BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

STAFF'S SUPPLEMENTAL PRE-HEARING BRIEF

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TABLE OF CONTENTS

CALLAWAY NON-LABOR MAINTENANCE EXPENSE

Should Callaway Refueling non-labor maintenance expense be based on an average of the last three refuelings or on the most recent refueling as the appropriate level, given Callaway's total operating and maintenance expenses?

Because AmerenUE refuels its Callaway Nuclear Plant approximately on an eighteen-month cycle, the refueling expense must be normalized in order to put the recommended cost of refueling on an annual basis. The Company's test year level of non-labor maintenance expense was $21.5 million for what is Refueling number 14. Accordingly, the Staff and AmerenUE adjusted this figure downward by one-third, or approximately $7.2 million. (Cassidy Direct, p. 26, ln. 21 – p.28, ln. 9; Cassidy Surrebuttal, p. 3, ln. 5-7).

In his direct testimony and his supplemental direct testimony, AmerenUE witness Gary S. Weiss took the same position as the Staff. (Weiss Direct, p. 20, ln. 1-10; Weiss Supplemental Direct, p. 20, ln. 5-14). However, for the rebuttal filing, AmerenUE introduced a new witness, Alan M. Rutz, to support a new Company position on the issue of Callaway refueling non-labor maintenance expense. Whereas the Company previously proposed to include $14.3 million for this item, it now is recommending an increase in this amount to approximately $18.7 million. This amount represents two-thirds of an average ($28.1 million) of the last three refuelings (nos. 14, 13 and 12), including the aforementioned $21.5 million refueling expense. (Rutz Rebuttal, p. 5, ln. 2-4). Thus, the resultant increase in AmerenUE's revenue requirement request is approximately $4.4 million. (Cassidy Surrebuttal, p. 3, ln. 20 – p. 4, ln. 4).

The Staff opposes this revised request for three reasons, as set out in the Surrebuttal testimony of Staff witness John P. Cassidy. First, no new information has surfaced between the Company's direct, supplemental direct and rebuttal filings that might serve to justify the Company's new position. The test year refueling was completed in November of 2005.

AmerenUE had knowledge of all of the information appearing in Mr. Rutz's rebuttal testimony when Company witness Gary Weiss made both of his direct testimony filings (July and September of 2006) and therefore could certainly have taken the position Mr. Rutz now supports. AmerenUE did not do so. (Cassidy Surrebuttal, p. 4, ln. 16 – p. 5, ln. 4).

The second reason for the Staff's opposition to AmerenUE's proposal is that Mr. Rutz's three-refueling average for non-labor maintenance expense includes Refueling 13 (Spring of 2004), which represents the highest level of non-labor maintenance expense ever experienced by AmerenUE. In fact, the Refueling 13 expenditure exceeds the next most costly level by $17 million, or almost 75%[1]. Because of the unexpected problems with this particular refueling, the associated costs should be considered anomalous. By including the non-labor maintenance expenses associated with Callaway Refueling 13, Mr. Rutz inappropriately inflates his three refueling average. (Cassidy Surrebuttal, p. 5, ln. 5 – p. 6, ln. 6).

Third, according to AmerenUE's response to Staff Data Request Nos. 141 and 529, the Company's attempt to boost revenue requirement by shifting its position ** ________________

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** (Cassidy Surrebuttal, p. , ln. 7 – p. 7, ln. 7).

For the above reasons, the Staff continues to support its recommendation for non-labor maintenance expense associated with Callaway refueling of approximately $14.3 million.

[1] The three-refueling average of non-labor maintenance expense of $28.1 million exceeds the Company's second highest non-labor maintenance expense level by $5 million, or more than 20%.

FUEL AND PURCHASED POWER

A. DIESEL FUEL HEDGE COSTS

Should diesel fuel hedge costs be included in the cost of service?

As a result of a recent change in the provision of service by rail transporters, AmerenUE will be required to pay the railroads in accordance with a diesel fuel rider, which permits the carrier to adjust its charges based on changes in the cost of diesel fuel. For purposes of determining an adjustment, the rail carriers' tariff programs are tied to, among other things, On-Highway Diesel Pricing Index Reports. (Neff Direct, p. 32, ln. 3 – p. 33, ln. 3).

AmerenUE has sought to protect itself from exposure to rail transportation cost increases due to diesel fuel by purchasing heating oil call options on the New York Mercantile Exchange ("NYMEX")[2]. The number of call options purchased is a function of the tonnage of coal to be purchased under the transportation contract. During the fourth quarter of 2005, the Company began an earnest effort to put hedges in place for 2006. (Neff Direct, p. 33, ln. 4-19; p. 34, ln. 6-7).

As Staff witness John Cassidy states in his surrebuttal testimony (p. 8, ln. 5-8), **

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For purposes of this rate proceeding, the cost of service impact of the hedging program, as proposed by AmerenUE, is approximately ** __________ **. (Neff Rebuttal, p. 2, ln. 8).

[2] There is an established commodity market for heating oil, and the Company regards the price of heating oil to be highly correlated to the price of on-highway diesel fuel. (Neff Direct, p. 33, ln. 7-9).

The Staff is opposed to inclusion of these hedge costs in the cost of service calculation because currently ratepayers do not stand to benefit from them. (Cassidy Surrebuttal, p. 7, ln. 12-14). As part of its fuel and purchased power expense annualization for the twelve months ending December 31, 2006, the Staff has included ** ____

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______________________________ ** (Cassidy Surrebuttal, p. 8, ln. 12-14). The Company and the Staff agree that this ** ____

____ ** results for the year ending December 31, 2006, represents the proper inclusion in the cost of service calculation. (Neff Direct, p. 34, ln. 20-23; Cassidy Surrebuttal, p. 8, ln. 18-20). ** ____

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__________________** Both of the 2007 and 2008 forcasted prices are ** _____________

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____ ** The current hedges for 2007 can only begin to protect AmerenUE if diesel fuel prices rise above ** _____ ** on average for the entire 2007 calendar year. (Cassidy Surrebuttal, p 9, ln. 1-3). Therefore, the ** ___________** hedge provides no benefit to AmerenUE's ratepayers, and the Commission should reject the Company's proposal to include that amount in cost of service.

B. NUCLEAR FUEL PRICES

Should nuclear fuel expense include the cost of new fuel assemblies that will be loaded into the reactor in the next scheduled refueling?

Refueling of the Callaway nuclear plant is conducted every eighteen months. At that time, approximately one-half of the fuel assemblies in the reactor are replaced. (Irwin Rebuttal,

p. 3, ln. 2-4). In its surrebuttal filing in this proceeding, the Staff recommended using a twelve month ending December 31, 2006 nuclear fuel price of ** ____________________ **, to be included in its cost of service calculation, which reflects the Company's known and measurable nuclear fuel costs in existence at the cutoff date for this proceeding. (Cassidy Surrebuttal, p. 10, ln. 21 – p. 11, ln. 2.).

AmerenUE witness Randall J. Irwin filed rebuttal testimony in which he proposed that the fuel price be increased to ** ___________________ **, which would be in effect for the period May 2007 through December 2007[3]. The higher price figure is intended to reflect the higher cost of new fuel assemblies already on site in preparation for refueling Cycle 15, scheduled for May of 2007. (Irwin Rebuttal, p. 3. ln. 18 – p. 4, ln. 14).

The Staff is opposed to the Company's proposal to increase the price of the nuclear fuel in this proceeding. It is inappropriate to include prices that will not be in effect until completion of the next refueling project in May of 2007, which is well beyond the cutoff date for this rate proceeding. (Cassidy Surrebuttal, p. 10, ln. 12 – p. 11, ln. 2). The Commission should reject AmerenUE's proposal in favor of the Staff's recommendation.

B. NUCLEAR FUEL INVENTORY

What amount should be included in rates to reflect the unamortized balance of nuclear fuel assemblies in the reactor?

For rate base purposes, "[t]he Staff included the average balances that existed for the 18 months ending June 30, 2006 for nuclear fuel, as a representative ongoing level." (Cassidy Direct, p. 24, ln. 6-8). The Staff's direct testimony position of including ** _____________ ** for nuclear fuel inventory in rate base was consistent with the ** _____________ ** inclusion

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[3] Mr. Irwin revised his nuclear fuel price position to ** ___________________**, which reflects his calculation of an average nuclear fuel price for calendar year ending 2007 (Irwin Surrebuttal, p. 4, ln. 1-3).

that was proposed by Company witness Gary Weiss in his supplemental direct testimony. (Weiss Supplemental Direct, p, 10, ln. 21-23; p. 11 ln. 1-5; Sched. GSW-E22-2).

In his rebuttal testimony, AmerenUE witness Irwin asserts that this value of inventory is not representative of an ongoing level. As support for his assertion, Mr. Irwin points to the same fuel price increases he noted in his discussion of nuclear fuel prices. His recommendation proposes to include ** ____________ **nuclear fuel inventory value in rate base, which is based upon an average of the 18-month period ending October 2008. (Irwin Rebuttal, p. 6, ln. 6-20). For purposes of the true-up audit, the Staff proposes to include the average of the 18 month nuclear fuel inventory balances that exist at December 31, 2006 to be consistent with the true-up cutoff date that was established by the Commission and agreed to by the parties in this rate proceeding. (Cassidy Surrebuttal, p.12 , lines 4-8)

The Staff is opposed to the Company's proposal for essentially the same reason it opposes the AmerenUE recommendation to increase the level of nuclear fuel costs for cost of service purposes; namely, that the higher costs do not come into play until well beyond the cutoff date of January 1, 2007. As Staff witness John Cassidy notes, the higher dollar balance supported by AmerenUE "represents fuel assemblies that will not be loaded in the reactor until May 2007." Accordingly, "these assemblies are incapable of providing service to ratepayers as of January 1, 2007, the cutoff date established in this rate proceeding. The Staff believes it is inappropriate to include the Company's proposed rate base inclusion in the cost of service calculation for nuclear fuel assemblies that will not be providing service to AmerenUE customers until sometime during May 2007, well beyond the established cut off period for this rate proceeding." Mr. Cassidy further noted that the Company did not make this proposal in its direct filing, and that the proposal represents a departure also from the methodology established

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in all previous rate cases, where inventory amounts were set on the basis of the average balance of unburned nuclear fuel actually in the reactor. (Cassidy Surrebuttal, p. 11, ln. 3-19). For these reasons, the Commission should reject the Company's recommendation to increase the nuclear fuel inventory above the level proposed by the Staff.

FUEL ADJUSTMENT CLAUSE

Should AmerenUE's proposed fuel adjustment clause be approved and, if so, with what modifications or conditions?

The Staff believes that the Commission should not allow AmerenUE to implement a fuel and purchased power costs recovery mechanism, a fuel adjustment clause (FAC) or an interim energy charge (IEC). The Staff's opposition is based on the following considerations:

(1) AmerenUE does not need a FAC, or an IEC, since its revenue opportunities in off-system sales mitigate much of its fuel price rice risk

(2) AmerenUE does not need a FAC, or an IEC, in order to have a reasonable opportunity to achieve its authorized rate of return

(3) Although it is not a sufficient reason alone, not providing AmerenUE with a FAC, or an IEC, preserves strong incentives for AmerenUE to be prudent in its efforts to purchase fuel and power

(Wood Rebuttal, pp. 3-4).

Staff's analysis shows that AmerenUE's revenues from off-system sales significantly reduce its downside risk related to fuel expense. Higher fuel costs to AmerenUE tend to directly correlate with higher off-system sales revenues to AmerenUE. In simple terms, lower fuel costs correlate with lower off-system sales revenues and higher fuel costs correlate with higher off-system sales revenues. Thus, increases in fuel costs are mitigated by increases in off-system sales revenues. Staff witness Dr. Michael S. Proctor presents this Staff analysis and testimony. (Wood Rebuttal, p. 4; Wood Surrebuttal, p. 5). Unlike The Empire District Electric Company and Aquila, Inc., a significant portion of AmerenUE's energy needs to serve its customers are provided by nuclear and coal fired generation rather than natural gas fired generation. Also, the inclusion of recent increases in coal costs that would not be certain until January 1, 2007 was one of the reasons that the update period to January 1, 2007 was agreed to for this case. Staff witness John Cassidy presents testimony and an assessment of coal and nuclear fuel cost increases that AmerenUE expects to incur in 2008 and 2009. (*Id*. at 5).

Mr. Cassidy's Rebuttal Testimony shows a table that summarizes AmerenUE's actual net generation including the amount of purchased power for both the test year ending June 30, 2006 and the twelve months ending December 31, 2006, the end of the true-up period. The table demonstrates that the majority of AmerenUE's actual net generation is provided through the use of its nuclear and coal fired plants:

Primary Fuel Source	**Purchases & Net MWH Generation 6/30/06 6/30/2006**	**% of Total**	**Purchases & Net MWH Generation 12/31/06 12/31/2006**	**% of Total**
Nuclear	8,079,309	15.1%	10,116,660	19.1%
Coal	39,458,584	73.5%	39,375,535	74.1%
CTG Gas/Oil	451,481	0.8%	409,889	0.8%
Hydro/Pump	958,832	1.8%	955,563	1.8%
Purchased Power	4,706,599	8.8%	2,252,920	4.2%
Total	53,654,805	100%	53,110,567	100%

(Cassidy Rebuttal, p. 2). In his Surrebuttal Testimony, Mr. Cassidy notes that the Staff does not disagree that AmerenUE has experienced significant increases in prices in coal during the recent past, but these increases will be included as part of the Staff's cost of service calculation which covers all known and measurable fuel prices through the January 1, 2007 true-up cutoff. (Cassidy Surrebuttal, p. 9). He further comments that future coal and related freight cost increases are largely known to occur at specific dates in the future, as are nuclear fuel cost increases which will increase over a longer interval, once every eighteen months, when

AmerenUE performs a refueling of Callaway. (Cassidy Rebuttal, p. 7; Cassidy Surrebuttal, p. 10).

Electric utilities that can adjust their rates between rate cases to reflect increases and decreases in fuel and purchase power costs do not have the same incentives to control these costs as electric utilities that recover fuel and purchase power costs based on a fixed amount set in a rate case. Of course, due to regulatory lag, if a utility can reduce its overall fuel and purchased power costs below the fixed amount set in rates, the difference improves the utility's profitability. (Wood Rebuttal, p. 6).

It is the Staff's position that if AmerenUE is granted a FAC by the Commission, revenues from off-system sales should flow-through the FAC to reduce both the level of the FAC rate and its volatility rather than be shared with AmerenUE shareholders. (Wood Surrebuttal, pp. 4-5).

Commission FAC rule 4 CSR 240-3.161(2)(P) requires an electric utility requesting an FAC to propose a schedule and testing plan for heat rates and/or efficiency test to determine a base level of efficiency for each of the utility's generation assets. Commission FAC rule 4 CSR 240-3.161(3)(Q) requires an electric utility requesting to continue or modify a rate adjustment mechanism to file the results of heat rate tests and/or efficiency tests on all of the electric utility's nuclear and non-nuclear steam generators, HSRG, steam turbines and combustion turbines conducted within the previous 24 months. If the Commission were to authorize an FAC for AmerenUE or any other electric utility, the Staff believes the electric utility must have procedures in place that:

(1) Require testing of generation plant heat rates no less frequently than every two (2) years;

(2) Generally conform to industry-standard performance testing methodologies;

(3) Require identification of plant components that are diminishing overall plant heat rates; and

(4) Require cost-effective maintenance or replacement activities to plant components that have been identified as diminishing overall plant heat rates.

(Wood Rebuttal, p. 8).

In the Staff's view a number of adequate testing procedures are provided in the American Society of Mechanical Engineers' Performance Test Codes (ASME-PTCs). Although the Staff does not believe that either 4 CSR 240-3.161 or 4CSR 240-20.090 require the ASME-PTC procedures, a robust heat rate and/or efficiency testing plan that uses the ASME-PTCs to develop simplified testing procedures would be acceptable to Staff. For all utilities that propose a FAC or IEC, the Staff intends to determine if the utility-proposed testing plans and procedures are adequate and address items (3) and (4) in the preceding list with the utility. (Wood Rebuttal, pp. 9-10). The Staff has reviewed AmerenUE's proposed heat rate and/or efficiency testing plan for its generation assets and believes that it is insufficient to determine a base level of efficiency for each generation asset. (Wood Rebuttal, p. 7).

OFF-SYSTEM SALES

How should off-system sales be recognized in AmerenUE's revenue requirement and what amount of off-system sales margin is appropriate for the test year? Should any tracking or sharing of changes in off-systems sales margins be implemented?

A. Off-System Sales Determinants

1. Fuel Dispatch Prices

The Staff recommends that the following fuel dispatch prices be used for the determination of the dispatch of AmerenUE's coal-fired and natural gas-fired generation units:

<u>Coal-fired generation</u> (cents/MMBtu):

Labadie ** ______ **
Sioux ** ______ **
Rush Island ** ______ **
Meramec ** ______ **

Average ** ______ **

** ________________________________. **

The Staff's recommended coal dispatch prices are not at issue, as AmerenUE has adopted the Staff's recommendation**.** (Finnell Rebuttal, p. 33, ln. 15-21; Proctor Surrebuttal, p. 32, ln. 1). The Company does, however, contest the Staff's recommended natural gas dispatch price.

The Staff witness on the issue of natural gas dispatch prices is Dr. Michael S. Proctor. Dr. Proctor addresses this topic at pages 13-14 of his direct testimony. After analyzing trends in natural gas prices over the past four years, Dr. Proctor reached the following conclusion: "The twelve-month average for the twelve months ending November 2006 appears to be an appropriate level to use for normal natural gas prices." (Proctor Direct, p. 14, ln. 3-4). "[T]his estimate for a normal level is consistent with both historical trends and recent, actual observations." (Proctor Direct, p. 14, ln. 6 -7). In support of these statements, Dr. Proctor attached Schedule 3 to his direct testimony, which is a plot over time of the twelve-month moving average of natural gas prices.

Natural gas prices are also addressed in Dr. Proctor's surrebuttal testimony (pages 9, 10, 28, 32 and 33). Among other things, he responds to a concern raised in the rebuttal testimony of AmerenUE witness Shawn E. Schukar regarding the data that Staff used for natural gas dispatch prices. (Schukar Rebuttal, p. 12, ln. 16-19). Dr. Proctor points out, however, that AmerenUE used the same data in its direct filing. (Proctor Surrebuttal, p. 9, ln. 24 – p. 10 ln. 3).

Furthermore, in response to Mr. Schukar's proposal that an alternative data source[4] be used for natural gas prices, Dr. Proctor states: "[f]or purposes of correlation to on-peak spot market electricity prices . . . it really doesn't matter which of the two natural gas price series is used. Both do equally well in predicting on-peak spot market electricity prices." (Proctor Surrebuttal, p. 10, ln. 9-11).

Mr. Schukar also proposes using a lower natural gas price during the summer to predict summer on-peak electricity prices (Schukar, Rebuttal, pp. 22-23). Dr. Proctor does not support the proposal, stating in support of his position: "While it is correct that during 2006, natural gas prices were lower during the summer months of June through August, this was not the case for the four year period 2003 through 2006. During the summer period, natural gas prices, adjusted for trend, averaged only four cents per MMBtu lower than in the non-summer period. This difference is neither numerically nor statistically significant." (Proctor Surrebuttal, p. 28, ln. 4-8).

The rebuttal testimony of AmerenUE witness Timothy D. Finnell indicates that the Company has changed its means of determining normal prices of natural gas for both dispatch and accounting purposes. Specifically, AmerenUE appears to have abandoned the historical three-year average (2003 through 2005) proposed in its direct filing, in favor of the cost of natural gas burned in AmerenUE combustion turbines in 2006. (Finnell Rebuttal, p. 32, ln. 14; Proctor Surrebuttal, p. 32, ln. 1-4). Although the Staff supports using the same natural gas price for accounting purposes as is used for the dispatch price for off-system sales, it does not support the use of only data from 2006 for establishing a normal price level. (Proctor Surrebuttal, p. 32, ln. 8-11; ln. 21 – p. 33, ln. 4). Instead, the Staff continues to support its position filed in direct

[4] Platts Gas Daily Midpoint for Chicago Large End Users daily gas price, which provides data for an entire month

testimony concerning the normal level for the natural gas dispatch price ($7/MMBtu). (Proctor Surrebuttal, p. 32, ln. 16-17). The average price from the new data proposed in Mr. Schukar's rebuttal testimony over the most recent three years (2004 through 2006) supports that same price level (Proctor Surrebuttal, p.32, ln. 21-22), as does the average of the most recent three years of the data originally used by both AmerenUE and the Staff. (Proctor Surrebuttal, p. 33, ln. 4-9)

2. Spot-Market Electricity Prices For Off-System Sales

The Staff recommends the following average annual prices for spot-market electricity prices for off-system sales:

** ___________.** Off-Peak – weekdays from 11 p.m. through 6 a.m. and weekends.

** __________. ** On-Peak – weekdays from 7 a.m. through 10 p.m.

The Staff has adopted AmerenUE's hourly price shape by applying a percentage increase to all off-peak hours and a percentage increase to all on-peak hours to yield the Staff's recommended average annual spot-market electricity prices. The resulting hourly spot-market electricity prices were then used in the Staff's production cost model to determine the levels of off-system purchases and sales. Both off-peak and on-peak average annual price levels for spot-market electricity prices are at issue.

Dr. Proctor is the Staff witness on this issue. He addresses normal off-peak and normal on-peak electricity price levels at pages 9-13 and 14-17 of his direct testimony. Off-peak electric prices are highly correlated to coal dispatch prices on an annual basis, and on-peak prices are highly correlated to natural gas dispatch prices on an annual basis (Proctor Surrebuttal, p. 14, ln. 11-22; p. 9, ln. 4-22). (See also Schedules 2.1 and 4.1 attached to Dr. Proctor's direct testimony.) Dr. Proctor used the correlation between annual fuel dispatch prices and annual average spot-market electricity prices to determine the normal levels for spot-market electricity prices. (Proctor Surrebuttal, p. 10, ln. 3-8; p. 15, ln. 3-6). After checking the results of the correlation against historical trends, he concluded that the Staff's proposed normal level for twelve-month average spot-market electricity prices is consistent with those observations. (Proctor Surrebuttal, p. 10, ln. 11-19; p. 15, ln. 9-13) (See also Schedules 2.1 and 4.2 attached to Dr. Proctor's direct testimony.)

The topic of normal spot-market price levels is also addressed on pages 5-31 of Dr. Proctor's surrebuttal testimony, as a response to the criticisms raised in the rebuttal testimony of AmerenUE witness Shawn Schukar. Mr. Schukar's concerns can be broken into price data issues and methodology issues. These are discussed below:

1. **Price Data Issues**: Mr. Schukar claims that the spot market electricity price data used by Staff (which was furnished by the Company) does not include losses and congestion for the period starting with Day 2 of the Midwest ISO Day 2 market (Schukar Rebuttal, p. 10, ln. 6-21; Proctor Surrebuttal, p. 6, ln. 3-5). However, the Staff used the same data that AmerenUE used in its direct filed case. (Proctor Surrebuttal, p. 6, ln. 5-6; p. 8, ln. 3-13). Moreover, if AmerenUE intentionally used this data to take "a 'conservative approach,' how can it now criticize the Staff for taking that same approach?" (Proctor Surrebuttal, p. 6, ln. 15-18). Since Staff is using the same data used by Mr. Schukar to develop normal prices, "if this approach was okay for AmerenUE to use, why is it now not okay for the Staff to use?" (Proctor Surrebuttal, p. 8, ln. 10-13).

> Mr. Schukar proposes to use the average Locational Marginal Prices (LMPs) at AmerenUE's coal-fired plants as representing the price that AmerenUE received for off-system sales. The Staff does not support this approach. Since not all sales come proportionately from all four coal-fired plants or for that matter, from coal-fired generation,

these prices likely represent "a lower bound on prices actually received by AmerenUE for off-system sales." (Proctor Surrebuttal at page 9, ln. 16-18). Nevertheless, if the Commission believes it is important to reflect some adjustment to Staff's original prices filed in its direct case because of congestion and losses, the Staff would recommend at most a two percent decrease. (Proctor Surrebuttal at page 31, ln. 13). Dr. Proctor's reasoning is that two percent is essentially the amount of decrease in off-peak prices that would result from moving from the original spot-market electricity price data to the coal-fired unit average LMP data proposed by Mr. Schukar in rebuttal, and further, that the same two percent decrease should also be applied to the on-peak price levels, where Mr. Schukar's data is very likely to be an "overestimate of the decrease needed to properly reflect congestion and losses in the on-peak period." (Proctor Surrebuttal, p. 31, ln. 15-17). If the Commission were to adopt this two percent adjustment, the Staff's recommended normals for the average annual off-peak price and the average annual on-peak price would be reduced by $0.61/MWh and $1.09/MWh, respectively. (Proctor Surrebuttal, p. 31, ln. 17-19).

2. **Methodology Issues**: The Staff correlated twelve-month moving average spot-market electricity prices to twelve-month moving average fuel dispatch prices. (Proctor Direct, p. 9, ln. 13-17; p. 14, ln. 14-17).

In rebuttal, AmerenUE witness Schukar mischaracterized Staff's basic methodology as one that correlates monthly spot-market electricity prices to monthly fuel dispatch prices (Proctor Surrebuttal, p. 11, ln. 5-15). Dr. Proctor shows that while spot-market electricity prices follow a monthly "cyclical" pattern, this is not the case for fuel dispatch prices. (Proctor Surrebuttal, p. 11, ln. 18 – p. 16, ln. 7). To demonstrate this, Dr. Proctor separates the four years of historical price series for coal, natural gas, off-peak electricity and on-peak electricity into three components: trend, cyclical and random. (Proctor Surrebuttal, Sched. 2.1 - 3.4). He then shows that the cyclical component for fuel prices is small compared to the cyclical component for spot-market electricity prices (Proctor Surrebuttal, Sched. 4.1), and that this results in very low correlations between spot-market prices and fuel dispatch prices on a monthly level. (Proctor Surrebuttal, p. 16, ln. 10-16). Thus, Dr. Proctor concludes that all of the analysis presented by Mr. Schukar in his rebuttal testimony is flawed, and he "should not have used either monthly coal prices or monthly natural gas prices to predict monthly electricity prices." (Proctor Surrebuttal, p. 16, ln. 16-18).

In addition, Dr. Proctor finds that Mr. Schukar's approach "results in an underestimate of the correlation in the annual levels of the fuel dispatch prices to the spot-market electricity prices, and a biased estimate of their relationship." (Proctor Surrebuttal, p. 17, ln. 5-8). In support of this finding, Dr. Proctor constructs a simple example to demonstrate that applying Mr. Schukar's method of correlating monthly prices to two perfectly correlated time series, one with a cyclical component and the other without, produces an R-squared value less than the 100% required by the perfect correlation of the time series, and under-estimates the true relationship, as well. (Proctor Surrebuttal, p. 17, ln. 20 – p. 18, ln. 10).

While Dr. Proctor presents testimony on how Mr. Schukar's methodology errors might be corrected (Proctor Surrebuttal, p. 24, ln. 9 – p. 26, ln. 22), he recommends that the Commission adopt the Staff's original approach because it is simpler and less prone to misspecification. (Proctor Surrebuttal, p. 27, ln. 1-7).

Because he is "not comfortable" with the revised AmerenUE prices for off-system sales proposed by Mr. Schukar, Dr. Proctor uses AmerenUE's 2007 fuel budget as a "sanity" check (Proctor Surrebuttal, p. 31, ln.1-3; p. 29, ln. 3-6). A comparison of the Staff's revised production cost runs to AmerenUE's 2007 fuel budget (Proctor Surrebuttal at page 29, ln. 16-27) leads to a conclusion that "the Staff's assumptions were conservative compared to AmerenUE's fuel budget for 2007." (Proctor Surrebuttal, p. 31, ln. 5-9). As indicated earlier, only if the Commission found it important to adjust Staff's recommended annual average prices for spot-market electricity downward for losses and congestion, would Dr. Proctor recommend at most a two- percent downward adjustment (Proctor Surrebuttal, p. 31, ln. 13).

For the reasons stated, the Staff recommends that the Commission adopt the Staff's natural gas dispatch price of $7/MMBtu and the spot-market electricity prices of ** ___________ ** (Off-Peak) and ** ___________ ** (On-Peak), as developed by Dr. Proctor.

B. Sharing Mechanism

The Staff is not recommending a sharing mechanism for profit margins from off-system sales. In its direct filing, AmerenUE proposed a sharing mechanism for profit margins from off-system sales that was separate from its proposed Fuel Adjustment Clause (FAC). In Surrebuttal Testimony, AmerenUE witness Mr. Martin J. Lyons, Jr. has proposed to combine profit margins from off-system sales with fuel expense to serve native load in a combined FAC. However, this new proposal includes a one-sided sharing mechanism which the Staff has already objected to in the form of AmerenUE's proposed sharing mechanism for profits from off-system sales. Thus, the treatment of profit margins by means of a sharing mechanism remains an issue, although now it may be in the form of an FAC.

Insufficient Evidence to Support the Need for a Sharing Mechanism

The Staff's evidence in support of its position is found in the rebuttal testimony of Dr. Michael S. Proctor. AmerenUE provides insufficient evidence to support the need for a sharing mechanism. The Staff maintains that to provide sufficient evidence to support the need for a sharing mechanism for profit margins from off-system sales, AmerenUE should have: 1) Determined the specific uncertain variables; 2) Determined statistical measures for the uncertain variables; 3) Determined correlations among uncertain variables; 4) Set out all of the scenarios involving uncertain variables to be analyzed; and 5) Run production cost models to determine the level of profit margins associated with each scenario (Proctor Rebuttal, pp. 6 – 11). To date, the Staff has not seen a detailed study from AmerenUE, but is willing to work with AmerenUE to design such a study that includes the design element set out in Dr. Proctor's rebuttal testimony.

Based on analysis of risks associated with spot-market electricity price and fuel price variability, the Staff concludes: "variability in profit margins from spot sales price risk is significantly mitigated by the correlation between fuel prices and spot-market prices. In order to determine whether a sharing mechanism is needed, the Commission should require AmerenUE to produce a similar type of study that also includes the variability from load and unit forced outages." (Proctor Rebuttal, p. 12).

While AmerenUE did a form of analysis on variability in profit margins from off-system sales related to variability in load and generation unit forced outages, the calculations used by AmerenUE are not accurate. (Proctor Rebuttal, pp. 12-13 regarding variability in profit margins from off-system sales; pp. 13-15 regarding variability in load and generation unit forced outages). The Staff identifies shortcomings in AmerenUE's calculations with respect to load variability and recommends that AmerenUE be required "to perform a detailed study of how seasonal loads and off-peak and on-peak loads vary with weather to determine what the impact would be on off-system sales." (*Id*. at 13).

With respect to variability in unit forced (unplanned) outages, the Staff points out that AmerenUE's calculations assume that the additional outages would only occur in hours when AmerenUE is making sales, and that the outages will be no greater than the amount of sales being made. The Staff contends that this is highly unlikely and that AmerenUE's estimate of lost off-system sales from outages is high. In order to correct this problem, the Staff recommends that AmerenUE factor the forced outages into its production cost model on a random basis in order to determine the probable impact on off-system sales. (Proctor Rebuttal, p. 14). The Staff points out that to get the level of forced outages assumed by AmerenUE would require one of the large coal units at Labadie, Rush Island or Sioux to be forced out of service for an extended period of time. Because of the size of these units (495 to 616 megawatts), AmerenUE's off-system sales would have to exceed these megawatt levels in every hour, and it is unlikely this would occur in every hour over an extended period of time required to get the higher level of forced outages proposed by AmerenUE. (*Id*. at 14-15).

While Mr. Schukar addresses these concerns in his surrebuttal testimony (page 21, line 19 through page 23, line 17), AmerenUE has not produced a study that determines the level of probabilities to associate with increases in forced outage rates and changes in load from weather.

AmerenUE's Proposed Sharing Mechanism Lacks Required Specificity

The Staff expresses concern with the lack of specificity in AmerenUE's proposed sharing mechanism with respect to the calculation of profit margins from off-system sales. The Staff expresses concern regarding the specification of generation that is used to meet load and generation used to meet off-system sales. (Proctor Rebuttal, p. 15-16). AmerenUE attempts to address this concern in the rebuttal testimony of Shawn Schukar filed on February 5 by stacking units in ascending order of incremental cost and assigning the lowest incremental cost generation to native load and the highest incremental cost generation to off-system sale. (Schukar 2/5/07 Rebuttal, Schedule SES-12-3). This does not address all of the Staff's concerns regarding the allocation of AmerenUE generation between native load and off-system sales.

The Staff expresses concern regarding the determination of whether or not variable operating and maintenance costs are included in the determination of the generation costs that are assigned to off-system sales. (Proctor Rebuttal, p. 16). This matter was <u>not</u> addressed in AmerenUE's February 5 rebuttal testimony and remains a concern to the Staff. The Staff expresses concern regarding the allocation of Midwest ISO related costs between native load and off-system sales. (*Id.* at 16 -17). AmerenUE attempts to address this concern in rebuttal testimony filed on February 5 by proposing allocations of aggregates of Midwest ISO related cost between native load and off-system sales (Schukar 2/5/07 Rebuttal, Schedule SES-12-6). The Staff still has concerns regarding AmerenUE's proposed approach for allocating Midwest ISO related cost between native load and off-system sales.

AmerenUE witness Martin J. Lyons, Jr. submitted a second proposal in his surrebuttal testimony, in which profit margins from off-system sales would be included in its fuel adjustment clause. (Lyons Surrebuttal, pp. 20-22). While this proposal addresses the Staff's concern with the lack of specificity required to separate profit margins from off-system sales from variable generation costs to serve native load, this proposal does not meet other concerns expressed by the Staff as discussed below.

Base Level of AmerenUE's Proposed Sharing Mechanism is a Rough Approximation

The AmerenUE proposed sharing mechanism sets a "base level" for profit margins above which all off-system sales margins would be shared between AmerenUE and its customers. (Schukar Direct, pp. 20). The Staff's concern is that the estimate used to set this base level utilizes rough calculations with incomplete information and is based on assumptions that are not valid. (Proctor Rebuttal, p. 18). The Staff points out that a base level cannot properly be set without AmerenUE proving an estimate of the probability distribution for profit margins from off-system sales. The Staff provides a specific illustration of the type of probability distribution for profit margins from off-system sales that would be required. (Proctor Rebuttal, pp. 19-20). This specific issue is relevant to AmerenUE's sharing mechanism proposed in its direct filing, and is also relevant to AmerenUE's sharing mechanism proposed in it surrebuttal filing. While there is no component labeled "base level" in AmerenUE's surrebuttal filing, there is a specific sharing grid proposed (Lyons Surrebuttal, p. 22) that effectively raises the same questions as raised by setting a base level in AmerenUE's original sharing mechanism: What are the probabilities associated with each portion of the newly proposed sharing grid?

AmerenUE's Proposed Sharing Mechanism is Arbitrary and Unfair

The Staff points out that the design of the AmerenUE proposed sharing grid would treat customers unfairly by raising their rates even when AmerenUE earns the profit margins from off-system sales approved by the Commission as the normalized level for this case. (Proctor Rebuttal, pp. 21- 22).

The Staff specifies two design principles that must be met in order for a sharing grid to be properly designed: 1) the expected value of the sharing grid should be equal to the normal level for profit margins approved by the Commission for this case; and 2) the probability of the downside risk or detriment should be equal to the probability of the upside reward or benefit. (Proctor Rebuttal, p. 25). AmerenUE's sharing mechanism filed in its direct testimony does not meet these two principles. (*Id*. at 26). Dr. Proctor provides illustrations of sharing mechanisms that do meet these two principles. (*Id*. at 23-25).

AmerenUE has not shown that the new sharing mechanism proposed in its surrebuttal testimony meets the design principles proposed by the Staff. In fact, the proposed sharing mechanism is one-sided, providing only benefits to shareholders when fuel costs net of profit margins from off-system sales go above the normalized level for this case, but does not provide for shareholders taking on downside risk when fuel costs net of profit margins go below the normalized level for this case.

AmerenUE's Proposed Sharing Mechanism Contributes to AmerenUE's Downside Risk Related to Fuel Expense

The Staff presents calculations that illustrate the differences in downside risk when comparing a fuel costs treatment in a fuel adjustment clause where off-system sales are excluded to one that includes off-system sales. (Proctor Rebuttal, p. 27, tables at line 1 and at line 12). These comparisons demonstrate that when off-system sales are included, the downside risk to AmerenUE is significantly reduced, perhaps to a level that brings into question AmerenUE's need for a fuel adjustment clause. (*Id*. at 26-27).

In the Rules that the Commission adopted to implement the electric utility FAC and IEC provisions of Section 386.266 RSMo. (Senate Bill 179), the Commission adopted standards regarding incentive mechanisms or performance based programs in 4 CSR 240-20.090(11)(B), which states as follows:

> Any incentive mechanism or performance based program shall be structured to align the interests of the electric utility's customers and shareholders. The anticipated benefits to the electric utility's customers from the incentive or

> performance based program shall equal or exceed the anticipated costs of the mechanism or program to the electric utility's customers. For this purpose, the cost of an incentive mechanism or performance based program shall include any increase in expense or reduction in revenue credit that increases rates to customers in any time period above what they would be without the incentive mechanism or performance based program.

The Staff submitted surrebuttal testimony stating that AmerenUE has not met the standard of 4 CSR 240-20.090(11)(B). The Staff is not aware of any studies or analyses that show that AmerenUE's proposed incentive mechanism is structured such that anticipated benefits to the electric utility's customers from the incentive mechanism equal or exceed the anticipated costs of the mechanism. (Surrebuttal Wood, p. 6).

Based on the Staff's analysis, the Staff recommends against a sharing mechanism that separates profits from off-system sales from a fuel adjustment clause. (Proctor Rebuttal, p. 28). AmerenUE's proposed sharing mechanism in its Direct Testimony filing contributes to AmerenUE's downside risk and should be rejected. Although the new sharing mechanism proposed in AmerenUE's Surrebuttal Testimony does not separate profits from off-system sales, as indicated above, it has not been shown to meet the design principles required for a properly designed sharing mechanism.

INCOME TAX EXPENSE

Should net salvage be normalized?

In the filing of its case on December 15, 2006, in its original calculation of income tax expense, the Staff added back the amount of accrued net salvage (estimated salvage received less cost of removal) included in its annual amount of depreciation expense and deducted the amount of net salvage experienced as a result of actual plant retirements. This calculation resulted in "flow through" treatment for the timing difference associated with net salvage, when "normalization" is the correct treatment. A timing difference exists because the amount of net salvage included in depreciation expense will be recognized in the future and exceeds the actual amount of net salvage experienced from current plant retirements. The Staff has made a correction to its case to reflect normalization instead of flow through. The cumulative effect of this correction, as well as making other changes, is to eliminate a $35 million overstatement of AmerenUE's revenue requirement. (Rackers Surrebuttal, p. 4).

AmerenUE in its July 7, 2007 filed case reflects normalization treatment for the increase in the level of accrued net salvage that results from AmeranUE's proposed depreciation rates. AmerenUE's proposed depreciation rates significantly increase the amount of accrued net salvage included in depreciation expense. (*Id*. at 6).

The Staff should have recognized a negative amount of deferred tax expense to "normalize" net salvage. (Rackers Surrebuttal, p. 4). Normalization of net salvage was reflected in the rates recently ordered by the Commission in the rate cases for Kansas City Power & Light Company, The Empire District Electric Company and Atmos Energy, Inc. If AmerenUE receives flow through treatment for net salvage, it would be receiving preferential treatment. There is no reason for AmerenUE to receive preferential treatment. (*Id*. at 6).

Mr. Rackers identified other reasons why normalization of net salvage is appropriate. He related that one of these reasons is that based on the Staff's proposed depreciation rates, customers will supply approximately $96 million for net salvage while only $25 million is actually being incurred, resulting in approximately $71 million of cash being supplied by ratepayers for net salvage expenditures that will not occur until sometime in the future. Through normalization treatment, ratepayers receive credit for the advance payment in the calculation of income taxes for the determination of rates. (Rackers Surrebuttal, pp. 6-7).

DEMAND SIDE MANGEMENT

Should AmerenUE Set Megawatt and Megawatt Hour Goals for Demand Side Management (DSM)? If So, What Should Those Goals Be?

Staff recommends that the Commission require AmerenUE to adopt the DSM goals shown in Table 1 of Staff witness Lena Mantle's highly confidential rebuttal testimony. (Mantle Rebuttal, p. 3 ln. 18-19). These goals were proposed by Missouri Department of Natural Resources Energy Center (MEC) witness Brenda Wilbers' highly confidential direct testimony. (Wilbers HC Direct, p. 7 ln. 21-22, p. 8 ln. 1-2). Staff witness Mantle used these goals and the peak demand and energy forecast used in AmerenUE's preferred resource plan to calculate the megawatt and megawatt hour goals proposed in her highly confidential rebuttal testimony. (Mantle HC Rebuttal, p. 2, ln. 8-15). However, Staff believes that these goals may be unreasonably low. (*Id.*, at p. 2, ln, 18). Staff recommends that these "peak demand and energy reduction goals be revised after the Staff, Office of Public Counsel, MEC and other parties that intervene in the upcoming case have had an opportunity to review the comprehensive resource planning filing that AmerenUE has agreed to make on February 5, 2008 in Case No. EO-2006-0240." (*Id*. at p. 3, ln. 19-23).

Should AmerenUE Fund Demand Side Management Programs at Minimum Levels? If So, At What Levels?

Commission Rules provide that demand-side resources and supply-side resources should be evaluated on an equivalent basis. 4 CSR 240-22.010(2)(A). Staff does not recommend requiring an expenditure amount requirement for DSM programs. (Mantle HC Rebuttal, p. 4, ln. 1-2). "To require a specified level of resources be spent on DSM programs does not treat supply-side and demand-side resources on an equivalent basis." (*Id.* at p. 3, ln. 8-10). Staff takes the position that the cost-effectiveness of DSM programs for AmerenUE customers is more important than the specific dollar amount spent on the programs. (*Id.* at p. 3, ln. 10-11).

How Should DSM Programs Be Selected?

Staff takes the position that DSM programs should be screened for cost-effectiveness. (Mantle HC Rebuttal, p. 3, ln. 12). If a program is initially found to be cost-effective, the program should be subject to evaluation in an integrated resource planning screening model. (*Id.* at p. 3, 12-13). If, after this evaluation, the program is considered cost-effective, Staff recommends evaluation of the risk and uncertainty of the program. (*Id.*, p. 3, ln. 13-14). Staff does not recommend implementation of a DSM program that has not undergone this extensive analysis simply to fulfill a dollar amount spending requirement. (*Id.*, p. 3, ln. 15-16).

LOW-INCOME PROGRAMS.

Should AmerenUE continue to fund its current low-income weatherization program? If so, how should the program be funded?

A. The low-income weatherization program began as a result of the Stipulation and Agreement filed as a result of a Staff excess earnings complaint, Case No. EC-2002-0001. The Stipulation and Agreement created the weatherization fund for low-income customers and required AmerenUE to initially fund the program with $2 million on September 1, 2002, and contribute an additional $500,000 a year for the next four years to the program.[5] Staff recommends that AmerenUE continue to fund its current low-income weatherization program at an amount of approximately $1.2 million annually regardless of whether or not AmerenUE's fuel adjustment clause and off-system sales proposal is adopted. (Mantle rebuttal, pg. 4, ln. 11-23) One half of the expenditures for this program, or $600,000, should be placed in the demand-side

[5] See *Report and Order Approving Stipulation and Agreement*, Case No. EC-2002-0001, (July 25, 2002).

resource regulatory account and be recovered from ratepayers. The other half of this amount should be funded by AmerenUE. (Mantle rebuttal, pg. 4, ln. 21-23)

Staff notes that the weatherization program is not currently included in AmerenUE's electric tariffs. Staff therefore recommends that AmerenUE be required to include the weatherization program in its electric tariffs. (Mantle rebuttal, pg. 5, ln. 2-5) Inclusion of the weatherization program in the AmerenUE electric tariffs would provide a mechanism for AmerenUE customers to educate themselves of the funding and eligibility requirements of the program, and therefore have a greater opportunity to avail themselves of the program's benefits.

Staff further recommends that AmerenUE be required to perform a process and impact evaluation of the current weatherization program to determine if any improvements could be made to the program and to determine, if possible, the amount of energy savings being achieved as a result of the program. The cost of this evaluation could be funded from the $1.2 million amount set aside for the weatherization program. However, Staff believes that the cost of the evaluation should not exceed $120,000. (Mantle rebuttal, pg. 5, ln. 6-10

Should AmerenUE fund low income programs at minimum levels? If so, at what levels?

B. Staff does not recommend that AmerenUE should fund low income programs at minimum levels. Staff recommends that the funding of the program be set at $1.2 million a year.

VOLUNTARY GREEN PROGRAM

Should the Commission approve AmerenUE's proposed Voluntary Green Program?

It is the Staff's position that the Commission should not approve the Voluntary Green Program (VGP) proposed by AmerenUE. (Mantle Rebuttal, p. 2, ln. 11) AmenenUE's proposal is to provide a means to allow its customers to purchase Renewable Energy Certificates (RECs) and to retire those RECs on behalf of its customers. (Mill Direct, p. 13, ln. 2-11). RECs are "defined as the environmentally beneficial component of renewable energy and [are] equivalent to 1,000 kWh" per REC. (*Id.* at ln. 6-8). Staff witness Lena Mantle testified that "RECs are a market mechanism that represent the environmental benefits associated with generating electricity from renewable energy resources." (Mantle Rebuttal, p. 2, ln. 13-14). Purchasing a REC is a way to support renewable energy; it is not, however, the same as directly purchasing renewable energy. (*Id.,* p. 3, ln, 10-11).

Staff does not oppose the REC market; however Staff's position is that AmerenUE should be investing its resources in the development of renewable power generation rather than in the purchase of RECs. (Mantle Rebuttal, p. 2, ln. 15-17). RECs may be purchased by consumers who wish to support renewable energy from a number of websites, independent of an electric utility program. (*Id*., p. 4, ln. 1-2). RECs are available to be purchased by AmerenUE customers "even if AmerenUE does not offer the VGP program." (*Id.*, p. 4, ln. 6). Staff's position is that AmerenUE should demonstrate its commitment to the development of renewable energy in a more tangible way, "such as [by] development of a wind farm or biomass generation plant." (*Id*., p. 1, ln. 28-29). Staff believes that the Commission should not approve AmerenUE's VGP as presented in its proposed tariff.

ELECTRIC ENERGY, INC. (EEInc.)

How should the expiration of the affiliate power supply agreement with EEInc. be treated for ratemaking purposes? Would it be lawful and proper for the Commission to impute to AmerenUE's revenue requirement the net effect on AmerenUE's variable production costs of power from EEInc.? Was the action taken by AmerenUE respecting the expiration of the affiliate power supply agreement with EEInc. prudent?

Electric Energy, Inc. (EEInc.) is not a new issue before the Commission. It most recently appeared as an issue in Case No. EO-2004-0108, which is frequently referred to as the Metro East Transfer Case respecting AmerenUE seeking Commission authorization to transfer its

Illinois retail operations to AmerenCIPS. But Staff believes the genesis of the issue goes to 1999 a few years after UE merged with Central Illinois Public Service Company. (Schallenberg, Rebuttal, p. 16). AmerenUE seeks to characterize the EEInc. matter as principally an issue of fiduciary duty separate and distinct from public utility regulation and then as controlled by federal jurisdiction regarding whatever relevance utility regulation has respecting the issue. AmerenUE seeks to take the Commission in a new direction with the filing of the testimony of a law school professor on what it asserts are matters of law. The issue properly before the Commission is a question of prudence and is well within the jurisdiction of this Commission. Typical of AmerenUE's approach to this issue is the fact that Charles D. Naslund is a member of the EEInc. Board of Directors for AmerenUE yet he appears as a witness for AmerenUE in an entirely separate capacity and offers no testimony on the EEInc. issue. Instead, AmerenUE offers a witness with little actual experience with the operation of EEInc. or its decision-making. This is the reason that the Staff must call Mr. Gary L. Rainwater and Mr. Naslund to introduce evidence to show the true nature of this issue.

EEInc. was incorporated in 1950 in the State of Illinois for the construction of a generating facility in Joppa, Illinois to provide energy to the Atomic Energy Commission (AEC) for the purpose of providing electricity to a federal government owned uranium enrichment facility located in Paducah, Kentucky. Originally, UE and four other utilities acquired the stock of EEInc. and had the following ownership percentages:

Illinois Power Company	20%
Central Illinois Public Service Company	20%
Kentucky Utilities Company	10%
Middle South Utilities, Inc.	10%

Union Electric Company 40%

(Middle South Utilities, Inc later transferred its ownership share to Kentucky Utilities Company.) (Meyer Direct, p. 6). Pursuant to Section 5651 RSMo. 1939, later 393.190 RSMo. 1949, UE sought the Commission's authority to acquire the stock of EEInc. on the basis that it was another corporation incorporated for or engaged in the same or similar business as UE. The Commission's December 8, 1950 Report And Order in Case No. 12,064 (In the matter of the Application of Union Electric Company of Missouri for authorization to acquire shares of Capital Stock of Electric Energy, Inc.) stated, in part, at page 2, as follows:

> Petitioner [UE] states that it is expected that the facilities of Electric Energy, Inc. will cost approximately $65,000,000; and that the funds for providing such facilities are expected to be raised by Electric Energy, Inc. by borrowing approximately $61,500,000 from two institutional investors, and the investment of approximately $3,500,000 by the companies in the Capital Stock of Electric Energy, Inc. in the following amounts: Union Electric Company of Missouri, the Petitioner, 14,000 shares; Central Illinois Public Service Company, 3500 shares; Illinois Power Company, 7,000 shares; Kentucky Utilities Company, 7,000 shares; and Middle South Utilities, Inc., 3500 shares.
>
> Petitioner also states that, in order further to assure repayment of such loans, the companies will agree to be responsible for the use or sale of the capacity of such generating facilities, in case the Atomic Energy Commission should terminate its purchase of power from Electric Energy, Inc. in the same proportions as their respective investments in the Capital Stock of Electric Energy, Inc.

This Report And Order shows that EEInc. was financed with approximately ninety-five percent (95%) debt with the sponsoring utilities only investing five percent (5%) equity. Due to this minimal level of equity investment, the lenders also sought that the sponsoring utilities, including UE, agreed to purchase any energy generated from the unit not required to meet AEC's demand. (Meyer Direct, pp. 6-7).

The power supply agreements of the sponsoring utilities were critical to the operation of EEInc. due to the owning utilities' decision to finance EEInc. with high levels of debt and minimum investments of equity. Up through the instant case UE has received in rates from its customers rate treatment similar, if not better, for its share of the Joppa facility as the other generating units owned by UE and the obligation of UE was absolute, unconditional, and could not be discharged or affected by the failure, impossibility or impracticability of EEInc. to generate or deliver electricity. (Schallenberg Rebuttal, pp. 6-7).

In the Commission's Orders respecting EEInc., reference is also made to UE's system relative to the establishment and functioning of EEInc. The Commission's Report And Order in Case No. 12,463 (In the matter of the Application of Union Electric Company of Missouri for authorization to acquire shares of additional shares capital stock of Electric Energy, Inc.) states at page 3:

> *Petitioner further states* that when the entire generating station of Electric Energy, Inc. is in full scale operation *there will be available to Petitioner* as its share of the surplus power from such station approximately 600,000,000 kwh of *energy per annum at an economical cost which will provide an additional efficient and economic source of power to meet expanding requirements of the public in the service areas of Petitioner's system.*

(Emphasis added). The Commission's Report And Order states, in part, in *Re Union Electric Company*, Case No. EF-77-197, 21 Mo.P.S.C.(N.S.) 425, 427 (1977) respecting UE's request to enlarge its obligations under the Amended Intercompany Agreement to cover and include 8½ % First Mortgage Sinking Fund Bonds financing the cost of air pollution control equipment so as to induce the purchase of the bonds by Metropolitan Life Insurance Company:

> . . . In return for its "guaranty" of EEI's financial obligations, *Applicant will be assured of a continuous source of economical power*, its entitlement of the surplus power not contractually obligated to ERDA. *This surplus power is more economical to Applicant than the installation of other new generation or the purchase of such power from others*. . . .

(Emphasis added).

There is a Securities and Exchange Commission (SEC) decision of note to the question of whether EEInc. should be thought of in any capacity as constituting part of the AmerenUE system. When EEInc. was organized, the SEC authorized UE to acquire the stock of EEInc., but stated that time did not permit the development of an adequate record upon which a definitive ruling could be made whether the stock interests of the various Sponsoring Companies in EEInc. could be retained under the integration standards of Section 10 of the Public Utility Holding Company Act. Decision on that question was reserved until a more appropriate time. The SEC reopened the proceedings in November 1956 to consider the issues to which jurisdiction had been reserved. The SEC decision, *In Re EEInc., et al.*, SEC PUHCA Release No. 13871, 38 S.E.C. 658, 1958 SEC LEXIS 807 (1958), states UE is a registered holding company which owns substantially all of the common stock of two public utility subsidiary companies, Missouri Power & Light Company and Missouri Edison Company and they have been found by the SEC to constitute an integrated electric utility system. (38 S.E.C. at 661) The SEC noted there was a 25 year contract between AEC and EEInc.; the Sponsor Companies have severally agreed to supply EEInc. "'supplemental power'" in the maximum aggregate amount of 150 MW to assist EEInc. when and if necessary to meet its firm power commitment to AEC – Sponsor Companies have also agreed to purchase all of the "'surplus power'" generated by EEInc. in excess of its obligation to AEC. (38 S.E.C. at 663).

Under then PUHCA Section 9 Acquisition Of Securities And Utility Assets And Other Interests, the acquisitions of the EEInc. stock by the Sponsoring Companies must meet the standards of then PUHCA Section 10 Approval Of Acquisition Of Securities And Utility Assets And Other Securities Interests. (38 S.E.C. at 664).

Respecting Section 10(b)(3), the SEC held: ". . . the consumers in the territories served by the respective Sponsor companies are benefited by reason of the low cost power made available. Further, we observe no basis for adverse findings as to the public interest standard. We therefore make no adverse findings under Section 10(b)(3) of the Act." (38 S.E.C. at 668).

Under Section 10(c) of PUHCA, the SEC cannot approve the proposed acquisition of the stock of EEInc. by any of the Sponsoring companies unless it finds, affirmatively, that such acquisition will serve the public interest by tending towards the economical and efficient development of an integrated public utility system. "Each of the three applicant Sponsor companies states that the proposed acquisition by it would tend towards the development of its integrated public-utility system." (38 S.E.C. at 668). Section 2(a)(29)(A) of PUHCA defines the term "integrated public-utility system" as follows:

> As applied to electric utility companies, a system consisting of one or more units of generating plants and/or transmission lines and/or distributing facilities, whose utility assets, whether owned by one or more electric utility companies, are physically interconnected or capable of physical interconnection and which under normal conditions may be economically operated as a single interconnected and coordinated system confined in its operations to a single area or region, in one or more States, not so large as to impair (considering the state of the art and the area or region affected) the advantages of localized management, efficient operation, and the effectiveness of regulation

The SEC found that the electric utility assets of UE, Illinois Power Company, and Kentucky Utilities Company were physically interconnected with the facilities of the Joppa Plant within the meaning of Section 2(a)(29)(A). (38 S.E.C. at 670). The SEC further stated: " . . . we believe the addition of the Joppa generating station and the AEC plant to the systems of Illinois and Union would not extend the systems of either to such a degree as to preclude us from finding that, as enlarged, each system is within a single area or region." (38 S.E.C. at 672).

Having already noted that the operations of the Joppa Plant result in substantial monetary benefits to each of the applicant Sponsoring Companies, the SEC stated: "We therefore find that the standard of economic and coordinated operations is satisfied." (38 S.E.C. at 671). Finally, the SEC pronounced: "In view of all the above . . . affirmatively, the acquisitions will serve the public interest by tending towards the economical and efficient development of an integrated public utility system by each applicant." (38 S.E.C. at 672).

There were several contracts and modifications between EEInc. and the sponsoring utilities with continued provision for the sponsoring utilities to purchase any energy generated from the EEInc. units not required to meet AEC's demand. Respecting the contract with a December 31, 2005 termination date, AmerenUE made no effort to pursue with EEInc. any arrangement for the continued use of energy and capacity for its native system load for the period after this date. Instead, AmerenUE completely supported the Ameren effort to move the AmerenUE share of the Joppa Plant to serve Ameren's Illinois activities. Power from the EEInc. facility is now being sold on the outside market through an Ameren affiliate and AmerenUE ratepayers receive no benefit from their prior support of the EEInc. facility. The Staff believes that AmerenUE's action was imprudent and the Staff has made an adjustment to calculate its cost of service revenue requirement for AmerenUE as if the full capacity of EEInc. available to AmerenUE prior to December 31, 2005 at cost based rates continues to be available to AmerenUE for the remainder of the test year and on a going forward basis at cost based rates. (Meyer Direct, p. 7; Schallenberg Rebuttal, p. 16).

Mr. Naslund stated at his deposition that the decision to go to market based rates was based on ** ____

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________. ** (Schallenberg Rebuttal, p. 6).

In order for the AmerenUE decision to produce the result desired by Ameren's senior management, the Missouri Commission must authorize AmerenUE to charge its native load customers higher rates to reflect the increased cost of service caused by AmerenUE incurring (1) higher fuel and purchased power costs to replace the energy formerly provided by the EEInc. Joppa facility and (2) lower levels of off-system sales which formerly were available to offset AmerenUE other electric operations costs. AmerenUE's overall financial results is not negatively affected by the end of the availability of energy at cost based rates to its native system load since AmerenUE records an increase in income from EEInc. to offset the increase in fuel and purchase power expense and loss of off-system sales recorded elsewhere on AmerenUE's financial statements. (Schallenberg Rebuttal, p. 17).

The Staff maintains that AmerenUE, by itself, held more than the necessary share of votes under the EEInc. Bylaws to continue to purchase power from EEInc. at cost based rates after December 31, 2005. Each year for the period 1953-2003, EEInc.'s Form No. 1 to the Federal Power Commission, the FERC's predecessor, and then to the FERC, stated at page 102 that EEInc. is directly controlled by the Sponsoring Companies through their ownership of the voting securities of EEInc. (Schallenberg Surrebuttal, p. 9). "Article II, Section 6. Voting." of the EEInc. Bylaws provides that "decisions to allocate the sale of generating capacity of EEInc. among the EEInc. stockholders in a manner other than in accordance with their percentages of ownership of EEInc. stock in the event of such capacity available for sale to parties other than the U.S. Enrichment Corporation" and "a material change in the business purpose or objectives of EEInc." constitute "corporate restructuring transactions" and "other major corporate actions."

"Article II, Section 6. Voting." of the EEInc. Bylaws also provides that when any holder of voting capital of EEInc., including such holder's affiliates, owns in excess of 50% of the voting capital stock of EEInc., "all corporate restructuring transactions and other major corporate actions shall be decided by the vote of the holders of 75% or more of the outstanding shares of the Corporation entitled to vote." This latter provision is applicable because AmerenUE and its affiliate Ameren Energy Resources Company, combined, own 80% of the voting capital stock of EEInc.[6] (Schallenberg Rebuttal, pp. 21-22).

Contrary to all of AmerenUE's legal arguments on this issue, Kentucky Utilities, which owned the remaining 20% of the shares of EEInc., sought through most of 2005 to negotiate a cost based agreement with EEInc. to replace the expiring Power Supply Agreement with the Sponsoring Companies, failed in this effort and ** ____
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____
______________________________________ ** AmerenUE even admits in rebuttal testimony

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[6] AmerenUE owns 40% of the stock of EEInc. and Ameren Energy Resources Company owns 40% of the stock of EEInc. as a result of the following FERC Dockets. On December 13, 2001 in FERC Docket No. EC02-34-000, AmerenCIPS and Ameren Energy Resources Company filed, pursuant to Federal Power Act (FPA) Section 203, for authorization for AmerenCIPS to transfer its 20% common stock interest in EEInc. to Ameren Energy Resources Company. FERC issued its Order Authorizing Disposition Of Jurisdictional Facilities on February 25, 2002. In FERC Docket No. EC04-81-000, the Merger Application of Ameren, Dynegy, Inc., Illinova Corporation and Illinova Generating Company, the FERC issued on July 29, 2004 its Order Authorizing Disposition Of Jurisdictional Assets And Accepting Power Purchase Agreements Subject To Conditions. The FERC authorized Illinova Generating Company to transfer its 20% interest in EEInc. to Ameren Energy Resources Company. Prior to this merger with Ameren, Illinois Power Company had become a direct wholly owned subsidiary of Illinova.

that an exempt wholesale generator (EWG) such as EEInc., with market based rate authority, is not precluded from selling power at cost based rates. (Schallenberg Surrebuttal, pp. 10-11; Svanda Rebuttal Testimony, p. 14).

Among other things, AmerenUE has asserted that UE's investment in EEInc. is distinguishable because UE's ownership of stock in EEInc. has always been treated by UE as "below-the-line" for ratemaking purposes, i.e., it is not on AmerenUE's books as an asset in rate base on which a return is figured, such as a power plant or transmission line which is treated as an above-the-line investment. The Staff disagrees with AmerenUE's assertion. The term "below-the-line" is typically used to indicate that an item is not considered in the ratemaking process. UE's 40% share of EEInc. has always been treated as an above-the-line investment. (Schallenberg Surrebuttal, p. 7). The interest and profit for Joppa Plant was recorded in purchased power expense while the interest and profit on investment in AmerenUE's other generating units is recorded in below-the-line accounts requiring rate base treatment to place these costs in AmerenUE's cost of service for ratemaking purposes. (*Id*. at 18).

UE's return on its equity investment in EEInc. is specifically recorded in the capacity charges booked above-the-line and recorded in the costs used to set rates. Section 3.01 of the Power Supply Agreement between EEInc. and the Sponsoring Companies in effect with modifications from 1987 to December 31, 2005 sets the EEInc. rates to the Sponsoring Companies based upon a 15% return on equity. The return costs on UE's stock investment in EEInc. is included in demand charges booked above-the-line. Components A and D of Section 3.01 of the Power Supply Agreement provide for the payment of EEInc.'s interest and profit and constitute return in ratemaking proceedings. Thus, UE's stock investment in EEInc. never having been on AmerenUE's books as an asset on which a return is determined in calculating the rates paid by AmerenUE's ratepayers does not prove that Missouri native load customers have not been paying a return on UE's stock investment in EEInc. (Schallenberg Rebuttal, pp. 23-24). The Power Supply Agreement requires that monthly payments for power enable EEInc. to recover all of the facility's cost of service, including operating expenses, taxes and interest plus a 15% return on equity capital net of federal income tax. (*Id*. at 26). The feature of the Power Supply Agreement that the obligations of UE were absolute, unconditional, and were not discharged or affected by the failure, impossibility or impracticality of EEInc. to generate or deliver electricity reflects the obligation of an owner of EEInc., not the obligation of purchaser to buy capacity and energy from an independent separate third party supplier. (*Id*. at 26-27).

As part of its argument that EEInc. has always been treated as below-the-line by AmerenUE, Mr. Moehn of AmerenUE asserts that respecting EEInc., (1) AmerenUE is responsible for potential losses and imprudent costs, and (2) AmerenUE has never sought and never would seek to recover from its retail ratepayers the costs of any detrimental events relating to the operation of the Joppa Plant. The former assertion applies equally to AmerenUE's other generating units, and AmerenUE has never made the latter assertion before, nor has AmerenUE identified any such significant event having ever occurred regarding the Joppa Plant. The assertions by AmerenUE are not the distinguishing factors that AmerenUE asserts them to be because AmerenUE has provided the same assurances regarding the costs of the December 2005 Taum Sauk catastrophic event. (Schallenberg Surrebuttal, p. 18).

The Staff refutes the repeated assertions of AmerenUE's witnesses that the EEInc. power supply agreements with the Sponsoring Companies were nothing more than typical power supply agreements between separate, independent electric utilities. These power supply agreements were more like operating agreements among multiple owners of a generating unit. (Schallenberg

Surrebuttal, p. 12). Mr. Schallenberg distinguished the only purchased power agreements identified by an AmerenUE witness, Mr. Michael Moehn. A long-term purchased power agreement with Arkansas Power & Light Company, subsequently replaced and superseded by a service agreement with Entergy Arkansas, Inc., was the result of UE acquiring the Missouri operations of APL. UE was to use the purchase power agreement with APL to serve the newly acquired load from APL. Thus, Mr. Moehn's examples are not relevant. (Schallenberg Surrebuttal, p. 13).

The FERC has stated on a number of occasions that the Missouri Commission has jurisdiction regarding the retail ratemaking treatment of AmerenUE's EEInc. decisions. OPC filed a Protest in the FERC proceeding, Docket No. EC04-81, where Ameren, Dynegy, Illinois Power sought FERC authorization to merge. At pages 43 and 44 of Applicants' (Ameren, Dynegy, Illinois Power, et al.) May 25, 2004 Motion For Leave To Submit Answer And Answer, in FERC Docket No. EC04-81 Applicants told the FERC that the EEInc. issue is a Missouri Commission issue. In fact, Ameren stated that "[if] any entity should have the right to compel AmerenUE to purchase capacity or energy from EEInc. to serve native load, it should be the MoPSC, as part of a prudence review of AmerenUE's retail rates, or some similar proceeding":

> IV.A.2.c. The Missouri Office of the Public Counsel's Concerns About AmerenUE's Rights To Power From EEInc. Facilities Are Erroneous And Should Be Addressed By The MoPSC, Not FERC.
>
> In protest, MOPC raises certain concerns related to the proposed acquisition of a 20 percent ownership interest in EEInc. by AER. . . . according to MOPC, Missouri ratepayers have historically supported the costs of the EEInc. capacity and output, and should continue to have access to the 40 percent of output to which AmerenUE is entitled. [footnote omitted.] . . . .
>
> MOPC recently raised these same issues before the Missouri Public Service Commission ("MoPSC") in AmerenUE's Metro East proceeding, in which AmerenUE has requested MoPSC authority to transfer its Illinois-based assets to AmerenCIPS. In particular, MOPC has asked the MoPSC to require AmerenUE

> to extend its agreement to purchase energy from EEInc. [footnote omitted.] . . . This issue remains pending before the MoPSC and falls squarely within the area of primary jurisdiction of the MoPSC – retail utility rates. The Commission should not concern itself with these state retail rate issues – which are nonetheless false – and should instead require MOPC to continue to litigate its issues at the MoPSC.
>
> . . . If any entity should have the right to compel AmerenUE to purchase capacity or energy from EEInc. to serve native load, it should be the MoPSC, as part of a prudence review of AmerenUE's retail rates, or some similar proceeding. The Commission should not allow itself to be dragged into theses issues by the MOPC.

On July 29, 2004 the FERC issued an Order Authorizing Disposition Of Jurisdictional Assets And Accepting Power Purchase Agreements Subject To Conditions in which it stated in relevant part OPC's EEInc. issues were a state commission matter:

> 66. . . . Regarding MOPC's request that Applicants commit that AmerenUE's current 40 percent entitlement to the output of the Joppa Facility be preserved, Applicants argue that this is a state retail ratemaking issue that will be addressed by the Missouri Commission.
>
> . . . .
>
> 68. . . . Regarding MOPC's request that Applicants commit that AmerenUE's current entitlement to the output of the Joppa Facility be preserved, we agree with Applicants that the issue is under the state's jurisdiction. The Missouri Commission has intervened in the proceeding but has not filed comments or a protest. . . .

OPC and MIEC filed Requests For Rehearing and Ameren, Dynegy and Illinois Power filed on September 7, 2004 Motion For Leave To Submit Answer And Answer To Requests For Rehearing wherein it stated at pages 3-4 that the Missouri Commission has primary jurisdiction:

> On July 29, 2004, the Commission issued its order approving, among other things, the sale of Illinova Generating's interest in EEInc. to AER. In doing so, *the Commission expressly declined to condition its approval on the requests of MOPC and MIEC*. Rather, the Commission sided with Applicants, stating "we agree with Applicants that the issue is under the state's jurisdiction." [footnote omitted.] Applicants believe that the Commission properly decided this issue, and nothing stated by MOPC or MIEC in their requests for rehearing should persuade the Commission to change its position.

> Indeed, the requests for rehearing of MOPC and MIEC are little more than the rehashing of the same unfounded arguments raised in their respective protests. [footnote omitted.] In all four pleadings – the MOPC Protest, the MIEC Response, and both the MOPC and MIEC requests for rehearing – the core of MOPC's and MIEC's claims is their theory that, if Ameren UE fails to continue receiving 40 percent of the capacity and energy of EEInc.'s Joppa facility, Missouri ratepayers will somehow be harmed. Not only are these arguments just as speculative now as they were when the MOPC Protest and MIEC Response were filed, but they (continue to) fall squarely within the primary jurisdiction of the Missouri Public Service Commission ("MoPSC"). This, precisely, is what the Commission held in the July 29 Order. [footnote omitted.] No different outcome is warranted here.

The FERC's April 18, 2005 Order Denying Rehearing unequivocally pointed again to the Missouri Commission's jurisdiction:

> 10. . . . MOPC's request for clarification appears to be an attempt to undermine the Commission's clear articulation of the appropriate forum for MOPC's concerns: the Commission has no jurisdiction over AmerenUE's retail rates or the manner in which it procures capacity or energy to serve its native load, except to the extent wholesale competition could be harmed, which is not at issue here. Clearly, the July 29 Order did not preempt state authority over retail rates. No further clarification is required.

On September 15, 2005, as amended on November 3, 2005, EEInc. filed an application with the FERC for market-based rate authority, with an accompanying tariff, in FERC Docket No. ER05-1482. The Missouri Commission and the Missouri Industrial Energy Consumers filed Notices Of Intervention and OPC filed a Motion To Intervene And Protest. FERC's December 8, 2005 Order Granting Market-Based Rate Authorization to EEInc. looks to the Missouri Commission for resolution of issues relating to retail rates:

> 34. The Missouri Office's concerns essentially center on the argument that it already made full payment of AmerenUE's share of all capital costs on a front-loaded basis and no longer will have the right to receive power from the plant once its contract expires. In particular, the Missouri Office argues that "Missouri ratepayers' historic cost support of the EEInc. power supply entitles them to the full value of the plant for its remaining life." This argument is not relevant to the decision of this Commission as to whether EEInc. meets this Commission's standards for market-based rate authority and further is an issue that is better resolved at the state level. In addition, the Missouri Commission

has intervened in this proceeding but has not filed comments or protested the application.

AmerenUE is seeking to take the Commission in a new direction with the filing of the testimony of Professor Robert C. Downs. Before the Commission follows this path, it best consider case law that indicates that Professor Downs testimony is improper. The Western District Court of Appeals held in *Wulfing v. Kansas City Southern Industries, Inc.*, 842 S.W.2d 133, 153 (Mo. App. W.D. 1992):

> It is the rule that the opinion of an expert on issues of law is not admissible. Young v. Wheelock, 333 Mo. 992, 64 S.W.2d 950, 957[24, 25] (1933). That is because the special legal knowledge of the judge makes such testimony of the witness superfluous. WIGMORE ON EVIDENCE § 1952, (Chadbourn rev. 1978). It also encroaches upon the duty of the court to instruct on the law. United States v. Bilzerian, 926 F.2d 1285, 1294[5] (2d Cir.1991).

The 10th Circuit Court of Appeals stated in *United States v. Vreeken*, 803 F.2d 1085 (10^{th} Cir. 1986):

> . . . As a general rule, questions of law are the subject of the court's instructions and not the subject of expert testimony. United States v. Ingredient Technology Corp., 698 F.2d 88, 97 (2d Cir.), *cert. denied,* 462 U.S. 1131, 103 S.Ct. 3111, 77 L.Ed.2d 1366 (1983); *see also* United States v. Jensen, 608 F.2d 1349, 1356 (10th Cir.1979) ("an expert witness cannot state legal conclusions by applying law to the facts").

SO_2 ALLOWANCES/SO_2 PREMIUMS/2006 STORM COSTS

Should revenues received from environmental allowance transactions be included in the revenue requirement and if so, what amount?

Should the Company establish a regulatory liability to account for sales of environmental allowances sold by the Company?

Should SO_2 premiums (net of discounts) be included in the regulatory liability account?

Should the balance of SO_2 allowances less SO_2 Premiums paid be used to offset 2006 storm costs? If so, what is the proper storm cost level to include in the cost of service?

Staff does not recommend that the Commission include revenues from SO_2 emission allowance sales in the Company's revenue requirement. Instead, Staff recommends that the Commission use SO_2 revenues, reduced by SO_2 premiums paid, to offset the Company's 2006 Storm Costs. Staff also recommends that the Commission direct the Company to record revenues received from emission allowance transactions, as well as expenses related to SO_2 premiums net of discounts, in a regulatory liability account as of January 1, 2007 on a going-forward basis. The Company received ** __________** of SO_2 revenues and also paid ** __________ ** for related SO_2 premiums (net of discounts) during the test year and through the January 1, 2007 cutoff date. (Surrebuttal Testimony of John P. Cassidy at 12.) The Company also recorded ** __________ ** of operations and maintenance expense related to storms occurring during the twelve months ending December 31, 2006. (Surrebuttal Testimony of Greg R. Meyer at 2.) The Staff recommends that the ** ___________ ** balance that results from netting the ** ___________ ** of SO_2 revenues the Company received and the ** ___________ ** of SO_2 premiums that the Company paid be used to offset the Company's ** __________ ** of 2006 storm expense. (Cassidy Surrebuttal at 12). Reducing the ** __________ ** of 2006 storm expense by the ** ___________ ** remaining balance of SO_2 revenues net of SO_2 premiums results in a ** ___________ ** remaining balance of storms costs. The Staff recommends that the ** __________ ** balance of 2006 storm costs be amortized over five years. (Meyer Surrebuttal at 3.) The Staff recommends that the Commission include in the revenue requirement the annual amortized amount of ** ___________ ** for recovery of the 2006 storm cost and that the Commission specifically order that these 2006 storm costs cannot be considered for recovery in any future ratemaking proceeding. (Meyer Surrebuttal at 3-4.)

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Staff also recommends that beginning January 1, 2007, the Company establish a regulatory liability (FERC USOA Account 254) to account for both the gains associated with the sale of emission allowances and the SO2 premiums (net of discounts that are either incurred or received by the Company). (Cassidy Surrebuttal at 12-13.) Gains on sales of emission allowances and the SO_2 premiums paid for coal are related. (*Id.* at 13.) Both of the related areas have exhibited volatility. Staff recommends that the Commission address these issues going forward (starting January 1, 2007) by directing the Company to record all transactions related to gains on sales of allowance emissions and SO_2 premiums paid (net of discounts) in the proposed regulatory liability account and net the balance. This tracking approach addresses the effects of volatility associated with these two areas and ensures that the Company receives regulatory treatment as part of its next rate proceeding for the balance that exists in this regulatory liability account. (*Id.* at 13.).

DEPRECIATION

The Staff has conducted its depreciation analysis in this case by following the guidance the Commission gave in its March 10, 2005, *Report and Order* in a recent The Empire District Electric Company general electric rate increase case, Case No. ER-2004-0570. (Staff witness Mathis Direct and Surrebuttal Testimony). In that *Report and Order* the Commission stated:

> In a recent case, the Commission stated that the fundamental goal of depreciation accounting is to allocate the full cost of an asset, including its Net Salvage cost, over its economic or service life so that utility customers will be charged for the cost of the asset in proportion to the benefit they receive from its consumption. The Commission found in that case that the traditional accrual method used by the utility was consistent with that fundamental goal. It is the policy of this Commission to return to traditional accounting methods for Net Salvage. *Report and Order* at 54.

(Footnotes omitted).

As background, at pages 47 to 49 of its *Report and Order* in Case No. ER-2004-0570 the Commission gave the following description of depreciation:

> Depreciation is an accounting convention under which the value of an asset is reduced proportionately over the course of its useful life. At the end of its life, the asset is considered to have lost all value except residual salvage value. If the accounting convention were perfect, an asset would be fully depreciated at the time it is actually retired, that is, removed from service. In ratemaking, depreciation is an operating expense, the purpose of which is to return to the investors their original investment in an asset as it is consumed in the public service. "The purpose of the annual allowance for depreciation and the resulting accumulation of a depreciation reserve is . . . to enable the utility to recover the cost of such property to it." Depreciation expense is booked to the depreciation reserve, which amount is deducted in ratemaking from the original cost basis of the utility's plant-in-service or rate base. The resulting net rate base is the present value of the investors' capital assets devoted to public service.
>
> The Constitution requires that the investors' original capital outlay be returned to them in rates as the utility's assets are expended in the public service:
>
>> A water plant, with all its additions, begins to depreciate in value from the moment of its use. Before coming to the question of profit at all the company is entitled to earn a sufficient sum annually to provide not only for current repairs but for making good the depreciation and replacing the parts of the property when they come to the end of their life. . . . [The Company] is entitled to see that from earnings the value of the property invested is kept unimpaired, so that at the end of any given term of years the original investment remains as it was at the beginning.
>
> It is well-established that depreciation is to be based on the original cost of the utility assets. "[T]his Court recognized in Lindheimer v. Illinois Bell Tel. Co., the propriety of basing annual depreciation on cost. By such a procedure the utility is made whole and the integrity of its investment maintained. No more is required." Section 393.240 authorizes the Commission to require electric utilities in Missouri to maintain depreciation accounts.

(Footnotes omitted).

With regard to net salvage, the Commission further stated in its *Report and Order* that traditional regulatory accounting includes Net Salvage as a component of Depreciation Expense under an accrual method where the depreciation rate for a particular asset or group of assets is calculated by the formula following:

$$\textit{Depreciation Rate} = \frac{100\% - \%\ \textit{Net Salvage}}{\textit{Average Service Life (years)}}$$

where net salvage equals the gross salvage value of the asset minus the cost of removing the asset from service and the net salvage percentage is determined by dividing the net salvage experienced for a period of time by the original cost of the property retired during that same period of time. *Report and Order* at 51-52.

In that same Report and Order, the Commission stated the following regarding terminal net salvage of production plant accounts:

> . . . [T]his Commission generally has not allowed the accrual of this item. The reason is that generating plants are rarely retired and any allowance for this item would necessarily be purely speculative. It is true that all depreciation is founded upon estimates, but all estimates are not unduly speculative. Just as utility companies plan rate cases around the projected in-service dates of new plants, so Empire can plan around the retirement of its generating plants so that the Net Salvage expense is incurred in a Test Year. Another alternative is the device of the Accounting Authority Order. As already discussed in connection with the Production Account Service Life issue, there is no evidence that the retirement of any of Empire's plants is imminent and the estimated retirement dates considered in this proceeding are not persuasive. For these reasons, the Commission will not allow the accrual of any amount for Terminal Net Salvage of Production Plants.

The Staff has applied the foregoing formula and guidance from the Commission in developing depreciation rates for AmerenUE in this case.

As stated in the List of Issues filed with the Commission, Monday, March 5, 2007, the depreciation issues in this case are:

A. Depreciation: Does 4 CSR 240-10.020 require any adjustment in this case for return on depreciation reserve? If so, what adjustment does 4 CSR 240-10.020 require? If AmerenUE is not in compliance with 4 CSR 240-10.020, what action should the Commission take as a consequence?

4 CSR 240-10.020 requires an adjustment in this case for return on depreciation reserve. The language of the rule is plain and unambiguous. 4 CSR 240-10.020 requires that, in setting

reasonable rates for service, income from funds in depreciation reserve be imputed at a rate of three percent (3%) per annum, or such other rate as may be prescribed by order of the Commission. If the rule is applied as Ameren argues it should, Ameren's cost of service shall be reduced by $134,294,027.[7]

The Commission must decide the rate base treatment for the depreciation reserve. In addition, the Commission must decide what action should be taken for Ameren's failure to comply with the Commission's rules. Ameren argues that depreciation reserve should not be taken out of gross plant in setting rates if the rule is applied. But Staff and Ameren have filed cases taking depreciation reserve from rate base consistent with the Commission's practice for the last thirty years or longer. Ameren has filed no testimony showing why its rate base in this case should exclude amounts in depreciation reserve. Ameren will be unable to show any language in the rule that specifies that depreciation reserve should be included in rate base in ratemaking. The customers have already paid Ameren for the amounts in depreciation reserve. Now Ameren wants to include the depreciation reserve in rate base and charge customers a rate of return on depreciation reserve, causing customers to pay twice.

But Ameren does not really propose to implement rates in compliance with this rule.[8] Instead, Ameren presents a tortuous interpretation of the rule in order to pressure the Commission to grant Ameren's entire revenue request of $360,709,000.[9]

Ameren argues that the rule requires that the Commission set rates by calculating its revenue requirement by: multiplying an undepreciated rate base by the rate of return, then subtracting 3% of deprecation reserve. But Ameren cites no Commission rule that requires rates

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[7] Schallenberg, Rebuttal, p. 8, l. 11-12.

[8] Weiss, Direct, p. 30, l. 8-16.

[9] Id.

to be set in this way. Instead, Ameren argues that the Commission should interpret rule 10.020 to determine rates using an undepreciated rate base. By Ameren's calculations this would increase its revenue requirement to over $747 million. Ameren's argument is interesting and nothing more. One need only read the rule to see that it says nothing about the treatment of rate base or Ameren's preferred use of an undepreciated rate base. Rather, the rule provides only for a reduction of Ameren's revenue requirement.

"If the intent of the legislature is clear and unambiguous, giving the language used in the statute its plain and ordinary meaning, then we are bound by that intent and cannot resort to any statutory construction in interpreting the statute."[10] The rule provides, quite explicitly, that in the process of determining the reasonableness of rates for service, income shall be determined on the depreciation funds of the … utilities pertaining to their properties used and useful in the public service in Missouri and shall be applied in reduction of the annual charges to operating income of those utilities.[11]

This section of the rule requires that income from the investment of depreciation funds shall be applied to reduce Ameren's rates. Section 2 provides that the income shall be computed at 3% of the principal amount of depreciation funds. No statutory construction is needed to understand the rule. Nor does any part of the rule mention rate base or how it is treated when applying the rule. The rule deals specifically and unambiguously with income on depreciation fund investments as a reduction of Ameren's revenue requirements.

[10] State v. Beck, 167 S.W.3d 767, 781, (Mo. App. 2005) citing Baxley v. Jarred, 91 S.W.3d 192, 196 (Mo. App. 2002)

[11] 4 CSR 240-10.020(1).

Ameren chooses to interpret the rule when the law does not allow interpretation. Instead of engaging in meaningless and inappropriate interpretation of a rule that is abundantly clear, Ameren should be arguing that section 4 of the rule applies:

> The rate of three percent (3%) per annum referred to in section (3) shall be applied in the case of each…utility of Missouri; provided, however, that modification of the rate may be made upon the commission's own motion or upon proper showing by a utility that the rate is not reasonably and equitably applicable to it.

Ameren has not made the argument that rule 10.020 does not reasonably and equitably apply to it. If the rule does apply, Ameren has filed deficient annual reports with the Commission since 1958, creating a substantial potential penalty liability if the Commission determines the rule applies to it without modification. If the Commission determines that the rate of imputation for depreciation reserve is not the rate of return as found in Commission orders since 1978, then the Commission should apply the 3% rule to Ameren, reduce its revenue requirement by $134 million, and use a depreciated rate base consistent with historical practice.

B. Fossil-fueled and hydro powered generation plant depreciation rates: Should depreciation rates for the plant accounts for fossil-fueled and hydro powered generation plants be based on average service lives with no truncation or a service life that is truncated at an estimated future final retirement date of each generation plant (Life Span)?

As will be presented in the testimony of Staff witnesses Jolie Mathis and Guy Gilbert, it is the Staff's position is that the depreciation rates for the plant accounts for fossil-fueled and hydro powered generation plants should be based on average service lives with no truncation because historical experience is that these types of plants remain in operation as long as it is economical and feasible to do so (Mathis direct, p. 8), the Staff has no indication from AmerenUE that the retirement of any of AmerenUE's fossil-fueled and hydro-powered generation plants is imminent (Mathis surrebuttal, pp. 8-10), and AmerenUE has disclosed no plans to the Staff, as it is required to by Commission rule, as to how is would replace any of the capacity it would lose if the plants were retired in the not so distant future (Gilbert rebuttal, pp. 2-4).

> C. Should the Commission assume that the Callaway Plant will be relicensed for an additional 20 year term, or should the Commission assume that the Callaway Plant will not be relicensed for purposes of calculating depreciation rates for the Callaway Plant?

As will be presented n the testimony of Staff witness Warren Wood it is the Staff's position the Callaway Nuclear Plant will be relicensed for an additional 20 years because 20-year license renewals is an industry practice, AmerenUE has made statements indicating it plans to seek such a renewal and AmerenUE has disclosed no plans to the Staff, as it is required to by Commission rule, as to how it would replace the capacity it would lose if the Callaway Nuclear Plant were not relicensed. (Wood Direct, pp. 9-23, Rebuttal, pp. 8-10 and Surrebuttal, pp. 2-3).

> D. Should terminal net salvage and inflation costs relating to the future retirement of the Company's generating plants be included in depreciation rates, and if so, how should such costs be calculated?

As will be presented in the testimony of Staff witnesses Jolie Mathis and Guy Gilbert, it is the Staff's position is that they should not because the Commission has in the past found an adjustment for anticipated inflation in the future is not known and measurable and, therefore, too speculative for purposes of setting rates. The Commission has also found, similarly the time when a plant will be dismantled—when terminal net salvage will occur—and the dollar amount that will then be incurred are both speculative, and not known or measurable. (Jolie Mathis Surrebuttal pp. 3-7).

> E. In the calculation of the Distribution, Transmission and General Plant depreciation rates, should the estimated Net Salvage Percents to be applied in the future determination of depreciation rates be calculated to reflect historic inflation rates based on analyses of historic net salvage percents or is an adjustment to such analyses required to reflect a different impact of cumulated historic inflation rates on historic net salvage as compared to the impact of cumulative expected inflation rates be reflected in the calculation on future net salvage.

The Staff has filed no testimony addressing this issue.

F. In the calculation of the Transmission, Distribution and General Plant depreciation rates should the net salvage percents applied in the determination of depreciation rates be based on actual net salvage expense?

The Staff has filed no testimony addressing this issue.

G. Is there a difference between the actual book accumulated depreciation and the theoretical accrued depreciation? If so, how should that difference be recovered from ratepayers?

As will be presented in the testimony of Staff witnesses Jolie Mathis and Guy Gilbert, it is the Staff's position that there is a difference between actual book accumulated depreciation and the theoretical accrued depreciation, but the Staff recommends no adjustment at this time to recover that difference from ratepayers.

(Gilbert rebuttal, pp. 4-7; Mathis direct, pp. 9-10, Mathis surrebuttal, p. 7)

H. What net salvage percentage should be used in the depreciation rate calculation for assets in Account 322?

As will be presented in the testimony of Staff witnesses Jolie Mathis and Guy Gilbert, it is the Staff's position the net salvage percentage that should be used in the depreciation rate calculation for assets in Account 322 is -37%. (Mathis direct, schedule JLM-2)

CLASS COST OF SERVICE ISSUES

What should be the increase or decrease in the revenue responsibility of each customer class?

A. To what extent, if any, are current rates for each customer class generating revenues that are greater or less than the cost of service for that customer class?

The following table summarizes the results of Staff's revised CCOS study on a revenue neutral basis.

	RES	SGS	LGS[1]	LPS	LTS	Total
Revenue Deficiency:	**($57,864,021)**	**($31,365,171)**	**($101,525,535)**	**$ 391,305**	**($12,500,590)**	**($202,864,013)**
Required % Increase:	**-6.55%**	**-13.11%**	**-16.30%**	**0.25%**	**-9.22%**	**-9.94%**

% Revenue Neutral Deficiency	**3.39%**	**-3.17%**	**-6.35%**	**10.19%**	**0.73%**	**0.00%**

On a revenue neutral basis, Staff's revised CCOS shows that the residential (RES), Large Primary Service (LPS), and Large Transmission Service (LTS) classes are providing approximately 3.39%, 10.19%, and 0.73% less revenues than the cost of serving each class, respectively. The Small General Service (SGS) and Large General Service (LGS) classes are providing 3.17% and 6.36% more revenues, respectively, than the cost of serving them. These results suggest AmerenUE's revenues from the RES, LGP, and LTS classes are less than AmerenUE's cost to serve them and that AmerenUE's revenues from the SGS and LGS classes exceed AmerenUE's cost to serve them. (Roos Surrebuttal p.3).

B. How should AmerenUE's cost of service be assigned to the customer classes?

There should be movement towards Class Cost of Service. Staff believes that any movement at this time should be tempered due to the fact that the overall increase could be significant. Therefore, Staff believes that any class within 5% of its cost of service should not be given any increase or decrease in revenue responsibility. Any class that is providing revenues that are greater than 5% of its cost of service should get a reduction of revenues until that class is within 5%. This shift in revenue responsibility should come from the classes that are providing revenues not within 5% of its cost of service. According to Staff's CCOS, this means that on a revenue neutral basis, LGS should see a reduction in revenue responsibility and LPS should receive an increase in revenue responsibility. Once this shift occurs, all rates should increase or decrease on an equal percentage basis. (Busch Rebuttal, p. x).

C. Should the Commission adopt AmerenUE's proposal to cap any residential class increase at no more than ten (10%) percent?

Any rate cap should be equally applicable to every Class Cost-of-Service Class. Thus, the impact of higher overall rate increases should be moderated only by making smaller revenue-neutral shifts in class revenue responsibility.

D. Should Staff's proposal to combine the Small Primary Service Class and the Large General Service Class in the Class Cost of Service Study be adopted?

Because the LGS and SPS customers differ only by delivery voltage and meter location, Staff combined the customers on both rate schedules into a single cost-of-service class. Failure to combine these groups would result in too much demand-related cost being allocated to them because these customers would loose the benefits of load diversity when determining their level of demand, i.e., the sum of the non-coincident peaks of two groups is always higher than their coincident peak. (Roos Surrebuttal, p.7).

E. On what basis should production capacity be allocated to classes?

Production capacity should be allocated to the classes based on the 12 Noncoincident Peak (NCP) Average and Peak (A&P) allocation method. This method properly assigns the year round capacity costs to each class based on the strains put on the system by each class during the entire year. The 12 NCP A&P method properly takes into account average usage and peak requirements of each class.

In three cases decided in the early and mid-1980s the Commission relied on the approach the Staff takes here. In each case, the issue was both significant and hotly contested. The first case is In the matter of Arkansas Power & Light Company of Little Rock, Arkansas, for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company, Case No. ER-81-364 (Report and Order, April 20, 1982), 25 Mo.P.S.C.(N.S.) 101. In its Report and Order the Commission stated the Staff suggested that the most appropriate manner of allocating fixed generation and transmission costs to customer classes was on a time-of-use basis, which involves the consideration of customer class contribution to generation demand for every hour of the year, rather than solely at the hour of generation peak demand; however, due to data limitations the Staff presented an average and peak method. 25 Mo. P.S.C. (N.S.) at 106-07. In that case the company relied on a peak responsibility method—the coincidental peak allocation method. Id. In addressing the issue of what method to employ for allocating fixed generation and transmission costs the Commission stated the following:

> Based upon the evidence and arguments presented in this case, the Commission cannot conclude that the coincidental peak method, as advocated by AP&L and the Mining Intervenors, represents a reasonable method for allocating fixed generation and transmission costs. The arguments of these parties are not persuasive in support of the use of the coincidental peak method. The fact that the Company's total generating capacity must be sufficient to meet peak demand does not, of itself, indicate that class contribution to demand at the time of system peak is an appropriate method for explaining class causation of fixed generation and transmission costs.
>
> In evaluating application of the coincidental peak method to the allocation of fixed generation and transmission costs, consideration of several points is of prime importance. First, no matter which allocation method is used, each customer class will be assigned a percentage of AP&L's total jurisdictional fixed generation and transmission costs. It is the percentage share of the total of these costs which each customer class will be assigned that varies depending upon the allocation method chosen. Secondly, these costs consist primarily of the investment for electric generating capacity. These generating facilities can be broadly divided into the categories of baseload, intermediate and peaking units. As discussed previously, these units have different cost characteristics, with baseload units having relatively high capital costs and relatively low operating costs, and, conversely, peaking units having relatively low capital costs and relatively high operating costs.

25 Mo.P.S.C.(N.S.) at 114-15.

The Commission noted that AP&L's baseload units accounted for most of the company's capacity yet allocation of the cost of those units based on coincident peak would make low load factor customers' (residential) relative contribution to demand high and make high load factor customers' (e.g. large power class) relative contribution to demand low, although those baseload units would generally operate throughout the year. In other words, the residential class would be assigned a disproportionately high level of the generation costs and the large general service class would be assigned a disproportionately low level of the generation costs. 25 Mo.P.S.C.(N.S.) at 115.

In the second case, Re Kansas City Power & Light Company, 53 PUR4th 315, 25 Mo.P.S.C.(N.S.) 605 (Case No. EO-78-161, March 30, 1983 Report and Order), the Commission made cost-of-service determinations based on load data collected in response to a July 1974 Commission order. In the beginning summary section of that order the Commission stated:

> . . . . As will be discussed in greater detail below, we find that an appropriate manner of proceeding from this docket is to direct KCPL to perform an updated cost-of-service study to be submitted in conjunction with its next Missouri general rate case subsequent to its presently pending rate case, Case Nos. ER 83 49, ER 83 72, and EO 82 65. Said updated cost-of-service study shall contain those methods and elements found to be appropriate in this report and order. Additionally, the lack of a clear record in this case regarding internal class rate design issues suggests that these issues cannot be resolved in this case. Issues regarding KCPL's internal class rate structures should be raised in the company's next Missouri general rate case subsequent to its pending rate case.
>
> The most important of the cost-of-service determinations made in this case involves the method for allocating fixed generation costs. As stated above, the updated cost-of-service study to be submitted by KCPL with its next Missouri general rate case should contain the methods and elements found to be proper in this report and order. As will be discussed in greater detail, infra, based on the evidence presented in this case, the commission finds the time-of-use method to be the most theoretically appropriate approach for allocating generation costs (emphasis added) and, further, finds the average and peak allocation method for fixed generation cost as the most reasonable alternative to a full time-of-use procedure. As a result of these findings, the updated cost-of-service study to be submitted by KCPL shall contain either: (a) a full hourly time-of-use allocation of both fixed and variable generation costs to the customer classes, or (b) an average and peak allocation of fixed generation costs and an allocation of variable generation costs on the basis of annual class energy usage adjusted for losses.

25 Mo.P.S.C.(N.S.) at 607.

In the body of its order the Commission described KCPL's fixed generation costs allocation methods as follows:

> Kansas City Power and Light Company. The company submitted two cost-of-service studies in this proceeding with the only difference between the studies consisting in the choice of allocation factor for the assignment of fixed generation costs to the customer classes. One study used the "coincidental peak method" (also referred to as the "single-peak method") whereby all fixed generation costs are assigned to the customer classes in proportion with the percentage contribution of each class to system demand at the hour of system peak demand. For KCPL, system peak demand occurs during the summer months. Kansas City Power and Light Company's other cost-of-service study used a combined summer and winter peak demand method, by which each customer class's percentage contribution both to the company's summer and winter peak demand hours are calculated and, together, form the basis for the share of fixed generation costs allocated to the customer classes. Both of these allocation methods can be categorized as "peak responsibility" methods in that they associate class causation of fixed generation costs with peak demand (in the first instance, system peak demand and, in the second, seasonal peak demands).

25 Mo.P.S.C.(N.S.) at 610-11.

In contrast it stated the Staff presented the following approach as an alternative to using a peak responsibility method:

> In its prepared rebuttal testimony and in its initial brief submitted herein, the staff takes the position that the "additional cost method" (also, referred to as the "time-of-use method") is the most theoretically correct procedure for allocating fixed generation, bulk transmission and energy costs to the customer classes. The additional cost method entails estimation of class contribution to system demand during each of the 8,760 hours of the year, identification of the generating plants operating during each hour and the capacity and energy costs associated with these plants, and the assignment of fixed generation, bulk transmission and energy costs to the customer classes based upon a matching of class demand contribution levels with the cost characteristics of the generating plants operating throughout the year.
>
> Recognizing that the additional cost allocation method requires the accumulation of a significant amount of load research data, the staff's position at the hearing was that the data requirements make regular use of the additional cost method impractical. In this context, the staff recommends that the commission approve use of the "average and peak method" for allocating fixed generation and bulk transmission costs as an approximation of the results of an additional cost allocation of fixed generation, bulk transmission, and energy costs. The average

and peak method allocates costs in the following manner: The average demand, as a percentage of peak demand, is determined and is applied to each class's percentage contribution to average demand; then, the difference between peak demand and average demand, as a percentage of peak demand, is determined, and is applied to each class's percentage contribution to peak demand. The results for each class are then combined to produce the average and peak class allocation factors.

In summary, the staff's recommendation for allocating fixed generation and bulk transmission costs is to use the average and peak method if the commission finds the additional cost approach to be theoretically correct or, alternatively, to use the 100-peak-hours method if the commission finds peak responsibility to be the proper allocation approach.

25 Mo.P.S.C.(N.S.) at 611-12.

In its conclusions the Commission stated:

Conclusions. A number of the methods proposed by the parties to this proceeding for the purpose of allocating fixed generation and bulk transmission costs to the customer classes can be categorized as peak responsibility methods. The common element of peak responsibility methods is an emphasis on peak demand or demands as the basis for assigning costs. The peak responsibility methods proposed in this case include: the coincidental peak (or single-peak) method advocated by Armco/GM and GSA; KCPL's combined summer and winter peak method; the staff's 100-peak-hours method; and DOE's marginal cost method using peak rating periods and relative loss of load probabilities.

The coincidental peak method is the purest form of peak responsibility allocation in that it assigns costs to each customer class based solely upon the contribution of each class to system demand at the single hour of system peak demand. Certain alternative peak responsibility approaches, such as KCPL's combined summer and winter peak method and the staff's 100-peak-hours method, give reduced weight to class contribution to demand during the single hour of system peak demand but, nevertheless, are premised on the principle that it is the system's peak demands which comprise the primary factor upon which the allocation of fixed generation and bulk transmission costs should depend.

The commission has previously considered the question of the proper allocation of fixed generation and bulk transmission costs in Re Arkansas Power & Light Co. Case No. ER 81 364, April 30, 1982 ("AP&L decision"). The rationale proffered in support of peak responsibility allocation methods in the instant case (that peak demand is the primary determinant of total generation capacity) was rejected in the AP&L decision as a basis for explaining class causation of these costs. While there can be no argument as to the critical importance of peak demand in capacity planning decisions, it does not follow that class contribution to peak demand provides an appropriate method for class allocation [of] fixed generation and bulk transmission costs.

As pointed out in the AP&L decision, these costs consist mainly of investment in electric generating facilities. The majority of these costs are related to base-load and intermediate plants which have relatively high capital costs and low running costs relative to peaking units, and which generally operate throughout the year. Peak responsibility methods emphasize class contribution to system peak demands in determining each class's share of these costs. Low load factor customer classes tend to contribute a relatively large proportion to demand at times of system peak as compared to demand at nonpeak hours, while high load factor customer classes tend to contribute a relatively small proportion to demand at times of system peak as compared with demand at nonpeak hours.

Thus, the inequity inherent in peak responsibility methods for allocating these costs to the customer classes is that the majority of the costs to be allocated relate to plants operating throughout the year, while the proportionate shares of these costs to be borne by the customer classes are determined by reference only to class demands during peak hours. The coincidental peak method is the least equitable of the peak responsibility methods proposed in that it places total dependence on the single hour of system peak demand. However, for the reasons stated herein, the commission finds that the evidence presented leads to the conclusion that peak responsibility methods, generally, do not provide appropriate and equitable allocations of fixed generation and bulk transmission costs to the customer classes.

* * * *

In the AP&L decision, the commission considered and rejected a similar recommendation by public counsel regarding allocation of Arkansas Power and Light Company's fixed generation and bulk transmission costs. Therein, while acknowledging that base-load generating units generally have lower running costs and higher capital costs as compared with peaking units, the commission was not persuaded that this fact should justify the allocation of investment in base-load capacity on the basis of class energy usage. As further noted therein, the goal of electric utility capacity planning should be the maintenance of sufficient capacity to meet projected system demands at the lowest total cost. As pointed out by public counsel, there are capacity cost/fuel cost "trade-offs" involved in decisions between building base-load versus peaking units. The composition of a utility's existing generating system, the shape of its load duration curve, and the cost characteristics of the generating unit candidates should be considerations in making a capacity expansion choice. Thus, public counsel's proposed allocation approach of categorizing planned capacity additions on the basis of benefits to be derived, such as the saving of fuel costs or the meeting of growth in peak demand, constitutes an oversimplification of the capacity planning process.

An additional problem with public counsel's approach is that it would allocate capacity costs associated with all existing generating facilities on the basis of an evaluation as to the benefits to be derived in building specific types of new units. The logic of public counsel's argument would call for an evaluation of the benefits derived from building each of the company's existing generating facilities, and the commission finds that such an approach is neither warranted nor capable of practical implementation.

A determination is made as to the propriety of including investment associated with a particular generating facility in a utility's cost of service when the company requests rate base treatment of the investment through a rate case. Such costs are "fixed" in nature in the sense that they generally will not vary depending on energy output but, instead, will be incurred by the utility regardless of energy levels. Once a commission determination has been made that a particular utility investment in generating facilities should be included in the company's cost of service, the commission finds that, for purposes of allocating costs to the customer classes, costs which are fixed in nature are appropriately allocated by reference to some type of customer class demand levels. Therefore, the commission concludes that public counsel's proposal to allocate fixed generation and bulk transmission costs on the basis of class energy usage is not justified by the evidence presented.

The commission agrees with the staff's position that the additional cost (time-of-use) method is the most theoretically appropriate approach for allocating fixed generation, bulk transmission, and energy costs to the customer classes. The generating facilities of KCPL are not homogeneous in nature but, rather, include plants with varying characteristics in terms of fixed and variable costs. Thus, customer class responsibility for the incurrence of these costs varies throughout the year depending upon hourly class demand levels and the "mix" of plants being used to meet the hourly loads. The time-of-use allocation approach is designed to consider these factors in making cost assignments to the customer classes.

The staff has suggested in this case the data requirements associated with the time-of-use allocation method may make its implementation on a regular basis impractical. However, no evidence has been presented by KCPL or any other party which would support a conclusion that the data requirements for time-of-use allocations would place an undue burden on the company. In this regard, the commission notes that Arkansas Power and Light Company is presently under a commission directive to collect and prepare load research data necessary for performing time-of-use allocations in a cost-of-service study to be submitted in conjunction with that company's next Missouri general rate proceeding.

The staff has recommended that the commission adopt the average and peak method for allocating fixed generation and bulk transmission costs if peak responsibility methods are rejected and the additional cost (time-of-use) allocation method is found to entail unduly burdensome data requirements. The staff supports the average and peak method as providing a reasonable approximation of the cost assignments which would result from allocating fixed generation, bulk transmission, and energy costs through the time-of-use procedures.

In the AP&L decision, the commission approved the average and peak method as the most reasonable approach of those presented therein for allocating fixed generation and bulk transmission costs. In that case, the staff also recommended use of the average and peak method as a proxy for the time-of-use allocation procedure since the data necessary for time-of-use allocations had not been available for use in that proceeding. The commission recognized that, while the average and peak method does not purport to track use of generation and bulk transmission facilities throughout the year, as is the case with the time-of-use procedure, the average and peak method does give consideration to off-peak usage of these facilities by allocating a portion of the involved costs on the basis of class contribution to average demand. These findings regarding the average and peak method which were made in the AP&L case are not contradicted by the evidence presented in the instant proceeding.

Armco/GM oppose the staff's recommendation in support of the average and peak method for allocating fixed generation and bulk transmission costs, but argue that if this method is to be utilized for allocating such costs, then the average and peak method should also be utilized for the allocation of energy costs. The usual method for allocating energy costs is on the basis of class kilowatt-hour sales adjusted for losses. The Armco/GM argument for applying the average and peak procedure to the allocation of energy costs is premised on the assumption that the average and peak allocation of fixed generation and bulk transmission costs results in high load factor customers bearing a disproportionately large share of such costs, and because of this alleged disproportionate burden, such high load factor customers should be allocated a reduced portion of energy costs. This same argument was advanced by the mining intervenors in the AP&L case and was rejected by the commission on the basis that it assumes the propriety of using the coincidental peak method or peak responsibility methods, generally, for allocating fixed generation and transmission costs. The commission rejected both the coincidental peak method and the mining intervenors" proposed application of the average and peak method to energy costs in the AP&L case and no evidence has been presented in this record which persuades the commission that application of the average and peak method to energy costs is appropriate in this proceeding.

Therefore, based on the findings that fixed generation and bulk transmission costs should be allocated to the customer classes based on class demand levels and that the average and peak method gives a degree of consideration to off-peak usage of generation facilities, the commission concludes that the average and peak method, as proposed by the staff, provides the most

> reasonable alternative to the time-of-use procedure for allocating the costs involved.
>
> 25 Mo.P.S.C.(N.S.) at 613-17.

In the third case, Re Union Electric Company, 66 PUR4th 202, 27 Mo.P.S.C.(N.S.) 166, Case Nos. EO-85-17, ER-85-160 (Missouri Commission, Report and Order March 29, 1985), the Commission again addressed the issue that is before the Commission in this case: Should fixed generation capacity costs be allocated based on system peak demand or on total system demand? In that case the Commission characterized the issue as follows:

> The parties are in fairly uniform agreement that the proper method chosen to allocate costs should assign costs based upon cost causation as closely as practical. The parties here present two basic theories concerning what causes costs and how to assign those costs. The two approaches of the parties separate over the issue of whether capacity is built to meet system peak demand or total system demand. Staff and PC support the theory that the need for generating capacity is caused by total system demand. UE, industrials, Dundee, and MSD support the principle that generating capacity is caused primarily by system peak demand. Retailers agree with staff and PC on the causation issue, but reject staff and PC's method of allocating costs. Staff, PC, UE, industrials, and retailers have presented cost-of-service studies for allocating the total revenue requirements among the customer classes.
>
> Although the parties have approached the allocation of cost to the classes on a cost causation basis, there are other influences which affect the ultimate rates to be charged individual customers. The commission agrees that allocating the costs of providing service to the classes and customers who cause these costs is the basic function of the rate design of a public utility company. The commission, though, is also aware of other influences which affect the ultimate decision of what price a customer should pay for electric service. The straight assignment of costs to customers based upon any allocation method chosen by the commission will be tempered by attempts to ensure the efficient use of the service and social policies regarding use of the service.
>
> Rate design in this case involves two concerns. The first concern is the impact rate design will have upon the various classes where any change is made in the method of allocation. The other concern is that the rate design adopted will be the method by which the substantial increase in rates caused by the Callaway plant will be allocated.

27 Mo.P.S.C.(N.S.) at 275-76. As AmerenUE, MIEC and TCG present here, in that case UE presented cost-of-service studies using peak responsibility methods. As to those methods the Commission stated:

> . . . . These methods are based upon the underlying principle that the company's capacity requirements are determined by peak demand. To allocate costs on a causation basis, UE contends, one must look both at the amount of capacity needed to meet the system peak and the amount of energy needed to meet the system energy needs. UE's position is that capacity costs are fixed and are related to demand. These costs do not change with kilowatt-hour consumption. Variable costs are those associated with fuel costs (energy) and do vary with kilowatt-hour consumption. UE contends that fixed production capacity should be allocated on a demand basis and not by a kilowatt-hour or variable basis.
>
> UE contends that the coincident peak method of allocation places the cost of additional capacity on the customers causing increased peak demand. Offpeak customers do not cause the additional capacity, but in fact made the system more efficient by using capacity during nonpeak periods, thus increasing UE's load factor. UE contends these offpeak customers benefit the system by increasing the load factor of the system and thereby reducing overall costs. Since these offpeak customers do not cause additional capacity, they should not be allocated costs for their offpeak use. UE views its system as having fixed capacity; any new capacity is constructed to meet peak use and peak users should bear the cost of its construction.

27 Mo.P.S.C.(N.S.) at 276.

In the UE case, as in the AP&L and KCPL cases, the Staff took the position that production capacity costs are caused by the total demand on the system. The Commission described the Staff's position in that case as follows:

> . . . . Staff's position is that production capacity costs are caused by the total demand placed on the system. The total demand on the system varies from hour to hour throughout the year. The generating units are categorized as base load, intermediate, and peak. The utilization (mix) of these different types of generating units will vary throughout the year in relation to such factors as hourly the availability of power on UE's interconnect system. Staff contends that as the mix varies, so do total costs vary.
>
> Staff's cost-of-service study is based upon these variations of plant mix and customer usage throughout the year. It asserts the theoretically most correct

approach to designing rates is based on this condition and is a method that determines the production costs of meeting system demand in each hour of the year. Thus the method should create 8,760 power pools to be allocated to customer classes based upon their use of the system during the hourly pools. This method is described as a time-of-use (TOU) method. Staff states, though, that there is insufficient load data to determine hourly demand for the UE system. Staff has thus proposed a TOU/average-and-peak (AP) method which it considers most closely approximates the preferable hourly TOU method. The AP method allocates the monthly production (capacity and running) costs to the classes based upon the class contribution to system average and to system peak demands. Production capacity costs related to average demand were allocated to classes based on their monthly contribution to energy measured with losses, and production capacity costs related to peak demand were allocated to classes based upon their monthly contribution to coincidental peak demand. The separation between average and peak demand was determined by use of a monthly loading factor for each power source (plant). Average demand was determined by multiplying the monthly plant loading factor times the monthly capacity costs. This figure was then subtracted from total costs to give the peak demand figure.

Staff developed a TOU production costing model to simulate operations of the UE system. Staff's production costing model was then used to allocate production capacity and running costs to the months. Staff then allocated the monthly costs to the classes through the AP method, since hourly load data was not available for a TOU allocation. Staff contends the AP method most closely matches the TOU hourly method. Underlying staff's cost-of-service study are the principles of cost causation staff feels are correct. Staff states the CP methods answer the wrong question concerning production capacity costs. The question is not the timing of future capacity additions and megawatt amount of those additions, but rather the responsibility of each customer class for the causation of the utility's embedded production capacity costs. The proper method for answering the question is to determine how UE's power sources (plants) are utilized by the classes. Staff asserts its TOU/AP method accomplishes this goal.

Staff bases its position on the premise that capacity utilization throughout the year is the proper method to allocate costs. It has classified production costs as capacity costs and running costs. Capacity costs are the replacement costs for each source of supply (plants); running costs are fuel and variable operating and maintenance costs. Staff's method views the UE system from a standpoint of what types and how much capacity would be purchased to meet demands in every hour of the year if it is assumed no production plant exists at the beginning of the year.

27 Mo.P.S.C.(N.S.) at 276-77.

As in this case, in the UE case “[t]he decision of what cost-of-service study most closely reflects the class responsibility for the UE system most dramatically impacts on the distribution of production generation costs.” 27 Mo.P.S.C.(N.S.) at 279.

In the paragraph where the Commission states its decision on this issue the Commission states:

> The main concern of the commission is to determine which theory most reasonably reflects the causation of production costs on the UE system. As stated earlier, the commission has accepted in prior decisions, and again accepts, the TOU method as the most reasonable method for allocating the production costs of serving the various classes. The commission thinks that staff's position concerning causation is the most accurate and reasonable concerning the UE system. The Commission finds the evidence in this case supports the adoption of the TOU method. To adopt a CP method, one must first accept the contention that UE only builds new capacity to meet peak demand. The commission cannot accept this. It is obvious Callaway was built to meet both base load and peak demand, and its cost should be shared on that basis. The Callaway plant is the first plant in UE's loading order and UE will operate the Callaway plant as long as possible year round.

27 Mo. P.S.C. (N.S.) at 281-82.

Finally, in addressing the use by Staff of replacement costs rather than historical costs, the Commission made the following observation regarding the Staff’s approach: “Staff’s method is based upon the concept that each class is responsible for its utilization of the system at any given hour.” 27 Mo.P.S.C.(N.S.) at 284.

In a later rate design case, In the matter of the investigation of the electric class cost of service for St. Joseph Light & Power Company, 1 Mo.P.S.C.3rd 450 (Case No. EO-88-158, December 11, 1992 Report and Order), the Commission addressed the cost of service for St. Joseph Light & Power Company, the predecessor to Aquila Networks-L&P. In that case the parties agreed to use three customer classes: Residential, General Service and Large Power. 1 Mo.P.S.C. at 453. Costs were taken from the calendar year 1990. Id. And the parties agreed some form of "Average and Peak" allocator should be used to allocate production capacity. 1 Mo.P.S.C.3rd at 455. They agreed that the "Average Demand" portion should be allocated on "Annual Energy," but disagreed on the "Split Between Average and Peak" and what "Peak Demand" should be used. In that case the Staff advocated use of class peak demands from each of the twelve months in the test year to calculate the peak demand allocator. St. Joseph Light & Power Company and AG Processing, Inc. advocated use of the class contribution to peak demand to calculate the peak demand allocator. The Commission stated:

> The Commission is of the opinion that the class noncoincident peak demands from each of the twelve (12) months (12NCP), with each month weighted according to capacity utilization, should be used as the peak demand allocator. This allocation method accounts for the fact that the amount of PRODUCTION-DEMAND is driven by the need to meet varying peak demand levels throughout the year. By weighting each class's monthly NCP by capacity utilization, the Staff's and Public Counsel's method places greater emphasis on peak months in recognition of the significant impact system peak has upon the peak portion of costs in the PRODUCTION-DEMAND function. The Staff's and Public Counsel's peak demand allocator (12NCP weighted by each month's capacity utilization) assigns responsibility for peak demand costs accurately and minimizes the instability that may result from allocating such costs on the basis of class contribution to: (1) the system peak during the test period as advocated by AGP, or (2) an average of the two system peaks each in 1989 and 1990 as advocated by SJLP.
>
> SJLP argues that Staff's and Public Counsel's method places too much responsibility on the Large Power class and not enough responsibility on the Residential class. SJLP also argues that not enough recognition is given to the system peak demand. SJLP argues that the use of 12 noncoincident demands does not recognize the system maximum peak demand placed on the system by its customers. SJLP also argues that AGP's method give the high load factor customer too high of a recognition for its benefits to the system. SJLP argues that using its method places an equal responsibility for the coincident peak demands and the annual energy requirements. Coincident demand is the classes' demand at the time of system maximum demand.
>
> The Commission is of the opinion that AGP's peak demand allocator is extremely narrow, focusing on one hour from the test year. It is premised on the assumption that the amount of PRODUCTION-DEMAND is determined solely on the basis of the 1990 system peak. SJLP's method places equal weights on the two highest peak demands from both 1989 and 1990. By using a four-period

> average to measure the classes' peak responsibility, SJLP has attempted to minimize the volatility inherent in measuring coincident peak on the basis of a single hour as advocated by AGP, due to the fact that the peak may have been caused by an unpredictable event that is not likely to be repeated. However, the Commission is of the opinion that a 12-month demand allocation method is preferable in that it is based on the principle that a utility installs facilities to maintain a reasonably constant level of reliability throughout the year or that significant variations in monthly peak demands are not present. Under this method, no single peak demand or combination of single peak demands is of any significantly greater magnitude than any of the other monthly peak demands. Thus, the relative importance of each month is considered. Also, the NCP method attempts to give recognition to the maximum demand placed upon a system during the year by all customers. This method is based on the theory that facilities are sized to meet these maximum demands. Therefore, the costs of the facilities are allocated in accordance with each customer's contribution to the sum of the maximum demands of all customers imposed on the facilities. The monthly average NCP demand allocation method attempts to give recognition to the variation or diversity among monthly NCP demands placed on a system during the year by all customers. This in effect recognizes the fact that facilities are installed to provide reliable service throughout the year, including periods of scheduled maintenance. Costs of the facilities are allocated in accordance with each customer's average monthly contribution to the sum of the average monthly maximum demands of all customers. Also, the Commission is of the opinion that capacity utilization places greater emphasis on peak months in recognition of the significance that system peak has upon the peak portion of costs in the PRODUCTION-DEMAND function. This method counteracts the argument of SJLP that not enough recognition is given in the Staff's and Public Counsel's method to system peak demand. While not giving the recognition to system peak demand that SJLP's method gives, Staff's and Public Counsel's method assigns a more appropriate level to system peak demand, in the Commission's opinion.
>
> Staff's and Public Counsel's position for the allocation for the peak demand portion of PRODUCTION-DEMAND costs using class noncoincident peak demands from each of the twelve (12) months (12NCP), with each month weighted according to capacity utilization, is adopted by the Commission.

1 Mo.P.S.C.3rd at 455-57.

Staff's method here is the same method the Commission described in the foregoing case. The contentions of AmerenUE, MIEC and TCG that a peak responsibility method should be followed, rather than following an established norm, are a renewed effort to convince the Commission to adopt an approach the Commission discarded some 25 years ago.

The Commission should reject the proposals of AmerenUE, MIEC and TCG because they, by relying on a peak responsibility method, assume that all generation is added to serve peak load.

F. On what basis should transmission costs be allocated to classes?

Transmission costs should be allocated to the classes in the same manner as the production capacity costs.

G. On what basis should distribution costs be allocated to classes? Should the allocation of primary distribution costs include any customer-related component?

Diversified Demand should be used to allocate the demand-related portion of the distribution system. The length–related portion of the distribution system should be allocated using a density-weighted customer allocator based on the number of customers in each class multiplied by a set of weights that approximately reflect customer density for each class. (Roos Direct, p.12)

H. On what basis should non-fuel generation expenses be allocated?

The allocation of plant-related expenses should use the same method used to allocate the type of plant to which it is related.

I. On what basis?

The revenues from off-system sales should first be offset by the fuel and purchased power costs associated with making those off-system sales to determine the profit or "margin" from off-system sales; then only the margin from off-system sales should be allocated to the customer classes using the production capacity allocator. (Roos Surrebuttal, p. 2)

J. On what basis should credit and collection expenses be allocated?

Staff supports AmerenUE's method for allocating credit and collection expenses to the classes.

RATE DESIGN

How should the Commission implement any revenue change it orders in this case and address proposed revisions to existing tariffs?

Staff believes that any revenue change should be implemented on an equal percentage basis after the appropriate revenue neutral shifts are accomplished as described above. Within each rate schedule, Staff believes that all rate elements should be increased or decreased by the same percentage as the overall increase or decrease.

A. Should the Commission adopt AARP's proposal to recover less of the Company's demand related costs in the summer, and more of the demand related costs in the winter?

No, neither AARP, AmerenUE, nor any other party presented a seasonal cost study to determine the appropriate distribution of costs to the seasons. The current tariffs reflect a summer/winter distribution of demand-related costs based on the most recent such studies. While no real evidence has been presented on this issue in this case, Staff posits that the percentage of demand-related costs presently collected in the summer is much less than either AmerenUE or AARP have proposed. Staff recommends maintaining the present differential by changing each rate component in the summer and each rate component in the winter by the same percentage.

B. Should the Commission adopt the Missouri Association for Social Welfare's proposal to create an "essential service rate"?

No. The Staff objects to offering an initial Essential Service Rate block for Residential customers because it distorts the price of electricity for all customers, while providing only limited assistance to those who need it the most. The most needy customers are those with usage well in excess of the average for low-income customers because they live in poorly insulated housing with inefficient appliances and heating/cooling systems. The bulk of electric utility efforts to help low-income customers have been directed toward programs that actually reduce the cost of providing service to these customers, thus reducing their bills. These programs include weatherizing homes, offering rebates for installing energy efficient appliances, and others. (Watkins Rebuttal, p. 5).

C. Should the Commission adopt AmerenUE's proposal for economic development and retention riders?

The Staff supports AmerenUE's economic development efforts and recommends the Commission approve both of these riders. (Watkins Rebuttal, p. 2).

D. Should AmerenUE have an Industrial Demand Response program? If so, what should be the parameters of that program?

The "pilot" proposed by AmerenUE looks a lot like AmerenUE's old 10(M) Rate that was terminated in Case No. ER-96-15 and again rejected in Case No. EO-2000-580; however, the Staff does not oppose AmerenUE undertaking this limited two-year pilot that requires an evaluation by AmerenUE by November 30, 2009. No more permanent rate schedule or expansion of the pilot should be approved until the evaluation of the pilot has been completed and reviewed by the Commission. (Watkins Rebuttal, p. 3).

E. Does the Large Primary Rate need to be changed? If so, should the Commission adopt AmerenUE's proposal for changes to the Large Primary Service Rate?

The Large Primary Rate should not be changed to include AmerenUE's proposal of a 10% discount for "high" load factor customers. It makes no sense to change the current rate schedule so that a customer which has an 80% load factor pays 10% less than a nearly identical customer with a 79.99% load factor. That is a bad rate design. There should be no big discontinuities in the rate design that allow very small changes in usage to cause very large changes in a customer's bill. It would make more sense to redesign the rate schedule to include hours-of-use energy blocks. (Watkins Rebuttal, p. 3).

The Large Primary Rate should not be changed to include AmerenUE's proposal to require a customer with a demand of 5,000 kW to be billed on the Large Primary Rate. Under this proposal, a customer with a demand of 4,999 kW could pay almost 20% less than a customer with a demand of 5,000 kW with the same load factor and usage characteristics. There should be no big discontinuities in the rate design that allow very small changes in usage to cause very large changes in a customer's bill. (Watkins Rebuttal, p. 4)

F. Does the Large Transmission Service Rate need to be changed? If so, should the Commission adopt AmerenUE's proposal for changes to the Large Transmission Service Rate?

No. None of AmerenUE's proposals should be adopted. Certainly the Annual Contribution Factor should not be eliminated unless the resulting $9 million revenue shortfall is recovered by an equivalent increase in the base rates, prior to any revenue shifts of changes to AmerenUE's revenue requirement. (Watkins Surrebuttal, all)

G. Should the Commission adopt AmerenUE's proposal for changes to miscellaneous tariff provisions?

Only to the extent that they are consistent with Staff witness Mack McDuffey's recommendations as outlined below.

MISCELLANEOUS TARIFF ISSUES

In response to Ameren's tariff filings, Staff witness William McDuffey has identified the following tariff issues for determination:

1. Ameren proposes to change the definition of a residential customer to exclude separately metered usage from service under the Residential Service Rate. The Staff opposes this change as it may have significant impact on customers.

2. Ameren proposes to add a Service Call Charge to apply where a customer reports a service problem, Ameren dispatches a service person, and finds the problem to be in the customer's equipment. The Staff recommends this change be accepted.

3. Ameren proposes to change Rider B and Rider C of its tariff to make them available to customers served at 115,000 kilovolts and 138,000 kilovolts and to reword the delivery and metering conditions. Staff believes these changes will promote better administration and customer understanding of these riders.

4. Ameren proposes to change its cost recovery mechanism for burying its facilities in municipalities where Ameren would use overhead facilities if permitted by the municipality. Ameren would extend the life cycle cost and extend the recovery period from seven to fifteen years. Staff recommends the Commission accept this change and suggests tariff language that includes the total cost of undergrounding.

5. Ameren proposes to change tariff language regarding line extensions to add a Large Lot Subdivision subgroup. The Staff recommends the change when line extensions are made into subdivisions having lots exceeding 100,000 square feet and where the lot frontage exceeds 500 feet or overhead service is longer than a single span or the underground service is longer than 250 feet.

6. Ameren proposes to delete seasonal revenue as an offset to the costs of relocating distribution facilities for non-residential extensions. This has been extremely limited and determining the seasonal revenue to offset has been burdensome. The Staff agrees with this proposal.

7. Ameren proposes to change it guarantee agreements with customers when competing with electric cooperatives and municipals. Ameren proposes to extend the payment

period for lines to new customers from one year to three. Staff recommends the Commission reject this proposal as unduly discriminatory, unless the guarantee agreement payment period is extended to three years for all new customers.

8. Ameren proposes to change its tariff regarding special demand metering equipment by deleting language to eliminate customer confusion. The Staff recommends the deletion.

9. Ameren proposes to change the Multiple Occupancy Building Metering section of its tariff. The Staff recommends this change be rejected as less restrictive than rule 4 CSR 240-20.050(6) and impossible to administer.

10. Ameren proposes changes to the number of billing periods used to make billing adjustments. One change is to extend the period from twelve months to 24 months for meter error. The other is to reduce from 60 to 24 months the period for billing adjustments for improper meter connections, meter constant, rate schedule or similar reasons. The Staff recommends these billing adjustments be accepted.

11. Ameren proposes to impose charges for seasonal disconnection by charging customers a monthly minimum charge for each month a customer is disconnected if fewer than twelve months. Additionally, Ameren would charge a service reconnection charge. At present the monthly minimum charge is $7.25 and the reconnection charge is $30. The Staff opposes these charges for seasonal disconnection.

Ameren does not have a weatherization program in its tariff. Staff witness Lena Mantle addresses this issue in her rebuttal testimony. Staff recommends that the weatherization program be included in Ameren's tariff and that it be funded 50% by the company and 50% by ratepayers.

To conclude, the Staff notes that the implementation of its tariff recommendations will have no effect on Staff's revenue requirement recommendation.

COST OF CAPITAL ISSUES

What return on equity should be used in determining revenue requirement?

One of the most important and most difficult tasks facing the Commission in this and every rate case is determining the cost of common equity, or return on equity (ROE), to be used in calculating the rate of return (ROR) that is intended to compensate AmerenUE's shareholders for the use of their private property committed to the public service. It is said that this "is an area of ratemaking in which agencies welcome expert testimony and yet must often make difficult choices between conflicting testimony."[12] This task is important because each "basis point" is worth approximately $540,000 dollars that Missouri working families and small business owners will have to provide to AmerenUE by paying their electric bills.[13] The task is difficult because it is a matter of expert analysis and the Commission will have to sift through the conflicting opinions of various expert witnesses in seeking a reliable and fair estimate of AmerenUE's ROE. Oddly enough, these experts will look at the same data and, using much the same methods, reach wildly differing conclusions, depending on whether they are testifying for the Company – which naturally desires a high ROE in order to maximize its profits – or testifying for the other parties, most of whom desire a low ROE in order to minimize the electric bills they will have to pay.

An expert witness is a witness that is qualified by "knowledge, skill, experience, training, or education" to assist the tribunal in understanding the evidence or determining a fact in issue.[14] Expert witnesses differ from ordinary witnesses in at least two important respects: first, they

[12] L.S. Goodman, 1 *The Process of Ratemaking,* 606 (1998).

[13] *See* Hill Direct, Sch. 12-2. UE's rate base is approximately $5,400 million dollars, which, when multiplied by one basis point – one hundredth of a percentage point, 0.01 – yields $540,000 dollars.

[14] Section 490.065.1, RSMo 2000.

may testify as to their opinions and, second, they are paid – often very handsomely – to testify.[15] This is an important distinction because it is a crime to pay a non-expert witness for his or her testimony. Given that expert witnesses are hired by the parties to testify in support of the parties' positions, one should naturally take the experts' testimony with a grain of salt. In evaluating the expert testimony in this case regarding AmerenUE's ROE, Staff urges the Commission to be ever mindful of the bias inherent in the testimony of these hired guns. It is worth noting, in this regard, that only the Commission's Staff has no axe to grind.

The Missouri Supreme Court has held that the standard for the admission of expert testimony in administrative contested case proceedings is that set forth in § 490.065, RSMo 2000. *St. Bd. of Registration for the Healing Arts v. McDonagh,* 123 S.W.3d 146, 149 (Mo. banc 2003); *Lasky v. Union Electric Co.*, 936 S.W.2d 797, 802 (Mo. banc 1997). Section 490.065.3, RSMo 2000, provides:

> The facts or data in a particular case upon which an expert bases an opinion or inference may be those perceived by or made known to him at or before the hearing and **must be of a type reasonably relied upon by experts in the field in forming opinions or inferences upon the subject and must be otherwise reasonably reliable**.

(Emphasis added.) Staff directs the Commission's attention to this binding provision because some of the expert testimony offered in this case is not, in fact, "of a type reasonably relied upon by experts in the field" and "otherwise reasonably reliable." In particular, the Company's expert ROE witnesses have knowingly and purposefully manipulated the data by the use of unusual and novel methodologies in order to achieve inflated – if not bloated – ROE estimates. This sort of expert testimony is unreliable and, pursuant to § 490.065.3, RSMo 2000, inadmissible. Staff will

[15] In the recent KCP&L rate case, Case No. ER-2006-0314, expert witness Robert Camfield testified that he had been paid $160,000 for his testimony.

make appropriate objections to this testimony at the proper time.[16]

Staff has presented the expert testimony of Stephen G. Hill, a well-regarded and experienced expert in the field of ROE estimation. Hill, Direct: 1-2 and App. A. Using classic, time-tested methods applied to two comparable groups of utilities, including 15 electric utilities and 10 gas distribution utilities, Hill proposes a range of 9.00% to 9.75% for AmerenUE's ROE, selecting 9.25% as his final recommendation because AmerenUE has more equity in its capital structure than the comparable companies and is thus less risky. Hill, Direct:6-8, 23-24, 27-28. Hill relies primarily on the comparative Discounted Cash Flow (DCF) method, tested against the results of three other methods: the Capital Asset Pricing Model (CAPM), the Modified Earnings-Price Ratio (MEPR) analysis favored by the Federal Energy Regulatory Commission (FERC), and a Market-to-Book (MTB) analysis. Hill, Direct: 25-52 (*passim*). All of these methods yielded results that support Hill's DCF result:

Method	**Electric**	**Gas**
DCF	9.26	9.22
CAPM	9.19-10.62	9.00-10.36
MEPR	8.37-8.60	8.54-8.62
MTB	9.07-9.22	8.87-9.14

In further support of his recommendation, Hill noted that AmerenUE's 10-K for 2005 shows that the Company expects a long-term return of only 8.5 percent on its pension fund portfolio (a mix of equity and debt investments) and that AmerenUE, in a DR response, indicated that a reasonable expectation for a long-term return for common equities ranges from 8.4 to 10.6, midpoint 9.5. Given that that range is for common stocks generally, the expected return on substantially less-risky utility stocks is necessarily lower. Hill, Direct: 6-8. These

[16] This pre-hearing brief is not the place for a detailed critique of the frankly astonishing methodological flaws found in the positions asserted by AmerenUE's hired experts.

considerations also support Hill's ROE estimate.

Because the evaluation of expert ROE testimony is so fraught with difficulty and because the Commission rightly regards this expert testimony with some suspicion, the Commission has adopted in recent years a benchmark referred to as the "zone of reasonableness" against which the recommendations of the experts may be compared. This zone is defined as extending one hundred basis points – one percentage point – above and one hundred basis points below the recent national average of ROE awards in the appropriate regulated industry.[17] Mr. Hill testified that the national average ROE award for electric utilities last year was 10.5%, so the "zone of reasonableness" extends from 9.5% to 11.5%. Hill, Direct: 15. With this benchmark in mind, it is useful to compare the recommendations offered in this case:

Analyst	ROE	ROR
Woolridge (AGO)	9.00	7.308
Hill (Staff)	9.25	7.403
King (OPC)	9.65	7.550
Gorman (MIEC)	9.80	7.700
McShane (UE)	12.00	8.843
Vander Weide (UE)	12.20	8.948
LaConte (MEG)	N/A	N/A
Svanda (UE)	N/A	N/A

It is readily-apparent that the estimates offered by AmerenUE's two expert witnesses, Vander Weide and McShane, are both significantly above the top of the Commission's "zone of reasonableness."[18] Vander Weide's recommendation results in an ROR that is 154 basis points higher than Staff's; McShane's is 144 basis points higher. Those differences are worth $83 million dollars in Vander Weide's case and $77 million dollars in McShane's case.

[17] *See, e.g., In the Matter of The Empire District Electric Company,* Case No. ER-2004-0570 (*Report & Order,* issued Mar. 27, 2005) at 45: "the 'zone of reasonableness' defined by this Commission . . . (within 100 basis points above or below the industry average).

[18] The RORs for McShane and Vander Weide were calculated using Hill's capital structure.

As in any rate case, the ROE determined by the Commission in this case must meet the constitutional parameters established by the United States Supreme Court in two famous cases.[19] In the earlier of these cases, *Bluefield Water Works*, the Court stated that:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[20]

In the same case, the Court provided the following guidance as to the return due to equity owners:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[21]

The Court restated these principles in *Hope Natural Gas Company*, the later of the two cases:

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[22]

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[19] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1943); *Bluefield Water Works & Improv. Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176 (1923).

[20] *Bluefield*, *supra,* 262 U.S. at 690, 43 S.Ct. at 678, 67 L.Ed. at 1181.

[21] *Id.,* 262 U.S. at 692-93, 43 S.Ct. at 679, 67 L.Ed. at 1182-1183.

[22] *Hope Nat. Gas Co.*, *supra,* 320 U.S. at 603, 64 S.Ct. 288, 88 L.Ed. 345 (citations omitted).

In the past, the Commission has stated that:[23]

> The Commission is of the opinion that it must draw primary guidance in the evaluation of the expert testimony from the Supreme Court's *Hope* and *Bluefield* decisions. Pursuant to those decisions, returns for . . . shareholders must be commensurate with returns in other enterprises with corresponding risks. Just and reasonable rates must include revenue sufficient to cover operating expenses, service debt and pay a dividend commensurate with the risk involved. The language of *Hope* and *Bluefield* unmistakably requires a *comparative method*, based on a quantification of risk.

The lesson of *Hope* and *Bluefield* is that it is not investor expectations, but rather the performance of companies of comparable risk and the ability to attract capital that is determinative in selecting an ROE.[24] Stephen Hill's recommended ROE -- 9.25% -- is based upon a comparative study of electric and gas utilities with risk profiles similar to AmerenUE's. Hill, Direct: 25-52 (*passim*). Furthermore, it is sufficient to permit AmerenUE to improve its credit rating and thus improve its ability to attract capital.[25]

WHEREFORE, the Commission's Staff prays that the Commission will accept its position on each contested issue and set just and reasonable rates in this matter as Staff has recommended.

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[23] *In the Matter of The Empire District Electric Company, supra,* 43-44.

[24] *Id.,* at 44-45.

[25] The resulting pre-tax interest coverage ratio is 4.36x. S&P indicates that for a utility with a business position of 5 like AmerenUE, pre-tax interest coverage ratios between 3.5x and 4.3x are sufficient to support an A rating, higher than AmerenUE's present rating of BBB. Hill, Direct: 56-57 *and see* cash flow metrics at Sch. 12-2.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been mailed, hand-delivered, transmitted by facsimile or electronic mail to all counsel of record this **7th day of March, 2007**.

s/ Kevin A. Thompson