and choosing to give more weight to dissimilar companies is another example of Dr. Van der Weide's intellectual cherry-picking.

iv. Ms. McShane provided no empirical evidence to support her use of GDP to measure of long-term growth rate in her DCF model.

A key part of Ms. McShane's inflated DCF calculation is her use of Gross Domestic Product (GDP) to measure expectations for long term growth. Yet, in response to a data request, she admitted that she used no empirical evidence to support that choice. (Ex. 507, p. 8, l. 10-12.) This means she did not provide, and presumably did not use, any evidence that investors would presume that electric utilities have grown in the past at the GDP rate, or would be expected to grow in the future at the GDP rate. (Ex. 507, p. 8, l. 14-16.) That amounts to cherry-picking an essentially arbitrary number, albeit with a fancy-name, to artificially boost UE's ROE.

e. AmerenUE's Capital Structure Adjustment is erroneous, unwarranted and illogical.

Both Ms. McShane and Dr. Vas der Weide apply a creative concept called the Capital Structure Adjustment ("CSA") to further increase UE's ROE beyond the inflated cost of equity approaches they previously used. Using such an adjustment is yet another example of the cherry-picking that UE's witnesses engage in. Here they dust-off an erroneous and unwarranted concept, the CSA, solely to artificially boost UE's ROE after calculating the cost of equity. The CSA depends on two critical assumptions, (1) that the market values are greater than book values, and (2) the overall rate of return is applied to book value in the ratemaking process. (Ex. 507, p. 36, l. 12-15.)

The CSA and its two assumptions are erroneous and unwarranted for three reasons. First, the reason that market values exceed book values is that electric utility companies earn rate of return on common equity in excess of their costs of equity capital. (Ex. 507, p. 36, l. 19-21.) Second, financial publications and investment firms report capitalizations on a book value and not a market basis. (Ex. 507, p. 36, l. 22-23.) Third, neither Ms. McShane or Dr. Van der Weide provided any evidence that any regulatory commission has ever adopted the Capital Structure Adjustment based upon their recommendation. (Ex. 507, p. 37, l. 1-4.) In addition to being erroneous, the CSA is illogical because it increases the returns for utilities that have high returns on equity but decreases the returns for utilities that have low returns on common equity. (Ex. 507, p. 37, l. 8-10.)

f. Ms. McShane's Financial Cherry-Picking

Ms. McShane's financial cherry-picking is clear in three more places. First, she takes contradictory positions on risk. Ms. McShane ignored historical data in her calculation of ROE under the DCF model, even though she admitted that such is important to investors. (Tr. p 2831, l. 4-16.) She did use historical rates in calculating her CAPM. (Tr. p. 2835, l. 22-23.) But the use of historical returns as market expectations in the CAPM model has been criticized in numerous academic studies. (Ex. 506, p. 37, l. 11.) Continuing with the cherry-picking of historical data, she also uses historical data in her risk premium analysis, but most reputable analysts believe risk premiums will be lower in the future and historical data skews risk premiums excessively upward. (Tr. p. 2835, l. 7-9; Ex. 506, p. 6, l. 2-4, 1. 8-20.) Second, at one point she stated that *Value Line* is important and widely relied upon. (Tr. p. 2827, l. 17-18.) But then she doesn't use any *Value Line* EPS estimates, presumably because they did not fit within her cherry-picking method. (Tr. p. 2834, l. 3-4.) Third, since the average of risk premiums did not yield a sufficiently high number, she used a subjective "range" of risk premiums instead. (Tr. p. 2835, l. 18-19.)

The results of her cherry-picking become clear when her results are considered in the context of the other witnesses. As mentioned above, her calculations are well outside the zone of reasonableness and much higher than every non-UE witness. Lastly, her calculations are even higher than any ROE given to other utilities that face more risk and are not as financially healthy as UE.

i. Comparable Earnings Test

For the most part, Ms. McShane confines her cherry-picking to subtle variables and tweaking otherwise-acceptable methods. But with the comparable earnings ("CE") test she cherry-picks an entire method that is really not needed and then she skews the variables within it. First, given the widespread acceptance of the DCF and, to a lesser extent, the CAPM, there simply is no need to introduce a not-as-accepted model into the proceedings. But, the CE method does allow Ms. McShane to increase the equity cost estimate for UE. (Ex. 507, p. 35, l. 14.)

The CE approach proposed by Ms. McShane is fundamentally flawed for three reasons. First, she did not perform any analysis to examine whether her return on equity figures are likely measures of long-term earnings expectations. (Ex. 507, p. 35, l. 15-17.) Second, Ms. McShane did not evaluate the market-to-book ratios for these companies, thus she cannot indicate whether the past or projected returns on common equity are above or below investors' requirements. (Ex. 507, p. 35, l. 17-20.) The returns on common equity are excessive if the market-to-book ratios for these companies are above 1.0, and that leads to the third point. (Ex. 507, p. 35, l. 20-21.) Ms. McShane included two companies that have massively excessive market-to-book rations, Sysco and

Kimberly-Clark at 48.5% and 33.8%, respectively. (Ex. 507, p. 35, l. 21-23.) But no analyst would suggest that these are really the equity cost rates for Sysco and Kimberly-Clark. (Ex. 507, p. 35, l. 23; p. 36, l. 2.)

g. Dr. Van der Weide

The cherry-picking method continues with Dr. Van der Weide who uses variables and methods far outside any proper and useful financial decisions. In addition to ways described in the many pages above, Dr. Van der Weide cherry-picks in many other ways. First, Dr. Van der Weide, like Ms. McShane, picks and chooses certain historical data to use. (Tr. p. 2855, l. 20.) Another illustration of Dr. Van der Weide's cherry-picking is in his direct and rebuttal testimony. For his direct, he uses six different methods to calculate UE's return on equity. (Ex. 52, p. 6, l. 2-3.) Once done with those six, he declares that UE's ROE is actually well beyond five of those calculation methods. (Ex. 52, p. 6, l. 2-16.) In those six methods, the lowest ROE was 10.7 under the DCF, the method used by just about every other party in this case. (Ex. 52, p. 6, l. 2-3.) Given more time to intellectually cherry-pick, Dr. Van der Weide then increased that lowest estimate in his rebuttal testimony to 11.75, but, curiously, did not adjust any of his higher estimates. (Tr. p. 2870, l. 2-9.) His suspicious increase is a great illustration of his intellectual cherry-picking; he even admitted that if he had calculated the DCF as the Commission requested in the Empire case, it would actually be 10.8, a full 95 basis points less than his speculative DCF-generated ROE of 11.75. (Tr. p. 2870, l. 2-9.) Further, in calculating that number he used utilities outside of the Midwest and thus not comparable to UE. (Tr. p. 2872, l. 18-22.)

Dr. Van der Weide's financial cherry-picking is also revealed in his contradictory positions on risk. First, he states that less risk generally means that a lower return on equity is needed. But then he states that although UE has average risk, it needs the highest ROE in the nation. (Tr. p. 2879, l. 25; p. 2880, l. 1-19.) Second, in the Empire case, Dr. Van der Weide testified that its unique dependence on natural gas was the ultimate cause of higher risk. (Tr. p. 2883, l. 10.) But here he is arguing for an even higher ROE in this proceeding, despite UE's less volatile coal-heavy generation mix. Third, Dr. Van der Weide testified that a better bond rating generally means a lower ROE. (Tr. p. 2889, l. 22-25.) Here, UE has historically had a better bond rating than both KCP&L and Empire, despite having its overall rating hurt by its Illinois operations. (Tr. p. 2884, l. 13-22; Tr. p. 2885, l. 11-15.) Yet, Dr. Van der Weide still insists that UE needs a return on equity far above that of KCP&L and Empire.

Again, as with Ms. McShane, when the results of Dr. Van der Weide's intellectual cherry-picking are considered in the context of this case his conclusion is well outside the zone of reasonableness, it is above more-risky utilities, well-above national norms, and far beyond anything proposed by the other parties

5. AmerenUE's Inefficiency and Inferior Services Merit This Commission Awarding a Lower Return on Equity.

UE's poor service and ineffective storm response merit a lower return. The Supreme Court of the United States left no doubt in its Bluefield decision that efficient and economic management must be considered in the context of setting the allowed return on a utility company's rate base:

> *"The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit, and enable it to raise money necessary for the proper discharge of its public duties."* (Emphasis added)

Bluefield Water Works & Improv. Company v. Public Service Commission, 262 U.S. 679, 693, 43 S. Ct. 675, 679, 67 L.Ed. 1177, 1183 (1923). Moreover, since Bluefield, "[n]umerous other decisions have recognized that superior service commands a higher rate of return as a reward for management efficiency and, conversely, that *inefficiency and inferior services merits a lower return*." (Emphasis added.) Note, "Public Utility Law – Public Service Commission Ordered Rebates for Inadequate Service," 1976 Wisc. L. Rev. 584, 594 (1976). In fact, this Commission has previously considered and granted adjustments for inferior service in many cases. See: Re: Middle States Utilities Company, 72 PUR (N.S.) 17, 28-30 (Mo. P.S.C. 1947); Re: North Missouri Tel. Company, 49 PUR 3d 313, 317-19 (Mo. P.S.C. 1963): Re: Western Light & Tel. Company 10 PUR 3d 70, 74-76 (Mo. P.S.C. 1955); Re: The United Tel. Company, 1 Mo. P.S.C. (N.S.) 341, 349-50 (1948); Public Service Commission v. Missouri Utilities Company, 1932 E PUR 449, 489 (Mo. P.S.C. 1928); Re: Lexington Water Company, 1928 E PUR 322, 345-6 (Mo. P.S.C. 1928); Re: Missouri Public Service 25 Mo. P.S.C. (N.S.) 139, 178 (1982).

A good example is In Re: Middle States Utilities Company, in that case this Commission was faced with a telephone company that was requesting higher rates while providing inadequate service. This Commission, in addressing its concomitant ratemaking duty and its duty ensuring services the utility provided are just, reasonable, adequate, and efficient stated:

> The Commission is charged with the duty of fixing rates which will yield a reasonable average return upon the value of the property actually used in public service and to determine what are just and reasonable rates,... The Commission is further charged with the duty of seeing that the practices, equipment, and services are just, reasonable, adequate, and efficient. It is the Commission's opinion that these two requirements are interrelated and that a reasonable average rate of return can be determined only after consideration has been given to the question of whether the practice, equipment, and services are reasonable and just. (72 PUR NS at p. 28.)

The Commission held that a determination of the reasonableness and justness of a proposed rate could only be made after consideration had been given to the question of whether the practices and services provided were reasonable. In conclusion, the Commission recognized the fundamental principle that:

> The Commission represents both the applicant and the public in its rate-making authority and must give consideration to the quality of service in determining a fair rate of return to be paid by the subscriber.

The United States Supreme Court concurred, in Market Street R. Co. v. Calf. R. Commission, 324 U.S. 548, 563, 58 PUR NS 18, 28, (1945) held:

> "Certainly the due process clause of the Constitution is not violated when a commission takes into consideration practical results to the public of advances which is has allowed in rates. To the extent that the commission was influences by considerations of the value of the service in this case, we find nothing that denies the company any rights possessed under the federal Constitution."

In D.C. Transit System, Inc. v. Washington Metropolitan Area Transit Commission, 151 U.S. App. D.C. 223, 466 F. 2d 394 (1972) cert. den., 409 U.S. 1086, (1972), the U.S. Court of Appeals dealt with a utility that had provided inadequate service. The circuit court appropriately stated... "the question is not whether a fare can be reduced on account of poor service, but whether poor service can constitutionally justify postponement of consideration of an increase until the service is improved." The circuit court answered the question affirmatively; poor service can postpone a rate increase. The U.S. Court of Appeals, in upholding the circuit court and the Washington Commission's refusal to increase rates until service improvements were made stated:

> "The sole question at this point is whether the [Washington] commission can insist upon compliance with such a condition [i.e., improvements in service] prior to further treatment of an application for approval of higher fares. *We answer that question in the affirmative.*" (Emphasis added.)

The U.S. Court of Appeals further stated (466 F. 2d at p. 412)

> *"We perceive no legal barrier to an order by the [Washington] commission, securely founded upon an evidentiary record, preconditioning a fare raise upon terms calculated to safeguard the public interest in economical, efficient, and adequate transportation."* (Emphasis added.)

UE has provided inefficient and inferior services that merit a lower rate of return. Its failure to adequately respond to two severe storms in 2006 led to 100,000's of people being without power for extended stretches of time. Huge amounts of public frustration were expressed at the many public hearings in the storm effected areas generating volumes upon volumes of frustrated testimony from ratepayers. (Tr. Volumes 2-12). Some people reported outages up to 9 days long. (Tr. Vol. 2, p. 8, l. 20). Even at public hearings outside of storm-affected areas, many ratepayers vented their frustration. The ratepayers complained about many things, but especially sporadic service and excessive or unexplained outages. All together in 2006, UE customers were out of power an average of 3.18 times for an average of 46.5 hours. (Tr. 4363. l. 15 – p.4364, l.16). In a show of indifference, none of Ameren's senior management attended any of the hearings.

Staff witness Warren Wood attended most of the public hearings, and at those hearings he was surprised by the number of complaints regarding non-storm issues. (Tr. 4359, l. 13-21). Not only was he surprised, the frequency of complaints about non-storm outages was the most in his nine years as a Commission employee. (Tr. 4360, l. 3-14). And the issues came up with surprising frequency at every public hearing Mr. Wood attended. (Tr. 4360, l. 23 – p. 4361, l. 4). That frequency caused concern about UE's reliability. (Tr. 4361, l. 5-12).

If UE had done a better job of tree-trimming, their system's reliability would have been better. (Tr. 4338, l. 5-19). Prior to the storms, UE simply had not been tree-trimming as per its schedule. In 2004, the amount of money it spent on tree-trimming dipped. (Tr. 4312, l. 10-17 & Ex. 975, p.1-3). By 2006, UE had fallen behind on its tree-trimming and vegetation management schedule. (Tr. 4322, l. 3-9). And they will not catch-up with the schedule until the end of 2008. (Tr. 4340, l. 4-8). Further, the Staff reported that many parts of UE infrastructure was old and needed to be replaced, including clearly rotting poles. (Tr. p. 4346, l. 2-20). Those failures left UE's system vulnerable to the 2006 storms and contributed to the massive resulting outages. (Ex. 501, p.31, l. 4-16).

Another aspect of inferior service that should lower UE's rate is the Taum Sauk incident. There is no need to recount the incident's destruction. It is sufficient to say that UE has admitted the release was caused by a series of internal mistakes for which UE is responsible. (Tr. p. 2049, l. 6-18.) Further, UE's CEO, Gary Rainwater, had been aware of the potentially dangerous conditions at Taum Sauk since 1982. (Tr. p. 2046, l. 15 – p. 2049, l.12.) Not only did UE incur expenses for the immediate environmental costs, the incident also removed the Taum Sauk plant from UE's power plant fleet. That removal has caused UE to increase reliance on its more expensive gas-fired plants and pricey off-system purchases. (Ex. 506, p.31, 1.6-8).

It is within this Commission's power to lower UE's return on equity based UE's inferior service. Re: Matter of Missouri Gas Energy, Case No.: GR-2004-0209, p. 27; Bluefield, 262 U.S. 679, 693 (1923). And while this Commission has stated its reluctance to adjust ROE based solely on inferior service, it has, on occasion, considered inferior service as a factor. Re: Matter of Missouri Gas Energy, Case No.: GR-2004-0209, p. 27. Here, the Commission should definitely consider UE's many outages, vegetation management failures causing reduced reliability, the intense frustration expressed at the public hearings, and the havoc wrought by Taum Sauk when setting UE's return on equity.

C. Off System Sales:

UE engages in off system sales transactions of electricity when it has available generating capacity beyond what is required to serve UE's native load customers and when that capacity can economically meet market demands for bulk energy. The State and UE agree that because such off-system sales of electricity are made utilizing jurisdictional generating facilities, it is appropriate that a reasonable estimate of the ongoing level of profit margins on such sales (revenues less incurred energy costs) be credited to ratepayers. (Ex. 501, p. 8, l. 19-23; p. 9, l. 1-3; Tr. p. 1184, l. 23-25; p.1185, l. 1-13.) However, the State and UE disagree on the appropriate level of off-system sales margin that should be credited to ratepayers. The State of Missouri believes that the amount of margins to be credited to ratepayers should be the recently approved 2007 Fuel Budget amount of **[redacted]**million. (Ex. 504, p. 9, l. 4-9.) As noted by Mr. Brosch, if this budgeted level of off-system sales is accurate and representative enough to satisfy the Company's board of directors, it is worthy of consideration and adoption by the Commission. (Tr. p. 2680, l.12-14.) This amount is considerably above the $202.5 million UE witness Schukar asked the Commission to include in setting the Company's base rates. (Tr. p. 1184, l. 3-8; l. 16-18.)

UE's position with respect to the treatment of off-system sales revenue has been one of continual change – both in the level of off-system sales margin and in the proposed treatment of the off-system sales ("OSS") margin. In direct testimony witness Schukar recommended $180 million in OSS margin be credited to ratepayers. (Tr. p. 1184, l. 11-13.) In supplemental direct he recommended $183 million. (Tr. p. 1184, l. 14-15.) And finally at the time of his testimony he was recommending $202.5 million in

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OSS margin be credited to ratepayers. (Tr. p. 1184, l. 16-18.) Witness Schukar's ever changing OSS margins number is still too low and does not reflect UE's opportunity to sell energy off system or the fact that UE has actually secured some fixed price capacity sales commencing in January 2007, as more fully described below.

UE's Chief Financial Officer, Mr. Baxter testified that he is in charge of the budget function at UE. (Tr. p. 156, l. 8-11.) He testified that budget assumptions should be reasonable and achievable. (Tr. p. 157, l. 10-18.) In the case at bar, the UE Board of Directors approved a fuel budget for 2007 that includes **[redacted]** million of off-system sales margin revenues. (Ex. 504, p. 9, l. 4-5.) Re-enforcing UE's confidence in its budget number UE has determined its incentive compensation plan in part based upon the fact that UE is going to achieve its budgeted number. (Ex. 421HC.) UE's incentive plan would pay the full amount of incentive compensation if UE reaches the budgeted level and would still pay fifty percent incentive compensation if UE achieves a much lower level of **[redacted]** million. (Tr. p. 1323, 10-25; p. 1324, 1-2; Ex. 421HC.) These facts demonstrate that UE firmly anticipates that it will achieve much higher levels of OSS margins than the $202.5 million recommended by Mr. Schukar.

In fact, UE's strategic plan contained in H.C. Exhibit 421 notes that UE has a target net income of **[redacted]** million. (Tr. p. 1333 l. 2-8.) Of that amount the budgeted 2007 off-system sales margin number represents the lion's share of UE's target for net income. (Tr. p. 1333 l. 12-16.) UE's own internal documents demonstrate that UE

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believes that its margins from off-system sales will be considerably higher than its proposed $202.5 million.

i. Hedged Fixed-Price Capacity Sales Should be Recognized

UE's proposed $202.5 million amount fails to take into account that UE already has entered into new fixed price off-system contracts. UE witness Mr. Schukar testified that he is aware that Ameren Energy has entered into transactions on UE's behalf to hedge future power sales. (Tr. p.1236, l.1-3.) Mr. Schukar acknowledged that actual hedged sales for 2007 should be included in the Company's 2007 fuel budget (Tr.p.1235, l.10-16), but he was unable to state whether the Company's proposed rate case level of off-system sales margin contained the capacity sales recently made by UE. (Tr.p.1234, l.4-25, p.1235, l. 1-5.) Schedule MLB-8 attached to Mr. Brosch's Surrebuttal (Ex. 509) clearly shows that significant "Fixed price sales", shown on page 2 of Schedule MLB-8, were included in the UE 2007 budgeted off-system sales. These capacity sales are confirmed in the Company's response to Data Request AG/UTI-319 (Ex. 514HC). Thus, only the State's position of inclusion of the 2007 budgeted amount of off-system sales margin recognizes the known and measurable value of significant capacity sales that have already been hedged at fixed prices. The fact that UE already has new contracts pertaining to off-system sales that were not included in its proposed OSS margin also demonstrates that UE's proposed off-system sales number is too low.

ii. Use of the Company's 2007 Budgeted Off-system Sales Margins is Conservative

Use of the Company's Board Approved-2007 off-system margin budget should be conservative for use in this rate case proceeding for several reasons:

1) Budgeted 2007 off-system sales margins do not reflect availability of Taum Sauk. When Taum Sauk is available, significant additional off-system sales margins will be earned by UE. The negative impact upon off-system sales margins from the Taum Sauk incident was estimated to be $15 million annually in UE's response to AG/UTI-83. This impact should be larger at the higher 2007 market energy prices.

2) Native loads should be higher in 2007 than in the rate case test year, due to ongoing customer and load growth. Higher native loads will reduce the amount of generation available to make off-system sales relative to the test year levels.

3) The average prices assumed in the UE internal Fuel Budget are considerably lower than the market energy prices assumed by Electric Energy Inc. in its own 2007 Budget. (Ex. 504, p.10, l. 1-10.)

4) UE has already realized significantly higher off-system sales margins in January 2007, the only available month in 2007 that was analyzed by Staff, having already recorded off-system margins in this single month of **[redacted]** million. (Tr.p.1623, l.9-25, p.1624, l.1-9.)

5) UE may argue that more work is needed to "normalize" the budgeted 2007 off-system sales margins before they can be used in ratemaking, but the budget has not been shown by UE to be abnormal or unachievable. Moreover, if any FAC is approved for UE that nets off-system sales margins against fuel costs, with incentives awarded upon

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6) reduction of the resulting <u>net</u> fuel expenses, as now proposed by UE, it is essential that representative budgeted 2007 off-systems sales amounts be used to ensure that any sharing incentives do not produce unjust rewards to shareholders. This concern is explained in additional detail the FAC portion of this brief.

iii. Sharing of Off-system Margins is Not Justified

UE witness Schukar initially proposed that there should be some sharing of off-system sales margins if such margins are subject to rate tracking. (Ex.28, p.20, l. 3-10; p. 22, l. 2-8.) However, at hearings UE revised its position on the treatment of OSS margins and now proposes that off-system sales margins be treated as an offset to fuel costs within an FAC. Under this new proposal, UE asserts that it should be granted an incentive to share in a portion of net fuel cost savings after recognizing off-system sales as an offset to gross fuel costs. The State in the FAC section of this brief discusses its opposition to that new proposal. As a general proposition, shareholders are not entitled to retain any portion of off-system sales margins. There has been no evidence showing that shareholders bear any costs or risks associated with the generating facilities or other resources involved in making off-system sales. (Ex. 501, p. 14, l. 7-10.) With ratepayers supporting the costs to make such sales available, ratepayers should receive all of the margins that are realized. (Ex. 501, p. 14, l. 10-11.) Moreover, this Commission has rejected claims by Missouri utilities that shareholders should be allowed to retain a share of off-system sales margin. See: <u>In re Missouri Public Service a division of UtiliCorp United, Inc.</u>, Case No. ER-97-394. (Ex. 501, p. 15, l. 1-11.)

The record evidence supports that UE should have no less than its budgeted 2007 off-system sales included in setting rates. The value of the State's adjustment can be found in its Revised State Accounting Schedule attached as Schedule MLB-9 to Mr. Brosch's surrebuttal testimony, Exhibit 504.

D. Pinckneyville & Kinmundy:

On May 2, 2005, UE closed on an acquisition of new regulated generating capacity-the Pinckneyville and Kinmundy combustion turbine generators ("CTGs"). This capacity was acquired from UE's affiliate, Ameren Energy Generating Company ("AEG") at prices equal to the affiliate's net book value, which as of September 30, 2002 was $161.5 million for Pinckneyville and $96.4 million for Kinmundy. (Ex. 501, p. 52, l. 6-17.) The cost per KW associated with UE's acquisition of these facilities from its corporate affiliate AEG at these prices was $511 per KW at Pinckneyville and $416 per KW at Kinmundy. (Ex. 501, p. 52, l. 19-22.) Because UE acquired these assets from its affiliate AEG this transaction is subject to the requirements of the Missouri affiliate transaction rule 4 CSR 240-20.015.

4 CSR 240-20.15 (2)(A)1.A.B. prohibits UE from compensating an affiliated entity such as AEG above the lesser of "fair market value" or "fully distributed cost to the regulated electrical corporation to provide goods or services for itself." Subsection (3)(B) of the affiliate rule sets out the evidentiary standards for affiliate transaction and requires UE to document both the fair market price of the asset purchased, in this case CTGs, and the fully distributed cost to UE to build the CTGs. The record evidence in this case demonstrates that UE paid an excessive price in 2005 that was equivalent to

AEG's net book cost in the CTGs effectively making AEG "whole" on its investments in the CTGs, at a time when "market" prices were considerably lower. (Ex. 501, p 56, l 13-20.)

The State provided the undisputed testimony of Michael Brosch on this issue.[6] Mr. Brosch examined comparable pricing information for transactions involving combustion turbine capacity that was compiled by UE and provided to the State in Data Request No. AG/UTI-94. (Ex. 501, p. 56, l. 7-9.) Based on UE's response to data request number 94 Mr. Brosch summarized eight comparable market transactions involving simple cycle combustion turbine generating assets. (See Ex. 500, Schedule B-3 for listing of the eight comparable transactions). The transfer prices paid by UE for Pinckneyville and Kinmundy compare unfavorably to the average transfer prices for the eight comparable market transactions. (Tr. p. 3255, l. 17-21.) In fact, the Pinckneyville and Kinmundy's transfer price at cost exceeds, on a per KW basis, every single one of the comparable transactions provided by UE. (Tr. p. 3255, l. 21-25; p. 3256, l.1-7.) While UE can be expected to argue that any individual combustion turbine is distinguishable from another in terms of specific unit size, dual-fuel capability, transmission access and other characteristics, there has been no showing by UE that its acquisition of Pinckneyville and Kinmundy is reasonable in relation to 2005 fair market value price data at the date of closing.

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[6] In UE Exhibit 60HC, Company witness Richard A. Voytas sponsored significant Rebuttal evidence in response to Staff witness Rackers' proposed Pinckneyville and Kinmundy adjustment, that was later withdrawn by Staff, and to Public Counsel witness Kind's adjustment, but did not rebut the State's adjustment for Pinckneyville and Kinmundy.

Another indication of market value for combustion turbine generating assets can be observed in UE's own replacement cost study for CT capacity at Venice Station. In a report dated June 8, 2005, R.W. Beck indicated a Fair Market Value for a single 117MW combustion turbine to be only $217 per MW, based upon the estimated replacement cost for the asset. (Ex. 501, p. 57, l. 13-20.) This indication of market value indicates the reasonableness of the State's proposed adjustment reducing Pinckneyville and Kinmundy station rate base valuation to $288 per KW.

The graph based on UE's own information attached to Exhibit 435 unquestionably demonstrates that the value for CTGs in 2005, when this transaction was consummated, had declined sharply. Despite this decline in CTG prices, UE paid net book value for these assets. Indeed, UE's own testimony in this proceeding demonstrates that the CTG market was distressed in 2005 and that it was possible to purchase CTG assets well below net book value. UE witness Moehn notes in his direct testimony that in 2005 UE was able to acquire its Audrain, Goose Creek, Raccoon Creek combustion turbine generating facilities from non-affiliates NRG and Aquila at market prices averaging $200 and $260 per KW respectively. (Ex. 035, pps. 3-10.) Thus, UE's own evidence is supportive of the State's proposed adjustment.

Based on the record evidence, UE paid more than the fair market value for the CTGs at Pinckneyville and Kinmundy when it purchased those assets from its affiliate in May of 2005. This Commission's affiliate transaction rule requires that UE purchase the Pinckneyville and Kinmundy assets at the lower of cost or fair market value. Based upon an average of transaction prices for combustion turbine generating facility transfers between non-affiliate entities that occurred in 2003, 2004 and 2005 State witness Brosch adjusted the valuation for Pinckneyville and Kinmundy downward to $288 per MW. (Ex. 501, p. 57, l. 3-11, 20-22.) Mr. Brosch noted in response to questions from Commissioner Gaw that the calculations set forth in State Accounting Schedule B-3 represent "decision quality" information that is the "best available information" from which to value the Pinckneyville and Kinmundy assets when including them in rate base. (Tr. p. 3275, l. 6-8.)

All charges for electric service must be just and reasonable. Section 393.130.1 RSMo 2000. This Commission applies a "prudence" standard to determine whether UE's request to include the Pinckneyville and Kinmundy assets in rate base at net book value is appropriate. This Commission has defined the prudence standard as follows:

> [A] utility's costs are presumed to be prudently incurred...However, the presumption does not survive "a showing of inefficiency or improvidence."
>
> ...[W]here some other participants in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent.

Union Electric, 27 Mo. P.S.C. (N.S.) 183, 193 (1985) (quoting *Anaheim, Riverside Etc. v. FERC,* 669 F.2d 799, 809 (D.C. Cir. 1981). In the case at bar, State witnesses Brosch's unrebutted testimony has raised serious doubt about the prudence of UE purchasing the Pinckneyville and Kinmundy CTGs at net book value. The record evidence demonstrates that UE failed to carry its burden of demonstrating that its purchase of the CTGs for net book value was prudent or consistent with 4 CSR 240-20.15 (2)(A)(1). According to UE's own information, comparable CTGs were purchased in the same time period at considerably less than the purchase price the UE paid its affiliate AEG. Moreover, as demonstrated by UE's response to State data request AG/UTI 293 Exhibit 522 UE wholly failed to comply with the evidentiary requirements of this Commission's affiliate transaction rule by not documenting that it paid fair market price for the Pinckneyville and Kinmundy CTGs. Exhibit 522 points out that UE failed to evaluate any of the CTG purchases that it claimed in response to AG/UTI data request 94 to be comparable to determine the appropriate valuation of the Pinckneyville and Kinmundy CTGs.

UE in an attempt to justify the inflated price at which it acquired the Pinckneyville and Kinmundy CTGs from its affiliate AEG raises three red herring arguments:

- First, UE argues that the Stipulation and Agreement in Case No. EC-2002-1 included a commitment by UE to add 700 MW of new regulated generating capacity, which could "include the purchase of generation plant from an Ameren affiliate at net book value."
- Second, that in some way the FERC's decision in cases docketed as EC03-53-000 and EC03-53-001 that sought authority to transfer these CTGs from AEG to UE somehow settled the issue of the appropriate cost for ratemaking purposes at the state level.
- Finally, UE asserts that the Commission's decision in EO-2004-0108 (the Metro East Transfer case) in some way justifies the transfer prices for Pinckneyville and Kinmundy.

Each of these "reasons" do not support UE's claim that these assets should be placed in rate base at net book value.

Regarding the first point, UE is correct that the stipulation and agreement in Case No. EC-2002-1 included the phrase, UE can "include the purchase of generation plant from an Ameren affiliate at net book value." (Ex. 116, p. 6.) What UE fails to mention is the fact that the section of the stipulation and agreement covering timely infrastructure investments also contains the following language "…nothing in this Section would prohibit any signatory to this Agreement from raising issues regarding the prudence and reasonableness of the foregoing investment decisions." (Ex. 116, p. 7.) Moreover, the Commission's Report and Order Approving Stipulation and Agreement in Case No. EC-2002-1 notes that "[a]nother important consideration in the Commission's conclusion that the agreement is in the public interest in that it does not restrict the Commission's powers in any way." (Ex. 117, p. 5.) Simply put the Stipulation and Agreement in EC-2002-1 and the Order approving that Stipulation and Agreement do not in any way limit the rights of the State or any other party from challenging the prudence and compliance with the affiliated transaction rules regarding UE's purchase of the Pinckneyville and Kinmundy CTGs from AEG. Nor does the Stipulation or Agreement in any way guarantee that UE is entitled to place the Pinckneyville and Kinmundy CTGs in rate base at net book value.

Regarding UE's insinuation that the FERC's decision in Docket No. EC03-53-000 and EC03-53-001 settled the value of the Pinckneyville and Kinmundy assets, the Company is simply incorrect. The Commission was granted late intervention in the referenced FERC case and submitted two letters dated March 18, 2003 and June 3, 2003. (Ex. 501, Schedule MLB-4 and Schedule MLB-5.) In these letters this Commission indicated its intent to scrutinize the Pinckneyville and Kinmundy transfers in this rate case stating in the March 18 letter, "At the time the costs from this transaction are considered for ratemaking purposes, UE will be responsible to demonstrate that this transaction was prudent and reasonable in light of other available options" and in the June 3 2003 letter, "…the prudency of this transaction will be reviewed by the Missouri Commission. UE agrees that the Missouri Commission has the authority to fully analyze the prudency of this proposed transaction, including, but not limited to, the timing of the purchase, the amount of the purchase, the need for the purchase, and the appropriateness of the purchase in light of other options, including purchase on the market or acquisition of other assets. In exercising this authority, the Missouri Commission is confident that it can protect the interest on ratepayers and shareholders." (Ex. 501, Schedule MLB-4.) The FERC Opinion contained the following "without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of costs, or any other matter whatsoever now pending or which may come before the Commission." (108 FERC, ¶ 61,081.) The issue of the proper value for the acquisition of the Pinckneyville and Kinmundy CTGs was not determined by the FERC proceeding and this Commission retains complete authority to determine the appropriate value for rate making purposes. The FERC decision is simply not relevant to the issue that is presented to this Commission for decision in this rate case. In fact, Regulatory Law Judge Woodruff correctly ruled on more than one occasion that the FERC's actions are not relevant to the issues presented for determination in this proceeding. (Tr. p. 3182, l. 9-14; p. 3186, l. 14-25; p. 3187, l. 1-19.) UE's counsel candidly admitted that the FERC proceedings are not controlling in this proceeding. (Tr. p.3187, l. 10-12.)

Finally, UE asserts that the Commission's decision in EO-2004-0108 (Metro East Transfer case) in some way validated UE's purchase of the Pinckneyville and Kinmundy assets from its affiliate AEG at net book value. UE is again over-reaching in its characterization of what was resolved in the Metro East Transfer case. The proposed pricing for the CTGs in the Metro East Transfer case was for purposes of determining whether or not UE's cost benefit analysis was appropriate for purposes of the proposed transfer. (Tr. p. 3225, l. 3-7.) In that case, the Commission was talking about pricing of CTGs in a very different context that is not relevant to the way in which the transfer price of the CTGs at issue is being dealt with in this separate and discrete proceeding. In fact, Regulatory Law Judge Woodruff correctly ruled that the Commission's decision in the Metro East Transfer case is not relevant to the decision before the Commission in this case. (Tr. p 3232, l. 5-17.) UE's counsel candidly admitted that the Metro East case is not controlling in this proceeding. (Tr. p. 3231, l.21-25; p.3232, l. 1-4.)

Compliance with the Commission's affiliate transaction rules and basic fairness to ratepayers requires that the valuation of Pinckneyville and Kinmundy CTGs be adjusted downward to $288 per KW. The best available measure of fair market value, based upon the broad average of comparable combustion turbine sales between non-affiliated parties in the years 2003 through 2005, demonstrates that the adjustment proposed by the State is appropriate and is conservative, particularly in light of the other indications of market value at Venice, Raccoon Creek, Goose Creek and Audrain. The calculation of this adjustment can be found in State Exhibit 500 Highly Confidential Schedule B-3.

E. Callaway License Extension

In this proceeding the Commission is asked to decide whether the estimated life of the Callaway Nuclear Plant for purposes of depreciation expense should remain at 2024, at the original expiration date for UE's initial operating license granted by the Nuclear Regulatory Commission ("NRC") or whether the estimated life should be extended until 2044, recognizing that UE can and most likely will seek and be granted a 20-year extension of its NRC operating license. The weight of the evidence and the facts and circumstances surrounding the operation of Callaway lead to the conclusion that the Callaway plant will more likely than not have its operating license life extended another 20 years.

Several considerations make Callaway relicensing likely. First, the plant most similar to Callaway is Wolf Creek, which has already applied for license extension and for which regulators in Missouri and Kansas have recognized the re-licensed longer remaining life for that plant. Second, major investments have been made by UE to ensure that equipment at the plant and recent upgrades support the opportunity to seek license extension. Third, UE management is not aware of any safety or environmental issues that would complicate license extension for Callaway. Finally, UE has carefully monitored the condition of critical components at Callaway and is aware of no reason why such components would not support a license extension. While, there is no certainty regarding an application or NRC approval of a Callaway operating license extension, available information suggest that license extension is more likely than not, for purposes of ratemaking decisions at this time.

The nuclear unit most comparable to Callaway is Wolf Creek. (Tr. p. 4209, l. 2-7; Ex. 463.) Wolf Creek has already applied for an operating license extension. (Ex. 501, p. 44, l. 14-16.) Callaway and Wolf Creek have the same design for the plant component known as the power block. (Ex. 501, p. 48, l. 5-11.) Notably, Wolf Creek's owner already reduced its annual depreciation accruals as well as its decommissioning accruals for Missouri ratemaking purposes, as a result of anticipated re-licensing of that plant. (Ex. 501, p. 49, l. 1-10.)

i. UE's upgrades of Callaway's equipment make relicensing likely

UE has made extensive recent investments at Callaway that make re-licensing more likely to be approved. Examples of such investments include the steam generator replacements, condenser replacement, and high and low-pressure turbines. (Ex. 501, p. 46, l. 11-2; Tr. p. 4211-4212.) Additional upgrades are planned for replacement of Callaway's reactor vessel head in 2013, at which time only 11 years will remain on the existing operating license. (Tr. p. 4212, l. 23; p. 4213 l. 4, Ex. 466.) UE has identified a listing of monitoring activities and tests used to track component life at Callaway and the expenses for this activity have been significant in the past and are expected to grow in the future. These investments and monitoring costs are sought for recovery by UE in its revenue requirements. (Ex. 501, p. 50, l. 1-6.) According to UE, the single most critical consideration in determining whether or not relicensing may be feasible is the condition of the reactor vessel. According to UE, extensive monitoring is in place at Callaway to measure neutron embrittlement of the vessel wall and current shelf-life energies equate to a vessel life of greater than 80 years. (Ex. 467, Tr. p. 4215, l. 17-22.)

ii. No known issues would complicate Callaway Relicensing

The record evidence demonstrates that UE is not aware at this time of any safety or environmental issues that would preclude the license renewal for an additional 20 years. (Tr. p. 4209, l. 20-25; p.4210, l. 1-4; Ex. 464) Witness Naslund told KOMU news that the upgrades undertaken at Callaway have "rejuvenated" the plant and that it is ready for "the next 20 and 20 [years] beyond that." (Tr. p. 4217, l. 6-11; p. 4218, l. 1-6.) Finally Commissioner Appling asked the following:

> Q: You-all are gonna extend this thing?
>
> A: That certainly would be our plan, Commissioner.

(Tr. p. 4233, l. 22-25.) Witness Naslund candidly admitted that UE is indeed planning on extending its NRC operating license. While there will continue to be substantial capital expenditures made by UE to maintain Callaway and re-licensing will undoubtedly entail further capital commitments, the Company should not be allowed to increase nuclear depreciation accruals that increase its revenue requirement simply by electing to not make a formal determination regarding whether a license extension will be sought. (Ex. 501, p. 45, l. 1-13.)

iii. Callaway Depreciation Accruals Should Not Be Increased

The currently effective Callaway depreciation rate is 2.6% for all nuclear plant accounts. (GSW-WP-E1335, Ex.501, p. 45, l. 18.) UE is seeking approval for a depreciation accrual rate for Callaway of 3.44%, based upon the unreasonable assumption that no re-licensing will ever be secured for Callaway. (Ex. 501, p. 45, l. 18-22; p. 46, l. 11-4.) The additional depreciation expense associated with this proposal is an increase of $22.9 million. (Ex. 501, p. 46, l. 2-4.) Given the reasonable expectation that an operating license extension will ultimately be requested and approved for Callaway, the existing Commission approved depreciation-accrual rates should not be changed until a re-licensing decision is made and the associated known and measurable retirement date becomes known.

In the alternative, if the Commission determines it appropriate to revise the Callaway depreciation accrual rates at this time, care should be taken to account for the reasonable expectation that NRC license extension will be requested and granted, as an offset to the upward pressure on nuclear depreciation accruals caused by interim additions. (Ex. 501, p. 47, l. 19-22.) Any newly prescribed nuclear plant depreciation accrual rates in this rate case should be based upon an assumption that Callaway Plant retirement will occur in 2044, given the reasonable expectation that re-licensing will ultimately be granted for Callaway.

F. SO2 Emission Allowances :

The Commission must decide an appropriate ratemaking treatment of proceeds from UE's sale of SO2 Emission Allowances in this proceeding. The facts surrounding this issue are undisputed and the need for ratepayer participation in allowance sales proceeds is also undisputed, but the parties disagree regarding when and how ratepayers should benefit from the sale of allowances. The State recommends crediting an average historical amount of $20.3 million of such annual SO2 emission allowance sales in determining the Company's revenue requirement calculation, as set forth on page 39 of Mr. Brosch's testimony. (Ex. 501, p. 39, l. 1. see also Ex. 500 State Accounting Schedule, C-8.) As a note, the AARP agrees with the State on this position. Then, to account for future fluctuations in actual SO2 allowances sales, the State proposes that a regulatory asset or liability be recorded each month reflecting the amount that the retail portion of actual allowance sales varies from the average amount credited to customers in base rates. (Ex. 504, p. 15, l. 18-19.) Under this approach, ratepayers would receive some immediate and tangible benefit from allowances sales, while UE would be made whole for any differences between the ratemaking level of sales and actual future allowance sales. (Ex. 504, p. 16, l. 5-8.)

i. Ratepayer Entitlement to Allowance Sales is Undisputed

UE ratepayers have borne all of the costs associated with UE's large inventory of SO2 allowances, thus they should receiver full credit from all SO2 allowance sales. UE has a surplus of SO2 emission allowances currently worth **[redacted]** million. (Ex. 501, p. 38,

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l. 4-5.) UE's emission allowance surplus that permits it to prudently sell allowances arises primarily from the Company's strategy of purchasing low-sulfur Powder River Basin "PRB" coal. The costs to purchase and burn PRB compliance fuels, as well as all environmental facilities investment and expenses that are incurred are fully includable within the Company's operating expenses and/or rate base. Thus, all costs of Clean Air Act compliance incurred by UE have been recoverable from ratepayers. For example, during the test year, UE paid net SO2 premiums as part of the price of its pooled purchases of PRB coal totaling approximately **[redacted]** million. (Ex. 501, p. 38, l. 11-14.) UE admits that it has accumulated its large inventory of allowances because it shifted to its compliance coal strategy early on. (Tr. p. 3457, l. 6-9.) UE's long position in emission allowances is also a result of the Company receiving favorable treatment under the Clean Air Act. (Tr. p. 3458, l.16- Tr. p. 3459, l. 2) Therefore, it is undisputed that ratepayers are entitled to participate in the profits from emission allowance sales that are made. (Ex. 501, p. 38, l. 11-17; p. 39, l. 8-15.)

ii. UE Prefiled Position Regarding SO2 Emission Allowance Sales

In its prefiled evidence, UE made no adjustment to revise the $3.9 million of SO2 allowance sales that were recorded during the test year. (Ex. 501, p.37, l. 11.) Since UE was advocating no adjustment to the test year amount, the Company had no Direct Testimony on this subject. In Rebuttal, the Company continued to support its prefiled position to recognize $3.9 of allowance sales in setting rates, but acknowledged that

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substantially higher amount of allowance sales had occurred subsequent to the test year, for which Mr. Baxter stated, "...the Company proposes that the July and November/December storm-related O&M expenditures be offset directly by the approximately **[redacted]** million of SO2 allowances sales revenues that the Company was able to realize during the second half of 2006. (Ex. 2, p.12, l. 1-4.) Mr. Baxter voiced his objection to Staff's proposed creation of a regulatory asset for the large allowance sales in late 2006, stating in Rebuttal, "The creation of a regulatory liability has merit, but only on a going forward basis. Aside from the legal issues associated with retroactively moving allowance revenues into the proposed regulatory liability, I strongly believe that using the recent SO2 allowance revenues as an offset to storm-related O&M costs from the July and November/December storms constitutes better regulatory policy." (Ex. 2, p.13, l. 9-13.)

iii. UE's Adoption of the Staff's position

In an apparent effort to maximize revenue requirements, UE abandoned its original and Rebuttal proposals for SO2 allowance sales ratemaking and adopted the Staff's plan at the hearing. The reason for this late change is transparent; UE retains all future allowance sales money under the Staff's plan. Warner Baxter first announced UE's position change on the 11th day of hearings. He testified that UE's new position on SO2 allowance sales is now consistent with the Staff and that new position supersedes

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UE's previous position. (Tr. p. 3443, l. 5-7.) The only difference is that UE proposes a four-year amortization of remaining storm costs instead of five years.

iv. Staff's Position is Fatally Flawed

Although UE now seeks to adopt the Staff's position, the Company's support does not resolve the many problems with the Staff's proposal for SO2 allowances. The Staff's emission allowance proposal is unworkable and should not be adopted for many reasons, including that: 1) it is harmful to ratepayers, 2) it lacks effective definitions of how to implement it, 3) it provides perverse incentives in dealing with coal suppliers, 4) it constitutes retroactive ratemaking, and 5) many of the concerns it tries to address are completely speculative. In a bizarre turn of events, Staff's own witness on this issue testified that Mr. Baxter's rebuttal offer with a full offset of 2006 storm costs with 2006 emission allowance sales is much cheaper for customers than Staff's approach that leaves significant dollars to be amortized, stating, "...we would accept the company's proposal for that portion." (Tr. p. 3554, l. 14-19.)

Under Staff's proposal to address the SO2 allowance sales, the Staff started with UE's gain on SO2 allowance sales for the historical period July 1, 2005 through a January 1, 2007 cutoff date of \$35.8 million and then subtracted what UE paid in SO2 premiums during this period, \$15.4 million (\$35.8 - \$15.4 = \$20.4 million). (Ex. 209, p. 12, l. 12-16.) The staff defined this net \$20.11 million amount as the net gain from sales of emission allowances in excess of SO2 premiums. They then want to use that \$20.4 million to offset the \$34 million of 2006 storm-related O&M costs. (Ex. 209, p. 12, l. 15-

18 & Ex. 226, p. 3, l. 13-14.) As for the future, the Staff proposes that beginning on January 1, 2007, all gains from SO2 allowance sales be recorded in a regulatory liability account. (Ex. 209, p. 12, l. 23.) The net balance in that account would be addressed as part of the fuel expense calculation in the Company's next rate proceeding.

This approach is harmful to ratepayers because it raises the revenue requirement above UE's original position in two ways. First, UE had previously proposed to offset nearly all of the $34 million in storm costs. (Ex. 2HC, p. 12, l. 3-7.) But the staff's approach only offsets $20.4 million, and makes the ratepayers pay for the remainder over the next 5 years through amortization. Second, UE originally proposed to include $3.9 million of revenue from allowance sales in base rates. But the Staff removed that, allowing UE to retain all revenue from SO2 allowance sales. The Staff even admitted that its position increases the revenue requirement beyond what UE had proposed. (Tr. p. 3555, l. 17.)

The Staff's (and now UE's) emission allowance ratemaking position is remarkable for what it lacks, clearly defined terms and implementation plans. First, neither party ever says what they mean by "addressed in the next rate case." Mr. Baxter of UE was exhaustively questioned on this point and he never commits to a definite answer. (Tr. p. 3446-3448.) Indeed, the amounts in the regulatory tracking account would just keep on accruing without ever giving any benefit until ratepayers until UE has another rate case. (Tr. p. 3447, l. 16-22.) Further, the Staff seeks to justify its position with generalized statements that emission allowance prices and sales volumes are volatile and that Staff's position would "help mitigate" effects of volatility. (Ex. 209, p. 13, l. 10-13.) But the

Staff never demonstrates any benefit to ratepayers by netting and offsetting these items in a regulatory liability account.

The Staff's proposal also creates a perverse incentive for UE to structure future coal supply contracts with larger SO2 premium pricing, because the Staff's proposal allows deferral accounting for only the SO2 premium portion of coal prices, while the rest of coal prices would be recoverable through UE base rates. (Tr. p. 3536, l. 1.) Thus, UE could agree with a coal vendor to pay a higher SO2 premium in order to get a lower coal base price. (Tr. p. 3536, l. 15.) Therefore, the Staff's proposal gives UE a perverse incentive to accept higher prices in the SO2 premium element of coal pricing which is subject to regulatory asset tracking, if it can get a lower coal base price that is not tracked. (Tr. p. 3536, l. 22; p. 3537, l. 3.) To make things worse, the Staff does not propose a mechanism to prevent this problem.

Another problem with the Staff's proposal is retroactive rate-making. Staff seeks to commence recording regulatory asset entries for the net amount of SO2 premiums and emission allowance gains as of January 1, 2007, even though new rates from this proceeding are not effective on that date. (Tr. p. 3538, l. 2-19.) Retroactive ratemaking is when a rate is changed after it has been established and paid, and the Commission may only consider past over or under-recovery of costs insofar as is relevant to determine the necessary rate. *State ex rel. Midwest Gas Users' Assoc. v. Public Service Commission*, 976 S.W.2d 470, 480-481 (Mo. App. W.D. 1998); *State ex rel. UCCM v. Public Service Commission*, 585 S.W.2d 41, 58 (Mo. banc 1979) Specifically, Staff proposes that the regulatory liability account tracking gains from SO2 allowance sales begin on January 1,

2007. (Tr. p. 3537, l. 6.) But UE's new rates will not be effective until sometime in June, 2007. Thus, by starting the regulatory liability account on January 1, 2007, the Staff is going back to capture those gains (or losses) in a manner that constitutes forbidden retroactive rate-making. Moreover, the Staff proposal is retroactive ratemaking because there is no Commission order allowing it to engage in such retrospective deferral accounting.

The historical netting of costs is also problematic under Staff's proposal. As mentioned above, Staff would use the allowance sales that occurred from July 1, 2005 through December 31, 2006, reduced by historical SO2 premiums paid by UE as part of its coal prices. But historically the costs of SO2 premiums were being recovered as part of the cost of coal in existing utility rates. Since the rates were in effect, it must be assumed that UE recovered its costs, including the cost of SO2 premiums, within historical coal prices. Further, there is no Commission order authorizing any form of deferral accounting for SO2 premiums during that time period. Thus, to use past SO2 allowance sales, net of SO2 premiums paid for coal as part of storm cost offset is another example of retroactive ratemaking. Imposing accumulation of prior transactions in that manner without any accounting order in place is also retroactive ratemaking. UE admitted there was possibly a problem with retroactive ratemaking under Staff's proposal, before it opportunistically adopted such approach during the hearings. (Ex. 2, p. 13, l. 10.)

v. UE has Not Justified Retaining Allowance Sales Proceeds for its Shareholders

UE witness Baxter opposes crediting of the Company's considerable allowance sales proceeds to customers by referring to, "UE's environmental capital expenditure requirements are estimated to range from $365 million and $505 million during the 2007 to 2010 period, with an additional $750 million to $1.04 billion of investments required in the 2011 to 2016 time frame." (Ex. 2, p.14, l. 2.) UE witness Moore echoes this theme stating, "The uncertainty of future regulation also makes the attribution of a set amount of SO2 sales per year problematic. The potential for further tightening of SO2 emissions, ongoing uncertainty surrounding the EPA's mercury rules and potential greenhouse gas legislation make the future of SO2 allowances difficult to predict. UE's management of SO2 allowance depends on future legislation and regulations that are not clear at this time." (Ex 62, p.5, l. 13.) But UE made no showing regarding its implied inability to reasonably finance or recover future environmental expenditures that may be required. Additionally, UE has provided no estimates of its future revenue requirements under any assumed future environmental spending scenario. The Commission should reject the Company's unsupported speculation about future environmental changes that UE believes serve to justify shareholder retention of allowance sales proceeds.

The State's proposal for sales of emission allowances explicitly recognizes the uncertainties associated with future environmental compliance and the expected variability in future emission allowance sales. Revenue requirement recognition of a normalized average of historical allowance sales should be employed, instead of UE's and the Staff's proposal allowing UE retention of such sales for the many reasons described herein. First, UE has a history of significant emission allowance sales that are clearly utility-related and for which ratepayers have an undisputed claim to participate. (Ex. 504, p.17, l. 12-14.) Second, ratepayers will bear significant ongoing costs as part of UE's SO2 coal price adjustments and the allowance sales should be recognized as offsets of these current period costs. (Ex. 504, p.17, l. 15-17.)

The State's proposal does not "force" UE to make any specific level of future allowance sales because departures from the normalized test year level would be subject to regulatory asset accounting and future true-up. Any remaining concerns about future volatility in allowance sales that may occur are addressed by the State's regulatory tracking proposal. (Tr. p. 3560, l. 1-17.) If future actual allowance sales are less than the base rate amount, than a regulatory asset balance will be created that UE could recover. And if actual sales are over the base rate amount, then a regulatory liability would result. (Tr. p. 3560, l. 5-8.) The State's ratemaking proposal for emission allowance sales, with this form of regulatory tracking, does not force UE to sell any particular level of allowances in the future and thereby protects against volatility and essentially holds both UE and its ratepayers harmless.

G. 4 CSR 240-10.020:

UE alleges that 4 CSR 240-10.020 Income on Depreciation Fund Investments allows it to increase its rate request by an additional $264 million and provides additional support for the Company's asserted revenue requirement. In support of its interpretation of this rule UE presented the testimony of witness Weiss. According to Mr. Weiss this "...rule generally requires that in the process of setting a utility's rates, the Commission must provide the utility's customers with a 3% annual credit to reflect income from investment of the money in the utility's depreciation reserve account." (Ex. 11, p. 29, l. 7-9.) In Supplemental Direct Testimony, Mr. Weiss opined that 4 CSR 240-10.020 applies regardless of whether the utility's depreciation reserve account is represented by a fund earmarked for that purpose. (Ex. 11, p. 29, l. 9-11.) Based upon this interpretation of 4 CSR 240-10.020, Mr. Weiss performed calculations set forth in Schedule GSW-E38 and claims UE is entitled to an additional revenue requirement amount of $264,147,000. Through Mr. Weiss' Supplemental Direct Testimony, UE seeks to use its interpretation of 4 CSR 240-10.020 to backstop each instance where the Company is found to have overstated its traditionally measured revenue requirement. The record evidence by State and Staff witnesses and the cross-examination testimony of Mr. Weiss demonstrates that UE is simply incorrect regarding its claims related to 4 CSR 240-10.020.

State Exhibit 523 reveals that no Missouri utility has been awarded rate relief based upon the type of calculations performed by witness Weiss in Schedule GSW-E38. In fact, Mr. Weiss admitted during cross-examination that UE was not proposing to implement rates in compliance with its interpretation of 4 CSR 240-10.020. (Tr. p. 3604, l. 16-19; Tr. p. 3622, l. 24-25; Tr. p. 3623 l. 1-3.) Mr. Weiss was even unwilling to say that his assertions in his Supplemental Direct Testimony about the application of 4 CSR 240-10.020 were correct. Instead, witness Weiss merely testified that he was asked to provide a calculation of the impact of UE's interpretation of 4 CSR 240-10.020 he was not providing testimony about the correct interpretation of 4 CSR 240-10.020. (Tr. p. 3607 l. 14-19; Tr. p. 3608, l. 9-11; Tr. p. 3623 l. 4-17.)

On the other hand, State witness Mr. Brosch and Staff witness Mr. Schallenberg testified that UE's proposed interpretation of 4 CSR 240-10.020 was incorrect and should be rejected by this Commission. Mr. Brosch testified that there is no support within 4 CSR 240-10.020 for adding back the depreciation reserve as suggested by witness Weiss. (Ex. 503, p. 4, l. 17-22; p.5, l. 1-2.) The result of such calculations would be an overstatement of the Company's return requirement, because ratepayers would pay a net return of 5.876% (8.876% less 3.0%) on investment balances that have already been returned to investors via depreciation recoveries in prior years. More importantly, UE has no capital investment remaining in plant that has not already been recovered through depreciation, as reflected in the depreciation reserve balance, and should not be allowed to charge ratepayers a return as if there is any remaining capital cost to be recovered. There is no economic justification for including any capital costs within revenue requirements for the depreciation reserve balance that is, by definition, capital that has already been returned to the Company by its ratepayers. (Ex. 503, p. 7, l. 10-19.)

Mr. Schallenberg supported the State's position on this issue, stating, "It has been recognized, since at least 1946, that customers are entitled to a reasonable and equitable return for the use of the funds that they provided in the form of depreciation reserves. If the MoPSC believes that it must impute a 3% income from the depreciation reserve, then the MoPSC should decide what treatment of the depreciation reserve produces the most reasonable result. The rule does not state that the depreciation reserve cannot be used as a rate base offset as asserted by UE on this issue. The question that must be determined under this scenario is whether the return that customers receive should be more or less than UE's return on its investment. I believe it is reasonable to assume that customers should receive a greater return than UE given the customers' higher borrowing and opportunity costs." (Ex. 236, p. 14, l. 20-23; p. 15, l. 1-6.)

The Commission should clearly articulate its policy regarding 4 CSR 240-10.020 in this rate case proceeding, to remove any ambiguity surrounding how depreciation reserves are to be treated in quantification of utility rate base. In this proceeding, it is obvious that UE's own witness is not comfortable with the Company's stated interpretation of this Rule and evidence of record indicates that public utilities in this State will have an opportunity to earn a reasonable return on their invested capital without application of the stated 3 percent return in the Rule with regard to depreciation funds that are believed to exist.

H. Fuel Adjustment Clause:

Senate Bill 179 and recently enacted administrative rules by the Commission implementing Senate Bill 179 allow an electric utility to seek a fuel adjustment clause ("FAC"). SB 179 does not require that this Commission grant an electric utility an FAC. SB 179 merely gives the Commission the authority to grant a FAC to an electric utility if the facts and circumstances support such action. (Tr. p. 597, l. 10-19.) In the case at bar, UE has simply not demonstrated that its proposed FAC is needed or is consistent with the public interest.

Generally, an FAC should only be allowed in compelling or extraordinary circumstances when the types of costs to be tracked on a piecemeal basis have the following attributes:

1) Costs are large enough to have a material impact on revenue requirements and the utility's financial performance, if not tracked;

2) Costs that are beyond the control of management, such that regulatory lag incentives are ineffective;

3) Costs that are volatile enough to cause significant swings in income and cash flows, if not tracked;

4) Cost tracking tariffs should be straightforward and simple to administer; and

5) Tracking of costs must be balanced and not distortive of test period relationships. (Ex. 502, p. 16, l. 6-16.)

The record evidence establishes that UE does not meet any of these five criteria.

1. Piecemeal Ratemaking Should Be Avoided Unless Traditional Test Year Regulation Fails

An FAC is a regulatory tool that systematically changes utility pricing between rate case test years, to track changes in fuel costs in isolation, without regard to how the utility's overall costs or revenue levels are changing. (Ex. 502, p. 3, l. 4-10.) In this way, an FAC is different from traditional ratemaking using test years to quantify all revenue requirement components. Traditional regulation is based upon balanced measurement of all elements of costs and revenues, not just one cost considered in isolation. (Ex. 502, p. 4, l. 1-7.) Overall analysis is important because it accounts for the fact that over time favorable changes tend to offset unfavorable changes. (Ex. 502, p. 4, l. 3-7.) This offsetting concept is particularly relevant to UE, a utility that has not required any traditional rate increase for 20 years because revenue growth and cost reductions have apparently mitigated increases in fuel and other costs.

The primary problem with an FAC is the potential for serious distortion of the "matching" that is desirable in rate case test years. (Ex. 502, p. 9, l. 6-8.) The matching principle recognizes the importance of matching all revenues and costs in a consistent time period to determine if changes are needed in utility rates. (Ex. 502, p. 9, l. 8-10.) An FAC is piecemeal rate-making, ratepayers are only charged for pieces of the overall revenue requirement without regard to whether changes to other expenses or increasing sales levels mitigate the fuel cost changes. (Ex. 502, p. 9, l. 11-14.) All elements of the revenue requirement change over time and favorable changes tend to offset the unfavorable changes. But if UE can select certain items for special treatment, one can reasonably expect the selected items will be "cherry-picked" so to influence the regulatory process to the sole advantage of that party. (Ex. 502, p. 9, l. 15-23.) In this proceeding, UE desires a fuel adjustment clause because it expects its fuel expenses to increase in the future. (Tr. p. 447, l. 19-22.) But expected future fuel cost increases are probably the worst reason to adopt a fuel adjustment clause for UE, where management wants piecemeal rate tracking for these known cost increases and not the other costs and revenue changes that will be occurring in the background. (Tr. p. 1089, l. 11-17.)

UE's expectation of modest future fuel cost increases is unlikely to be problematic under continued traditional test-year regulation of the Company's overall revenue requirement. A balanced, periodic review of overall costs is the best answer under the facts of this case, because such an approach recognizes how UE could continue to add new customers and the margins that come with new customers and use those margins to help pay for increasing costs, how UE could realize the effects of the off-system sales markets and grow off-system sales margins to mitigate increasing fuel costs, and how UE could find ways to automate the business and implement better methods of operation to achieve productivity gains. (Tr. p. 1098, l. 9-16.)

2. Incentives for Management Efficiency are Blunted by FAC Regulation

The second problem with the piecemeal regulation resulting from use of an FAC is the elimination of incentives to reduce fuel and purchased power costs. (Ex. 502, p. 11, l. 4-9.) Traditional test period rate-making creates incentives for management to control and reduce costs to earn at or above authorized return levels. (Ex. 502, p. 5, l. 8-10.) Once utility rates are set in a rate case test year, any favorable changes such as cost reductions and sales margin growth work to produce returns over what the Commission authorized, providing management with a regulatory lag incentive to control costs. Through this process, regulatory "lag" causes management to be rewarded for controlling costs and penalized for not controlling costs between rate cases. (Ex. 502, p. 10, l. 19-23.) If an FAC is used, any incentive to control FAC-recoverable fuel costs is virtually eliminated. (Ex. 502, p. 11, l. 4-5.) In an FAC cost "pass through" environment regulatory auditing becomes critically important to review FAC cost recoveries, but such auditing is no substitute for ever-present incentives. (Ex. 502, p. 13, l. 18-23.).

Consider the fact that UE presently incurs significant capital and O&M expenses in an effort to maximize the availability and efficiency of its power plants. (Ex. 502, p. 11, l. 14-19.) Under traditional regulation, balanced incentives exist for management to optimize power plant investment and maintenance costs because non-fuel costs of this type are treated the same way as avoided fuel costs by regulators. (Ex. 502, p. 11, l. 19-21; p. 12, l. 1-2.) This balanced regulatory incentive is destroyed by introduction of an FAC. Entirely rational management behavior with an FAC in place would be to subtly reduce spending on production maintenance charges and de-emphasize capital projects aimed at improved generating unit availability or heat rates, because any corresponding reductions in energy costs simply flow through the FAC to ratepayers. (Ex. 502, p. 13, l. 4-10.)

UE has acknowledged an FAC's detrimental effect on incentives. In 1998, its then-CEO Charles Mueller stated, "The fact we have operated for years without a fuel adjustment in Missouri has given us additional incentive to continue to manage fuel costs effectively." (Ex. 502, p. 12, l. 8-18.) Despite UE efforts to reconstruct various incentive sharing provisions as part of any new FAC, only traditional, balanced test year regulation will treat all utility costs in exactly the same way, ensuring that increasing and declining costs are properly synchronized, along with growing energy sales margins and other changing inputs to revenue requirement calculations.

3. Regulatory Complexity and Risk Shifting Argue Against an FAC for UE

The third problem with an FAC is that it increases the financial burden on ratepayers. First, it shifts all risk of fuel and purchased energy costs from the utility to its ratepayers who are the least able to influence such costs levels. (Ex. 502, p. 14, l. 1-6.) Unless regulators allow an adjustment to authorized rates of return to account for that shift, there is no benefit to ratepayers from implementation of an FAC. (Ex. 502, p. 14, l. 6-9.) Moreover, an FAC produces less predictable energy costs and more complex billing to ratepayers. (Ex. 502, p. 15, l. 3-6.) Further, an FAC creates administrative complexity and increased costs associated with audit verification and administration of complex accounting entities, cost allocations and related tariff calculations. (Ex. 502, p. 15, l. 1-6.) UE even admitted that the FAC would create extensive minimum filing requirements and exhaustive monthly survey data. (Ex. 502, p. 15, l. 9-16.)

Any FAC granted for UE will prove to be particularly difficult to administer, audit and verify. If an FAC is approved, comprehensive monthly financial and operational data will need to be filed then reviewed analyzed, and/or audited by the Commission's Staff. (Ex. 502, p. 29, l. 19-23.) Additionally, surveillance monitoring reports are required and become much more important because they enable the Staff to track whether the FAC's piecemeal rate changes are contributing to excess earnings. (Ex. 502, p. 29, l. 23; p. 30, l. 1-5.) Further, additional, detailed quarterly reporting of rate change calculations would also be filed. (Ex. 502, p. 30, l. 1-12.) Lastly, UE has recommended that the Staff review all of that within 30 days, and this process does not include the 18-month prudence reviews that are required.

Administering an FAC for this utility becomes even more complex due to Taum Sauk outage and the EE, Inc. issue. (Ex. 502, p. 31, l. 1-12.) As discussed above, the Taum Sauk incident will cause higher fuel and purchased power costs to be incurred. (Ex. 501, p. 31, l. 6-8.) Those costs are not to be passed through to ratepayers because the Commission's FAC rules preclude recovery of increased costs resulting from negligent or wrongful acts or omissions by the utility. Thus, any UE FAC would require careful monitoring and ongoing special studies to ensure that ratepayers are not charged Taum Sauk outage effects. (Ex. 502, p. 31, l. 12-14.) Expiration of the EE, Inc. purchased power contract will also cause UE per books fuel and purchased energy expenses to be much higher than if the purchased power agreement with EE Inc. had been continued. (Ex. 502, p. 31, l. 16-22; p. 32, l. 1-3.) Accounting for Taum Sauk and EE Inc. adjustments will add considerable complexity to any FAC administration procedures.

Consideration of regulatory complexities and administrative burdens, when combined with UE's absence of any compelling financial need for an FAC, argues for rejection of the Company's proposal.

4. UE does not need an FAC to have a realistic opportunity to earn its return on equity.

UE's assertion that it requires an FAC to have a realistic opportunity to earn its authorized return on equity is not supported by the record evidence. In fact, the record evidence establishes that UE has not raised rates in 20 years and has cut rates by 13 percent since 1987. (Tr. p. 174, l. 12-17.) This was accomplished without any fuel adjustment mechanism. Exhibit 112 demonstrates that from 2000-2006 UE has earned at least an 11% ROE:

	2006	2005	2004	2003	2002	2001	2000
UE regulated	9%	11%	13%	15%	12%	14%	13%
UE total	11%	12%	13%	16%	13%	14%	13%

The only reason UE's regulated ROE for 2006 is at 9.00% is because UE no longer has access to the low cost power from EE, Inc. (Tr. p. 178, l. 17-25; Tr. p. 175, l. 1-19; Tr. p. 182, l. 8-11.) Obviously, the traditional regulatory model has given UE more than an adequate opportunity to earn a reasonable return. There is no justification for allowing UE to recover its increasing fuel costs on a piecemeal basis via an FAC. In fact, UE's anticipated modest future increases in fuel costs are exactly the wrong reason to depart from the balanced overall periodic analysis of UE revenue requirement that has historically produced stable and predictable rates for consumers. The reality is that UE has been able to go a number of years without a rate increase historically. During this time the prices of materials have changed, inflation has existed for a very long time, and you can pick things out in isolation and make a case for tracking just about anything, but that's the wrong thing to do in most instances. (Tr. p. 1097, l. 5-11.)

5. UE is not exposed to significant fuel cost volatility

UE asserts that because it is unable to adequately control its fuel costs it is appropriate to grant UE an FAC. However, close scrutiny of UE's fuel mix and the measures that UE currently has in place that are included in its cost of service demonstrate that UE is not exposed to significant fuel cost volatility. This lack of price volatility in its fuel costs means that an FAC is an inappropriate regulatory tool for use by UE. Specifically, UE fails the first three criteria needed for special rate tracking treatment because changes in its fuel costs do not threaten its financial performance, changes in its fuel costs are largely hedged and are not volatile, and because management successfully exerts considerable control over UE fuel cost levels, as more fully described below.

6. UE's coal costs are stable and make up most of its fuel costs

UE's assertion that it requires a FAC because of its fuel costs are beyond its control likewise is not supported by the record evidence. The testimony of UE witness Neff and State witness Brosch demonstrated that UE has been able to assert control over its largest fuel costs – coal and coal transportation costs.

Coal price volatility is very important to evaluation of UE's FAC request because 79% of UE's electricity is from coal-fired power plants. (Ex. 502, p. 20, l. 6-9.) UE employs a coal price hedging strategy with the primary goal of protecting against the volatility of coal prices and a secondary goal of lowering prices. (Ex. 502, p. 21, l. 6-23.) UE ** [redacted] ** (Ex. 502, p. 20, l. 22-23; p. 21, l. 1-5.)

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While UE emphasized in its testimony that coal prices have increased in the past few years, these historical price increases will be completely captured in the true up calculations for this rate case, making only future prices relevant. (Ex. 502, p.21, l. 7-17.) UE's future price of coal is not expected to materially increase. Coal industry publications do not predict continuation of the increases and note several reasons for flat prices in the future. (Ex. 502, p. 22, l. 2-21.) Lastly, it is reasonably expected that the true-up of UE fuel prices will show a downward adjustment in coal costs. (Ex. 502, p. 22, l. 19-21; Ex. 500, l. 1.)

The cross examination of Mr. Neff, UE's Vice-President of coal supply, confirmed the fact that UE has stable and predictable future coal costs. Mr. Neff admitted that UE has locked in 100% of it coal supply costs for 2007, 2008 and significant amounts for future years. UE's hedging program is "highly successful" according to Mr. Neff and through it UE has locked in known prices for all of its 2007 Powder River Basin coal and (Tr. p. 880, l. 9-18; Tr. H.C. p. 895, l. 8-12.) Moreover, UE utilizes numerous techniques that have been successful in ensuring that UE avoids price spikes in the coal market. (Tr. H.C. p. 904, p. 905, p. 906, l. 1-5; Tr. p. 914, l. 15-20.) In fact, the UE Fuels affiliate **[redacted].** (Tr. p. 891, l. 1; Tr. p. 982, l. 18.)

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Finally, the known contractual coal price increases that UE will experience for 2007 are included in this rate case proceeding. (Tr. p. 914, l. 21-24.)

UE has also failed to demonstrate that its coal prices are volatile. UE's volatility claim deals with the spot market price of coal. (Tr. p. 913, l. 24-25; p. 914, l. 1-3.) Witness Neff admitted that, given UE's coal purchasing practices that use fixed price term contracts, the spot market price of coal is not a meaningful number because of UE's coal purchasing practices. (Tr. p. 915, l. 5-9.) Also, witness Neff admitted that coal prices currently are decreasing (Tr. p. 896, l. 23-24) and that UE has its coal prices locked in for 2007 and 2008. (Tr. 914, l. 15-17.)

Rail freight costs make up a large percentage of overall delivered coal costs, and have experienced large price increases historically, that are effective January 1, 2007. (Ex. 502, p.22, l. 23-28.) But, as with coal prices, the past expenses and January 1, 2007 increase are fully includable in true-up expense calculations for this rate case. Future rail freight prices after 2007 will not be volatile because UE has ** [redacted] ** (Ex. 502, p. 23, l. 9-15.) Also, for freight costs not covered under the ** [redacted] ** the predicted increases are not material. Based upon existing fixed price contracts for rail freight, the predicted overall increase is only ** [redacted] ** per ton, which represents less than 1% of UE's annual Missouri retail revenue. (Ex. 502, p. 24, l. 1-16.) Yet again the record evidence does not support UE's

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claim that coal transportation costs are volatile or will threaten financial stability if not tracked through an FAC. Mr. Neff testified that UE has secured its coal transportation contracts for 2007 and 2008. (Tr. p. 902, l. 21-25.) Those costs will be included in the costs of service. (Tr. p. 898, l. 1-4.) Moreover, UE uses hedging mechanisms to dampen price volatility with respect to diesel fuel surcharges, the only variable cost element within rail prices. (Tr. p. 918, l. 2-8; Tr. p. 915, l. 20-24.)

7. Purchased power costs do not support an FAC for UE

Purchased power costs represent the source for about 14% of UE's test year kilowatt hours, and also do not represent a cost exposure that merits FAC tracking. (Ex. 502, p. 25, l. 4-8.) A significant portion of recorded purchased power expense relates to MISO, charges for transmission line losses which should remain stable in the future. (Ex. 502, p. 25, l. 8-9.) Most of UE's remaining purchased power expense is associated with a cost-based power supply contract with Entergy Arkansas. (Ex. 502, p. 25, l. 10-17.) Once that contract expires in **[redacted]**, UE will be exposed to market prices for purchased power. However, UE's contract with Entergy Arkansas is a good example of the complexity and inequity that will arise from any FAC that may be granted to UE. When this power supply contract expires, UE will recognize a capacity charge savings of ** [redacted] ** million, an amount within its current base rate. (Ex. 502, p. 26, l. 18-21; p. 27, l. 1-7.) With an FAC in place, ratepayers will pay for the replacement energy through the FAC, while the shareholders get to keep the substantial capacity charge savings that are

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not proposed to be "tracked" through the proposed FAC. (Ex. 502, p. 26, l. 15-20; p. 27, l. 18-21.) This significant inequity is caused entirely by the company's FAC proposal, because continued traditional regulation would capture both the capacity charge savings and the replacement energy costs in a balanced "net" fashion when any future test year occurs, while the FAC desired by UE would track only the replacement energy costs directly into a piecemeal FAC rate increase to customers.

Another consideration in evaluating UE's requested FAC is whether energy markets represent a risk or an opportunity for the Company and its ability to recover increasing fuel costs. Overall, UE is a net seller of energy since it sells more off-system energy than it buys, such that the Company should profit from any higher market energy prices in the future. (Ex. 502, p. 26, l. 2-7.) The Company appears to have conceded this point in advocating during the hearings for a revised FAC that fully offsets off-system sales margins against fuel costs, but even this revised proposal is seriously flawed as noted below.

8. Nuclear Fuel prices do not create volatility or significant financial exposure.

The Callaway Nuclear plant generates the next largest component part of test year energy, representing about 7% of UE's energy supply costs. There are three components of the Company's nuclear fuel costs: fuel expenses, spent fuel costs, and nuclear decommissioning and dismantling charges. (Ex. 502, p. 27, l. 9-14.) The last two components have a fixed per year cost: for spent fuel and the decommissioning and dismantling charges. (Ex. 502, p. 27, l. 14-15.) The first and largest component, the cost of nuclear fuel, has experienced stable prices that are expected to remain stable. Nuclear fuel costs are subject to change only at the time of each refueling outage for Callaway. The prices reflected in the Company's test year fuel run reflect prices effective with the spring 2007 refueling outage cost levels. (Ex. 502, p. 27, l. 16-20.) Thus, there is no significant volatility or cost exposure associated with nuclear costs that merit FAC rate treatment.

9. UE uses very little oil and natural gas, thus it has no material financial exposure

While there is significant volatility in fuel oil and natural gas market prices, UE has little exposure because it uses very little of these fuels. UE relies on oil and natural gas fired units for less than ** [redacted] ** percent of annual generation. (Ex. 502, p. 28, l. 1-7.) Further, oil and natural gas makes up only about 3% of UE's total energy supply costs. Additionally, UE expects to run its oil and natural gas fleet only a small percentage of the time over the next few years. (Ex. 502, p. 20, l. 7-9.) Thus, UE does not have the significant financial exposure to oil and natural gas price volatility that is needed to justify an FAC.

UE witness Neff recognized that oil and natural gas fired generation are only a small percentage of UE's annual generation. (Tr. p. 911, l. 17-20.) In fact, Nr. Neff did not even mention oil and natural gas price volatility in his direct testimony. (Tr. p. 911, l. 21-23.)

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10. UE's Proposed FAC

UE has offered three separate FAC proposals. However, at the hearing UE abandoned its first two proposals and now is asking the Commission to adopt its FAC proposal set out in the surrebuttal testimony of UE witnesses Baxter and Lyons. (Tr. p. 452, l. 13-23; p. 601, l. 21-25; p. 602, l. 1-4.) Despite all of its changes intended to should reject UE's FAC proposal. State witness Brosch testified that UE's latest proposal should be rejected.

Mr. Brosch testified that UE's latest FAC proposal does not rectify the problems identified in his prefiled testimony. First, the problem with the Taum Sauk outage remains unsolved. Actual fuel and purchased powers costs are directly impacted by the non-availability of Taum Sauk. (Tr. p. 1070, l. 21-25, p. 1071, l. 1-2.) The Commission's fuel adjustment rules preclude recovery of increased costs resulting from negligent or wrongful acts or omissions by the utility. 4CSR 240.090(1). Any FAC approved for UE would require careful monitoring and ongoing special studies to adjust recorded costs to ensure that ratepayers are not charged for Taum Sauk outage effects. (Ex. 502, p. 31, l. 12-14.) Nor does the proposed FAC take into account the expiration of the EE, Inc. contract or model the availability of the Joppa plant. (Tr. p. 1071, l. 3-11.) If the Staff or Public Counsel's proposed EE, Inc. adjustments are adopted by the Commission, considerable complexity will be added to any FAC administration procedures because reported actual energy costs must be revised using a second special study and a related adjustment prior to calculating FAC rate adjustments. (Ex. 502, p. 32, l. 1-3.)

Additionally, UE's proposed FAC fails to incorporate the sales of emission allowances as a credit against fuel costs. If the Commission rejects the State's recommendation that UE not be granted an FAC, UE's emission allowance cost and revenues should be included in an FAC. (Ex. 501, p. 39, l. 16-20; p. 40, l. 1-2.) This would ensure a more balanced regulatory treatment of complementary resources used by UE in the conduct of its business.

In a clear acknowledgment of the incentive destruction that is caused by FAC regulation, UE's final revised form of proposed FAC contains an incentive sharing component, but this element of UE's proposed FAC is unlikely to operate appropriately. The new sharing grid introduced in Exhibit 104 increases the administrative complexity of the FAC. (Tr. p. 1076, l. 2-11.) With UE's latest new proposal off-system sales margins must be monitored, audited and reviewed along with all of the fuel and purchased power costs included in the FAC. (Tr. p. 1076, l. 11-15.) The off-system sales margin sharing grid recommended by UE is one-sided in that it only proposes to net off-system sales against recoverable fuel costs with rewards in one direction – UE's. (Tr. p. 1077, l. 18-23.) It is simply unreasonable to give UE a 75% bonus if the net fuel cost falls below the level set by the Commission. (Tr. p. 1078, l. 1-9.) The best way to preserve incentives that are otherwise blunted by a fuel adjustment clause is to not implement a fuel adjustment clause. But if a restoration of lost incentives is desired, a modest sharing of <u>both</u> the gains and the pains associated with changes in energy costs could be implemented, however the Company's revised FAC tariff does not do this. (Tr. p. 1075, l. 10-17.)

Another problem with the Company's revised FAC is that its sharing grid makes precise establishment of the amounts of fuel and purchased power in base rates, as well as off-system sales margins, extremely important, because these amounts define the base point for administering the proposed sharing provision. (Tr. p. 1076, l. 16-25; p. 1077, l. 1-10.) This problem is amplified by the potential for an excessive reward to UE that may result even if there is no improved performance, because of the potential for the base amounts of fuel, purchase power and off-system sales to be misstated in the Commission's order. (Tr. p. 1078, l. 3-9.) An example of the magnitude of this problem can be seen in the range of disputed values for off-system sales margins of approximately \$70 million, a dispute that must be precisely resolved by the Commission for the FAC sharing grid now proposed by UE to function reasonably. (Tr. p. 1080, l. 6-21.) If UE prevails in the off-system sales dispute, but then its actual future off-system sales margins reach the State's proposed level, net FAC costs could fall \$70 million below base rate levels, and UE will be granted an \$18 million reward for simply duping the Commission into accepting its off-system sales proposal.

Yet another problem with the sharing incentive within the Company's revised FAC arises from the fact that it is reasonable to expect future actual net fuel costs (fuel less off-system margins) to fluctuate around the normalized level established by the Commission in this case, because of weather impacts or Callaway outage cycles. (Tr. p. 1078, l. 10-17.) The Company's revised FAC proposal would provide incentives for shareholders for movement of net costs in only one direction, when net energy costs go down, even if this movement in reported net costs is caused solely by the absence of

Callaway refueling or by a year with unusually mild weather. Finally, the Company's revised FAC proposal provides no incentive if net fuel costs rise considerably in the future, causing management to perceive no hope that it may reach the sharing threshold (Tr. p. 1078, l. 18-25, p. 1079, l. 1) while providing repeated rewards year after year if structural changes occur causing future net fuel costs to decline and remain below base rate levels. (Tr. p. 1079, l. 2-11.)

Simply put, UE's proposed FAC is not consumer friendly because it is piecemeal ratemaking that is administratively complex, because it includes an ineffective incentive structure and because it would track all of the expected increases in fuel and purchased power costs, while only tracking a fraction of net cost savings once the sharing threshold is achieved. (Tr. p. 1075, l. 18-25; p. 1076, l. 1-15.)

11. Critical Elements for any UE Fuel Adjustment Clause

If the Commission decides, over the objections of the State, OPC and the Staff, that an FAC is appropriate for UE, certain parameters must be contained within such an FAC. For example, while the concept of tracking off-system sales margins is appropriate and necessary, (Ex. 501, p. 13, l. 1-19.) it is essential that off-system sales margins be established at levels that will be comparable to recorded future levels, which in this case means that the Commission should employ the UE 2007 budget level of such margins to achieve such comparability. Next, it is essential that all sales of emission allowances be netted against recorded net energy costs; to the extent such sale amounts exceed allowance sales included in the establishment of base rates. (Ex. 501, p. 39, l. 16-20; p.

40, l. 1-2; Tr. p. 1080, l. 22-25; p. 1081, l. 1-2.) If any sharing is allowed for net energy costs within an FAC, the sharing should be a modest percentage of both increases and decreases in net energy costs; using a sharing percentage of 5-10 percent applied symmetrically both above and below baseline levels. (Ex.504, p. 12, l. 15-20; Tr. p. 1075, l. 10-17.) Finally, a correction is needed to reduce FAC-includable net energy costs to account for the expiring capacity charges in **[redacted]** that will inure to the sole benefit of UE shareholders under the company's proposed FAC which would exclude changes in such capacity charges. (Ex. 502, p. 25, l. 10-17.) These modifications, along with careful specification of net fuel costs in this rate case and rigorous auditing of all future reported UE-incurred energy costs and off-system sales margins will help to reduce the inequities that will be experienced under piecemeal tracker regulation of UE's net energy costs.

I. Economic Development Rate Rider (EDRR)

UE has proposed a flawed economic development rate rider ("EDRR") as part of its rate design. Its primary flaw is that it expires on December 31, 2008. (Tr. p. 4021, l.15-16.) Like past riders, the goal is to support economic development, and future large customers, in the Missouri service area. UE likes to boast about its commitment to economic development, including three full-time professionals working on community development and "extensive" resources on its website. (Tr. p. 4161, l. 3-13.) As part of

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this commitment, the EDRR supports economic development by helping develop new business and retain existing businesses. (Tr. p. 4161, l. 19-20.) UE even testified about how beneficial the EDRR is to the system as a whole and stating that it is good for customers, UE, and the state of Missouri. (Tr. p. 4163, l. 20 – p. 4164, l. 4.) In fact, it seems that one of the few things that all parties agree on is that an EDRR is a positive and should be a part of the rate design.

All of the positives about the EDRR make its large flaw all the more glaring. After December 31, 2008, no one can sign up for it, thus restricting its benefits to an 18-month window. (Tr. p. 4162, l. 5-8 & p. 4021, 1. 17-20.) Why UE would choose to limit something it believes to be beneficial is a mystery. UE claims it will apply to the Commission for a renewal. Unfortunately, UE cannot be relied upon to apply for a renewal because it allowed the last EDRR to expire on March 31, 2006. (Tr. p. 4131, l. 1318.) And, ominously, UE chose to put an expiration date in the proposed EDRR. UE's excuse for the expiration date is that it wants to be able to tweak or amend the EDRR. (Tr. p. 4165, l. 11-19.) But nothing prevents UE from asking this Commission to amend or tweak an EDRR that lacks an expiration date before its next rate case. Therefore, the best solution is to create an EDRR without any expiration date or signup cut-off. That will allow the most benefit from the EDRR until it is revised in UE's next rate case. The staff also supports the removal of the termination date. (Tr. p. 4022, 1. 8-11.)

III. Conclusion

For the above reasons the Commission should lower UE's rated by $71.9 million, Reject UE's proposed Fuel Adjustment Clause and implement a more user friendly economic development rate rider.

Respectfully submitted,

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